



Oil & Gas, Environmental, Regulatory Compliance, and Training

**Review of Alyeska Pipeline Service Company's (APSC's)
2010 American Petroleum Institute Standard No. 653 (API 653)
out-of-service internal and external inspection on
Crude Oil Tank No. 12 (Tank 12).**

Purchase Order 16704

January 22, 2016

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1. Introduction

In 2010, Alyeska Pipeline Service Company (APSC) completed an American Petroleum Institute Standard No. 653 (API 653) out-of-service inspection (internal and external inspection) on Crude Oil Tank No. 12 (Tank 12) to meet regulatory requirements. API 653 inspection methods are used to determine the suitability of a tank structure for continued service, to identify any necessary repairs, and to make sure repairs are completed before the tank is returned to service.

This report was intended to summarize the findings of the 193-page inspection report produced by APSC's API 653 inspector, and compare the inspector's findings to prior in 2000 (out-of-service), 2005 (in-service, external only), and 2015 (in-service, external only). This report was also intended to examine whether the Cathodic Protection System installed under the new tank floor (installed in 2000) has remained operational and protective during the period of 2000 to 2015.

PWSRCAC provided a copy of the year 2000, 2005, 2010, and 2015 inspections, and Cathodic Protection System data from APSC.

The three primary documents reviewed for this report were:

- (1) APSC's Engineering Summary Report, prepared by Hally Cooper, APSC Project Engineer, July 2010 summarizing the July 2010 inspection; and,
- (2) The API 653 Inspector's Report prepared by Thomas Hazlett, Team Peak Alaska, for APSC on November 1, 2010, summarizing the July 2010 inspection.
- (3) Cathodic protection system data for Tank 12 (2005 to 2015).

Additionally, Harvey Consulting, LLC compared the 2010 out-of-service inspection results to the year 2000 out-of-service inspection results, and the 2005 and 2015 in-service inspection results to evaluate corrosion trends and improvements in report content and methods.

A list of findings is provided in Section 2, and a list of recommendations is provided in Section 15 of this report.

2. Executive Summary of Tank 12 Inspection Findings

- 2.1** A new tank floor was installed in year 2000. A maximum floor plate corrosion loss of 18% was measured during the 2010 inspection (soil-side corrosion). Assuming this corrosion rate continues on a linear trend, the 2010 inspector computed a remaining service life of 24 years for the tank.
- 2.2** The 2010 inspection measured minor soil-side corrosion pitting of the annular ring plates including the 3" critical zone of the annular ring plates. The inspector computed corrosion rates of up to 17%.
- 2.3** All annular ring plate measurements taken in 2010 exceeded the minimum required plate thickness of 0.580"; however, the thinnest 2010 inspection measurement (0.675") was higher than the prior year 2000 inspection measurement of 0.615".
- 2.4** Tank 12's shell has very little corrosion. Thickness measurements of the 1st, 2nd, 4th through 7th courses showed less than 5% corrosion since original installation in 1976. Slightly higher corrosion rates were found on the 3rd course (10%) and 8th course (8%). External API 653 (in-service)

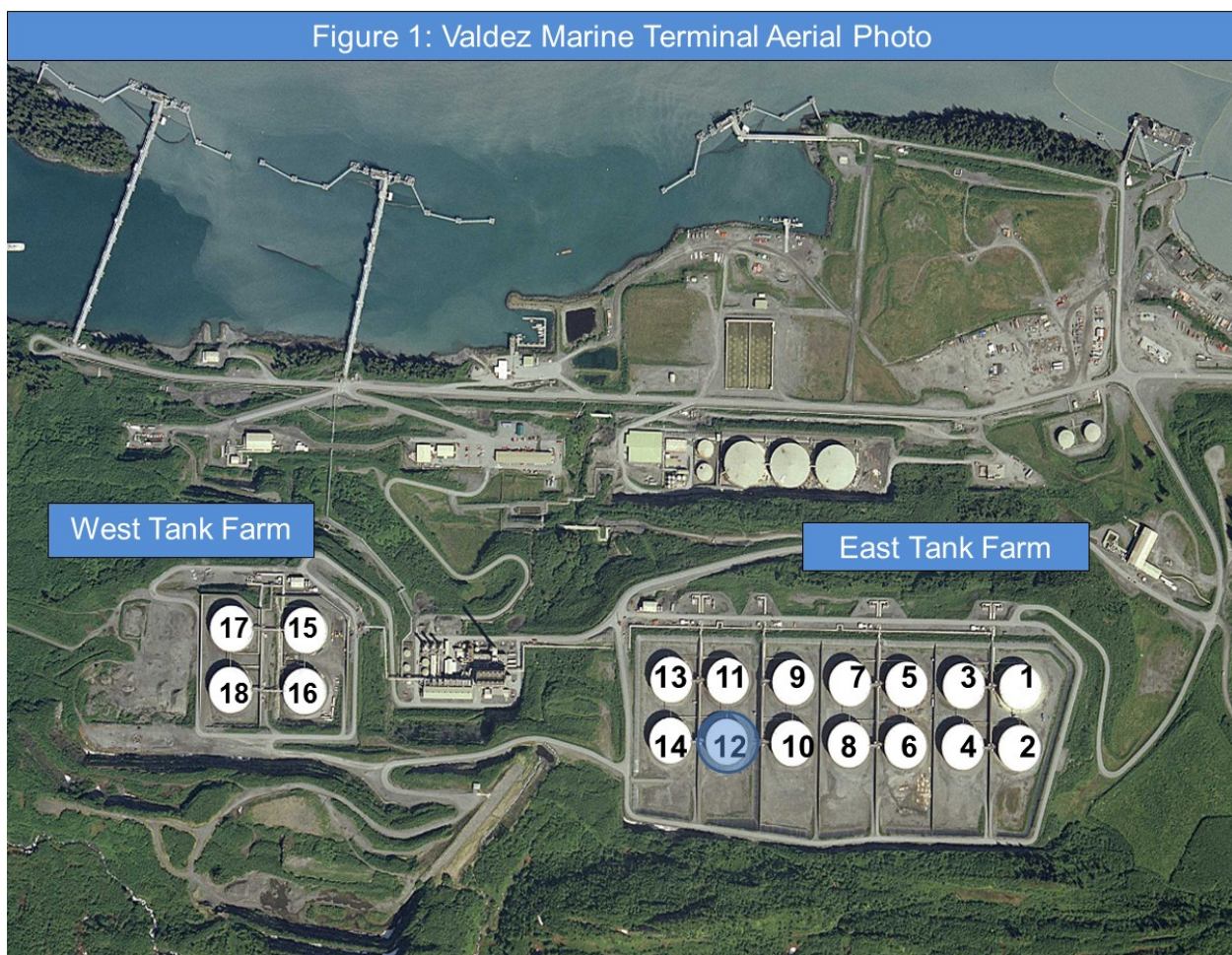
inspections are completed every 5 years. External inspections provide additional data to monitor the tank shell's condition prior to the next scheduled out-of-service API 653 inspection (Year 2030).

- 2.5** Very little of the roof was inspected in 2010. Tank 12's roof area is larger than one acre. Less than 1% of the roof was inspected, and the inspection was limited to six roof plates. The inspector reported a minimum roof plate thickness of 0.313", and a maximum 17% corrosion loss. External roof inspection data from 2005 and 2015 reported thinner roof plate measurements, with the 2015 showing at least one plate with a thickness of 0.280", equating to a remaining life of 12 years.
- 2.6** Fifty-four (54) of Tank 12's 61 internal roof support columns had no corrosion, and seven (7) columns had less than 4% corrosion.
- 2.7** Tank 12 has a concrete ring wall foundation. The inspector found the seal around the bottom of the tank had "*mostly failed*" with vegetation and root systems prevalent in 2010. The seal is used to prevent water from running beneath the tank. Vegetation and root systems can damage the liner and foundation. Neither the 2010 inspection report, nor the APSC Engineer's report that followed in 2010, explained what (if any) repairs were made to the seal around the bottom of the tank. The prior 2005 external inspection also recorded the sealant at the bottom of the tank and the top of the concrete foundation was loose or missing, and the 2015 external inspection identified seal integrity issues.
- 2.8** The 2010 inspection report did not provide information on the amount of sediment found in the tanks, and did not provide sufficient information on the condition of the in-tank firefighting foam distribution piping system. Tank 12 has a history of sediment accumulation impeding the foam distribution piping. In 1999-2001, JPO required Tank 12 to be cleaned of sediment. APSC is required to routinely flush the foam line to ensure it remains free of sediment, and to manually map the amount of sediment found in each tank when the tank is opened for an internal inspection. More information is needed on the condition of Tank 12's foam piping. Information is also needed to better understand whether sediment had accumulated in Tank 12 to a level that interfered with the foam system functionality after ten years of use (from 2000 to 2010). This information is important when considering the next internal inspection interval.
- 2.9** The 2010 inspector recommended Tank 12's next API 653 out-of-service inspection to be completed in 2030, 20 years after the 2010 inspection, based on the estimated remaining service life of the tank floor and annular ring.
- 2.10** Cathodic protection system records for 2005 to 2015 were provided by APSC. Cathodic protection system data for those periods showed the system was operational from 2005 to 2009, and from 2011 to 2015. During these periods the system met National Association of Corrosion Engineers (NACE) Recommended Practice (RP-0193-93) for all points measured, with two exceptions. The cathodic protection system was shut down from April 2010 to December 2010 during the Tank 12 out-of-service inspection and to complete maintenance and repair work within the tank's secondary containment area.
- 2.11** APSC substantially reduced the number of cathodic protection system test points it measured under Tank 12 from 41 test points in 1999-2002 to only nine (9) test points in 2009-2011. In 2010, PWSRCAC raised concern about the reduced number of test points. In 2013 and 2014, APSC resumed the higher testing frequency to 39 test points.

3. Tank 12 Construction and Inspection History

Tank 12 is a crude oil storage tank at the Valdez Marine Terminal (VMT). Tank 12 was built on site at the VMT in 1976. As of this report (year 2015), Tank 12 is 39 years old. Tank 12 is a carbon steel tank with a concrete ring wall and a fixed welded cone roof, and welded shell. Tank 12 is 62'4" tall,¹ and 250' in diameter. If filled full, Tank 12 can hold 547,574 barrels. However, APSC limits the fill level to 58'6". Tank 12's maximum storage capacity at the 58'6" fill level is 510,000 barrels.²

Figure 1 is an aerial photo of the VMT tank farm, showing the East Tank Farm (Tanks 1-14) and the West Tank Farm (Tanks 15-18). Tank 12 is located in the East Tank Farm and is highlighted in blue color for ease of location in this photo.



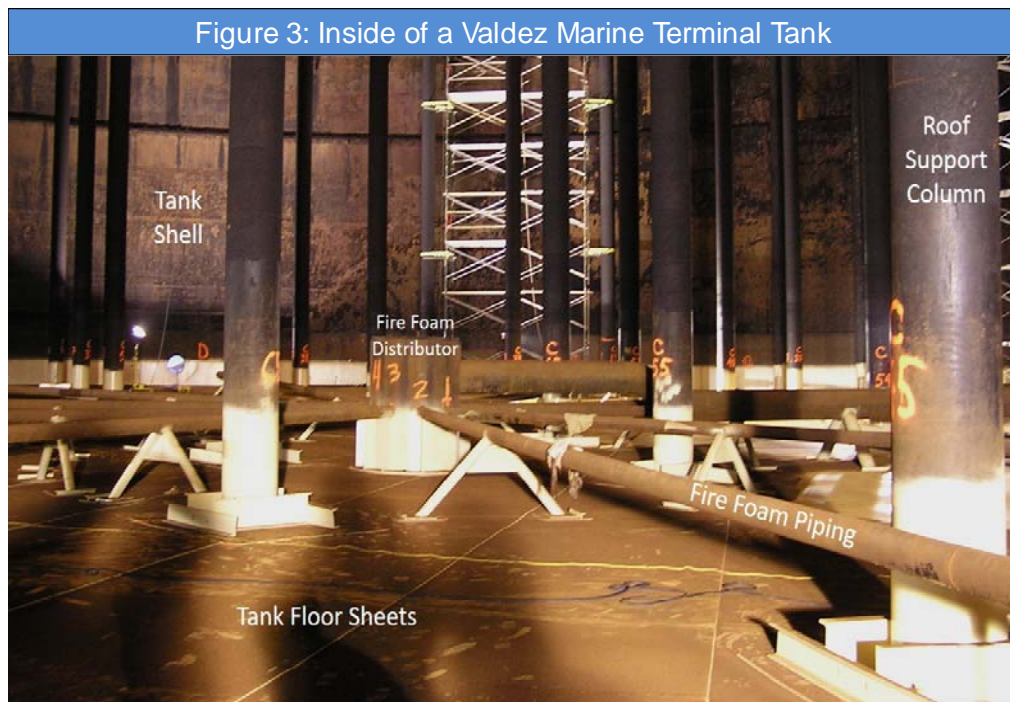
¹ The 2010 API 653 Inspector's report lists the tank height at 62'3" whereas, APSC's VMT C-Plan (November 21, 2014), Page 3-3 lists the tank height at 62'4".

² APSC's VMT C-Plan (November 21, 2014), Page 3-3.

Figure 2 is a photograph of the VMT East Tank Farm. The location of Tank 12 is marked on this photograph. This photograph shows the tank farm is located very close to the Port of Valdez and the marine waters of Prince William Sound.



Figure 3 provides a photograph of the inside of a VMT tank. This photograph was labeled to show the main components of the tank.



In 1999, a Joint Pipeline Office (JPO) Order No. 99-095-JS required APSC to clean and inspect Tank 12 (among a list of other tanks at the VMT) because sediment levels were blocking the subsurface firefighting foam systems. APSC's correspondence to JPO stated that Tank 12 had "*elevated sediment levels*" that exceeded 5' deep.³ Sediment removal was completed in year 2000 when Tank 12 was opened up and cleaned during an out-of-service tank inspection. The JPO Order was closed out March 19, 2001.⁴ However, resolution of this order resulted in a long-term commitment by APSC to monitor sediment levels in Tank 12, to ensure sediment does not obstruct the firefighting foam system piping again in the future.

Tank 12's firefighting foam spider piping is located inside the crude oil tank, on top of the tank floor. The spider piping has ten 6" spider branches extending radially from a center hub. Foam solution flows into the center hub through a 20" foam line and discharges through the spider branches.

Figure 4 is a photo of the inside of a VMT tank showing the location of the fire foam system piping at the bottom of the tank, above the tank floor. This tank was opened for inspection and repair. This photo shows the open end of the fire foam system piping. The open end is 10" in diameter.



In year 2000, APSC attempted to use sonar technology to map the sediment level in the tanks; this was not successful. APSC also attempted Infrared Thermography to examine foam system blockage, from the outside of the crude oil tanks; however, the infrared signal was unable to provide accurate information and was discontinued. Alternatively, cross over piping was added to connect the 36" crude inlet/outlet line to the 20" foam line to allow APSC to divert oil into the foam spider piping to periodically flush it of

³ APSC Government Letter: 00-15522, to JPO, March 8, 2000.

⁴ JPO Letter 01-003-JS, from the JPO to APSC, on March 19, 2011.

sediment.⁵ The 2001 JPO Closeout Report for JPO Order No. 99-095-JS states: “A *Preventive Maintenance Task* has been created for each of the eighteen crude tanks. Every crude tank will be flushed by flowing crude oil through the fire foam system at least once each year. In addition to the annual flushing, the tank could be also flushed if JPO has questions regarding the operability of the foam distribution system and requests that a specific tank be flushed.” Additionally, the 2001 JPO Closeout Report for JPO Order No. 99-095-JS states: “The final APSC process is to provide the JPO with manual mapping of the tank bottoms for crude tanks that are undergoing the tank bottom inspection or floor bottom replacement.”

APSC has not provided PWSRCAC with any tank inspection reports prior to year 2000 for Tank 12; therefore, this report does not include information on the condition of the tank floor prior to year 2000. However, at some point prior to year 2000, APSC determined Tank 12’s floor needed to be replaced, and that work was completed in year 2000.

In year 2000, the original tank floor was replaced and coated with Devoe Bar Rust 236. The shell and columns were coated three feet up from the floor. A foot of clean sand was placed under the new tank floor and a grid anode ribbon cathodic protection system was installed to protect the tank floor from the corrosive effects of the soil. Tank 12 has an impressed current Cathodic Protection (CP) system that uses Mixed Metal Oxide (MMO) ribbon anodes in a grid and perimeter ring orientation under the tank floor. The anodes are buried approximately 9” below the tank on 2’6” center spacing.⁶ Cathodic protection is applied to the steel tank by providing small amounts of direct electrical current to the anodes buried below the tank to blanket the tank bottom with a hydrogen ion film (polarization) to interrupt the corrosion process.⁷

An internal and external out-of-service inspection was completed in 2000. The inspection was completed after the new tank floor was installed, to verify the tank was suitable for return to service.

The year 2000 tank inspection was not completed by an API 653 Inspector and no corrosion rate or retirement data analysis was included, as required by the API 653 standard and ADEC regulations. In 2003, APSC’s Engineer reviewed the 2000 inspection data, completed corrosion rate estimates, and scheduled the next out-of-service inspection for 2010. The fact that the tank inspection was not completed by an API 653 inspector was documented in APSC’s 2003 report.⁸ ADEC’s engineer reviewed APSC’s January 2003 summary report. APSC revised the report in March 2003 to provide roof inspection data and corrosion calculations and to correct cathodic protection system data.⁹

API 653 requires a new tank floor to be inspected within 10 years of installation to verify the corrosion rate; therefore, Tank 12’s inspection was due in 2010. APSC completed the second Tank 12 inspection on time in year 2010. The 2010 inspection is the second API 653 (out-of-service) inspection for Tank 12. The inspector completed the Tank 12 inspection in August 2010, and issued a final report in November 2010.¹⁰

⁵ JPO Letter No. 01-003-JS, Order to Clean and Inspect Tanks, February 12, 2001, Closeout Report by Joe Hughes.

⁶ 2002 TAPS Valdez Marine Terminal Cathodic Protection Survey, WO# 32000354-01, prepared for Alyeska Pipeline Service Company, by Corpro Companies, Inc., December 30, 2002.

⁷ Project L019, 1999 Annual Cathodic Protection Survey of the Valdez Marine Terminal and SERVS Facility, prepared for Alyeska Pipeline Service Company, by Corpro Companies, Inc., January 2000.

⁸ APSC’s X050 TK 12 review, prepared by Kelly Lee, January 16, 2003.

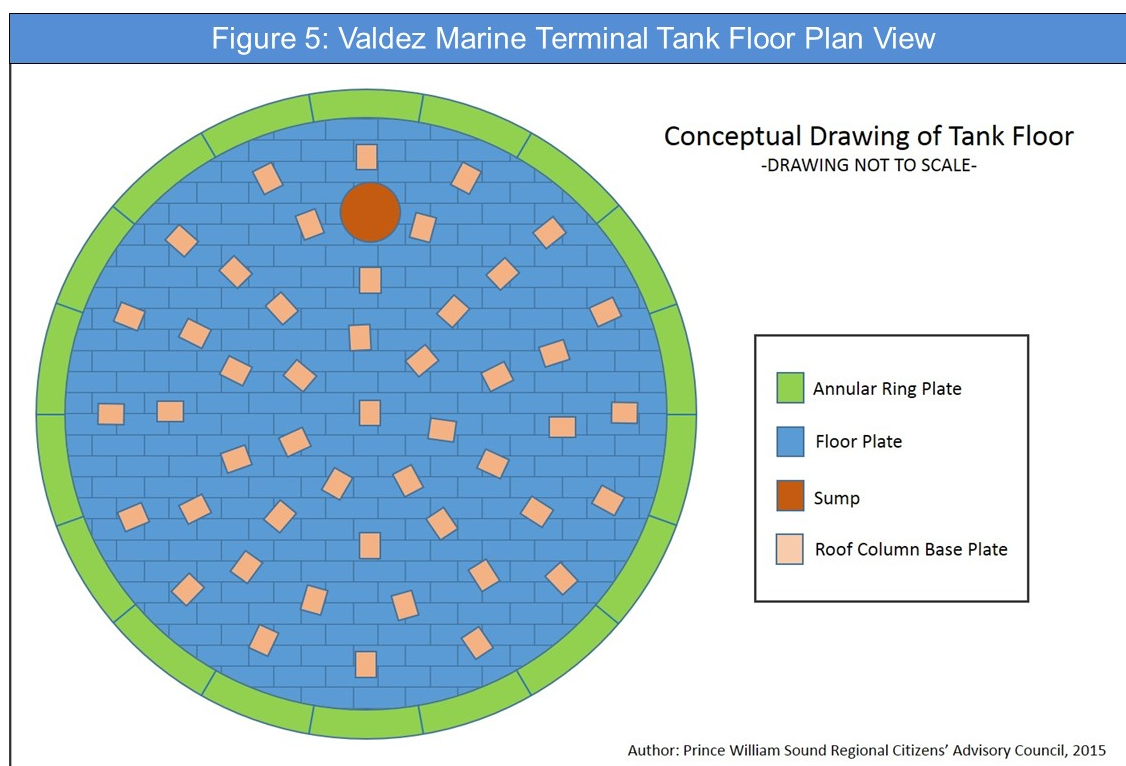
⁹ APSC’s X050 TK 12 review- Rev.1, prepared by Kelly Lee, March 12, 2003.

¹⁰ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection.

APSC requested, and received agency approval for a 20-year interval prior to the next inspection. The third inspection is planned for year 2030, when Tank 12 will be 54 years old.¹¹

4. Floor Inspection

Figure 3 (above) provides a photograph of a VMT Tank interior showing the tank floor plates. The tank floor is made up of numerous thick steel plates that are welded together. This report refers to several important features of a VMT tank, including the floor plates, annular ring plate, sump and roof column base plates. PWSRCAC staff thought it would be useful for PWSRCAC Committee members to have a conceptual drawing of the tank floor (plan view) showing the relative location of these tank components for reference while reading this report (Figure 5 below). Please note this drawing was developed by PWSRCAC staff is not drawn to scale, and does not show the fire foam system piping.



- 4.1 Design Information:** Tank 12's floor, installed in 2000, was made of 0.250" thick welded steel plates. The tank floor was coated with Devoe Bar Rust 236 approximately 0.012" – 0.016" thick.
- 4.2 2010 Inspection Method:** Tank 12's floor was inspected using a Magnetic Flux Leakage (MFL) tool. Manual Ultrasonic Testing (MUT) was also used to verify Magnetic Flux Leakage tool indications during the initial inspection and to inspect any areas that were not accessible to the Magnetic Flux Leakage scanner. A visual inspection of the shell-to-floor weld was completed.

¹¹ APSC's VMT C-Plan (November 21, 2014), Page 3-3 lists the next planned out-of-service inspection for Tank 12 in 2030.

- 4.3 2010 Inspection Results & Repairs:** The 10-year-old internal coating system (installed in year 2000) was found in good condition. A few minor chips exposed the metal substrate. No significant internal corrosion damage was found in the coated area.¹²

The Magnetic Flux Leakage tool and Manual Ultrasonic Testing detected “*minor*” soil-side corrosion pitting of the floor plates.¹³ The 2010 inspector characterized the soil-side floor plate corrosion as “*isolated pitting throughout*”. There was very little internal top-side corrosion found on the floor.¹⁴ Floor plate dents were found on Floor Plates 60, 61, 101 and 182;¹⁵ although remaining plate thickness measurements in the dented areas showed the damaged plates still had sufficient remaining thickness.¹⁶

Bell/Tikigaq J.V. Surveys conducted a tank shell and bottom settlement survey that was found to be within API 653 tolerable limits. This survey was also reviewed by Coffman Engineers.¹⁷

- 4.4 Comparison to Prior Inspection Results:** A new tank floor was installed in year 2000, with a nominal thickness of 0.250”. Some corrosion was found in 2010. A maximum corrosion loss of 0.044” occurred in the ten-year interval between the last inspection in year 2000.
- 4.5 Remaining Service Life Calculation Based on 2010 Inspection Results:** The floor plate thickness of the new tank floor installed in year 2000 was 0.250”. The maximum corrosion depth found during the 2010 inspection was 0.044”. Therefore, the lowest remaining floor thickness was computed to be 0.206” (Floor Plate 17). Using the maximum floor corrosion found since 2000 (0.044”) and the time interval between the date the new floor was installed (year 2000) and the inspection date (year 2010) of 10 years, a corrosion rate of 0.0044” per year was computed. API 653 recommends the minimum tank floor plate thickness for a tank bottom with no means for bottom leak detection of a bottom leak should be at least 0.100” thick.¹⁸ Using the lowest remaining floor thickness measured during the 2010 inspection, in the area with the highest corrosion (0.206”) and ensuring a 0.100” remaining floor thickness by the next inspection, a corrosion allowance of 0.106” was computed.

The 2010 inspector assumed the corrosion rate exhibited from 2000 to 2010 (0.0044” per year) would remain linear, with no future acceleration.¹⁹ Based on this assumption, the API 653 inspector computed a remaining service life of 24 years.²⁰

¹² Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 9.

¹³ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Pages 9-10.

¹⁴ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Pages 14 and 17.

¹⁵ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 112.

¹⁶ Remaining thickness was 0.24”. The original plate thickness was 0.25”.

¹⁷ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 10.

¹⁸ API 653 Standard, Chapter 6.

¹⁹ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 9.

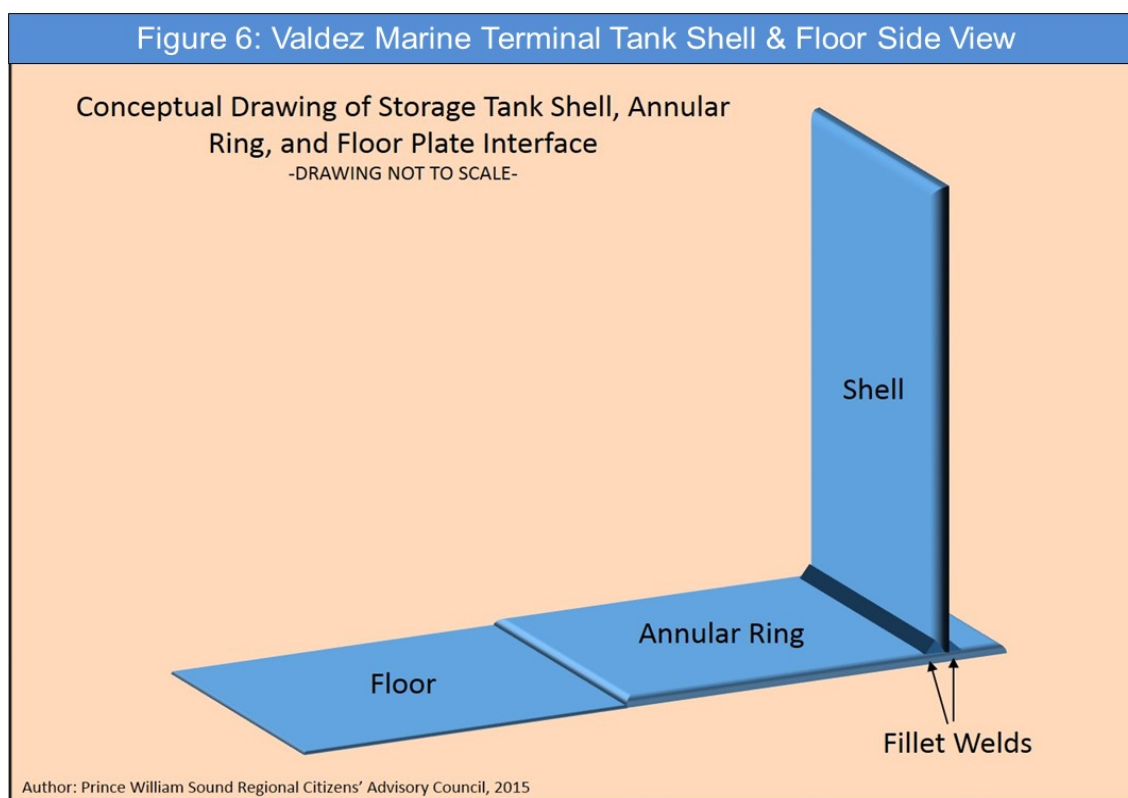
²⁰ 24 years= (0.106” corrosion allowance/ 0.0044” corrosion rate per year).

4.6 Floor Summary: A summary of the floor design and inspection data is shown in the table below.

Tank 12 Floor Design and Inspection Data	Inspection Year	Measured Thickness
New floor installed	2000	0.250"
MFE and MUT Inspection Data	2010	0.206"
Minimum required thickness for a tank with no leak detection below the tank floor (API 653)		0.100"

5. Annular Ring Plate Inspection

PWSRCAC staff thought it would be useful for PWSRCAC Committee members to have a simplified drawing showing the relationship of the tank shell to the tank floor and annular ring for reference while reading this report (Figure 6 below). Please note this drawing was developed by PWSRCAC staff and is not drawn to scale.



5.1 Design Information: The annular ring (that connects the tank floor to the tank shell) is made up of 0.8125" thick (13/16") welded steel plates. The ring is 6' wide. The tank floor and exposed section of the annular ring was coated with Devoe Bar Rust 236 approximately 0.012" – 0.016" thick.

API 653 recommends the minimum annular ring thickness for tanks (like Tank 12) that use thickened annular plates for seismic considerations, be established by a seismic engineering

evaluation, using the actual thickness of the existing annular plate.²¹ The 2010 APSC engineering report of the 2010 inspection, states “A *finite element analysis (FEA)* was completed by APSC to determine the minimum allowable continuous and isolated annular plate thickness. This analysis took into account all seismic and structural factors. The FEA analysis provides the minimum nominal thickness the annular plate must maintain, from a structural strength stand point, to ensure the integrity of the tank. The FEA concluded that the minimum continuous annular plate thickness allowable for this tank is 0.580”. It was also determined that an isolated pit on the annular ring does not affect the structural or seismic integrity of the tanks.” It is important for PWSRCAC to obtain a copy of APSC’s finite element analysis for review by PWSRCAC’s seismic expert to ensure the 0.580” is based on conservative assumptions.

5.2 2010 Inspection Method: Tank 12’s annular ring plates were inspected using an Electromagnetic Acoustic Transmission (EMAT) system and Manual Ultrasonic Testing (MUT).²² The critical zone of the annular ring (the 3” section of annular plate adjacent to the tank shell, measured from the inside edge of the shell radially inward) that is inaccessible to EMAT was inspected using MUT. The annular plate-to-shell weld was visually inspected.

5.3 2010 Inspection Results & Repairs. The inspection measured minor soil-side corrosion pitting of the annular ring plates including the 3” critical zone of the annular ring plates. The inspector computed corrosion rates up to 17% maximum at a remaining thickness of 0.675” from the original 0.8125” plate thickness.²³ The external annular ring was tested using Manual Ultrasound Testing; the inspector did not find significant external corrosion.²⁴ There was top-side mechanical damage on Annular Plate A-20 that required repair. The inspector thought this damage occurred during the floor installation in year 2000. Three top-side pitting locations on Annular Plate A-12 required repair.²⁵

5.4 Comparison to Prior Inspection Results: API 653 Section 6 requires an inspection history to be maintained on the tank, including corrosion rate and inspection interval calculations. The prior internal inspections in year 2000 measured annular ring corrosion that exceeded the measurements reported in 2010. The prior annular ring inspection data was not addressed in the 2010 inspector’s report and compared with the data collected in 2010. It is possible the 2010 inspector found the 2010 measurements to be more accurate (using EMAT followed by MUT instead of Automated Ultrasonic Testing (AUT) previously used), discounting the data collected in year 2000. However, it would have been useful for the 2010 inspection report to acknowledge prior measurements of the most significant corrosion found in prior inspections, explain what work was done to more thoroughly investigate those areas, and explain why the new, 2010 thicker measurements were more accurate, invalidating the prior data sets (if that was the case).

In year 2000, Manual and Automated Ultrasonic Testing was used to examine 100% of the exposed surface of the annular plate ring. Thirty 12” x 12” scans were completed on random annular ring plates. The 2000 inspection showed corrosion on the annular ring plates with the most significant corrosion on plates A13 (remaining thickness 0.615”) and A21 (remaining thickness 0.625”).²⁶

²¹ API 653 Standard, Chapter 4, Minimum Thickness for Annular Plate Ring.

²² Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 19.

²³ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 10.

²⁴ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 33.

²⁵ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Pages 19-23.

²⁶ APSC’s X050 TK 12 review, prepared by Kelly Lee, January 16, 2003, Page 3.

APSC's 2003 Engineering Report, summarizing the 2000 inspection also confirms the thinnest annular plate was A13 with a remaining thickness of 0.615."²⁷

The year 2010 inspection recorded a remaining plate thickness for plates A13 (0.766") and A21 (0.805") that exceed the year 2000 measurements.²⁸ The 2010 inspection report did not explain why the year 2000 and 2010 measurements differed.

5.5 Remaining Service Life Calculation: The annular ring plate thickness of the ring plates installed in 1976 was 0.8125". The 2010 inspection reported a maximum corrosion depth of 0.1375". The inspector's report stated this was an isolated, soil-sided corrosion pit, where the remaining plate thickness was measured at 0.675", and the nearby plate thickness was measured at 0.8125". A remaining plate thickness of 0.675" equates to a 17% corrosion loss since the tank was installed in 1976.

Using the maximum annular ring plate corrosion found since 1976 (0.1375") and the time interval between the date the ring plates were installed (1976) and the inspection date (2010) of 36 years, a corrosion rate of 0.0040" per year was computed. Using the lowest remaining annular ring plate thickness during the 2010 inspection, in the area with the highest corrosion (0.675") and ensuring a 0.580" remaining plate thickness by the next inspection, a corrosion allowance of 0.095" was computed. If one assumes the corrosion rate exhibited from 1976 to 2010 (0.00404" per year) would remain linear in the future, a 23.5 year remaining life can be estimated (0.095" corrosion allowance/ 0.00404" corrosion rate per year). However, if the year 2000 corrosion data was used to compute the remaining service life it would be substantially shorter. Therefore, it is important for APSC to be sure the year 2000 data was invalidated by the new data collected in 2010 and explain why a shorter, more conservative remaining service life should not be used.

The 2010 APSC engineering report, of the 2010 Tank 12 inspection, computed a remaining life of 27.8 years for the annular plate using a minimum allowable thickness of 0.58" and a minimum measured plate thickness of 0.700". The 0.700" minimum plate thickness was based on data obtained by Spectrum Sales & Service LLC that completed an additional annular plate test.²⁹

The 2010 API 653 Inspectors Report lists the lowest remaining annular plate thickness of 0.675" (Annular Plate A-19), not 0.700"; therefore, this report uses the more conservative number of 0.675".³⁰ If the more conservative year 2010 inspection data (0.675") is used, a 23.5 year remaining life is computed rather than 27.8 years.

²⁷ APSC's X050 TK 12 review, prepared by Kelly Lee, January 16, 2003, Page 1.

²⁸ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 101.

²⁹ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 181.

³⁰ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 10 and Page 105.

- 5.6 Annular Ring Plate Summary:** A summary of the annular ring plate design and inspection data is shown in the table below.

Tank 12 Annular Ring Plate Design and Inspection Data	Inspection Year	Measured Thickness
Annular Plate Installed	1976	0.8125"
AUT Inspection Data (general plate corrosion)	2000	0.6150"
EMAT and MUT Inspection Data (isolated pit)	2010	0.6750"
Minimum required thickness for a tank operating in a seismically active zone per APSC Spec. X058-T-500 (API 653)		0.5800"

6. Shell Inspection

- 6.1 Design Information:** The original design criteria for Tank 12 included a tank shell thickness that varies with height. The tank was constructed with eight tank shell courses: the 1st course at the bottom, and the 8th course at the top. The original thickness of the 1st course was 1.121" thick, 2nd course (0.969"), 3rd course (0.832"), 4th course (0.699"), 5th course (0.569"), and 6th to 8th courses (0.5"). All courses included a 0.125" corrosion allowance in the design.³¹

In year 2000, the tank shell was coated with Devoe Bar Rust 236 approximately 0.012" – 0.016" thick three feet up from the floor. The water draw valve was also coated.

- 6.2 2010 Inspection Method:** A limited area of Tank 12's 8th shell course (6.8 sq. ft) was scanned using an Automated Ultrasonic Testing system.³² Manual Ultrasonic Testing was used to inspect Tank 12's shell courses 2-7 and the shell nozzles. There were nine (9) readings on each plate of the first shell course; three (3) readings on one plate of the 2nd to 7th shell course; four (4) readings on each shell nozzle and each roof nozzle, and four (4) readings on each support column.³³
- 6.3 2010 Inspection Results & Repairs:** The inspector measured no corrosion on the 1st, 3rd, and 6th shell courses, 1% corrosion on the 2nd, 5th and 8th shell courses, 2% corrosion on the 7th shell course.³⁴

The inspector provided tables listing the shell nozzle, roof nozzle, and support column inspection data; however, the inspector did not provide information on the original design thickness, and did not make conclusions about whether the corrosion loss measured in the 2010 inspection was

³¹ The API 653 standard, *Minimum Thickness Calculation for Welded Tank Shell*, does not apply to tank diameters in excess of 200'. Tank 12's diameter is 250'. Therefore, the original design criteria for this tank must be used. API 653, *Tank Shell Evaluation*, requires corrosion greater than the original design allowance to be evaluated by an engineer to determine suitability for continued service if the corrosion might adversely affect the performance or structural integrity of the tank shell. API 653 requires "any thinning of the tank shell below minimum required wall thickness due to corrosion or other wastage may be evaluated to determine the adequacy for continued service by employing the design by analysis methods defined in Section VIII, Division 2, Appendix 4 of the ASME Code."

³² Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 25.

³³ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Pages 28-29.

³⁴ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Pages 24 and 25.

acceptable.

Bell/Tikigaq J.V. Surveys conducted a tank shell and bottom settlement survey that was found to be within API 653 tolerable limits. This survey was also reviewed by Coffman Engineers. The Bell/Tikigaq J.V. Surveys found “...no obvious peaking, banding or out-of-roundness of the tank shell”.³⁵

6.4 Comparison to Prior Inspection Results: Prior inspections measured minimum remaining shell thickness in 2000 (internal), 2005 (external)³⁶ and 2015 (external)³⁷. The year 2000 internal inspection obtained ultrasonic measurements on all (18) plates that make up the 1st course of the tank shell. Ultrasonic inspection of the 2nd through 8th courses was completed from the tank staircase. Thickness measurements of the 1st through 7th courses exceeded the original design nominal thickness. Corrosion was found on the 8th course where the shell plate thickness had minor corrosion, reducing the thickness from the original 0.500” to 0.494”. The 2005 external inspection had thinner shell measurements for courses 1, 4, 5, 6, and 7 than the 2015 external inspection. The table shown below highlights the thinnest shell measurement in bold red font for each shell course. The remaining service life was computed using the lowest, most conservative shell thickness measurement. All measurements predict a remaining service life of at least 20 years.

Course No.	Design Thickness (inches)	Corrosion Allowance (inches)	Minimum Allowable Thickness (inches)	2000 Internal Inspection, Lowest Remaining Thickness (inches)	2005 External Inspection, Lowest Remaining Thickness (inches)	2010 Internal Inspection, Lowest Remaining Thickness (inches)	2015 External Inspection, Lowest Remaining Thickness (inches)	Corrosion Loss (%) since 1976*	Corrosion Loss (mpy) since 1976**	Remaining Service Life** (years)
8	0.500	0.125	0.375	0.477	0.474	0.494	0.458	8%	0.0011	>20
7	0.500	0.125	0.375	> 0.500	0.476	0.490	0.487	5%	0.0006	>20
6	0.500	0.125	0.375	> 0.500	0.485	> 0.500	> 0.500	3%	0.0004	>20
5	0.569	0.125	0.444	> 0.569	0.550	0.565	> 0.569	3%	0.0005	>20
4	0.699	0.125	0.574	> 0.699	0.677	0.687	0.707	3%	0.0006	>20
3	0.832	0.125	0.707	> 0.832	> 0.832	> 0.832	0.751	10%	0.0021	>20
2	0.969	0.125	0.844	> 0.969	> 0.969	0.959	> 0.969	1%	0.0003	>20
1	1.121	0.125	0.996	> 1.121	1.070	> 1.121	> 1.121	5%	0.0013	>20
*Corrosion loss was computed using the thinnest shell plate measurement since 1976.										
**Remaining service life was estimated using the highest corrosion rate for each course.										

6.5 Remaining Service Life Calculation: The API 653 Standard “next inspection interval computation” does not take into account the condition of the tank shell, and is based only on the tank floor and annular ring condition. APSC recommended the next out-of-service inspection interval to be 20 years (2030).

However API 653 does recommend that in addition to completing the standard “next inspection interval computation” (based solely on the remaining floor and annular plate thickness), that the inspector also consider several other factors when setting the tank inspection interval, such as: “(a) the nature of product stored, (b) The results of visual maintenance checks, (c) Corrosion allowances and corrosion rates, (d) corrosion prevention systems, (e) conditions at previous inspections, (f) the methods and materials of construction and repair, (g) the location of the tanks, such as those in isolated or high risk areas, (h) The potential risk of air or water pollution, (i) leak

³⁵ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12’s August 2010 inspection, Page 10.

³⁶ 2005 External, In-service Inspection Report for Tank 12, Pages 6-7.

³⁷ 2015 External, In-service Inspection Report for Tank 12, Pages 6 and 12.

detection systems, (j) change in operating mode, (k) jurisdictional requirements, (l) changes in service (including changes in water bottoms), (m) the existence of a double bottom or a release prevention barrier.

Therefore, it is prudent to also consider the condition of the tank shell and roof, especially for tanks operating vapor recovery systems, located in a seismically active area, and in an environment of heavy snow/ice loading.

Based on the data collected in the year 2000 to 2015 inspections, the remaining service life of the shell is estimated at more than 20 years. Because Tank 12 operates a vapor recovery system, and corrosive vapors may exist toward the top of the tank, the corrosion rate may accelerate in future years. External API 653 inspections are completed on Tank 12 every five years. External tank inspections provide additional, more frequent measurements to monitor the tank shell condition.

In the past, three readings have been taken on each shell course (at different heights on one shell plate). This is a very low number of measurements for a tank that is 250' in diameter. As the tank ages, it would be beneficial to consider collecting additional measurement locations on each shell course during the 5-Year API 653 external inspections (especially those showing increasing corrosion), particularly for tanks that will not receive their next out-of-service inspection for 20 years. This approach would provide additional data and improve confidence in the statistical significance of the data set.

7. Roof Inspection

7.1 Design Information: Tank 12's roof was originally made of 0.375" thick, welded steel plates, placed over structural steel rafters. Tank 12 is 250' in diameter, with a cone shape roof made of over 49,000 ft² of welded steel plates.³⁸ The roof area is over an acre in size.

There are two standards to consider when evaluating whether to repair or replace a tank roof: (1) the original design criteria that takes into account heavy snow loads, and (2) the substantially less conservative minimum roof thickness allowed by API 653 standard. The roof plates were originally designed at 0.375" thick, including a 0.125" corrosion allowance. Roof thicknesses measured at or above 0.250" exceed the original design tolerance. The API 653 Standard requires repair or replacement of roof plates with any holes through the roof plate or corrosion to an average thickness of less than 0.090" in any 100 inch squared (in²) area.

Tank 12 has vapor control installed. Roof integrity is important for proper function and safety of this system. The roof was designed to hold the Valdez Alaska snow load. The API 653 standard (of 0.090" in any 100 inch squared (in²) area) does not take into account Tank 12's snow loading design requirement or vapor recovery system operation requirements. For this reason, APSC's design thickness of 0.375", with a 0.125" corrosion tolerance, requiring the minimum roof plate thickness to be 0.250" thick or greater should be used. The 0.250" minimum threshold takes into account both the need for a sealed roof with no through holes and the need for a strong roof capable of supporting snow, provided snow removal is done on a periodic basis.

³⁸ 49,000 sq. ft. is based on a simple calculation of the area would be covered by a flat roof on top of a 250' diameter tank. Tank 12 has a conical shape roof, which increases this area above the 49,000 sq. ft. amount. The 49,000 sq. ft. estimate was used as a conservative estimate.

- 7.2 2010 Inspection Method:** A limited area of Tank 12's roof was inspected using the Automated Ultrasonic Testing (AUT) system. The exact square footage tested was not listed in the report; however, it appears from the limited number of plates inspected (six plates) that the area was less than 1% of the roof. Sixteen (16) measurements were made on six roof plates.
- 7.3 2010 Inspection Results & Repairs:** The thinnest roof plate was measured at 0.313" thick (Roof Plate 110),³⁹ equating to a 17% corrosion rate.
- 7.4 Comparison to Prior Inspection Results:** The 2000 internal inspection showed the Roof Plate 26 had the highest corrosion measured at 0.315" remaining thickness. No measurement was taken on Roof Plate 26 in the 2010 inspection. The thinnest roof plates from the prior inspection should be known to the inspector, and measured in the next inspection.

The 2005 external inspection showed the highest corrosion measured at 0.302" remaining thickness.⁴⁰

The 2015 external inspection showed the highest corrosion measured at 0.280" remaining thickness.⁴¹

- 7.5 Remaining Service Life Calculation:** The API 653 Standard does not take into account the condition of the tank roof in its recommended next inspection interval calculation. Therefore, the API 653 inspector's 2010 tank inspection report only computes the remaining service life of the tank floor and annular ring. Based on those computations, the inspector makes a recommendation for the date of the next inspection interval. In the case of the 2010 inspection, the inspector recommended the next inspection interval to be 20 years (2030).

It is prudent to also consider the condition of the tank shell and roof, especially for tanks operating vapor recovery systems, located in a seismically active area, and in an environment of heavy snow/ice loading.

Based on the data collected during the year 2000 through 2015 inspections, the thinnest roof section was found during the 2015 inspection (0.280"). Using that measurement and APSC original design standard of 0.25" minimum roof plate thickness based on an original plate thickness of 0.375" (installed in 1976) and a 0.125" corrosion allowance, the remaining service life of the roof is estimated at 12 years.

- 7.6 Roof Summary:** A summary of Tank 12's roof design and inspection data is shown in the following table.

³⁹ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 32.

⁴⁰ 2005 External, In-service Inspection Report for Tank 12, Page 9.

⁴¹ 2015 External, In-service Inspection Report for Tank 12, Page 10.

Tank 12 Roof Design and Inspection Data	Inspection Year	Measured Thickness
Roof Installed	1976	0.375"
AUT Inspection Data	2000	0.315"
AUT Inspection Data	2005	0.302"
AUT Inspection Data	2010	0.313"
AUT Inspection Data	2015	0.280"
Minimum required thickness for Tank 12's roof considering Valdez snow loading		0.250"

8. Roof Support Column Inspection

- 8.1 Design Information:** Tank 12's roof support column design includes 61, 24-inch diameter columns. The column design is made of 0.50" thick nominal members. The Tank 12 reports do not specify the minimum thickness for roof support members (corrosion allowance) to ensure adequate support to the roof during heavy snow loads; this value should be listed in the reports and known to the inspector.
- 8.2 2010 Inspection Method:** Spot Manual Ultrasonic Testing was used to examine each of the columns, with four (4) readings taken on each column on the north, south, east, and west faces. A visual inspection of the support column bases was completed by the inspectors. Accessible areas of under support columns, near the areas that were re-padded, were inspected using Manual Ultrasonic Testing.
- 8.3 2010 Inspection Results and Repairs:** The 2010 inspection found no significant corrosion or damage to the support columns and the structure to be in good condition.⁴² The column thickness measurement (without coating) exceeded 0.500" for 54 of 61 columns, with only seven (7) columns that had readings of less than 4% corrosion loss.
- 8.4 Comparison to Prior Inspection Results:** The 2010 support column inspection was more comprehensive than the 2000 inspection. The 2010 inspection included all 61 columns. The year 2000 inspection only included 1/6th of the columns (10 columns). The data from the 10 columns inspected in 2000 was compared to the 2010 data for those same columns. In general, the trend over that 10-year interval showed some increasing corrosion.

9. Fire Foam System Inspection

- 9.1 Design Information:** Tank 12 has a 20" fire foam system piping network installed inside the tank at the bottom. Tank 12's firefighting foam spider piping is located inside the crude oil tank, on top of the tank floor. The spider piping has ten 6" spider branches extending radially from a center hub. Foam solution flows into the center hub through a 20" foam line and discharges through the spider branches.

⁴² Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Pages 29-31.

9.2 2010 Inspection Method: The 20" fire foam line shell nozzle was inspected using UT.⁴³ Some of the APSC tank inspections have used Manual Ultrasonic Testing to inspect the 20" fire foam piping inside the tank at random 1' locations along the pipe; however, this does not appear to have been done for Tank 12 in 2010.

9.3 2010 Inspection Results and Repairs: The inspector listed the UT data for the 20" fire foam line at the shell (0.427" minimum remaining thickness) but did not provide original design thickness for comparison. The inspector did not provide any data on the condition of the rest of the 20" fire foam piping inside the tank.

The 2010 inspection report stated "*the cleaning crew found only a fraction of the normally expected sludge build-up, which helped expedite the inspection schedule*".⁴⁴ No specific information was provided on the depth of sediment, at various points across the 250' diameter floor, or whether it covered the fire foam system piping.

9.4 Comparison to Prior Inspection Results: As explained above in Section 3, a 1999 JPO Order required APSC to cleanout sediment that had accumulated in Tank 12 and was obstructing the foam piping system. To close out the JPO order in year 2001, APSC made a long-term commitment to monitor sediment levels in Tank 12, to ensure sediment does not obstruct the firefighting foam system piping again in the future. APSC agreed to provide JPO with manual mapping of the tank bottom sediment depth at the next out-of-service inspection. The 2010 tank inspection report does not provide a map of the tank sediment depth across the 250' diameter tank floor, and is unclear about whether the foam piping had any sediment obstruction.

10. Sump Inspection

10.1 Design Information: Tank 12 has one sump located around and beneath the diffuser.

10.2 2010 Inspection Method: A one foot (1') wide circumferential band of the sump floor and 20% of each plate of the sump wall was inspected using Manual Ultrasonic Testing.⁴⁵

10.3 2010 Inspection Results & Repairs: The sump floor plates and wall plates were in good condition with no top or soil side corrosion. Three of the four diffuser wear plates were replaced because of mechanical wear.⁴⁶

10.4 Comparison to Prior Inspection Results: The prior 2000 internal inspection report prepared by APSC did not contain information on the sump condition.

11. Suction/Fill Line Inspection

11.1 Design Information: Tank 12 has a 36" Suction/Fill Line.

⁴³ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Pages 29.

⁴⁴ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 9.

⁴⁵ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 14 and Page 110.

⁴⁶ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 11.

11.2 2010 Inspection Method: The inspector collected UT data on the suction/fill line at the shell only.

11.3 2010 Inspection Results & Repairs: The inspector listed the UT data for the 36" Suction/Fill Line at the shell (0.619" minimum remaining thickness) but did not provide original design thickness for comparison. The inspector did not provide any data on the condition of the 36" Suction/Fill Line inside the tank.⁴⁷

11.4 Comparison to Prior Inspection Results: The prior 2000 internal inspection report prepared by APSC did not contain information on the suction/fill line condition.

12. Foundation Inspection

Tank 12's foundation is a concrete ring wall. A visual inspection of the foundation was completed. The 2010 API 653 inspector found the seal around the bottom of the tank had "*mostly failed*" with vegetation and "*considerable*" root systems prevalent.⁴⁸ The seal is used to prevent water from running beneath the tank. Vegetation and root systems can damage the liner and foundation. The API 653 inspection report did not state what, if any repairs were made to the seal around the bottom of the tank. The 2010 APSC Engineer's Report of the 2010 inspection was silent on the foundation inspection findings and any repairs, if any.

The 2005 external, in-service inspection report found the sealant at the bottom of the tank and top of the concrete foundation was loose or cracked at various locations.⁴⁹

The 2015 external, in-service inspection report found cracked areas of the tank sealing membrane between the exterior chime and the concrete slab.⁵⁰

13. New Stair Design

The 2010 inspector's report noted that: "*A new stair design has been implemented for all of the VMT Oil Storage Tanks because of continued damage from falling snow and ice. The original stairs wrapping around the tanks have been replaced with roof-access stairs from the center platforms.*"⁵¹

14. Cathodic Protection (CP) System

In year 2000, a cathodic protection system was installed under Tank 12 and a new tank floor was installed. Tank 12's floor was replaced due to significant soil side corrosion that occurred during the period of 1976 (original tank installation date) to 2000 when the tank was not protected by a cathodic protection system.

⁴⁷ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 29.

⁴⁸ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 33.

⁴⁹ 2005 External, In-service Inspection Report for Tank 12, Page 1.

⁵⁰ 2015 External, In-service Inspection Report for Tank 12, Page 1.

⁵¹ Team Peak Alaska Report, prepared for APSC November 2010, on Tank 12's August 2010 inspection, Page 34.

Steel tanks (like Tank 12) can corrode when a natural electrochemical reaction occurs between the tank and the surrounding soil. Steel naturally reacts with water (contained in the soil) and oxygen to convert the steel alloy to its more stable chemical state (iron oxide; more commonly called “rust”). Cathodic protection systems interrupt this natural reaction, to eliminate (or slow) the reaction process.

Several types of cathodic protection can be used to mitigate tank corrosion. Tank 12 has an impressed current cathodic protection system that provides direct current to the tank to interrupt the natural electrochemical reaction.

The corrosion process includes four components: (1) an anode, (2) a cathode, (3) a metallic path connecting the anode and cathode, and (4) an electrolyte. For corrosion to occur, areas with different electrical potentials (anodes and cathodes) must be present on a tank’s surface. Corrosion occurs at the anode. At an anode location on the tank, the tank’s metal goes into solution (corrodes) by releasing electrons and forming positive metal ions. The anode has a lower electronegative potential than the cathode. Current flows from the anode to the cathode to complete the corrosion reaction. At a cathode location on the tank, a chemical reaction takes place that uses the electrons released at the anode. No corrosion takes place at a cathode. Because steel is not homogeneous, (it is made of various alloys and may be welded with metals that slightly vary from alloys in the tank floor plates) there are differences in the electrical potential from one area to another along the tank. Therefore, the same piece of steel can provide both the anode and the cathode. The metallic path provides a way for electrons released at the anode to flow to the cathode completing the reaction circuit. Since steel conducts electricity, adjacent cathodic and anodic areas on a steel plate have a metallic path. The last component needed for a corrosion reaction is the electrolyte. The electrolyte is a conductive environment (e.g., wet soil or water) that supplies the reactants necessary for corrosion to occur. Snow, rain, and water draining down the mountainside behind the tank farm provide wet soil beneath Tank 12 providing the electrolyte needed for the corrosion reaction. Water and sludge inside the tank also provide an electrolyte.

In the simplest type of cathodic protection a sacrificial anode is installed on a metal surface (e.g., a zinc anode installed in a marine engine) to ensure corrosion occurs on a sacrificial metal plate that can be periodically replaced. Impressed current cathodic protection systems are used to reverse the natural electrochemical reaction on larger steel surfaces like Tank 12.

An impressed current system prevents tank floor corrosion by converting all of the anodic (active) sites on the tank floor to cathodic (passive) sites by supplying electrical current to another buried impressed current anode (separate from the tank), installed below the tank. Tank 12’s impressed current cathodic protection system uses Mixed Metal Oxide (MMO) ribbon anodes in a grid and perimeter ring orientation under the tank floor. The anodes are buried approximately 9” below the tank both on 2’6” center spacing.⁵²

An impressed current system uses a rectifier to convert alternating current (AC) (provided by the VMT power system) to direct current (DC). The rectifier supplies power to Tank 12’s anode grid.⁵³ Electrical current flows from the buried impressed current anode through the wet soil (the electrolyte) and onto the

⁵² 2002 TAPS Valdez Marine Terminal Cathodic Protection Survey, WO# 32000354-01, prepared for Alyeska Pipeline Service Company, by Corrpro Companies, Inc., December 30, 2002.

⁵³ Project L019, 1999 Annual Cathodic Protection Survey of the Valdez Marine Terminal and SERVS Facility, prepared for Alyeska Pipeline Service Company, by Corrpro Companies, Inc., January 2000.

tank bottom causing a build-up of hydrogen ions on the tank floor.⁵⁴ The hydrogen ion film blankets the tank bottom and reduces the rate of corrosion (this is also called a “polarization film”). The tank bottom then becomes a cathodic passive site where corrosion is less likely to occur.

APSC provided rectifier operation data from 2005 to 2015. This data showed the rectifier supplied power to Tank 12’s anode grid for most of 2005 to 2009 and 2011 to 2015 with minor outages for maintenance. However, in 2010, the power was turned off from April to December for the Tank 12 inspection, maintenance, and repair work within the tank secondary containment area.

When a structure (such as a tank bottom) is cathodically protected, it can take days to months to become polarized. Therefore, consistent and reliable operation of an impressed current cathodic protection system is critical to maintain corrosion protection.⁵⁵

To ensure the CP system is working effectively, a soil-to-structure potential test is conducted to verify a film of negatively-charged ions is forming across the tank bottom. This test verifies there is enough current by measuring the potential of the tank’s steel against a standard reference electrode. APSC uses copper/copper sulfate (Cu/CuSO_4) reference electrodes as a standard reference. The soil-to-structure potential test is completed using a direct current (DC) voltmeter and a reference cell (a reference electrode in contact with the electrolyte (the wet soil)).

For large tanks, like the Valdez Marine Terminal Crude Oil Storage Tanks (250’ diameter) it is important to measure the soil-to-structure potential at various points around and under the tank. At Tank 12, six (6) permanently installed copper/copper sulfate (Cu/CuSO_4) reference electrodes are installed to monitor the CP system. Four (4) monitoring tubes are also installed under the tank, spanning the tank floor. A portable reference electrode is used in the monitoring tubes to periodically collect measurements. It is important to make measurements under the tank, because measurements at the perimeter of the tank may not represent the tank-to-soil potential under the center of the tank, especially for such a large tank.

The soil-to-structure potential test can be conducted with the CP system operating (“On”) or with the CP system temporarily interrupted off (I/Off). The “On” reading can include a significant error caused by measuring the current flowing through the soil; therefore, it is standard practice to take the measurement with the protective current temporarily interrupted off (I/Off). National Association of Corrosion Engineers (NACE) Recommended Practice (RP-0193-93) standard for structure-to-soil potential is -850 mV (or more negative) with respect to a Cu/CuSO_4 reference electrode with the protective current temporarily interrupted off (I/Off). The natural potential is about -500 mV when measured against a reference copper sulfate electrode. Values that are more positive represent steel that has undergone corrosion. Values that are more negative indicate steel has been protected from corrosion.

NACE has a second standard called the “100 mV shift criteria”, or “100 mV polarization” that compares the protective current temporarily interrupted off (I/Off) reading to the potential measured prior to the application of cathodic protection (the “native” or “depolarized” potential). The 100 mV shift criteria are met if the instant off voltage minus the depolarized voltage reading is at least 100 mV.

⁵⁴ The AC power cable is connected to the rectifier input terminals. The rectifier output DC positive cable is connected to the Mixed Metal Oxide ribbon anodes. The output DC negative terminal is connected to the tank. Current is sent through the electric wire to the anodes buried below the tank. The current then flows from the anodes through the soil to the tank and returns to the rectifier through a wire attached to the tank. The current going to the tank needs to be sufficient to overcome the corrosion-causing current naturally flowing away from it.

⁵⁵ Meyers, P.E., Above Ground Storage Tanks. McGraw-Hill, 1997.

Typically, the structure-to-soil potential is tested to see if it measures at least -850mV (or more negative), if so, the inspector has verified the CP system is functioning effectively. If the -850 mV criteria is not met, it is an indication that the CP system may not be functioning effectively. Additional testing is completed to obtain a depolarization potential to determine whether the 100 mV shift criteria can be met.

Cathodic protection system records for 2005 to 2015 were provided by APSC. Cathodic protection system data for those periods showed the system was operational and met National Association of Corrosion Engineers (NACE) Recommended Practice (RP-0193-93) for all points measured, with two exceptions. Please see Attachments No. 1 and 2 to this report for a summary of the data.

Cathodic protection system data for 2010 was not available. Tank 12 was inspected in July 2010. The cathodic protection system was turned off in April 2010 and remained shut down until December 2010 during work in the tank secondary containment area.

APSC substantially reduced the number of cathodic protection system test points it measured under Tank 12 from 51 test points in 2005 to 2008 to only ten test points in 2009, 2011, 2012, and 2013. In 2010, PWSRCAC raised concern about the reduced number of test points. In 2014, APSC resumed the higher testing frequency to 49 test points. NACE RP-0193-93 recommends that on tanks greater than 60' cathodic protection system test points be collected both at the perimeter and under the tank, because measurements at the tank perimeter may not reflect actual conditions.

PWSRCAC should note that APSC stamped the cathodic protection system data with this limitation: *“NOTICE: Tank 12 CP Data 2005-2015 is the property of the Owners of the Trans-Alaska Pipeline System. Its sole use is for Alyeska Pipeline Service Company (Alyeska), and the state and federal regulatory agencies with authority to view the information. It may not be used for commercial or any other use. Any other use must be expressly permitted in writing by Alyeska as Agent for the Trans-Alaska Pipeline System Owners. This use restriction includes reproduction or redistribution of this document of any portion of this document.* It is recommended that PWSRCAC consult with APSC on the use of the data in this report, and obtain approval before the report is distributed.

15. Recommendations

A list of recommendations is provided below for PWSRCAC to consider for future crude oil tank inspections:

15.1 Number of Inspection Points on Shell and Roof Inspections. It is recommended that the number and location of additional shell and roof corrosion loss measurements be increased. External API 653 inspections are completed every 5 years. External inspections provide a more frequent opportunity to monitor the shell and roof corrosion rate during the 20 year period before the next out-of-service API 653 inspection. In the past, only three corrosion measurements have been taken on each shell course (2nd – 8th), usually in approximately the same location each inspection (along the stairs). This is a low number of measurements for a 250' diameter tank. As the tank ages, it would be beneficial to consider collecting additional measurement locations on each shell course during the 5-Year API 653 external inspections (especially if inspection data shows increasing corrosion). Less than 1% of the roof is currently being inspected; this area should be increased.

15.2 Evaluation of Corrosion Trends Using All Inspection Data. API 653 Section 6 requires an inspection history to be maintained on the tank, including corrosion rate and inspection interval

calculations. It is recommended that the scope of work requested by APSC for its API 653 inspectors, include review of prior inspections, re-measurement the areas of highest corrosion loss found in the prior inspection to determine whether corrosion loss has increased or stabilized, and an explanation of any measurements that are not consistent with past corrosion measurements or trends. Neither the 2010 inspector's report, nor the 2010 APSC Engineer's summary of the 2010 inspection evaluated corrosion trends based on prior inspection data.

For example, some year 2000, and 2005 inspection results reported corrosion that exceeded the measurements reported in 2010. It is possible that the 2010 inspector found the 2010 measurements to be more accurate, using newer technology, discounting the prior inspection data. However, it would have been useful for the 2010 inspection report to acknowledge prior measurements, explain what work was done to more thoroughly investigate those areas of known "worst-case" corrosion loss from the prior inspections, and explain why the new, 2010 thicker measurements were more accurate. Absent re-measurement, or an explanation of why prior data should not be considered, the most conservative corrosion data should be used in remaining service life computations.

15.3 Risk Reduction Through More Frequent Inspections. Future corrosion rates may increase or decrease based on a number of factors. Corrosion rate estimates based on previous tank operating history are only a guide and do not provide a guarantee of future corrosion rates. Routine inspections are a critical part of an oil spill prevention program. Additionally, more frequent internal tank inspections provide an opportunity to clean sediment and sludge out of the tank to ensure it is not impeding the firefighting foam distribution piping system, and to ensure the foam piping has not corroded to a point that it would fail to deliver sufficient foam to suppress a tank fire.

Due to the size, age, and location of this tank in a critically sensitive habitat area, it is recommended that a minimum inspection regime of 10-year API 653 out-of-service inspections and 5-year API 653 in-service inspections be maintained, with inspections that are more frequent if corrosion loss data warrants. Extending the API 653 out-of-service interval to the maximum 20-year interval allowed, based solely on the estimated remaining service life of a new tank floor installed in 2000 does not take into consideration that the other tank components will be 54 years old by the next out-of-service inspection and does not take into account that the tank is located in a highly sensitive location.

API 653 recommends that in addition to completing the standard "next inspection interval computation" (based solely on the remaining floor and annular plate thickness), that the inspector also consider several other factors when setting the tank inspection interval, such as: "(a) the nature of product stored, (b) The results of visual maintenance checks, (c) Corrosion allowances and corrosion rates, (d) corrosion prevention systems, (e) conditions at previous inspections, (f) the methods and materials of construction and repair, (g) the location of the tanks, such as those in isolated or high risk areas, (h) The potential risk of air or water pollution, (i) leak detection systems, (j) change in operating mode, (k) jurisdictional requirements, (l) changes in service (including changes in water bottoms), (m) the existence of a double bottom or a release prevention barrier.

More frequent out-of-service inspections provide the opportunity to evaluate the condition of all aging components of Tank 12, not just the new tank floor. More frequent out-of-service inspections also provide the opportunity for the operator to: clean out sediment buildup that can obstruct the fire foam system installed in the bottom of the tank; repair damaged coating that protects the tank floor and lower section of the tank where corrosive water and sediment can accumulate; provides earlier identification of tank floor leaks that could be significant and cumulative, but may fall below

the 3,000 barrel leak detection threshold of the sensitive gauging system installed on Tank 12. Tank 12 does not have any leak detection system installed below the tank floor that would alert the operator to a continuous leak that falls below the 3,000 barrel threshold.

- 15.4 Fire Foam System Inspection, Repair, and Replacement.** The 20" fire foam system is an important component of safe tank operation. The 2010 inspection did not provide sufficient information on the condition of the piping system, and did not provide quantitative data on the amount of sediment build up in the tank bottom when the tank was opened in 2010. More information is needed to: (1) better understand the condition of the foam piping, and (2) to understand if the next 20-year inspection interval (until 2030) is conservative based on the actual sediment accumulation that has been occurring in Tank 12. This would help to ensure the foam piping system is not obstructed during this longer period between tank clean outs.
- 15.5 Foundation Repairs.** The 2010 API 653 inspector found the seal around the bottom of the tank had "mostly failed" with vegetation and root systems prevalent. The API 653 inspection report did not state what, if any repairs were made to the seal around the bottom of the tank. External inspections in 2005 and 2015 also reported seal integrity issues. It would be useful to clarify with APSC if the seal repairs have been completed.
- 15.6 Roof Support Corrosion Allowance.** Tank 12's roof support column design includes 61, 24-inch diameter columns. The column design is made of 0.50" thick nominal members. The Tank 12 reports do not specify the minimum thickness for roof support members (corrosion allowance) to ensure adequate support to the roof during heavy snow loads; this value should be listed in the reports.
- 15.7 Cathodic Protection System Operation.** The cathodic protection system plays a critical role in protecting Tank 12's floor from soil-side corrosion. Continued annual monitoring of the cathodic protection system operability, collecting data at 10' intervals along each reference cell tube, and at the permanent reference cells should continue.
- 15.8 Report Distribution.** PWSRCAC should note that APSC stamped most of its Tank 12 reports with limitations on the use and distribution of the data. It is recommended that PWSRCAC consult with APSC on the use of the data in this report, and obtain approval before the report is distributed.

16. Acronym Summary

ADEC	Alaska Department of Environmental Conservation
API	American Petroleum Institute
API 653	American Petroleum Institute Standard No. 653
APSC	Alyeska Pipeline Service Company
AUT	Automated Ultrasonic Testing
CP	Cathodic Protection
C-Plan	Oil Discharge Prevention and Contingency Plan
EMAT	Electromagnetic Acoustic Transmission
ft ²	Square feet
in ²	Square inch
NACE	National Association of Corrosion Engineers
mpy	Mils per year (mpy), where a “mil” is a thousandth of an inch (0.001 inch)
MFL	Magnetic Flux Leakage
MMO	Mixed Metal Oxide
MUT	Manual Ultrasonic Testing
PWSRCAC	Prince William Sound Regional Citizens’ Advisory Council
RP	Recommended Practice
RT	Radiographic Testing
Tank 12	Crude Oil Tank No. 12
VMT	Valdez Marine Terminal
WFMT	Wet Fluorescent Magnetic Particle Testing