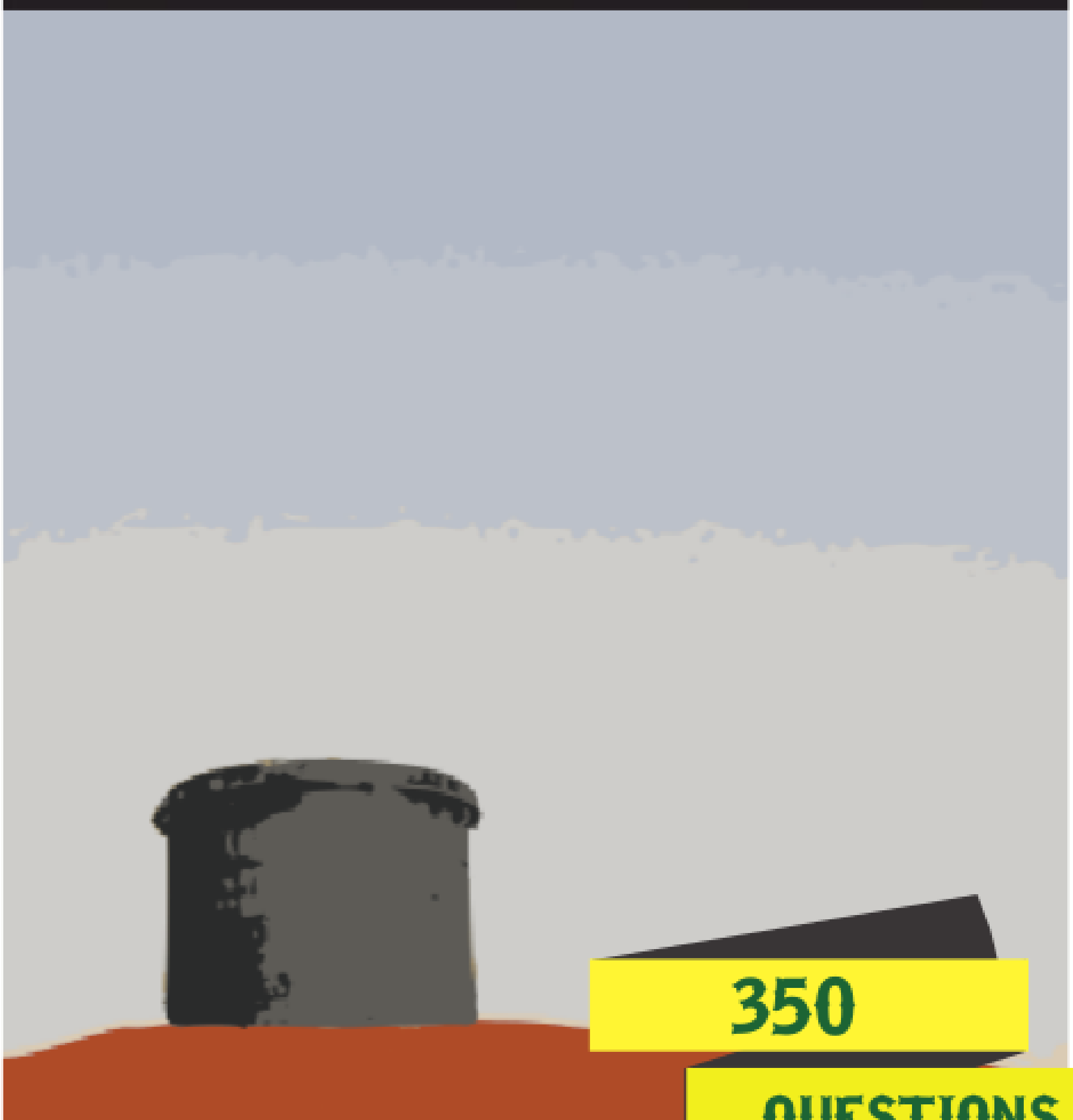
FIRST EDITION

653-Fix

Carlos F Molina



350 QUESTIONS

653-FIX

Carlos F Molina

December 31, 2016

About the Author

My name is Carlos F Molina, an Oil and Gas Mechanical Engineer and owner of APIEXAM.COM. I work full time as a mechanical inspector for construction and maintenance projects, besides taking time to write. I graduated with a Mechanical Engineer degree from the Universidad Industrial de Santander. I am an API 653 and API 580 certified inspector. I have been working in the oil and gas field for 9 years now, especially in tank repair and construction. I have mostly worked in NDE, tank repair and alteration, new construction tanks and pipes and quality system management. I have experience in shielded metal arc welding and coating of metallic substrates.

I have worked as an API 653 and quality control Engineer in charge of the Quality Management System during the following projects

- I took part in the following projects: "Abrasive cleaning, controlled lead removal and exterior Paint of Cooling water pipes of the Miraflores Termoelectric Plant, 48 and 54 inches' diameter". "Cleaning, exterior paint and internal inspection services for tanks 141 and 143 of the Miraflores Termoelectric Plant", for the Panama Canal Autorithy.

- "Maintenance of tanks at Ecopetrol's Apiay Station", for repairs of 5 tanks amounting to 300000Barrels of Oil. November 2011 til August 2013. API 653 and QA-QC Engineer during the project "Maintenance of tanks at Ecopetrol´s Sebastopol Station". Weld and coating quality control, record keeping, and pipe traceability in Aboveground Oil Storage Tanks. March 2011 to November 2011.

- API 653 and quality control Engineer, in charge of the Quality Management System for the project: “Maintenance of tanks installed in production plants belonging to the Huila- Tolima Operations Presidency of Ecopetrol S.A. located in the towns of Neiva, Aipe, Palermo, Baraya, Villavieja, Yaguara and Ortega”. August 2013 to March 21th 2014. I led all tank repairs.

- Leading Mechanical Inspector in welding, testing, surface preparation and coatings application of welded pipes and tanks, in the construction of a plant to treat and separate 330KBPD of oil and water in the project "30K" of Ecopetrol. I led quality control in the construction of process and storage tanks amounting to a total of 460000 Barrels in Castilla La Nueva, Meta, for the project "Castilla 3" of Ecopetrol.

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There was a lot of work that went into putting this document together. I can't tell you how many countless hours are spent putting together the apiexam blog and newsletter from which this information was compiled. That means that this information has value, and your friends and co-workers may want to share it.

The information in this document is copyrighted. I would ask that you do not share this information with others-you purchased this book, and you have a right to use it on your system. Another person who has not purchased this book does not have that right. It is the sales of this valuable information that makes the continued publishing of apiexam possible. If enough people disregard that simple economic fact, the newsletter will no longer be viable or available.

Please note that some of this publication is based on personal experience and anecdotal evidence. Although the author has made every reasonable attempt to achieve complete accuracy of the content in this Guide, he assumes no responsibility for errors or omissions. Also, you should use this information as you see fit, and at your own risk. Your situation may not be exactly suited to the examples here; in fact, it's likely that they won't be the same, and you should adjust your use of the information and recommendations accordingly.

A GUIDE TO PASS THE API 653 EXAM

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THE SCOPE OF API 653

If you read the first chapter of API 653, you will see it is a standard that covers Inspection, Repair, Alteration, and Reconstruction of steel storage tanks built to API 650 and its predecessor, API 12C. It provides minimum requirements for maintaining the integrity of such tanks after they have been placed in service and addresses inspection, repair, alteration, relocation, and reconstruction.

API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," was first published in January 1991, and is one of 11 standards of inspection that make part of the Individual Certification Programs of the American Petroleum Institute (API). It provides a certification which evaluates the knowledge and experience of technical and inspection personnel involved in tank inspections.

The scope of API 653 is limited to the tank foundation, bottom, shell, structure, roof, attached appurtenances, and nozzles to the face of the first flange, first threaded joint, or first welding-end connection. It means that if you look in API653 for inspection guidelines regarding dikes or even types of foundations, you won´t find them. However, as an inspector you should be able to deliver a report about them in case of need.

Many of the design, welding, examination, and material requirements of API 650 can be applied in the maintenance inspection, rating, repair, and alteration of in-service tanks. In the case of conflicts between the requirements of API 653 and API 650, API 653 shall govern for tanks that have been placed in service. API 653 should be followed over API 650 when we are treating tanks repair and reconstruction.

API 653 standard employs the principles of API 650; however, storage tank owner/operators, based on consideration of specific construction and operating details, may apply this standard to any steel tank constructed in accordance with a tank specification. Is understandable then that an API 653 certified inspector should be completely knowledgeable about API 650.

The API 653 standard does not contain rules or guidelines to cover all the varied conditions which may occur in an existing tank. When design and construction details are not given, and are not available in the as-built standard, details that will provide a level of integrity equal to the level provided by the current edition of API 650 must be used.

WHY BECOME CERTIFIED?

API's certifications have come to be regarded as the most demanded and desired credentials in the industry. They provide applicants with means to improve their skills through learning and strengthening their overall job performance. API certified inspectors and personnel are recognized worldwide as professionals who are fully knowledgeable of the relevant industry inspection codes and standards, and who can perform their jobs in accordance with the latest and most acceptable industry inspection practices.

API certification allows qualified personnel to establish a career path and make valuable contributions to the safety and quality of industry operations. In 2015, API received a total of 1216 new applications for the API 653 certification. A total of 1514 applicants took the 653 exam in 2015. 743 of them passed.

Here are 4 reasons to become certified

1. **API has instant name recognition.** When you become certified, you join a growing group of some 30.000 professionals worldwide who have become API certified. The popularity of API usually means respect in your field.

2. **Inspection industry is growing.** Your API credential will help you stand out from the competition for inspections projects in a tough market, especially in this rapidly expanding sector of the economy. API 653 inspector numbers grew 67% in 5 years, from 4768 in 2011 to 7986 in 2016. Job prospects should be best for those who are certified and have related work experience.
3. **API has become an industry standard.** Many employers in the oil industry expect job candidates to have API certifications. It is no longer an exception; it is the norm.
4. **Your employer may pay for you to take the exam.** Recognizing the value of a API trained workforce, many companies in the oil industry will pay for the course, exam and accreditation fees for their employees. In other words: your boss will approve, and it might be free!

If you already decided you want to try certification, you have 4 options....

Study on your own beforehand, don´t take the course then take the exam

Maybe you are one of those people that can read English very well, and are used to taking and passing tests of all kinds. However, have in mind that there are several differences and correlations between API 650 and 653 that are not so clear to see, so you will need someone´s guide to really understand what you are studying. It is up to you if you want to pass the exam by yourself, which is possible. Resources like this book will help you in that.

Study on your own beforehand, then take the course then take the exam

This is highly recommended, especially if you are already using the standards on a daily basis, if you have experience in the field or any certification in welding or NDE.

Don´t study beforehand, then take the course then take the exam

Not recommended if you are not using the standards daily. As you know, learning is a lot easier when you build up new concepts above old concepts you have. However, is not just knowing and not studying, given that standards are of changing nature. I know several people that are experts in the field of tanks, but as they are not used to taking tests, or they don´t understand English well, so they flunk the exam.

Take the course and don´t take the exam

This is a big mistake. I see many people doing it, especially older people. Ideally, you should try to take the exam immediately after you have taken the course, so the concepts are still "hot" in your mind. *The craziest mistake you can make is taking the course and not the exam, because, let´s face it, it is certification what we are talking about. Certification opens new doors. Taking the course and flunking is not precisely comfortable to say.*

So, what is this book for? To give students a possibility to have contact with the standards on a daily basis, by means of Questions and Answers, Exercises, Examples, Graphics, etc. My aim here is to make it so good that you won´t even have to take a course. Are you up to it?

TAKE ACTION: READ THE BODY OF KNOWLEDGE

API regularly launches a Body Of Knowledge (BOK), that summarizes the core teachings, concepts, and essential competencies that need to be mastered by new inspectors to receive certification. API 653´s body of knowledge is dynamic, since every year it incorporates new information and techniques.

Per the current BOK, to be a successful inspector you will need to know the following:

CONCEPTS FROM API 653	
1	How to evaluate corrosion rates and inspection intervals

2	Establish joint efficiencies
3	Calculate maximum Fill Height for a Hydrostatic test
4	Determining the sizes and spacing of welds for shell openings
5	Determining requirements for Hot Tapping
6	Settlement evaluation
7	Number of settlement points
8	Impact Testing
9	Calculate minimum thickness of tank shell
10	Calculate minimum thickness of tank shell for reconstructed tanks
11	Determine if a tank shell corroded area is acceptable for continued service
12	Evaluate a pitted area
13	Calculate dimensions for replacement plates
14	Calculate dimensions for lap welded patch plates
CONCEPTS FROM ASME IX	
Ensure you can proficiently review a PQR and a WPS and determine its conformance to Sec IX	
API 650 AND 653	
General welding requirements	
ASME V	
Be familiar with and understand NDE applied to tank repair and construction	
API 650 AND 653	
General NDE requirements	
GENERAL KNOWLEDGE	

1	API RP 571, Damage Mechanisms Affecting Fixed equipment in the Refining Industry
2	API Recommended Practice 575, Inspection of Atmospheric and Low-Pressure Storage Tanks
3	API RP 577, Welding Inspection and Metallurgy
4	API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction and the related portions of API Standard 650, Welded Steel Tanks for Oil Storage
5	API Recommended Practice 651, Cathodic Protection of Aboveground Petroleum Storage Tanks
6	API Recommended Practice 652, Lining of Aboveground Petroleum Storage Tank Bottom

Just study that, and you should do fine

HOW THE EXAMINATION IS ADMINISTERED?

Since 2012, there is a change in the way the exam is being held. Before that, you would go to a Prometrics place with your hard copy standards that would be checked and take a paper written exam. But now, the exam is administered via a computer in a Prometric´s testing center. (That means that you will save some dollars on standards)

The examination consists of two parts. The closed book part tests the candidate on knowledge and tasks requiring everyday working knowledge of API Standard 653 and the applicable reference documents. The open book portion of the examination requires the use of more detailed information that the inspector is expected to be able to find in the documents, but would not normally be committed to memory.

There are 150 questions on the exam, of which only 125 are scored. The remaining 25 are pretest questions. The exam day is 8.5 hours long, and includes 3 hours for the closed-book section, 4 hours for the open-book section, a half-hour tutorial session, and a 1-hour lunch break.

Papers and books are not allowed in Prometric's computer testing centers. All materials needed for the open-book portion of the exam will be displayed on your computer screen in English or other language of your choice. I recommend taking the test in English if you are confident, because standards are in English.

THE ROLE OF MEMORY IN YOUR LEARNING PROCESS

In some websites advertising API 653 training courses, they downplay memory as an important tool in learning technical subjects like standards and codes. I think they are wrong, because you learn mostly building above what you already know. There is no learning without memorization. In fact, the Body Of Knowledge states clearly that the fact that there is an open book and a closed book parts is because while there are some facts you need to use daily (closed book), so there are things that you won´t remember easily without opening the book.

With that in mind, I never discourage anyone to learn trough flash cards if they feel they are the best option for them.

I thank you dearly for your support and the success of Apiexam.com. Thank you, and good luck! Cheers!

HOW THIS BOOK IS ORGANIZED

The sections are in the same order than the numerals in the BOK. This is not true, however, for the subject of inspection intervals, that is disorganized in the BOK. I treat them in the same chapter for easier understanding

HOW TO USE THE RESOURCES OF APIEXAM.COM

You can find the Q&A here

HOW TO USE THE Q&A LISTS

The questions of the Q&A list were extracted from the standards by me, or remembered by me or other students that took the exam before. The format is a Q&A one, different from the multiple-choice question format from other courses I have seen online. I prefer this method because it takes away all the clutter that leads to confusion when treating these standards. I advise you to copy these questions (maybe you will have to actively copy and paste the Q&A sets in word or excel) and paste it in a spaced repetition software like Anki or Supermemo, as the Q&A format allows, and start studying right away. Please edit the questions yourself looking to the references if you have difficulty remembering any of them. When days pass by, you will see who you remember all the information with no problem.

Download the las version of Anki here. It is free.

Download the latest version of supermemo here. It is also free.

It is better if you give at least 3 months to your daily Spaced Repetition Study before the exam. Research has shown that the use of SRS improves test taking. [1]

If you use these tools well, you study well in advance and study the BOK, maybe you won´t need a course. It will save you money. You will have no hassle. Guaranteed.

Oh. And there is one more benefit with Spaced Repetition Software: The information stays there, in your mind, useful for when you present other API exams, and useful to surprise your colleagues.

I think that studying by answering tests may not be the best, because that´s not the best way to formulate knowledge. Check here to see what I say.

The following are the approximate weights of every area in the exam. You should be dedicating more time to API 653 and API 650

	Weight
API 653, Aboveground tanks Inspection Code	45 %
API RP 650 Vertical storage tanks Construction code	20 %
API RP 575, Inspection of Storage tanks	06 %
API RP 651 Cathodic Protection of Storage tanks	05 %
API RP 562 Lining of Tank bottom	03 %
API RP 571, Damage Mechanisms	03 %
API RP 577, Welding Inspection and Metallurgy	03 %

DECIMAL MARK

I use commas to separate *thousands*, and periods to separate *decimals*.

TABLE AND FIGURE INDEXING

Tables and figures have both internal numeration and original standard numeration.

STANDARDS

All info is taken with the best of my effort from:
API 653 Fifth edition, 2014.
API 650 12th edition, 2013 and 2014 addenda
API 575 Third edition 2014
ASME V 2013
ASME IX 2013
API RP 651
API RP 652 Fourth edition, 2014

CHAPTER 1: CORROSION RATES AND INITIAL INSPECTION INTERVAL

Among your duties as an inspector of static equipment, there is the need to calculate inspection intervals, metal loss (including corrosion averaging), corrosion rates and remaining service life. For an aboveground storage tank, you can calculate inspection intervals based on the Remaining Life of the containment of the tank (Shell and bottom). Remaining Life is determined using the Corrosion Rate of the tank. There are two aspects to consider when inspecting a tank: (a) the rate at which deterioration is proceeding and (b) the allowable limit of deterioration.

Let´s look at all the following definitions

Metal Loss due to general corrosion is defined as the difference between the thicknesses measured in the same spot before and after.

Eq. 1. $$Metal\ Loss = t_{previous} - t_{last}$$

Metal loss is measured in distance units, being mm the most common

Corrosion rate CR is metal loss divided by the time between measurements

Eq. 2. $$Corrosion\ Rate = \frac{Metal\ Loss}{Time\ period} = \frac{t_{previous} - t_{last}}{Time\ period}$$

Corrosion rate units are distance/time, being inches per year or mm per year the more common.

Remaining life is the time before the minimum allowable thickness is reached, at the calculated corrosion rate.

$$\text{Eq. 3.} \quad Remaining\ life = \frac{t_{actual} - t_{minimum}}{Corrosion\ Rate}$$

Values for Remaining life are commonly given in years. Corrosion rate here can be short-term (the most recent measured) or long-term.

Short term Corrosion

$$\text{Eq. 4.} \quad Short\ term\ Corrosion\ Rate = \frac{Metal\ Loss}{Short\ time\ period}$$

Long term Corrosion

$$\text{Eq. 5.} \quad Long\ term\ Corrosion\ Rate = \frac{Metal\ Loss}{Long\ time\ period}$$

Suitable use of short-term versus long-term corrosion rates is determined by the inspector. Short-term corrosion rates are typically determined by the two most recent thickness readings whereas long-term rates use the most recent reading and one taken earlier in the life of the equipment. These different rates help identify recent corrosion mechanisms from those acting over the long-term. Comparing the values of short term vs long term corrosion, you can find tendencies or discover damage mechanisms.

Corrosion allowance describes an extra measurement added to the thickness of the wall calculated for safe operation. Units for corrosion allowance are distance units. It is the metal expected to be lost over the life of the equipment. Basically, it is chosen by the designer

Eq. 6. $Corrosion\ Allowance = Design\ Corrosion\ Rate\ per\ year\ x\ Number\ of\ years\ until\ next\ inspection$

Remaining Corrosion Allowance (RCA) is the thickness remaining of the original Corrosion Allowance

Eq. 7. $Remaining\ Corrosion\ Allowance = Design\ Corrosion\ Allowance - Metal\ Loss$

Inspection interval is the time between the last inspection and the next one

Eq. 8. $Next\ Inspection\ Date = Last\ Inspection\ Date + Inspection\ Interval$

All inspection intervals in are given in years.

AND.... WE ARE GOING TO THE MEAT RIGHT NOW

The maximum allowable next inspection interval is given by codes and standards. For API 653, you can use the following summary.

External inspection: must be conducted at least every 5 years or RCA/4CR years, whichever is less

External Ultrasonic Measurements: if the corrosion rate is not known, the interval between inspections is 5 years, but if the corrosion rate is known, measurements shall be taken the lesser of RCA/2CR, or 15 years

Internal inspection: The interval from initial service date until the first internal inspection shall not exceed 10 years unless it has one or more of the leak prevention, detection, corrosion mitigation or containment safeguards listed in Table 6.1 of API 653. Subsequent inspection intervals can be determined using the measured tank bottom corrosion rate and the minimum remaining thickness in accordance with 4.4.5 of API 653. An RBI assessment or stress analysis can be used to establish the inspection interval from initial service, and also subsequent inspection intervals. (Check figure 1 for Initial inspection interval)

Tank safeguard	Add to initial interval
i. Fiberglass-reinforced lining of the product-side of the tank bottom installed per API 652	5 yrs
ii. Installation of an internal thin-film coating as installed per API 652	2 yrs
iii. Cathodic protection of the soil-side of the tank bottom installed, maintained and inspected per API 651	5 yrs
iv. Release prevention barrier installed per API 650, Annex I	10 yrs
v. Bottom corrosion allowance greater than 0.150in	Actual corrosion allowance - 150 mils) / 15 mpy
v. Bottom constructed from stainless steel material that meets requirements of API 650, Annex SC, and either Annex S or Annex X; and internal and external environments have beendetermined by a qualified corrosion specialist to present very low risk of cracking or corrosionfailure.	10 years

TABLE 1. TABLE 6-1 OF API 653. TANK SAFEGUARDS

For many parts of atmospheric storage tanks, neither the required thickness nor the methods for calculating the thickness are given in the tank standards. Such parts include pontoons, swing lines, floating-roof drain systems, nozzles, valves, and secondary structural members. A minimum acceptable thickness should be established for piping and nozzles that would set the retirement thickness to ensure replacement prior to the occurrence of leaks.

Methods for determining the minimum shell thickness suitable for continued operation are given in 4.3.2, 4.3.3, and 4.3.4 of API 653 (SEE SECTION X). Methods for determining minimum bottom thickness can be found in 4.4.5 of API 653 (SEE SECTION X).

EXERCISES

Q: Following are UT readings of the shell of a tank taken with a difference of 5 years in the same spot.

Thickness	Value
t_{1995}	9.7mm
t_{2000}	8.3mm

Find the corrosion rate.

A:

Q: If the minimum allowable thickness for tank in a given point is 5.8mm, right now thickness is 7.9mm, and the corrosion rate is 0.34mm/y, then what is the remaining life?

A:

Q: If the minimum allowable thickness for tank in a given point is 5.8mm, right now thickness is 7.9mm, and the corrosion rate is 0.34mm/y, then when should be scheduled the next UT measurement?

A:

Q: The following table is a record of average thickness of a tank shell in the same course over the years. Calculate the short-term corrosion rate and the long-term corrosion rate

YEAR	THICKNESS(mm)
2009	9.82
2010	9.71
2011	9.45
2012	9.36
2013	9.21

2014	8.99
2015	8.87

A:

POINTS TO REMEMBER

The initial internal inspection interval can be stablished this way:

Maximum initial inspection interval without safeguards= 10 years

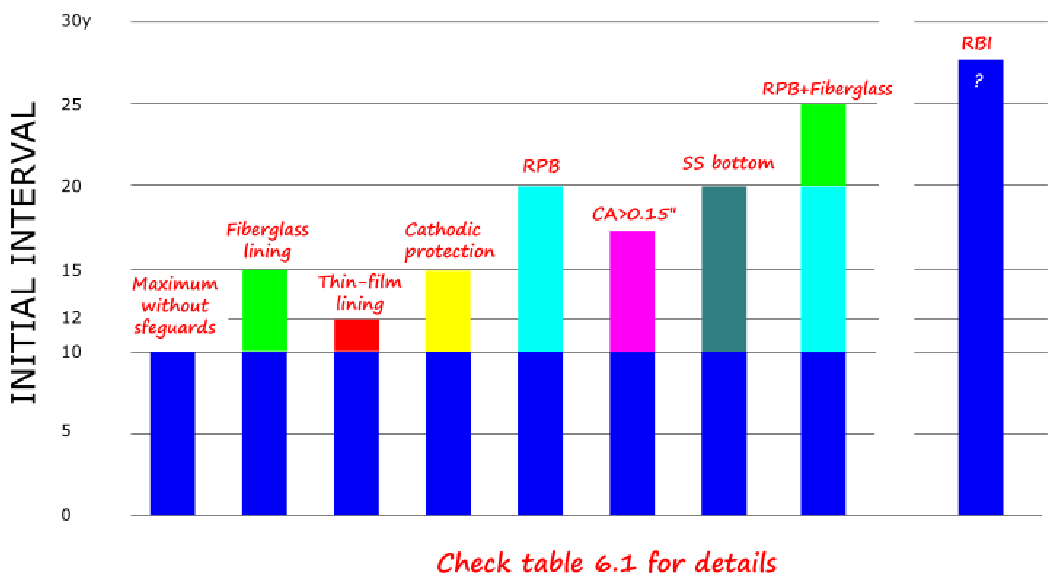

FIGURE 1 INITIAL INSPECTION INTERVALS IN TANKS (NOT STAINLESS STEEL TANKS)

You can make that longer if you use a safeguard, or Release Prevention *System*, one of which can be a Release Prevention *Barrier*. Years for each safeguard can be added, but there is a limit. Tanks with a RPB have a maximum inspection interval of 30 years, while tanks without a RPB have a maximum inspection interval of 20 years

Or

You can conduct an RBI assessment to establish the initial inspection interval

Now let´s go to subsequent inspection intervals....

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CHAPTER 2: CALCULATING SUBSEQUENT INTERNAL INSPECTION INTERVALS OF A TANK BOTTOM

Internal inspection of the tank is necessary usually when you don´t have access to the underside of the bottom of a tank, so it is very important that you can know in advance the next due inspection date.

To know how many years your tank will be operational until next inspection, you need to go to 4.4.5.1 of the API 653 standard. This numeral is used to calculate next interval inspection interval after bottom repairs, although calculations can be done at any time during tank operation.

The formula in 4.4.5.1 goes this way:

$$\text{Eq. 8.} \quad MRT = \left(Minimum\ of\ RT_{bc}\ or\ RT_{ip}\right) - O_R(S_tP_R + UP_R)$$

THIS EQUATION APPLIES TO BOTTOM PLATES, SKETCH PLATES IN THE CRITICAL ZONE, AND ANNULAR PLATES

But you are looking for an answer in years, so you will have to reorder the equation the following way

$$\text{Eq. 9.} \quad O_R = \frac{\left(Minimum\ of\ RT_{bc}\ or\ RT_{ip}\right) - MRT}{(S_tP_R + UP_R)}$$

This is the explanation for all those variables.

VARIABLE	DEFINITION
O_R	Is the in-service interval of operation in years
MRT	Is the minimum remaining thickness at the end of interval O_R
UP_R	Is the maximum rate of corrosion on the soil side
S_tP_R	Is the maximum rate of corrosion not repaired on the top side
RT_{bc}	Is the minimum remaining thickness from bottom side corrosion after repairs
RT_{ip}	Is the minimum remaining thickness from internal corrosion after repairs

TABLE 2. VARIABLES FOR THE FORMULA TO CALCULATE MINIMUM REMAINING THICKNESS OF BOTTOM

When the formula puts a value on any of these variables, is not an average between the measurements taken in a tank bottom, but the most critical spot value measured. Product side corrosion rate is zero while the lining is still in perfect condition ($S_tP_R = 0$) and soil side corrosion rate is 0 when the cathodic protection system is working properly ($UP_R = 0$).

Minimum Bottom Plate Thickness at next inspection	Tank Bottom/Foundation design
0.10in	Tank bottom/foundation design with no means for detection and containment of a bottom leak
0.05in	Tank bottom/foundation design with means to provide detection and containment of a bottom leak.
0.05in	Applied tank bottom reinforced lining, > 0.05in. thick, in accordance with API 652

TABLE 3. (TABLE 4.4 OF API 653)—BOTTOM PLATE MINIMUM THICKNESS

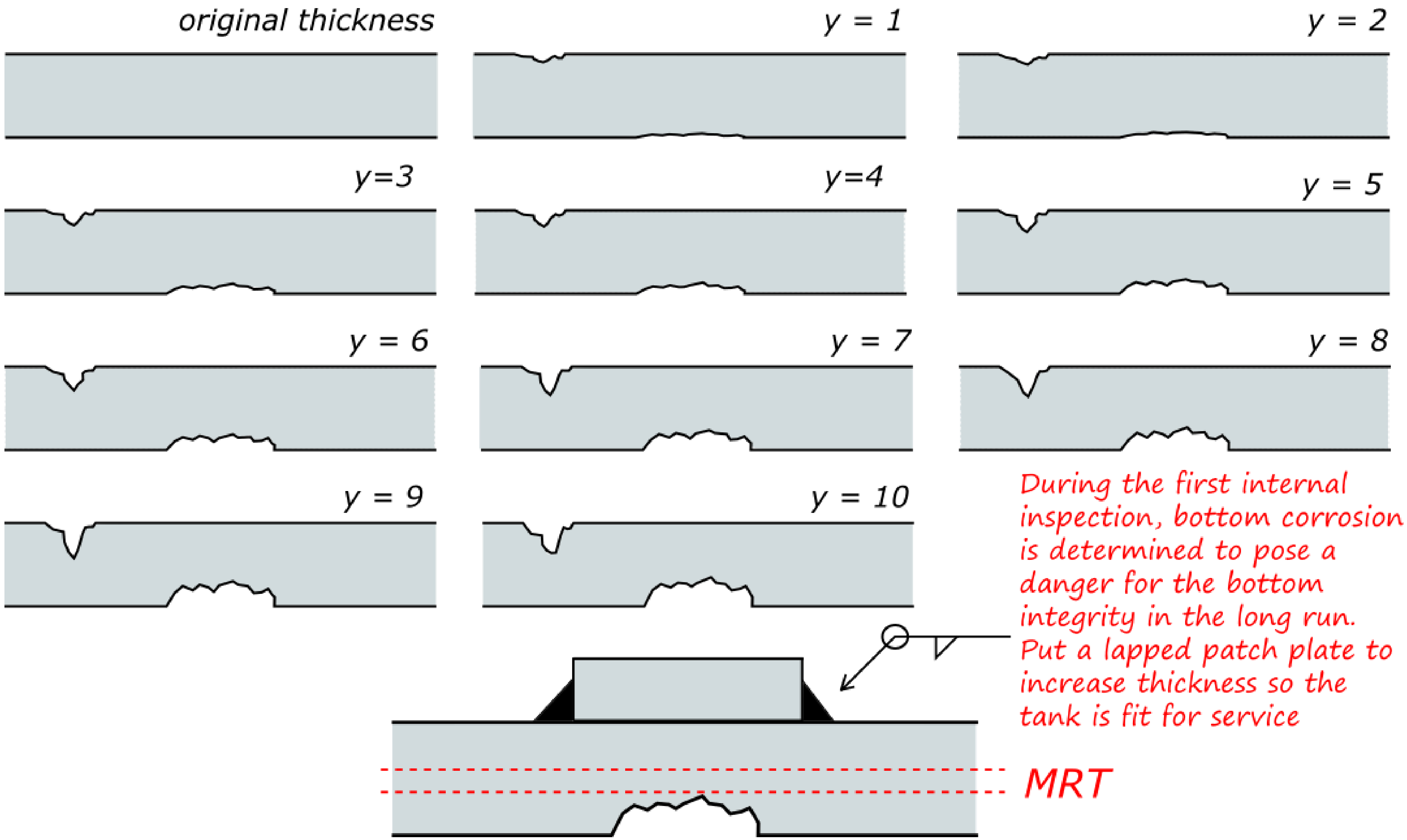

FIGURE 2 BOTTOM CORROSION AND TREATMENT ASSESSMENT

Subsequent inspection interval (it is, the ones after the initial inspection) can be determined using the measured tank bottom corrosion rate and the minimum remaining thickness in accordance with 4.4.5. They have invented some equipment that they claim can inspect the bottom of a tank without opening it, but the most effective and common method is the use of a combination of the MFL and UT techniques.

EXAMPLE

We have a tank that contains water; its original bottom thickness is 1/4", and the bottom was already repaired in some points by adding lapped patch plates. There is one point in the bottom, though, that is 5mm thick. Corrosion rate for the top side of the bottom is 0.5mm per year, and the corrosion rate for the underside of the bottom is 0. There are no corroded areas in the soil side. The owner/operator asks if the tank can resist 10 more years in service, since it has no means for detection and containment of a bottom leak.

SOLUTION:

MRT = 2.54mm

UP_R = 0

RT_{bc} = 6.35 – 0 = 6.35mm

RT_{ip} = 6.35 – 5 = 1.35mm

Minimum between RT_{bc} and RT_{ip} = 5mm

S_tP_R= 0.5$mm/year$

$$O_R = \frac{(5mm) - 2.5mm}{(0.5mm/year - 0)} = 5\ years$$

<u>The tank is NOT safe to operate until next internal inspection. Repair the corroded areas to increase inspection interval.</u>

EXAMPLE

An AST is being inspected. The original bottom thickness was 10 mm. Maximum depth of corrosion pits from inside of tank on the tank bottom = 4 mm. Maximum corrosion from bottom side = 5 mm. Rate of corrosion on topside of bottom = 50 microns / year. Rate of corrosion on bottom side = 150 microns / year. The tank does have a leak detection system on the bottom. Calculate when the next inspection interval should be due.

SOLUTION:

RT_{bc} =10 – 5 = 5mm

RT_{ip} = 10 – 4 = 6mm

MRT = 0.05” = 1.25mm

MRT = Minimum between RT_{bc} and RT_{ip} -$O_R(S_tP_R + UP_R)$

1.25mm = 5mm - O_R (0.05mm/y + 0.15mm/y)

O_R * 0.2mm/y = 3.75mm

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O_R = 3.0 / 0.25 = 18.75$years$

The next inspection interval is 18.75 years or earlier.

CRITICAL ZONE

The minimum bottom plate thickness in the critical zone of the tank bottom shall be the smaller of:

- 1/2 the original bottom plate thickness (not including the original corrosion allowance) or
- 50 % of t_{min} of the lower shell course per 4.3.3.1 but not less than 0.1 in.

Check figure 3 for better understanding.

ANNULAR PLATES

Annular plates also have a critical zone. However, the method to find the minimum thickness of an annular plate is different. For tanks in service with a product specific gravity less than 1.0, considerations, the thickness of the annular plates shall be not less than the thicknesses given in Table 4.5, plus any specified corrosion allowance.

Check figure 4 for better understanding.

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Plate thickness* of First Shell Course (in)	Stress in First shell course (lbf/in2)			
	24,300	27,000	29,700	32,400
t<=0.75	0.17	0.20	0.23	0.30
.75<t<=1.00	0.17	0.22	0.31	0.38
1.00<t<=1.25	0.17	0.26	0.38	0.48
1.25<t<=1.50	0.22	0.34	0.47	0.59
t>1.50	0.27	0.40	0.53	0.68

* As constructed

TABLE 4. (TABLE 4.5 OF API 653)—ANNULAR PLATE MINIMUM THICKNESS FOR TANKS WITH PRODUCT WITH SG<1

Stresses are calculated from $[2.34D(H-1)]/t$

t = nominal thickness of first shell course ("as constructed").

For tanks in service with a product specific gravity 1.0 or greater, go to API 650, Table 5.1*

EXAMPLE

Calculate the minimum thickness of the bottom and the critical zone of a tank bottom at the end of the in-service operation period. Use the following data:

$D = 35ft$

$H = 30ft$

Original bottom thickness = 0.354in

Tank has no lining or means for detection and containment of a bottom leak

Material: ASTM A36

Specific gravity of the product = 1 (water)

E = 1

SOLUTION

Minimum thickness of the bottom for containment reasons: 0.1$inches$

Minimum thickness of the critical zone for strength reasons:

the smaller of:

- ½*0.354" = 0.177$inches$
- 50 % of t_{min} of the lower shell course per 4.3.3.1 but not less than 0.1in.

$$t_{min} = \frac{2.6(H-1)DG}{SE}$$

$$t_{min} = \frac{2.6(30-1)35*1}{24{,}900*1} = .105 inches$$

Then, the minimum allowable thickness in the critical zone is 0.105$inches$

EXAMPLE:

Calculate the minimum thickness of the bottom and the annular plate of a tank bottom at the end of the in-service operation period. Use the following data:

$H = 52ft$

$D = 131ft$

Specific gravity of product: 0.9

Nominal thickness of first shell course = $0.61in$

SOLUTION:

- Minimum thickness of bottom plates: $0.05inches$

- Minimum thickness on annular plates

$$S = 2.34D(H-1)/t$$

$$S = 2.34 * \frac{131(52-1)}{0.61} = 25{,}268psi$$

From table 4.4, the minimum thickness of the annular plate is $0.2inches$

POINTS TO REMEMBER

During the first internal inspection, bottom thicknesses must be measured in order to calculate rates of corrosion in the product side and in the soil side. With these corrosion rates, choose the minimum thickness from table 4.4 (bottom), or section 4.4.5.4 (sketch plates in critical zone), or table 4.5 + CA (annular plates) and then compare against the MRT calculated from the equation.

Or

You can conduct an RBI assessment that can be used to establish the interval for subsequent inspection intervals for tank bottoms

Or

You could conduct a stress analysis to assess the annular plates or the critical zone of sketch plates

If the result indicates that the tank will have a small service life, make repairs, recoat if necessary and close the tank.

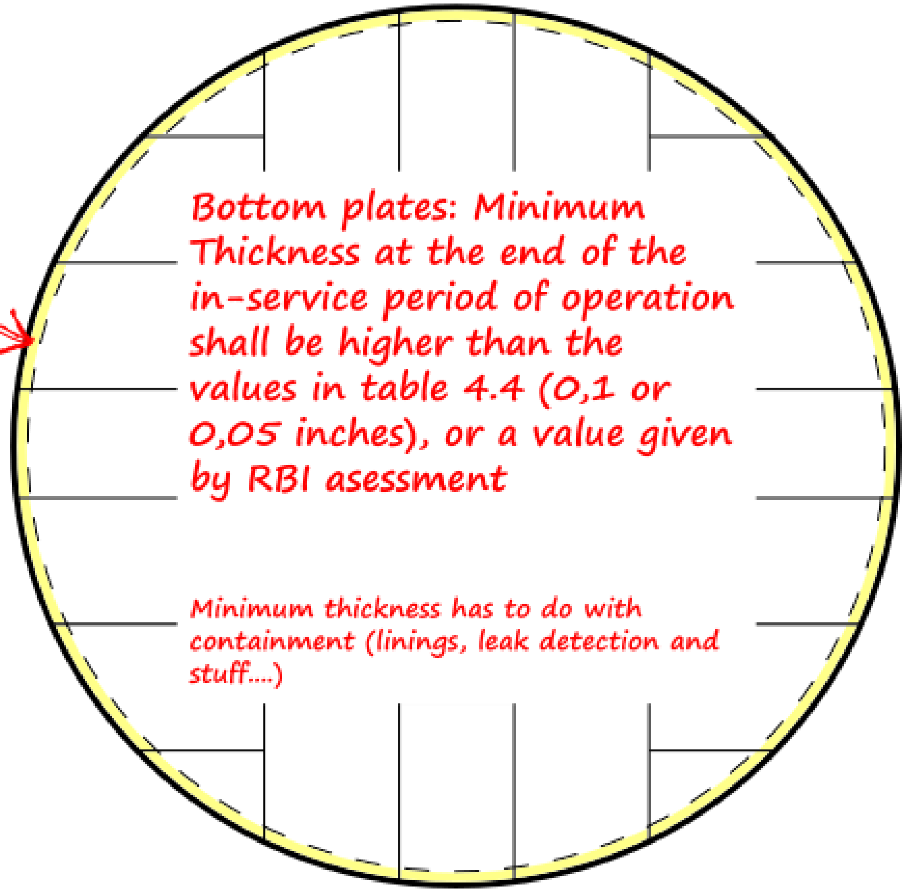

FIGURE 3 MINIMUM THICKNESS OF A BOTTOM OF A TANK WITHOUT ANNULAR PLATES

Annular plates: Minimum Thickness for tanks in service with a product specific gravity less than 1.0 at the end of the in-service period of operation shall be higher than the values in table 4.5 plus CA, or a value given by a stress analysis

Minimum thickness has to do with strenght

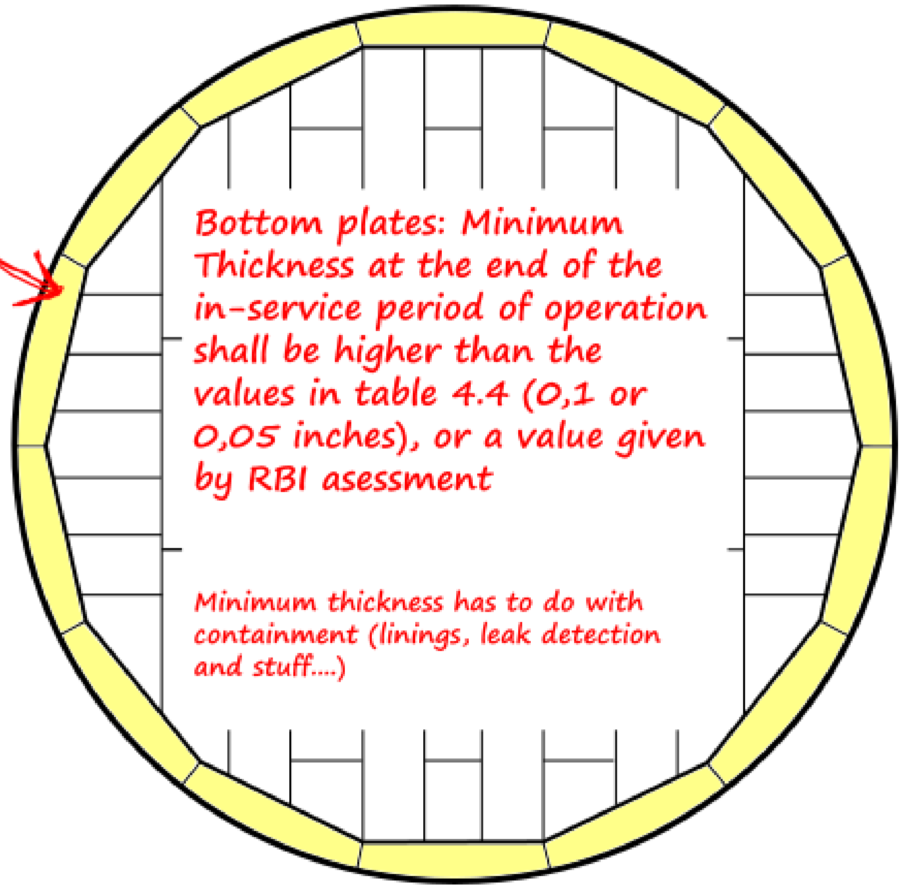

FIGURE 4 MINIMUM THICKNESS OF A BOTTOM OF A TANK WITH ANNULAR PLATES

IF YOU DON´T KNOW THE RATES OF CORROSION

Maybe you are inspecting a tank that has no information from the construction or from previous inspections and there is no possibility of a similar service assessment. If that´s the case, you won´t be able to calculate the remaining thickness at the end of your interval O_R. In this case, assess the risk of continued service (RBI) and take the action you think is the best.

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CHAPTER 3: CALCULATING CURRENT FITNESS FOR SERVICE AND NEXT INSPECTION INTERVAL OF A TANK SHELL

The first thing to realize here is that shell inspection are external inspections.

What we are going to do is to dissect the diagram in FIG. 4.1 of API653 until we truly understand it, and there will be no way we fail any of the questions related to this in the exam. First, we are going to see the following diagram.

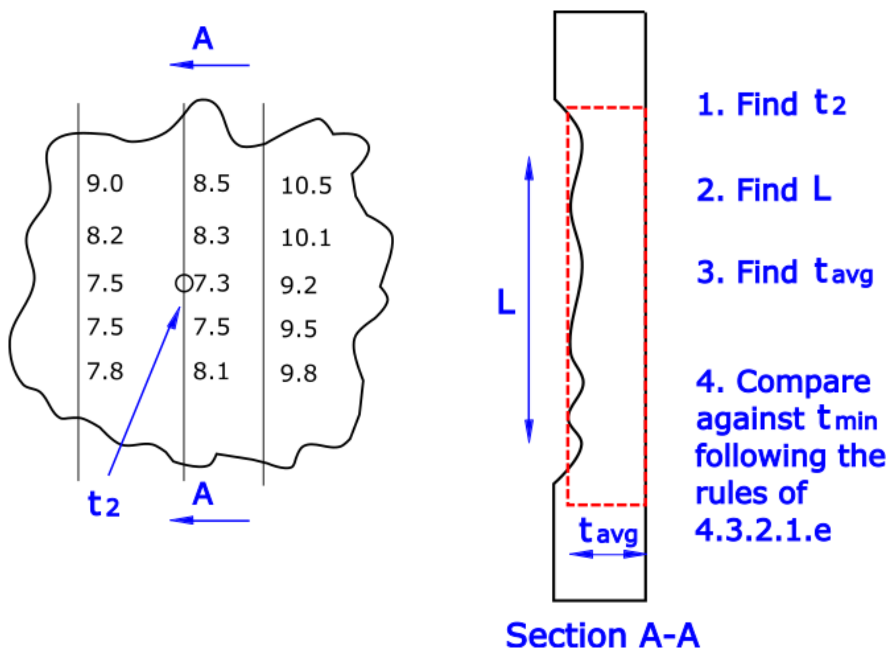

FIGURE 5 FIGURE 4.1 OF API 653 CALCULATION OF AVERAGE THICKNESS

Look at the vertical sections drawn in the picture. Remember that hoop stresses (stresses that are tangential to the shell of the tank) are higher in vertical planes than in horizontal planes. I will show you the demonstration later…

Corrosion can affect tank shells in many ways, as the standard says. In time, uncontrolled corrosion can weaken or destroy the tank´s shell, resulting in holes or possible structural failure, and release of stored products into the environment. But the most common form of damage is a "generally uniform loss of metal over a large area or in localized areas". In a scheduled external inspection scenario, where you must evaluate a tank shell, you will have to follow the procedure of 4.3.2.1. of API 653 and figure 4.1.

PROCEDURE FOR CALCULATING

API 653 4.3.2.1. For determining the controlling thicknesses in each shell course when there are corroded areas of considerable size, measured thicknesses shall be averaged in accordance with the following procedure.

1. Calculate the minimum thickness t_2 in the corroded area

2. Calculate the critical length L in which thicknesses "average out", with one of the following formulas

Eq. 10. $$L = 3.7\sqrt{Dt_2} \quad \text{(SI)}$$

Eq. 11. $$L = 33.75\sqrt{Dt_2} \quad \text{(USC)}$$

3. Locate L, in several vertical planes that you think are more affected by corrosion, and measure at least 5 points to get t_{avg} in each one of those vertical planes. One of those planes will have the lowest average thickness, which you should compare to t_{min} per the formulas in 4.3.3.1

Eq. 12. $$t_{min} = \frac{2.6(H-1)DG}{SE}$$

for an entire shell course

or

Eq. 13. $$t_{min} = \frac{2.6HDG}{SE}$$

for locally thinned areas

Essentially, this procedure limits the size of the zone you are evaluating so it is not too big. This way the "averaging out" is a more realistic way of evaluating metal loss than the arithmetical average.

It is like they say in my homeland about the problem with statistics: "If I eat 2 chickens and you don´t eat any, then we both ate 1 chicken each". Given that metal loss profiles can have very different thicknesses, there is a need for a method to average out the corrosion. That is what the standard is trying to avoid: a situation where the shell evaluation is too simplistic. What I try to say is that smaller the thickness in any point, the smaller the zone were thicknesses average out, with 40inches limit as a maximum. After you have calculated the critical length, then you must take five measures in it and calculate the arithmetical average and compare it to the minimum allowable.

4. Compare $t_1$and t_2 against t_{min} with the following criteria

i) the value t_1 shall be greater than or equal to t_{min}, subject to verification of all other loadings listed in 4.3.3.5;

ii) the value t_2 shall be greater than or equal to 60 % of t_{min}; and

iii) any corrosion allowance required for service until the time of the next inspection shall be added to t_{min} and 60 % of t_{min}

HINT

Realize that corroded areas can be present internally or externally. Anyway, the inspector needs to see the corroded area to assess which area is more affected by corrosion.

UT MEASUREMENT

Usually, 4, 6 or 8 measurements of shell thickness are taken in several vertical lines comprising 360° in each course of the tank shell to fulfill the UT requirements of external inspection, although this must be an agreement with the owner/operator. When using a tank crawler, usually you measure every foot on eight lines in the eight wind directions in the tank shell. This can be modified depending on the configuration of the tank.

Remember that this procedure for shell evaluation is for localized corroded areas. For a complete shell plate, you will have to take UT measurements in the best agreement with the owner.

EXAMPLE:

CUI was detected after the insulation of a tank was removed for inspection. It generated a corroded area away from vertical welds, in the bottom of the third course of the tank, which is in operation. The inspector took 5 UT measures along 3 vertical planes each, in the positions where he thought there was more corrosion, following the instructions in API 653, 4.3.2.1.c "*The authorized inspector shall visually or otherwise decide which vertical plane(s) in the area is likely to be the most affected by corrosion*". His findings are illustrated in Fig 1. The product stored is crude oil with a specific gravity of 0.978. Corrosion rate is 0.5*mm/year*. Having in mind the average corrosion measured, is the tank safe to operate until next inspection due in 5 years? D= 15.24m. The third course is originally 12*mm* thick ASTM-A-36M steel. Maximum liquid level is 11.88m and courses are 8ft wide.

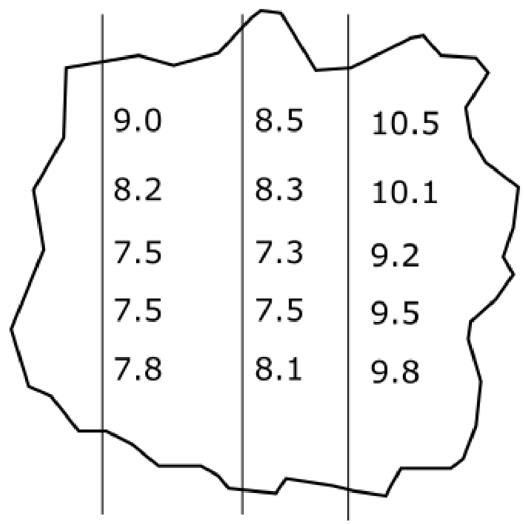

FIGURE 6 UT MEASUREMENTS OF A GENERALLY CORRODED AREA

SOLUTION:

1) Find the controlling thickness

$$t_2 = 7.3mm$$

2) Calculate the critical length

$$L = 33.75\sqrt{Dt_2} = 33.75\sqrt{15.24 * 7.3}$$

3) Calculate t_{avg} along several vertical planes, with at least 5 thickness measures in each plane, and compare against t_{min}

$$t_{avg1} = \frac{9 + 8.2 + 7.5 + 7.5 + 7.8}{5} = 8.0mm$$

$$t_{avg2} = \frac{8.5 + 8.3 + 7.3 + 7.5 + 8.1}{5} = 7.94mm$$

$$t_{avg3} = \frac{10.5 + 10.1 + 9.2 + 9.5 + 9.8}{5} = 9.82mm$$

The lowest average thickness is 7.94mm, in plane #2. Then we calculate t_{min} in USC

$$D = 15.24m = 50ft$$

$$H = 11.88m - 2 * 1.44m = 7m = 22.96ft$$

$$t_{min} = \frac{2.6 * 22.96 * 50 * 0.978}{27{,}400 * 1} = 0.106in = 2.7mm$$

As API 653 says, the criteria for continued operation is as follows:

i) the value t_1 shall be greater than or equal to t_{min} (see 4.3.3 or 4.3.4), subject to verification of all other loadings listed in 4.3.3.5; t_1 is t_{avg}

Eq. 13. $t_{avg} \geq t_{min}$

$$7.94mm \geq 2.7mm \quad OK$$

<u>The tank is fit for service.</u>

ii) the value t_2 shall be greater than or equal to 60 % of t_{min} and

Eq. 14. $t_2 \geq 0.6 * t_{min}$

$$7.3mm \geq 0.6 * 2{,}7mm = 1.62mm \quad OK$$

<u>The tank is fit for service.</u>

iii) any corrosion allowance required for service until the time of the next inspection shall be added to t_{min} and 60 % of t_{min}

$$\text{Eq. 15.} \quad t_{avg} \geq t_{min} + CR * interval$$

$$7.94mm \geq 2.7mm + 0.5\frac{mm}{y} * 5y = 5.2mm \quad OK$$

<u>The tank is safe to operate until next inspection</u>

$$\text{Eq. 16.} \quad t_2 \geq 0.6 * t_{min} + CR * interval$$

$$7.3mm \geq 0.6 * 2.7mm + 0.5\frac{mm}{y} * 5y = 3.12mm \quad OK$$

<u>The tank is safe to operate until next inspection</u>

This analysis shall be made for as many thinned areas there are in the tank shell. If the corroded area still is larger than 40 inches. If the corroded region is larger than L in the vertical direction, the region must be divided into multiple sections such that no individual section is larger than L. Each section must then be evaluated separately.

EXAMPLE

With the following data, tell if the tank is safe to operate UNTIL THE NEXT INSPECTION:

1) Tank constructed in 1984
2) Maximum liquid height = 56 feet
3) Tank diameter = 60 feet
4) Product specific gravity = 0.978
5) Course width = 8 feet

6) Corrosion rate = 0.1 mm / year
7) Material = ASTM-A-36
8) After 20 years, a patch was observed on the second shell course, at 46 feet from the top. The next interval for inspection is 10 years.
9) Original thickness of the second shell course = 12,5mm
10) Readings in vertical planes a, b, c, d, in millimeters, over the length L were:

	a	b	c	d
1	10.6	10.3	10.1	10.3
2	10.1	10.1	9.9	9.8
3	10.1	9.8	8.5	9.8
4	9.5	10.1	9.2	10.1
5	10.6	10.3	9.8	10.3
Σ	50.8	50.6	47.5	50.3

SOLUTION:

1) $t_2 = 8.5mm = \ 0.335inches$

2) $L = 3.7\sqrt{Dt_2} = 3.7\sqrt{120 * 0.335} = 23.46inches$

3) t_{avg} for plane a = 50.8/5 = 10.16mm

t_{avg} for plane b = 50.6/5 = 10.12mm

t_{avg} for plane c = 47.5/5 = 9.5mm

t_{avg} for plane d = 50.3/5 = 10.06mm

So, the weakest plane is c. And the lowest of t_{avg} is 9.5mm

$t_{avg} = 9.5mm$

4)

$$t_{min} = \frac{2.6 * 60 * 46 * 0.978}{24{,}900} = 0.281in = 7.15mm$$

For safe operation until next inspection:

$$t_{avg} \geq t_{min} + CR * interval$$

$$9.5mm \geq 7.15mm + 0.1\frac{mm}{y} * 10y = 8.15mm \quad OK$$

<u>The tank is safe to operate until next inspection.</u>

$$t_2 \geq 0.6 * t_{min} + CR * interval$$

$$8.5mm \geq 0.6 * 7.15mm + 0.1\frac{mm}{y} * 10y = 5.29mm \quad OK$$

<u>The tank is safe to operate until next inspection.</u>

WHAT TO DO IF YOUR TANK IS NOT FIT FOR SERVICE

If the minimum thickness "t" calculated is less than needed for the tank to continue providing service, then one of three things should be made

- the corroded or damaged areas shall be repaired, or
- the allowable liquid level of the tank reduced, or
- the tank retired

As an example, let´s suppose that, in the above exercise, t_2 is be less than 60% of t_{min}.

If $t_{min} = 7.15mm$, let´s give t_2 a value of 4.1mm. That´s not good. Luck that nothing happened.

Let´s suppose that the owner doesn´t want to make a repair, because it is too costly. He decides that it is best to reduce the tank level for 2 or 3 of years and after that, the tank will be retired. So, the new fill height must be calculated

SOLUTION:

In this case, you use the equation in 4.3.3.1 and solve for H. The actual thickness, as determined by inspection, minus the corrosion allowance shall be used to establish the liquid level limit.

$$CA = CR * 3years = 0.3mm$$

$$t_2 = 4.1 - 0.3 = 3.8mm = 0.149in$$

$$t_{min} = \frac{0.149}{0.6} = 0.248in$$

$$H = \frac{S_t E t}{2,6DG}$$

$$H = \frac{24,900 * 1 * 0.248}{2,6 * 60 * 0.978} = 40.48ft$$

Liquid level shall be reduced to 40.48*ft* over the locally thinned area

POINTS TO REMEMBER

You shall evaluate the shell for continued operation solving the equation in 4.3.3. If it doesn´t fulfill the equation, damaged areas should be repaired, or the inspection interval reduced, before the tank continues to work.

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CHAPTER 4: JOINT EFFICIENCIES

What is joint efficiency?

Joint efficiency is a concept found in several API and ASME codes. It is a numerical value, which represents a percentage, expressed as the ratio of the strength of a riveted, welded, or brazed joint to the strength of the base material. It is also a way to introduce safety factors in welding of shells for containment, and can be expressed as follows:

Eq. 17. $$Joint\ efficiency = \frac{Strength\ of\ weld}{Strength\ of\ base\ material}$$

In other standards, values for Joint Efficiency in welds are assumed according to 2 traits

1. Type of welded joint
2. Extent of NDE required for the welded joint

In the API 650 basic standard, joint efficiency for shell welds is currently 1 for complete penetration butt welds. In the API 653 standard, joint efficiency for welded joint varies with the as-built standard, while joint efficiency for rivet joints varies with geometry.

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Please take a look at the following table based on API 653

Standard	Edition and year	Type of joint	Joint Efficiency e	Applicability or limits
API 650	**Seventh and later**	Butt	1.00	Basic Standard
	(1980 to present)	Butt	0.85	Appendix A Optional Design Basis for Small Tanks spot RT
		Butt	0.70	Appendix A Optional Design Basis for Small Tanks no RT
	First to sixth	Butt	0.85	Basic Standard
	(1961 to 1978)	Butt	1.00	Appendices D and G
API 12C	14th and 15th	Butt	0.85	
	(1957 to 1958)			
	Ord to 13th	Lap*	0.75	3/8in max, t
	(1940 to 1956)	Butt*	0.85	
	First and second	Lap*	0.70	7/16in, max.t
Unknown		Lap*	0.70	7/16in max.t
		Lap*	0.50-k/5	1/4in max.t
		Butt	0.70	
		Lap*	0.35	

TABLE 5. TABLE 4.2 OF API 653 - JOINT EFFICIENCIES FOR WELDED JOINTS

Joint efficiency varies with weld type. Various weld types and joint efficiencies for them can be found in Table UW-12 "*Maximum allowable joint efficiencies for arc and gas welded joints*" of ASME VIII, Div 1, Sec B. for pressure vessels. A butt welded joint will have a greater value of *E* than a fillet welded joint.

Type of Joint	Number of Rivet Joints	Joint Efficiency E
Lap	1	0.45
Lap	2	0.60
Lap	3	0.70
Lap	4	0.75
Butt*	2**	0.75
Butt	3**	0.85
Butt	4**	0.90
Butt	5**	0.91
Butt	6**	0.92
All butt joints listed have butt straps both inside and outside		
Number of rows on each side of joint center line		

TABLE 6. TABLE 4.3—JOINT EFFICIENCIES FOR RIVETED JOINTS

Of course, regarding welded aboveground storage tanks, we will speak only about butt welded joints. According to API 650 5.1.5, vertical and horizontal shell joints shall be butt joints with complete penetration and complete fusion.

Since the seventh edition of API 650, all tanks are constructed with a default 1 joint efficiency, meaning that shells are the thinner they can be (See table 4.2). This only was reached, obviously, with improvements in base material (which improves the yield strength value), weld consumables and welding processes. Besides, only complete penetration butt welds are permitted in new tanks, simplifying the issue.

What has to do joint efficiency with tank inspections?

1. When determining the minimum acceptable thickness for an entire shell course, for any other portions of a shell course, according to the following equations

Eq. 18. $$t_{min} = \frac{2.6(H-1)DG}{SE}$$

Eq. 19. $$t_{min} = \frac{2.6HDG}{SE}$$

2. When determining the maximum level of water to be used during hydrostatic test of a tank (for example, if you need to change tank service to a higher specific gravity liquid), according to the following equations

Eq. 20. $$H_t = \frac{S_t E t_{min}}{2,6D} + 1$$

Eq. 21. $$H_t = \frac{S_t E t_{min}}{2,6D}$$

t_{min} is the minimum acceptable thickness, in inches for each course as calculated from the above equation;

however, t_{min}shall not be less than 0.1 in. for any tank course;

D is the nominal diameter of tank, in feet (ft);

H is the height from the bottom of the shell course under consideration to the maximum liquid level when evaluating an entire shell course, in feet (ft.); or

is the height from the bottom of the length L (see 4.3.2.1) from the lowest point of the bottom of L of the locally thinned area to the maximum liquid level, in feet (ft.); or

is the height from the lowest point within any location of interest to the maximum liquid level, in feet (ft.);

G is the highest specific gravity of the contents;

S is the maximum allowable stress in pound force per square inch (lbf/in.2); use the smaller of 0.80 Y or 0.429 T

for bottom and second course; use the smaller of 0.88 Y or 0.472 T for all other courses. Allowable shell

stresses are shown Table 4.1 for materials listed in the current and previous editions of API 12C and API 650;

NOTE for reconstructed tanks, S shall be in accordance with the current applicable standard;

Y is the specified minimum yield strength of the plate; use 30,000 lbf/in.2 if not known;

T is the smaller of the specified minimum tensile strength of the plate or 80,000 lbf/in.2; use 55,000 lbf/in.2 if not known;

E is the original joint efficiency for the tank. Use Table 4.2 if original E is unknown. E = 1.0 when evaluating the retirement thickness in a corroded plate, when away from welds or joints by at least the greater of 1 in. or twice the plate thickness.

H_t is the height from the bottom of the shell course under consideration to the hydrostatic test height when evaluating an entire shell course in feet; or is the height from the bottom of the length, L, (see 4.3.2.1) for the most severely thinned area in each shell course to the hydrostatic test height in feet; or

is the height from the lowest point within any other location of interest to the hydrostatic test height in feet;

S_t is the maximum allowable hydrostatic test stress in pound force per square inch (lbf/in.2); use the smaller of 0.88 Y or 0.472 T for bottom and second courses; use the smaller of 0.9 Y or 0.519 T for all other courses.

When you know the standard by which a tank was built, and solve any of the equations above, you can see if it is fit for continued service. Have in mind that joint efficiency evaluation makes sense only when the corrosion is in close proximity to the joints. The value of E is 1 for any spot 1inch or more apart from the weld in welded joints or 6inches to the outermost rivet away from the centerline in a riveted joint.

In the exam, one or two questions about joint efficiency will show up. That´s why you need this subject fully understood.

EXAMPLE

Q: A riveted tank built in 1984 is being inspected. Calculate the joint efficiency for a butt joint with a total of 4 rows of rivets. What is the joint efficiency?

A:

EXERCISE:

A tank has 4 courses. Year of construction is unknown. Shell height is 21.87 and diameter is 12.22ft (Maximum liquid level is unknown). Please inform if the tank can be put in service right away for oil.

SOLUTION:

D = 12.22 ft.

H = 21.87 ft.

G = 1.0.

S = Given that the steel is of unknown quality, S is 23,600psi for the 2 lower courses, and 26,000 psi for the upper courses. API 653 Table 4-1.

E = 0.70 (The minimum of table 4-2, because year of construction is unknown)

$$t_{min} = \frac{2.6(H-1)DG}{SE}$$

We arrange the data in a table and we find that the tank is fit for service in all its courses.

COURSE	Heigth (ft)	Liquid level (ft)	Allowable stress (psi)	Diameter (ft)	Specific gravity	Joint efficiency	Average thickness (in)	Minimum thickness (in)
1	5.99	21.87	23,600	12.22	1.00	0.70	0.181	0.040
2	5.77	15.88	23,600	12.22	1.00	0.70	0.181	0.029
3	4.94	10.11	26,000	12.22	1.00	0.70	0.168	0.016
4	5.17	5.17	26,000	12.22	1.00	0.70	0.167	0.007

POINTS TO REMEMBER

Joint efficiency is.....

....Taken from table 4-2 if the point is less than 1inch or 2 times the thickness away from the weld in welded seams.

....Taken from table 4-3 if the point is less than 6inches away from the centerline of the riveted joint.

.... 1 for de-seamed reconstructed tanks. It is the lowest allowed in table 4-2 if the seams are left in place.

In normal conditions, when you open a tank, you will ALWAYS want to improve the internal conditions, given the high expenses associated with opening a tank. So, as an Inspector you just don´t say things like "you can put it in service". You would say something more like "Please repair this and then put the tank back to service"

CHAPTER 5: HYDROSTATIC TESTING

Hydrostatic testing is (or a least should be) done in every new welded tank for oil storage and it is mandatory for any tank that has been under a major alteration, per API 653.

What is an hydrotest? According to API 653, it is a test performed with water, in which static fluid head is used to produce test loads. As it says, for new or repaired tanks, the purpose of hydrostatic testing is to demonstrate the tank´s fitness for service, and the better you test, the less risk you have once the tank is in operation. <u>This goes for all those that try to avoid the hydrostatic test with thousands of tricks: *there is one and only way to test the tank thoroughly for operation and that is the hydrostatic test*</u>.

If you are planning to take the exam, you should be familiar with all the requirements of API 650 and 653 regarding hydrotest. But right now, we will concentrate in calculating hydrostatic test height.

HOW TO CALCULATE HYDROSTATIC TEST HEIGHT?

For a tank that has been in operation, several things can happen that may highlight the need for a hydrostatic test

- If the tank is going to be used for a new, more sever service. That means, when the liquid that will be stored has a higher specific gravity than the current stored product.

- When there have been major repairs in the tank shell or bottom, involving critical welds.

Determination of hydrostatic test height H_t, when you have calculated a controlling thickness for an entire shell course, can be achieved solving for the following equation, where H_t is the height from the bottom of the shell course under consideration to the hydrostatic test height

$$\text{Eq. 22.} \quad H_t = \frac{S_t E t_{min}}{2.6D} + 1$$

Over entire shell course

Determination of hydrostatic test height H_t, when you have calculated controlling thickness for a locally thinned area can be achieved solving for the following equation, where H_t is the height from the bottom of the length, L, (see 4.3.2.1) for the most severely thinned area in each shell course to the hydrostatic test height in feet

$$\text{Eq. 23.} \quad H_t = \frac{S_t E t_{min}}{2.6D}$$

Over locally thinned area

So, hydrostatic test height depends on 4 variables, which are.

S_t: the smaller value between fractions of yield strength or tensile strength, or the maximum allowable hydrostatic test stress.

Lower two courses	The smaller between 0.88Y or 0.472T
Upper courses	The smaller between 0.9Y or 0.519T

TABLE 7. STRESS VALUES FOR HYDROSTATIC HEIGHT CALCULATIONS

E: the joint efficiency

t_{min}: is the controlling thickness

D: the diameter of the tank.

Let´s see an example of height calculation. I am assuming you have some background on the formulas of API 650 and API 653.

EXAMPLE.

A tank will be subjected to hydrostatic testing after repairs. After some study, the inspector decides to run calculations for hydrostatic test height over the first shell course and over a locally thinned area close to a vertical seam, 36 inches high in the 4th shell course. Steel is A36 with Y = 36000psi and T =58000psi. Shell courses are 6ft high and the tank is 48ft diameter. First two courses were welded before 1980 (sixth edition), and the other courses were added recently. The controlling thickness for the first shell course is 7mm and for the locally thinned area is 6,35mm. What should be the hydrostatic test height?

SOLUTION:

Well, for the equations, values are these

<u>Case 1. Lower shell course</u>

E =0.85. See Table 4-2

S_t = smaller of 0.88 Y or 0.472 T, then S_t = 27,376psi
D = 48ft
t_{min}= 7mm = 0.275in

$$H_t = \frac{27{,}376 * 0.85 * 0.275}{2.6 * 48} + 1 = 52.27ft = 15.93m$$

So, hydrostatic test height will be 15,93m.

<u>Case 2. Locally thinned area in 4th course</u>
E =1. See Table 4-2.
S_t = smaller of 0.9 Y or 0.519 T, then S_t = 30,102psi
D = 48
t_{min} = 6.35mm=0.25in

$$H_t = \frac{30{,}102 * 1 * 0.25}{2.6 * 48} = 60.3ft = 18.37m$$

Hydrostatic test height over the locally thinned area can be 18,37m. (An hypothetical total height of 23,01m)

Then the tank has a hydrostatic test height of 15,93m.

EXAMPLE

With the following data, calculate the fill height of a tank and the hydrostatic test height

$D = 120ft$

Minimum thickness of the first course = 0.3in

Specific Gravity = .85

Material = ASTM-A-283-C

Year of construction = 1990.

SOLUTION

$$Fill\ height\ H = \frac{23{,}600 * 1 * .3}{2.6 * 120 * 0.85} = 26.69ft$$

$$Hydrostatic\ test\ height\ H_t = \frac{26{,}000 * 1 * .3}{2.6 * 120} = 25ft$$

HAVE IN MIND FOR YOUR EXAM

You must be aware that variables in these and other equations of the standards can have different values depending on year of fabrication, purpose of calculation (design or hydrostatic loads), etc. In the exam, you should be very careful to avoid mistakes, as they always throw some confusing questions.

Notice that the presence of different defects in tank shells implies than more than one value of t_{min} or H_t should be calculated in a real tank inspection.

CHAPTER 6: WELD SIZING AND SPACING IN TANKS

First let me ask you a question: In which plane are tank shell stresses higher, in a vertical or a horizontal plane...?

Weld spacing in tanks depends on several factors. First, the extent of the HAZ (Heat affected zone) of a weld, in which the magnitude of property change depends primarily on the base material, the weld filler metal, and the amount and concentration of heat input by the welding process. And second, and most importantly, weld spacing depends on the magnitude of the stress of the joint being considered.

Let´s go to the meat. That´s it, what the BOK for the API 653 says is this:

> The inspector should be familiar with determining the sizes and spacing of welds for shell openings to the extent of being able to use the information in the following Figures and Tables:
>
> a) API-650, Figures 5-7A, 5-7B, 5-8, 5-9, 5-12, 5-14, 5-16, 5-17, 5-19, 5-20, 5-21
>
> b) API-650, Tables 5-6, 5-7, 5-9
>
> c) API-653, Figures 9-1, 9-2, 9-4, 9-5

Watching this tables and figures in the standards, you can see that questions for them will rather be made in the open book part of the exam, as difficult it is to illustrate it is to remember.

Therefore, the bulk of tables and figures in this part of the BOK is not treated in this book

For example, check the following, based on figure 9-1 of API 653. This is for shells thinner than 0.5in.

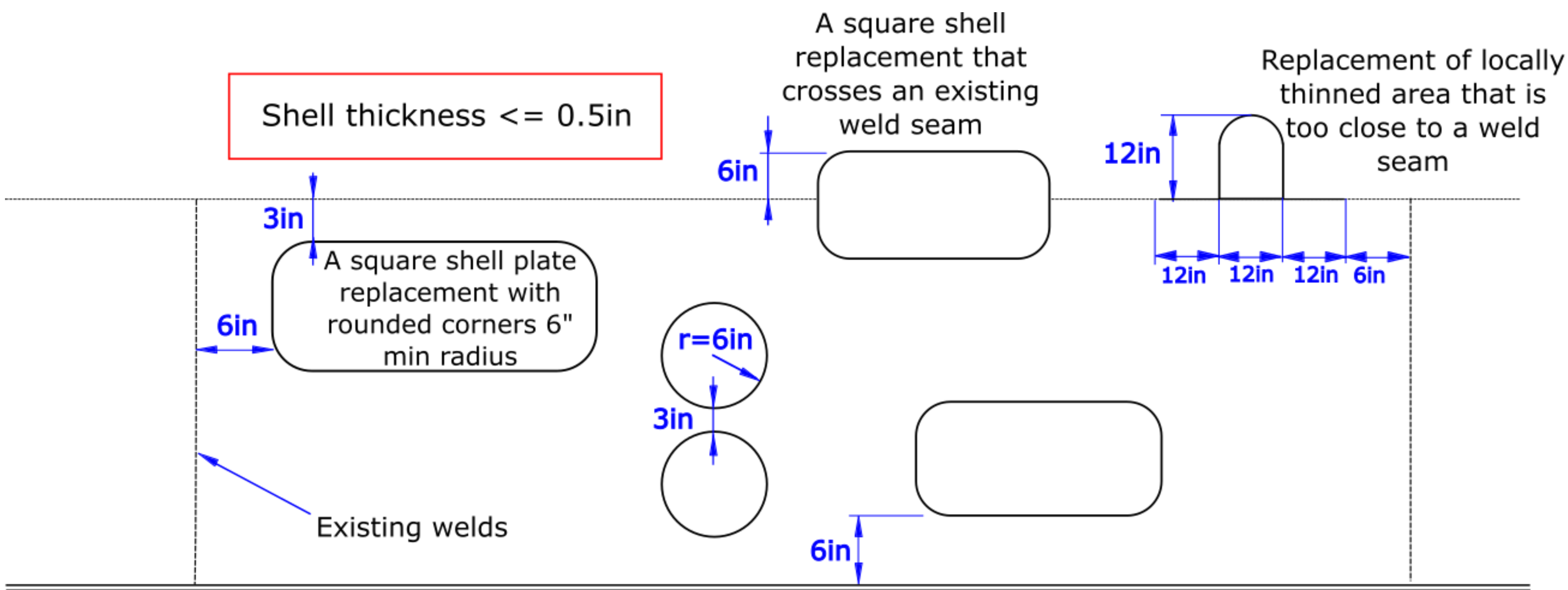


FIGURE 7. FIGURE 9.1-WELD SPACING REQUIREMENTS OF A SHELL 0.5IN OR LOWER

The following figure and table (9) stablishes minimum weld spacing between the toes of welds for thickness of replacement shell plate for sets of thickness above and below 0.5*in*.

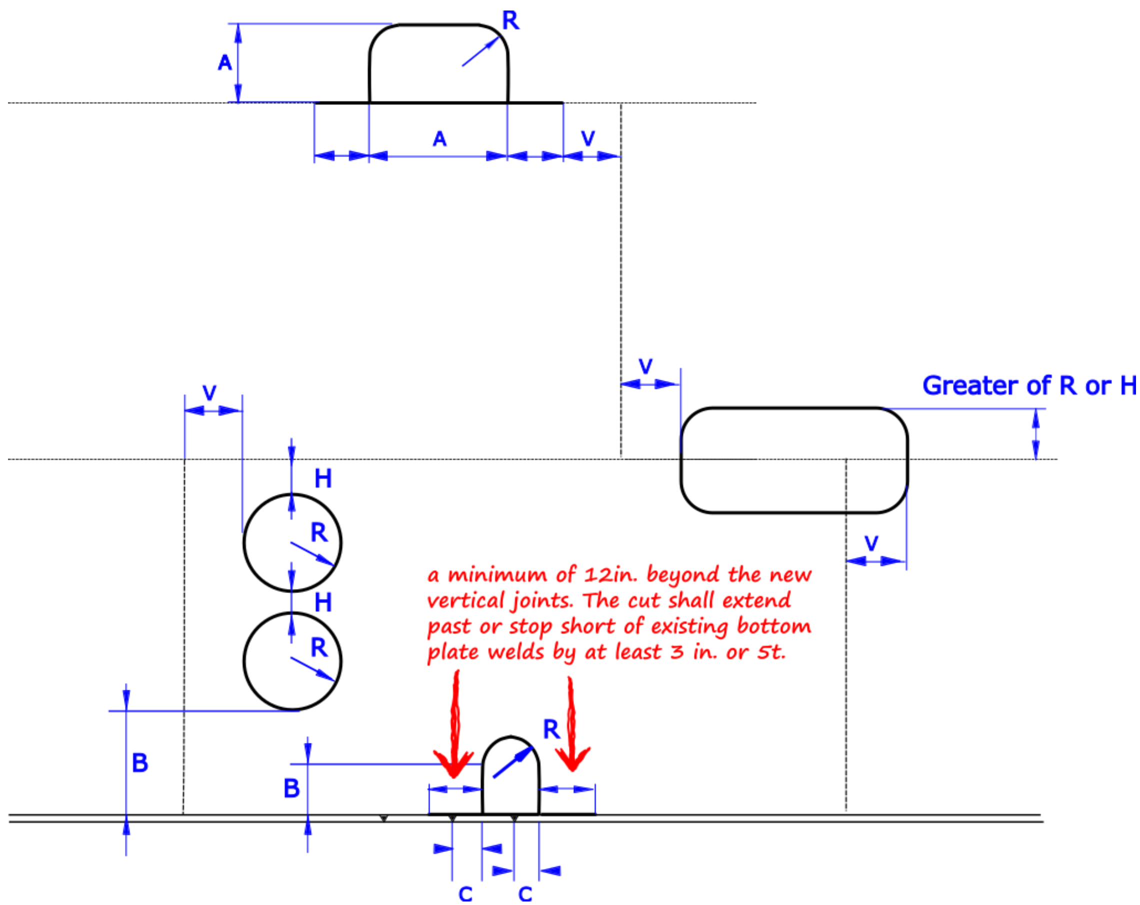
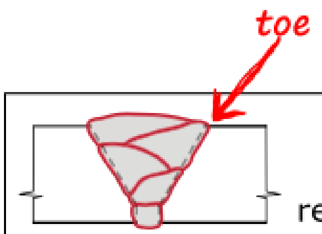


FIGURE 8, FIGURE 9-1 -WELD SPACING IN GENERAL (WORKS WITH THE FOLLOWING TABLE)



	Minimum Weld Spacing Between Toes of Welds for Thickness of replacement Shell Plate, t , (inches)	
Dimension	$t<=0.5$in	$t>0.5$in
R	6in	Greater of 6in. or 6t
B	6in	Greater of 10in. or 8t
H	3in	Greater of 10in. or 8t
V	6in	Greater of 10in. or 8t
A	12in	Greater of 12in. or 12t
C	Greater of 3in. or 5t	

FIGURE 9 - WELD SPACING (WORKS WITH FIGURE 9-1 OF API 653)

You can see that, in general, weld spacing is higher related to vertical joints. The vertical spacing also dictates the sizes of rounded corners.

Arrived to this point, I think it is important to remember the formulas for longitudinal and circumferential stress in a thin walled cylindrical vessel like large tanks are.

Following are the equations used to calculate the stress of a thin wall vessel with an internal pressure. The forces related are a consequence of pressure inside the cylindrical vessel.

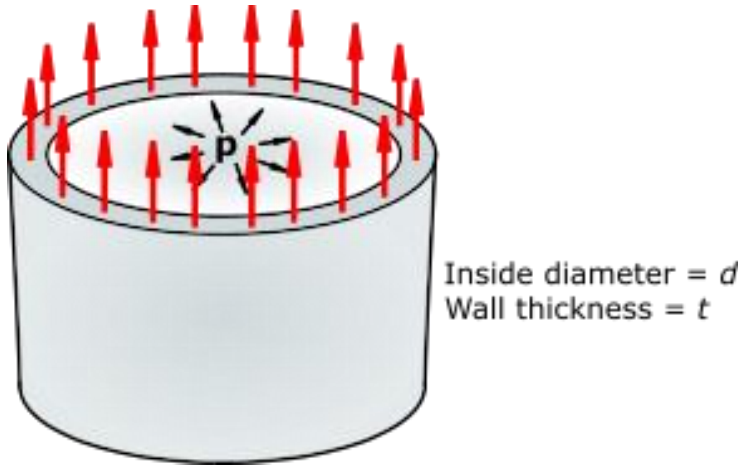


FIGURE 10 - HORIZONTAL STRESS IN A THIN WALL VESSEL

Considering pressure stresses only, the longitudinal weld force P, resulting from internal pressure p, acting on a thin wall tank of thickness t , length l , and diameter d is:

$$\text{Eq. 24.} \quad P = \frac{p\pi d^2}{4}$$

Where P= force tending to rupture the tank horizontally.

If a= area of metal resisting longitudinal force, then

$$\text{Eq. 25.} \quad a = t\pi d$$

Then

$$\text{Eq. 26.} \quad S = \frac{P}{a} = \frac{p\pi d^2/_4}{t\pi d} = \frac{pd}{4t}$$

Where S = stress on the wall of the tank

Solving for t

$$\text{Eq. 26.} \quad t = \frac{pd}{4S}$$

Considering pressure stress only, the following analysis can be made.

Where P = force tending to rupture the tank vertically.

$$\text{Eq. 27.} \quad P = pdl$$

If a = area of metal resisting vertical force, then

$$\text{Eq. 28.} \quad a = 2tl$$

Then

$$\text{Eq. 29.} \quad S = \frac{p}{a} = \frac{pdl}{2tl} = \frac{pd}{2t}$$

(Space intentionally left blank)

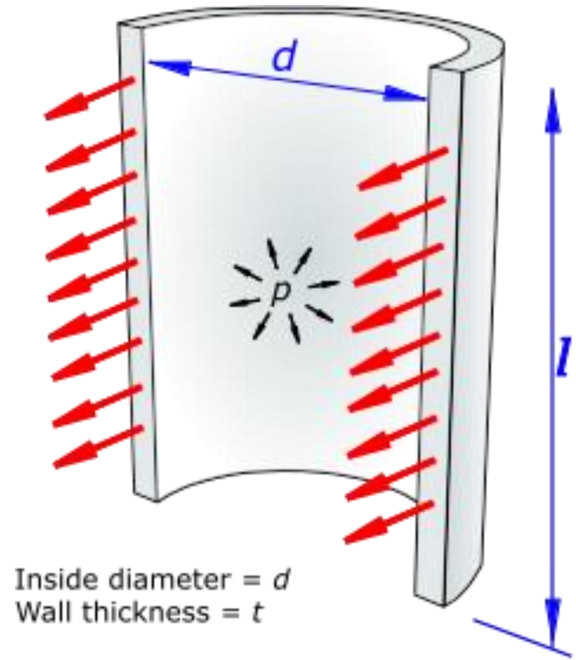


FIGURE 11 VERTICAL STRESS IN A THIN WALL VESSEL

Where S = stress on the wall of the tank

Solving for t

$$\text{Eq. 30.} \quad t = \frac{pd}{2S}$$

From these equations, you can see that vertical stress is twice as high as horizontal stress. It is more likely that, in normal conditions, a tank shell will be torn apart first in the vertical than in the horizontal welds. Therefore, weld spacing should be higher related to vertical welds than horizontal welds

Figures 5-7a, 5-7b, 5-8, 5-9, 5-12, 5-14, 5-16, 5-17, 5-19, 5-20, 5-21 and Tables 5-6, 5-7, 5-9 of API 650, and Figures 9-2, 9-4 and 9-5 of API 653, are not part of this review. Please check them in the standards. Questions based in these numerals will likely be open-book.

POINTS TO REMEMBER

Weld spacing is always larger in the vertical than in the horizontal.

Weld spacing in the shell is more critical than in the bottom.

There are no requirements to weld spacing in roofs.

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CHAPTER 7: HOT TAPPING

According to API 653 3.14, Hot tapping identifies a procedure for installing a nozzle in the shell of a tank that is in service. This means that a tank can continue to be in operation whilst maintenance or modifications are being done to it. This is in complete compliance with the API 653 standard, but following some rules. First, for all of you students, let´s review what the BOK of the API 653 has to say.

a) The Inspector should be familiar with the Hot Tapping requirements. (API-653, Paragraph 9.14)
b) The inspector should be able to calculate the minimum spacing between an existing nozzle and a new hot tap nozzle. (API-653 Paragraph 9.14.3)

Hot tapping is more common in pipelines, although the principles are the same that for tanks. In a normal pipe hot tapping operation, you wish 2 or 3 things.

1. You want flow in the pipe so you can cool the welded zone, given that the liquid works as a heat sink.
2. You want no gases or vapors in the pipe
3. You want to weld nozzles and reinforcements to the pipe without penetrating too much in the base metal, because of pressure.

With tanks, it is the same, with the difference that flow conditions in tanks are close to stagnant.

REQUIREMENTS FOR HOT TAPPING

The following diagram summarizes the requirements for hot tapping found in API 653 9.14

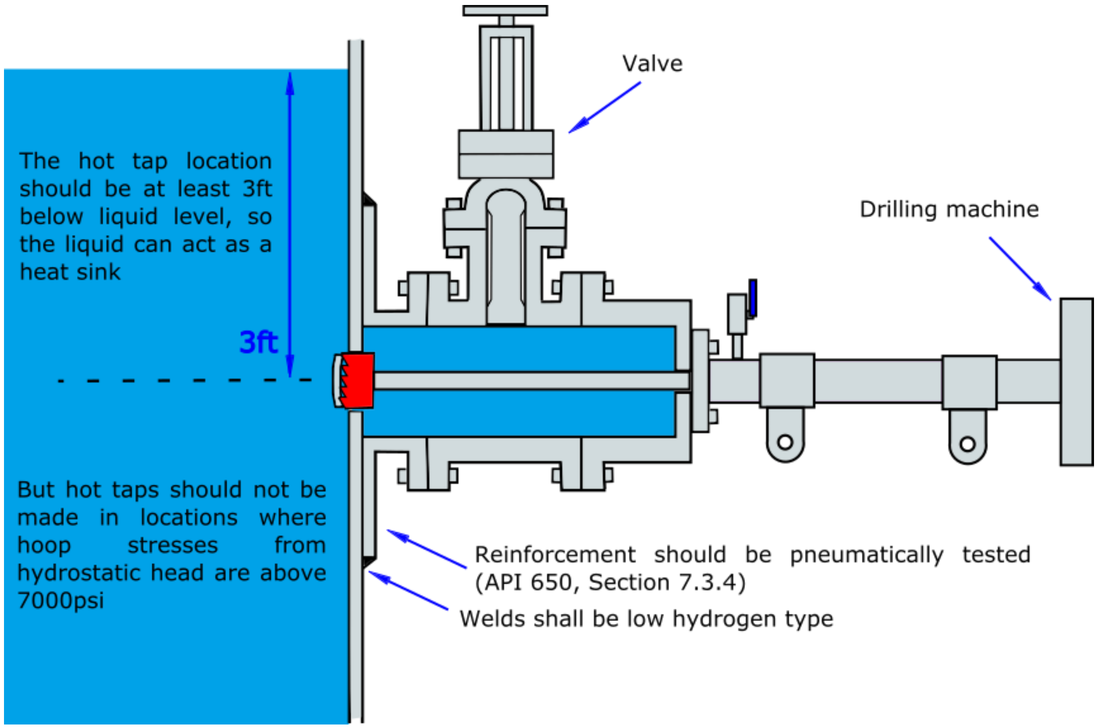

FIGURE 12 HOT TAP ARRANGEMENT

Requirements for hot-taps in tanks

1. Hot taps are not permitted on shell material requiring thermal stress relief
2. Welding shall be done with low hydrogen electrodes.
3. Hot taps are not permitted on the roof of a tank or within the gas/vapor space of the tank.

4. Hot taps shall not be installed on laminated or severely pitted shell plate. As an inspector, you have to make sure that thickness measures are taken in the proposed area for a hot tap.
5. Hot taps are not permitted on tanks where the heat of welding may cause environmental cracking (such as caustic cracking or stress corrosion cracking).
6. Minimum spacing in any direction (toe-to-toe of welds) between the hot tap and adjacent nozzles shall be equivalent to the square root of RT where R is the tank shell radius, in inches, and T is the shell plate thickness, in inches.
7. Minimum distance between the toe of the hot tap weld and a vertical seam should be 12in. According to API RP 2201 (Remember this number very well as could be a question of the exam), the hazards for a hot tapping operation in tanks are the following:

a. Tank venting, with vapors reaching the exterior area where welding is taking place.

b. Product within the tank rising and overflowing.

c. Inadvertently allowing the liquid level within the tank to fall below the point of welding, exposing the vapor space within the tank to an ignition source.

Welding on the exterior of tanks in service shall not be conducted unless controls are established and in place to prevent flammable vapors from reaching the area of welding. Work must be stopped immediately should flammable vapors be detected in the welding area.

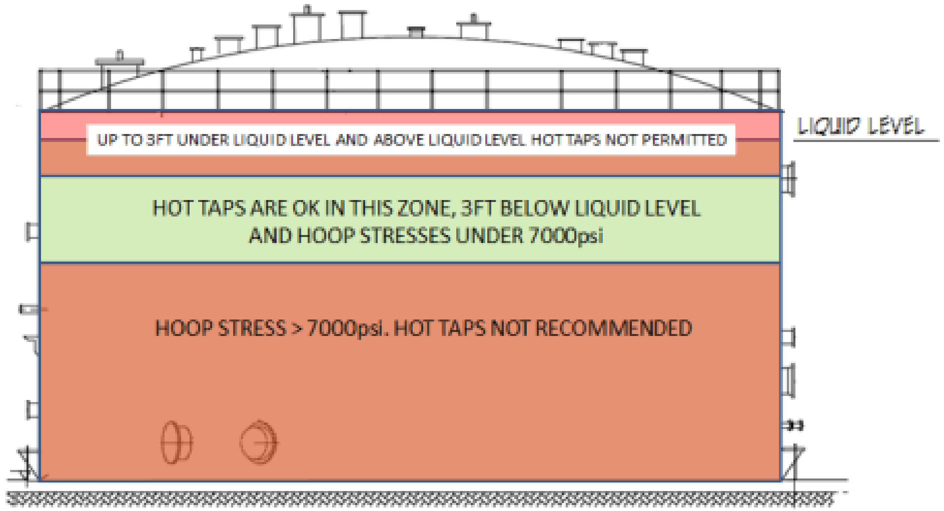

FIGURE 13 WHERE TO MAKE A HOT TAP

WHERE TO MAKE A HOT-TAP

When hot tapping or welding on a tank in service maintain liquid in the tank at a level at least 3 feet (1 meter) above the area where the work is being performed. No attempt should be made to hot tap or weld above this liquid level in atmospheric pressure petroleum storage tanks because of the potential danger of an explosive atmosphere inside the tank vapor space. *Measurements of the tank level should be made by a hand tape gauge to verify the accuracy of automatic or remote reading gauges.*

WELDING ON FLOATING ROOFS

Welding should never be allowed on the decks of floating roof tanks, as they are subject to flammability hazards in several locations:

a. Inside the pontoons.

b. Between the deck and liquid surface near the tank roof gauge float compartment

c. Near the roof seal vent.

d. Near the floating roof lift leg vent.

e. Between the primary and secondary seal.

f. Near the roof drain.

Hot tapping operations must be conducted by experienced personnel. Recommendations in this book don´t constitute a procedure for hot tapping operations

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CHAPTER 8: ASME IX

Before you read this chapter on welding, please look at the WPS that is in Annex 1 of this eBook. Try to realize what is wrong with it. Some Q&A from that document are at the end of this chapter.

One of the content areas that worked out best for me during my exam years ago, was welding. In the time I presented the exam, the number of questions was different from nowadays. From a total of 16 questions about welding, I got 15 right (nowadays they ask only 8). It helped me a lot knowing about welding.

The body of knowledge gives a broad guide of what will appear in the exam related to welding. It says:

> The inspector should have the knowledge and skills required to review a Procedure Qualification Record and a Welding Procedure Specification or to answer questions requiring the same level of knowledge and skill. Questions covering the specific rules of Section IX will be limited in complexity and scope to the SMAW and SAW welding processes.
>
> 1. Questions will be based on:
>
> a) No more than one process
>
> b) Filler metals limited to one
>
> c) Essential, non-essential, variables only will be covered
>
> d) Number, type, and results of mechanical tests
>
> e) Base metals limited to P1
>
> f) Additional essential variables required by API-650 or API-653

2. The following are specifically excluded:

a) Dissimilar base metal joints
b) Supplemental powdered filler metals and consumable inserts
c) Special weld processes such as corrosion-resistant weld metal overlay, hard-facing overlay, and dissimilar
metal welds with buttering
d) Charpy impact requirements and supplementary essential variables
e) Any PQR and WPS included on the examination will not include heat treatment requirements. [.......]
As you can see, some of the questions are based on ASME IX.

The following point by point analysis will help you successfully read and review a WPS and a WPQ.

GENERALITIES

ASME IX "Welding, Brazing, and Fusing Qualifications. Qualification Standard for Welding, Brazing, and Fusing Procedures; Welders; Brazers; and Welding, Brazing, and Fusing Operators" is a part of the ASME Boiler and Pressure Vessel Code, that regulates the design and construction of boilers and pressure vessels. API 650 trusts ASME IX for welding procedure and welder performance qualifications

Some important definitions found in QW-200

WPS: A **Welding Procedure Specification** (WPS) is a formal written document describing welding procedures, which provides direction to the welder or welding operators for making sound and quality production welds as per the code requirements

PQR: The **Procedure Qualification Record** is a Record containing information about the tests conducted over the welds made to a WPS, the variables used during welding of the test coupon, and the successful qualification of that WPS.

WPQ: A **Welder Performance Qualification** is a document recording the ability of a welder to deposit welds in the manner described in the WPS.

All of the three documents contain a set of variables to control. Variables that may be used in a welding procedure test are divided into 3 categories.

Essential Variables Are variables that have a significant effect on the mechanical properties of a joint. They must not be changed except within the limits specified by this code. e.g. Material thickness range, Material Group, welding process, etc. The PQR shall contain all the essential variables.

Non-Essential Variables Are variables that have no significant effect on mechanical properties. They can be changed without re qualification of the PQR.

Supplementary Variables Are variables that influence the impact properties of a joint. They are classed as Non-Essential if impact testing is not required. This kind of variables won´t show up in the exam.

All variables listed as ***essential*** and ***non-essential*** should be addressed on the WPS, while all listed as ***essential*** should be addressed in the PQR. ***Supplementary essential*** variables should be addressed in both documents when required (See QW-200 of ASME IX). If any of the variables do not apply to the particular application, then they should be specified as not applicable. The welding organization can have its own formats for these documents, as long as they meet the aforementioned requirements.

Understanding of the information that should a WPS and a PQR contain is critical. Several WPS can be written on the basis of the successful qualification of the initial preliminary WPS. There is no limit on the number of production WPSs that can be generated from a PQR. And as for the other way around, several PQR can be “summed up” to support a broad WPS, just making sure that the ranges of the variables in the PQRs are the same for the WPS generated.

HOW ASME IX IS ORGANIZED

ASME IX is divided in 4 parts

PART QG, General requirements

PART QW, Welding

PART QB, brazing

PART QF, plastic fusing

We will concentrate in Part QW, which in turn is divided in 5 articles.

- **Article I** – Welding general requirements
- **Article II** - Welding procedure qualifications
- **Article III** – Welding performance qualifications
- **Article IV** – Welding data
- **Article V** – Standard welding procedure specifications (SWPS)

In ASME IX, as much as 20 different welding processes are mentioned when it has to do with procedure qualification. Essential, non-essential and supplementary variables for welding processes can be found in tables QW-252 to QW-269.1 of ASME IX.

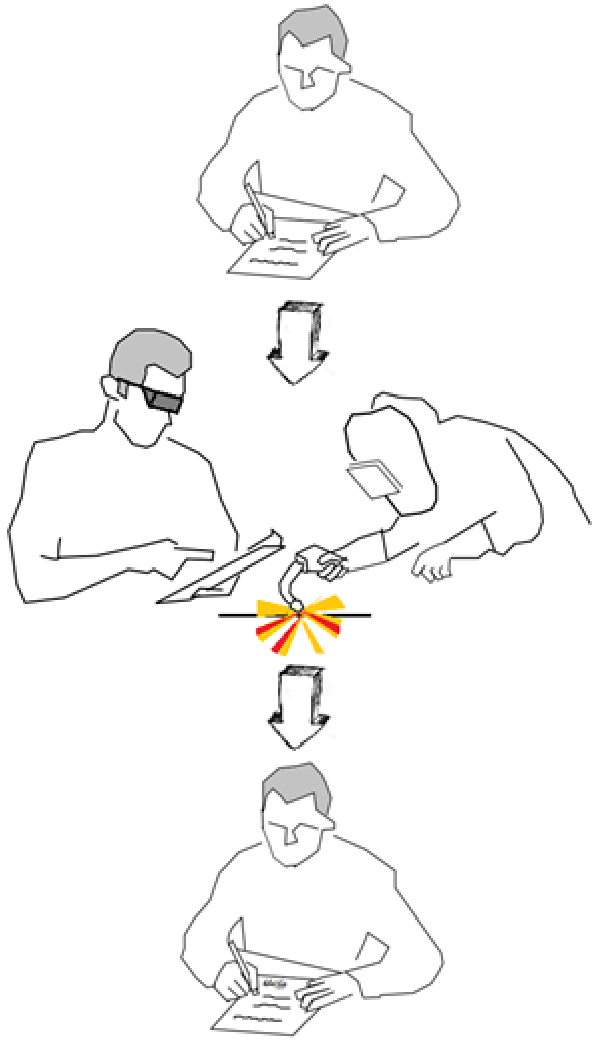
But remember "***Questions covering the specific rules of Section IX will be limited in complexity and scope to the* SMAW *and* SAW *welding processes***". Which are the essential variables needed for these 2 processes? We can find them in QW-253 and QW-254

The nonmandatory appendix B of ASME IX illustrates the different formats for welding procedure specifications, Procedure Qualification records and Welder Performance Qualifications, for the SMAW, SAW, GMAW and GTAW processes, and the basis for other welding processes may follow the general format as applicable. You should look at them.

In the exam, it is required from the candidate to proficiently review a WPS and its supporting PQR that will be given to him. That´s why it is a good idea to be familiar with the appendix B formats.

SIMPLE FLOWCHART OF A WPS AND ITS SUPPORTING PQR

As we said before, a PQR can be the basis of several WPSs and vice versa. The code only asks for the essential variables to be recorded in the PQR. But just complying with the standard may not be enough to make Welding Procedures of consistent quality. The fact is that a preliminary WPS can be made (although not mandatory), a test set up for this preliminary WPS where all variables should be recorded (essential, non-essential and supplementary), and a PQR containing all that variables created. After the weld is accepted by testing, now you can establish a WPS and make it into your procedures. With this recommendation, I created a simple drawing to understand the process.



A formal preliminary WPS can be created (although is not mandatory), with all the essential, non-essential and supplementary essential variables

A welder is given the task to make welds according to the WPS, while someone else records all the essential, non-essential and supplementary essential variables during the process. The resulting PQR must contain at least the essential variables, and supplementary essential variables when required

After the weld has passed tests, the WPS can be oficialized. It must include esential and non-essential variables , and supplementary essential variables when required

FIGURE 14 THE PROCESS OF A WPS

THE MAKING OF A WPS

THE VARIABLES IN A WPS

An aspiring API 653 certified inspector should understand a written WPS and its corresponding PQR. A reviewer of a WPS should verify that

•each WPS has an entry for every essential, (supplementary essential variable when required) and nonessential variable, as listed for the process in QW-250. For SMAW, there are 27 entries to be recorded.

•the WPS covers the ranges for the welding application for each variable listed for each process, as specified in QW-250.

•the WPS meets all other requirements of Section IX.

• the WPS meets all requirements of the construction code.

•the WPS has been properly supported by one or more PQRs, and the supporting PQRs are listed on the WPS.

•every variable range on the WPS is being followed during fabrication or repairs

During the variables review, remember the meanings of the following symbols:

Φ: It means change of a variable
+: It means addition of a variable
-: It means deletion of a variable

ESSENTIAL VARIABLES

As for the Body of Knowledge for the API 653, Essential and Non-Essential variables only will be covered in the exam. Let´s remember that essential variables are different for procedure specification and for performance qualification. The following are definitions of both, according to ASME IX.

QW-401.1 Essential Variable (Procedure). A change in a welding condition which will affect the mechanical properties (other than notch toughness) of the weldment (e.g., change in P-Number, welding process, filler metal, electrode, preheat or post-weld heat treatment).

QW-401.2 Essential Variable (Performance). A change in a welding condition which will affect the ability of a welder to deposit sound weld metal (such as a change in welding process, deletion of backing, electrode, F-Number, technique, etc.).

Next, we are going to make a point-by-point analysis of the 27 variables that should appear in a WPS for the SMAW process.

QW-402. JOINTS

TABLE QW-253

Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)

Paragraph		Brief of Variables	Essential	Non-Essential
QW-402 Joints	.1	ϕ Groove design		X
	.4	- Backing		X
	.10	ϕ Root spacing		X
	.11	± Retainers		X

1. **QW-402.1 A change in the type of groove [Vee-groove, U-groove, single-bevel, double-bevel, etc.).**

A change in groove type, most of the times, won´t affect the mechanical properties of the weld, so it is considered a non-essential variable for most of the processes (for example, it is a supplementary essential variable for PAW and an essential variable for EBW). Groove type can, however change mechanical properties of a weld by changing the A-number (chemical properties), especially when welding dissimilar metals. But its non-essential for SMAW and SAW, the processes of our interest.

2. QW-402.4 The deletion of the backing in single- welded groove welds. Double-welded groove welds are considered welding with backing.

Backing is defined as material placed at the root of a ***weld*** joint for the purpose of supporting molten ***weld*** metal. Its function is to facilitate complete joint penetration. Backing can be part of the weld and fuse with the weld deposit, but is a non-essential variable for the WPS for SMAW and SAW. Correct removal of backing bars after welding has been completed won´t affect the transverse area of the weld. For the welder, if he is tested without backing, he can weld with or without backing, but if he is tested with backing, he can only weld with backing as in the test. If the procedure is qualified with a backing, you can weld without backing, provided the welder is qualified without backing

3. QW-402.10 A change in the specified root spacing.

Root spacing as a non-essential variable illustrates why non-essential variables are recorded into a WPS, given that a change in root spacing won´t affect the mechanical properties, but a too-much-wide root will likely increase the probability of defects if it is out of a range in accordance with sound engineering practices.

4. QW-402.11 The addition or deletion of nonmetallic retainers or nonfusing metal retainers.

This is a difficult one. Not many sources deal with se subject of retainers. A retainer is a non-consumable material, either metallic or non-metallic, that is used to contain or shape the molten root run. It won´t fuse with the base metal, as backing does. It is not an essential variable

QW-403. BASE METALS

TABLE QW-253

Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)

Paragraph		Brief of Variables	Essential	Non-Essential
QW-403 Base Metals	.8	ϕ T Qualified	X	
	.9	t Pass > 1/2 in. (13mm)	X	
	.11	ϕ P-No Qualified	X	

5. QW-403.8. A change in base metal thickness beyond the range qualified in QW-451.

Welding strengths vary according to plate thickness and distance from the weld root. The risk of brittle fracture increases with thickness. Cracks susceptibility is more likely to happen with high thickness and high resistance. Those facts and others, shown by research, demonstrate why base metal thickness is an essential variable.

6. QW-403.9 For single- pass or multipass welding in which any pass is greater than 1/2 in. (13 mm) thick, an increase in base metal thickness beyond 1.1 times that of the qualification test coupon.

A weld pass > ½ inch thick will have sufficient heat input to anneal the HAZ, thus reducing the tensile strength of the weldment, or increase the time the HAZ is exposed to temperatures > 1900 °F, thus reducing the ductility of the weldment. When any single deposited weld pass is > ½ inch thick, the maximum base metal thickness qualified is less than that in table QW-451. Normally in SMAW, GTAW, GMAW, FCAW and SAW you don't exceed 13mm of weld metal thickness for each pass; it is more common for Electrogas and Electroslag welding.

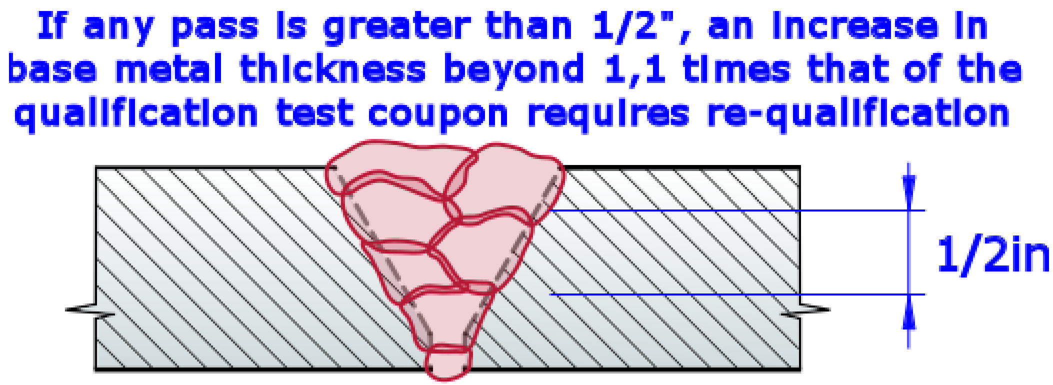


FIGURE 15 MULTIPASS WELDING

7. QW-403.11 Base metals specified in the WPS shall be qualified by a procedure qualification test that was made using base metals in accordance with QW-424.

Welding standards usually group the base metals into families that have similar chemistry and weldability. P-Numbers are assigned to base metals for the purpose of reducing the number of welding and brazing procedure qualifications required. A change from one P-number group to another affects the mechanical properties; therefore, base metals are classified as essential variables.

QW-404. FILLER METAL

TABLE QW-253 Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)				
Paragraph		Brief of Variables	Essential	Non-Essential
QW-404 Filler Metals	.4	ϕ F-Number	X	
	.5	ϕ A-Number	X	
	.6	ϕ Diameter		X
	.30	ϕ t	X	
	.37	ϕ Classification		X

8. QW-404.4 A change from one F- Number in Table QW-432 to any other F- Number or to any other filler metal not listed in Table QW-432.

Avoid confusing ASME IX with AWS D1.1 when it comes to F-numbers. Confusion of "if a welder/procedure is tested with an electrode with a higher F number, then he can weld with an electrode with lower F-number". In AWS D1.1, if a welder qualifies with an electrode with a higher F-number, he is qualified to weld with electrodes of lower F number. Regarding procedures, in ASME IX the procedure must be requalified if the F-number changes. The F-number is also an essential variable for performance qualification, but it's not as restrictive as the welding-procedure specification. For welders using F-1 through F-4 electrodes, the higher F-number electrode qualifies the lower just like in D1.1. Usually an F number is associated with an electrode specification.

9. QW-404.5 (Applicable only to ferrous metals.) A change in the chemical composition of the weld deposit from one A- Number to any other A- Number in Table QW-442. Qualification with A- No. 1 shall qualify for A- No. 2 and vice versa.

The weld metal chemical composition may be determined by any of the following:

(a) For all welding processes — from the chemical analysis of the weld deposit taken from the procedure qualification test coupon.

(b) For SMAW, GTAW, LBW, and PAW — from the chemical analysis of the weld deposit prepared according to the filler metal specification, or from the chemical composition as reported either in the filler metal specification or the manufacturer's or supplier's certificate of compliance.

(d) For SAW — from the chemical analysis of the weld deposit prepared according to the filler metal specification or the manufacturer's or supplier's certificate of compliance when the flux used was the same as that used to weld the procedure qualification test coupon.

In lieu of an A- Number designation, the nominal chemical composition of the weld deposit shall be indicated on the WPS and on the PQR. Designation of nominal chemical composition may also be by reference to the AWS classification except for the "G" suffix classification, the manufacturer's trade designation, or other established procurement documents.

P- and S-numbers are groupings of base metals with similar weldability. F-numbers are groupings of filler metals, and A-numbers are weld deposit chemistries. A-numbers are applicable only for ferrous-based filler metals. A number is usually provided by the manufacturer of the filler metal, as he has had time to make all laboratory tests on deposited metal. In other cases, such as when welding dissimilar metals, you have to send a section of the weld deposit out for chemical analysis and then see what A-number it matches. Only qualification with A No. 1 shall qualify for A No. 2 and vice versa. This was an exam question back then in 2012. A-numbers play no role in performance qualifications.

10. QW-404.6 A change in the nominal size of the electrode or electrodes specified in the WPS.

In production welds, a higher diameter electrode can induce more slag into the joint or augment heat input to the base metal being welded. Depending on the weld position and electrode size, the welder will have difficulties controlling the appearance of weld defects. But electrode size will not affect mechanical properties. Having this in mind, it is just natural that it is a non-essential variable that you may want to control anyways.

11. QW-404.30 A change in deposited weld metal thickness beyond that qualified in accordance with QW-451 for procedure qualification or QW-452 for performance qualification, except as otherwise permitted in QW-303.1 and QW-303.2. When a welder is qualified using volumetric examination, the maximum thickness stated in Table QW-452.1(b) applies.

Deposited weld metal is the sum of all the passes made with a single welding process. Where more than one different processes, is used in a joint, QW-451 shall be used to determine the range of maximum weld metal thickness qualified for each process. It is an essential variable.

12. QW-404.33 A change in the filler metal classification within an SFA specification, or, if not conforming to a filler metal classification within an SFA specification, a change in the manufacturer's trade name for the filler metal.

When a filler metal conforms to a filler metal classification, within an SFA specification, except for the “G” suffix classification, requalification is not required if a change is made in any of the following:

(a) from a filler metal that is designated as moisture- resistant to one that is not designated as moisture- resistant and vice versa (i.e., from E7018R to E7018)

(b) from one diffusible hydrogen level to another (i.e., from E7018- H8 to E7018- H16)
(c) for carbon, low alloy, and stainless steel filler metals having the same minimum tensile strength and the same nominal chemical composition, a change from one low hydrogen coating type to another low hydrogen coating type (i.e., a change among EXX15, 16, or 18 or EXXX15, 16, or 17 classifications)

(d) from one position- usability designation to another for flux- cored electrodes (i.e., a change from E70T- 1 to E71T- 1 or vice versa)

(e) from a classification that requires impact testing to the same classification which has a suffix which indicates that impact testing was performed at a lower temperature or exhibited greater toughness at the required temperature or both, as compared to the classification which was used during procedure qualification (i.e., a change from E7018 to E7018- 1)
(f) from the classification qualified to another filler metal within the same SFA specification when the weld metal is exempt from Impact Testing by other Sections. This exemption does not apply to hard- facing and corrosion- resistant overlays

The "G" filler metal suffix stands for "general" classification. It is general because not all the particular requirements specified for the other designation classifications are specified for this classification. The intent for the general designation is to allow newly developed flux-cored electrodes that may differ in one way or another to all the other usability designations a way to still be classified according to the filler metal specification. This allows an electrode to be used right away, without having to wait potentially years for the filler metal specification to be revised to create a new usability designation. So, two electrodes having the ‘G’ suffix, but made by different manufacturers, could have different chemical compositions. For this reason, a WPS requiring impact testing qualified with an electrode having the ‘G’ suffix from manufacturer ‘A’ could not use an electrode having a ‘G’ suffix from manufacturer ‘B’ because the chemical composition could be different, resulting in different notch toughness properties of the weld metal. The WPS would have to be requalified.

(a) The "R" suffix identifies electrodes passing the absorbed moisture test after exposure to an environment of 80ºF(26.7ºC) and 80% relative humidity for a period of not less than 9 hours (A.7.6.4 of AWS A5.1).

(b) The preferred method of controlling the level of hydrogen in a weld deposit is to use the optional hydrogen designators as defined by the American Welding Society. These designators are in the form of a suffix on the electrode classification (e.g., H8, H4, and H2, the examples given in numeral b) **(c)** On the other hand, low-hydrogen electrodes of the EXX15, EXX16, EXX18, EXX(X)15, EXX(X)16 and EXX(X)18 types, do share the same F-number, and differ in several things, being the most important the type of electrode coating (sodium for E7015, potassium form E7016 and iron powder for E7018) (AWS a5.1)

(d) is self-explanatory.

(e) Electrodes of the EXX15, EXX16 and EXX18 classifications are specified as requiring impact testing in some welding positions (See table 4 of AWS A5.1). E7018-1 shielded metal arc welding (SMAW) electrodes provide improved impact toughness over plain E7018 electrodes. The -1 stands for it. **(f)** Not treated herein.

QW-405. POSITIONS

TABLE QW-253 Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)				
Paragraph		Brief of Variables	Essential	Non-Essential
QW-405 Positions	.1	+ Position		X
	.3	ϕ Vertical welding		X

13. QW-405.1 The addition of other welding positions than those already qualified. See QW-120, QW-130, QW-203, and Qw-303.

A common mistake made by beginners is to think that the position chosen for procedure qualification limits the position of the production weld. In fact, qualifying a procedure in any welding position approves all positions providing no impact tests are required. Weld position is a non-essential variable.

14. QW-405.3 A change from upward to downward, or from downward to upward, in the progression specified for any pass of a vertical weld, except that the cover or wash pass may be up or down. The root pass may also be run either up or down when the root pass is removed to sound weld metal in the preparation for welding the second side.

In my country, welders usually think of themselves as API or ASME certified…… another mistake. They think that ASME welding is “upwards” and API 1104 welding is “downwards”. But the choice of weld progression doesn´t depend on the welding code, but usually in the electrode used and other considerations. Again, another non-essential variable for the WPS.

QW-406. PREHEAT

TABLE QW-253 Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)				
Paragraph		Brief of Variables	Essential	Non-Essential
QW-406 Preheat	.1	Decrease > 100°F (55°C)	X	
	.2	ϕ Preheat maint		X

15. QW-406.1 A decrease of more than 100°F (55°C) in the preheat temperature qualified. The minimum temperature for welding shall be specified in the WPS.

This was an exam question to get API 653 Certified back then in 2012. It had to be with the maximum temperature change allowed for preheat and the range of preheat qualified. As we can see, a decrease in preheat temperature higher than 100°F is considered to change mechanical properties (it also happens with interpass temperature)

16. Qw-406.2 A change in the maintenance or reduction of preheat upon completion of welding prior to any required post-weld heat treatment.

Preheat maintenance is used to assure freedom from hydrogen induced cracking prior to PWHT. Following a welding operation, the cooling and contracting of the weld metal cause stresses to be set up in the weld and in adjacent parts of the weldment which results to cracking and embrittlement in steel welds, depending of composition. The best way to minimize above difficulties is to reduce the heating and cooling rate of the parent metal and HAZ. Pre heating and/or Post heating have been widely employed in welding operation for preventing cold cracking.

QW-407. POST WELD HEAT TREATMENT

TABLE QW-253 Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)				
Paragraph		Brief of Variables	Essential	Non-Essential
QW-407 PWHT	.1	ϕ PWHT	X	
	.4	T Limits	X	

Let´s review a couple definitions

Lower Transformation Temperature – Temperature at which structure begins to change from ferrite and pearlite to austenite if being heated, upon cooling, temperature at which structure completes change from austenite to ferrite and pearlite. The line BGH in the diagram is the lower transformation temperature.

Upper Transformation Temperature – Temperature at which structure completes change from ferrite and pearlite to austenite if being heated, upon cooling, temperature at which structure begins change from austenite to ferrite and pearlite. The line AGH in the diagram is the upper transformation temperature.

17. QW-407.1 A separate procedure qualification is required for each of the following: (a) For P- Numbers 1 through 6 and 9 through 15F materials, the following postweld heat treatment conditions apply:

(1) no PWHT

(2) PWHT below the lower transformation temperature

(3) PWHT above the upper transformation temperature (e.g., normalizing)

(4) PWHT above the upper transformation temperature followed by heat treatment below the lower transformation temperature (e.g., normalizing or quenching followed by tempering)

(5) PWHT between the upper and lower transformation temperatures

(b) For all other materials, the following postweld heat treatment conditions apply:

(1) no PWHT

(2) PWHT within a specified temperature range

If you qualified a procedure with PWHT, if you intend to use this same procedure without (or No) PWHT, it must be requalified with NO PWHT. PWHT is not usually required for material thickness 5/8″ (16mm) or less at the weld. All the possible configurations for QW-407.1 are illustrated in the Fe-c diagram below, as a guide.

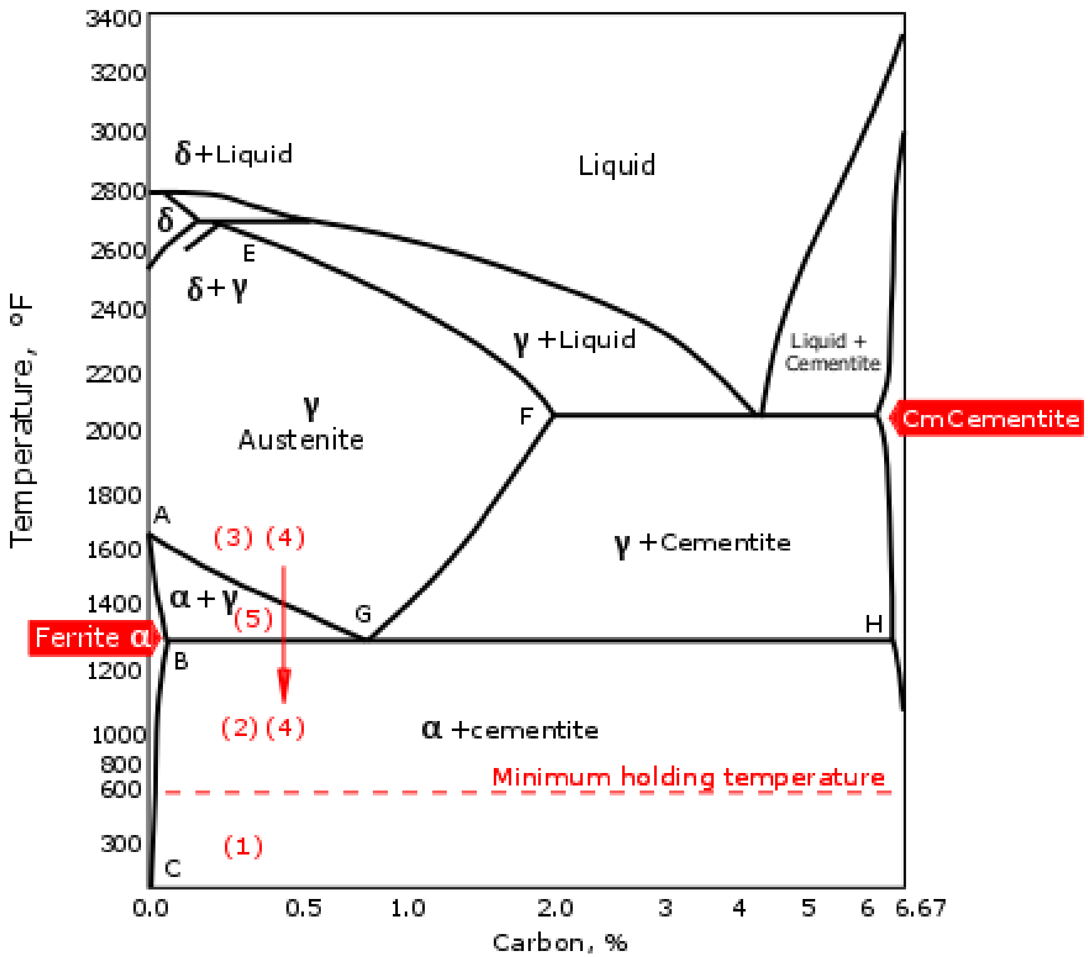


FIGURE 16 FE-C DIAGRAM

18. QW-407.4 For ferrous base metals other than P- No. 7, P- No. 8, and P- No. 45, when a procedure qualification test coupon receives a postweld heat treatment exceeding the upper transformation temperature or a solution heat treatment for P-No. 10H

materials, the maximum qualified base metal thickness, T, shall not exceed 1.1 times the thickness of the test coupon.

Because the microstructure completely changes above the upper transformation temperature, whatever was done in welding is gone. The Code recognizes this metallurgical reality and allows an exception to the variable because of it.

QW-409 ELECTRICAL CHARACTERISTICS

TABLE QW-253 Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)				
Paragraph		Brief of Variables	Essential	Non-Essential
QW-409	.4	ϕ Current or polarity		X
Electrical Carachteristics	.8	ϕ I & E range		X

19. QW-409.4 A change from AC to DC, or vice versa; and in DC welding, a change from electrode negative (straight polarity) to electrode positive (reverse polarity), or vice versa.

Power sources for welding produce DC with the electrode either positive or negative, or AC. The choice of current and polarity depends on the process, the type of electrode, the arc atmosphere and the metal being welded. A non-essential variable.

20. 409.8 A change in the range of amperage, or except for SMAW, GTAW, or waveform controlled welding, a change in the range of voltage. A change in the range of electrode wire feed speed may be used as an alternative to amperage. See Nonmandatory Appendix H.

What are the effects of current and voltage during the welding process? Consider the following excerpt Lincoln website

Current effects the melt-off rate or consumption rate of the electrode, whether it be a stick electrode or wire electrode. The higher the current level, the faster the electrode melts or the higher the melt-off rate, measured in pounds per hour (lbs./hr.) or kilograms per hour (kg/hr.). The lower the current, the lower the electrode's melt-off rate becomes. Voltage controls the length of the welding arc, and resulting width and volume of the arc cone. As voltage increases, the arc length gets longer (and arc cone broader), while as it decreases, the arc length gets shorter (and arc cone narrower). SMAW and GTAW are considered largely manual processes, and CC is the preferred type of output from the power source, meaning you control voltage.

Regarding waveform, the following excerpt is taken form ASME IX, non-mandatory appendix H

> Advances in microprocessor controls and welding power source technology have resulted in the ability to develop waveforms for welding that improve the control of droplet shape, penetration, bead shape and wetting. Some welding characteristics that were previously controlled by the welder or welding operator are controlled by software or firmware internal to the power source. It is recognized that the use of controlled waveforms in welding can result in improvements in productivity and quality.

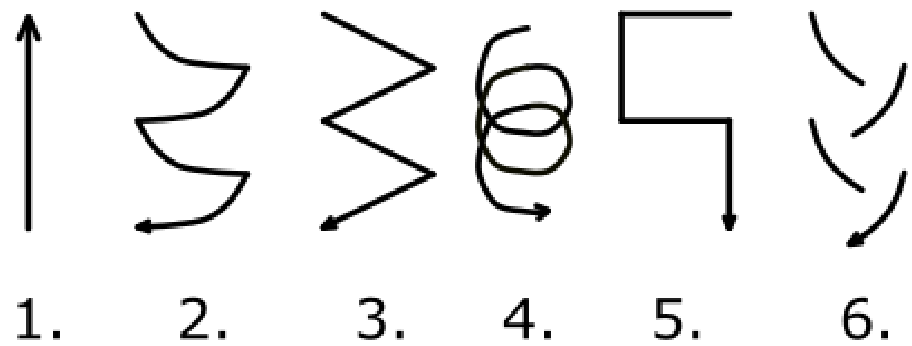
Electrical characteristics as amperage and voltage are non-essential variables.

QW-410 TECHNIQUE

TABLE QW-253 Welding Variables for Procedure Specification (WPS) - Shielded Metal Arc-Welding (SMAW)					
Paragraph		Brief of Variables		Essential	Non-Essential
QW-410 Technique	.1	φ	String/weave		X
	.5	φ	Method of cleaning		X
	.6	φ	Method of back gouge		X
	.9	φ	Multiple to single pass/side		X
	.25	φ	Manual or automatic		X
	.26	±	Peening		X
	.64		Use of thermal processes	X	

21. QW-410.1 For manual or semiautomatic welding, a change from the stringer bead technique to the weave bead technique, or vice versa.

Stringer bead a type of bead which is made by moving the welding electrode in a direction parallel to the axis of the bead, without appreciable transverse oscillation. Weave bead is a weld bead which is made with oscillations along the bead which are transverse to the length of the bead. Either technique can produce a sound weld with the mechanical properties the code requires. The election of one or the other, however, has an impact on another variable that is a supplementary essential and therefore not a subject of this summary: heat input.



1. Stringer bead
2. Weave bead. Crescent
3. Weave bead. Zig-zag
4. Weave bead. Circles
5. Weave bead. Box weave
6. Weave bead. Double J

FIGURE 17 WELDING TECHNIQUES

22. QW-410.5 A change in the method of initial and interpass cleaning (brushing, grinding, etc.).

Interpass cleaning is essential to ensure complete slag removal as well as fusion between the weld beads. Turning up the amperage to “burn away the slag” is not the way to make a cleaning. Welders need to take steps to properly clean between weld passes, even grinding the profiles if needed to improve fusion and bead placement. It can be done by using a needle descaler or a hand chipping hammer and a power brush. Not an essential variable.

23. QW-410.6 A change in the method of back gouging.

Back gouging is the removal of weld metal and base metal from the weld root side of a welded joint to facilitate complete fusion and complete joint penetration upon subsequent welding from that side. It does so by providing a better surface for the new weld and eliminating any edges of the weld metal that may have survived the root pass. Back gouging can be done using air grinders, electric grinders, or thermal processes for removing the material, like Manual Metal Arc gouging, Air Carbon Arc Gouging, Plasma Arc Gouging or Oxyfuel Gouging. Thermal processes can be up to 4 times faster and quieter than cold chipping operations.

24. QW-410.9 A change from multipass per side to single pass per side. This variable does not apply when a WPS is qualified with a PWHT above the upper transformation temperature or when an austenitic or P-No. 10H material is solution annealed after welding.

The big difference between single pass to multipass per side is heat input.

The process of solution annealing consists of heating the material up to a temperature above 1950°F and holding it long enough for the carbon to go into solution. After this, the material is quickly cooled to prevent the carbon from coming out of solution and achieve an evenly distributed solution of carbon and austenite in the metallurgical structure of the material. It improves corrosion resistance and ductility in both the weld and the HAZ. Properties • Reduction of stresses • Improved material structure • Improved magnetic properties • Reduction of hardness possible • Improved welding properties • Improved corrosion resistance • Good dimensional and shape accuracy • Clean process, parts remain bright

25. QW-410.25 A change from manual or semiautomatic to machine or automatic welding and vice versa.

Semiautomatic and automatic welding have less defects than manual welding. However, a change of it won´t affect mechanical properties by definition

26. QW-410.26 The addition or deletion of peening.

According to the ASME IX definition, peening is the mechanical working of metals using impact blows. Peening is a method of adding residual compressive stress to the component by bombarding the surface with high quality spherical media in a controlled operation. The media can be steel, ceramic, or glass and each piece acts like a tiny peening hammer producing a small indentation on the surface. The application locally yields the material, inducing beneficial compressive stress, the characteristics of which are dependent on the base material and component design. At the same time, unwanted tensile stresses are removed. Peening shows a beneficial effect on both the life and strength of a component, making the surface more resistant to fatigue, cracking, stress corrosion, and cavitation erosion, given than cracks will not grow in a compressive environment. If you wish to have your production weld peened, the WPS should include peening too. And why the addition of peening changes mechanical properties? it is demonstrated that an excess of peening will reduce fatigue life of a component. However, it is not an essential variable.

27. QW-410.64 For vessels or parts of vessels constructed with P- No. 11A and P- No. 11B base metals, weld grooves for thickness less than 5/8 in. (16 mm) shall be prepared by thermal processes when such processes are to be employed during fabrication. This groove preparation shall also include back gouging, back grooving, or removal of unsound weld metal by thermal processes when these processes are to be employed during fabrication.

I am not going to go deep in this point, given its complexity. P numbers 11A and 11B group various high strength low alloy steels that you can find in appendix P of the ASME IX. If you can look for the specifications of these metals in the internet, you will notice that most them require some kind of heat treatment during manufacturing. For these steels, use of thermal processes during part welding obliges the manufacturer to prepare a WPS using those thermal processes. So it becomes an essential variable.

POINTS TO REMEMBER

Regardless if it is an essential or a nonessential variable, you should make certain that an appropriate value for each variable is recorded on the WPS, that the WPS covers the ranges for the welding application for each variable listed for each process, as specified in QW-250 and that every variable range on the WPS is being followed during fabrication or repairs. Also, when qualifying the WPS, the final PQR should be signed.

Q&A Annex 1

What is the root face limitation as listed on the attached WPS and PQR?

a. 3/32”

b. 1/8”

c. No limit

d. Not designated

If the supporting PQR is used, are the P-no’s correct on the attached WPS?

a. Yes

b. No

c. Could be if properly preheated

d. Not enough information

Is the thickness range on the WPS supported by the PQR?

a. Yes

b. No

c. Requalification is required by API 570

d. Requalification is required by ASME V

Is the attached PQR properly qualified?

a. No, because RT is not allowed during PQR qualification

b. No

c. No, because peening is allowed by B31.3

d. Yes

What should have been the correct number and type of guided bends on the PQR?

a. 2 side bends

b. 2 face and 2 root bends

c. 1 side, 1 face and 1 root bend

d. 2 face, 2 root and 4 side bends

CHAPTER 9: TANK SETTLEMENT

Tank settlement is one of the topics of the Body Of Knowledge for the API 653 exam. It is a very important subject for us tank inspectors, although is also one of the vaguest topics for a new inspector. In fact, the word "settlement" is mentioned more than 250 times in the API 653 standard. As an inspector, you should be able to determine the type and extent of tank settlement, and decide if it can affect tank integrity. In the API 653 exam, maybe 2 questions will show up about this subject. And as complex as it may look in the API 653 standards, the limitations imposed by the BOK make it a really easy topic.

SETTLEMENT IN NEW CONSTRUCTION

In new tanks, the API 650 standard doesn´t necessarily asks for a settlement measurement to be done during hydrostatic tests. If there is no settlement expected (for example, a tank over a giant rock), it might not need settlement measurements, but that´s a decision that is entirely up to the owner.

FIGURE 18 A NEW TANK THAT PROBABLY WOULD NOT NEED SETTLEMENT MEASURED

In normal conditions, there will always be settlement. Anyway, you should design and construct foundations to limit settlement, as impossible it is to eliminate it.

For the sake of information, you should know how settlement measurements are made. During hydrostatic testing for new and old tanks, at least 6 sets of measurements shall be made.

1. When the tank is empty before hydrostatic testing

2. When the tank is 1/4 full

3. When the tank is 1/2 full

4. When the tank is 3/4 full

5. 24 hours after it is filled

6. With the tank empty again.

Shell elevation measurements shall be made at equally-spaced intervals around the tank circumference not exceeding 10 m (32 ft.)

SETTLEMENT OF IN-SERVICE TANKS

During operations, shell settlement measurements should be taken at a planned frequency, based on an assessment of soil settlement predictions. Bottom settlement monitoring is to be made during internal inspections, respecting the intervals given for inspections in API 653 4.4.6. Identify and evaluate any tank bottom settlement is one of the 3 key objectives of internal inspections, because it plays such an important role on many tank failures and floating-roof problems.

Settlement can be caused by the following:

1. Lack of support under the base circumference affecting the cylindrical shell and the tank bottom. Parts or the concrete ring may be lost.
2. Non homogeneous geometry or compressibility of the soil deposit (voids or crevices below the bottom plate)
3. Non uniform distribution of the load applied to the foundation. Differential pressure during emptying and filling cycles
4. Uniform stress acting over a limited area of the soil stratum
5. Wrongly constructed foundations (deficient reinforcement of the concrete, bad quality cement, etc.)
6. Liquefaction phenomenon around the foundation generated by earthquakes. Consider the following excerpt:

WHAT YOU SHOULD STUDY FOR YOUR EXAM

Various forms of settlements could take place in tanks. The BOK considers 3 types of settlement and their evaluation.

1. Edge settlement

Edge settlement occurs when the tank shell settles sharply around the periphery, resulting in deformation of the bottom plate near the shell-to-bottom corner weld, or the depth of the depressed area of the bottom plate. You can see a diagram for edge settlement below.

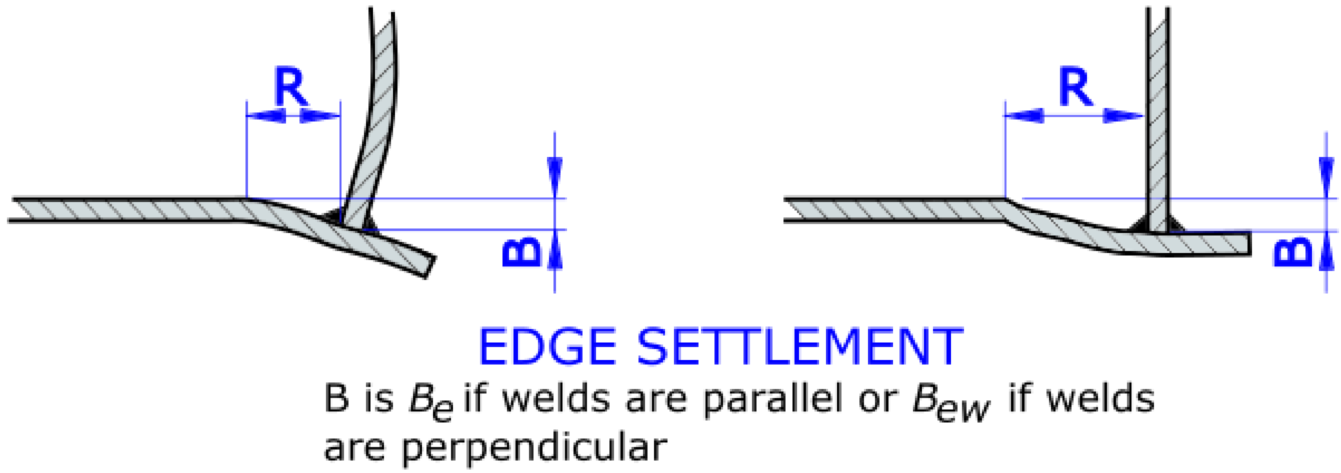


FIGURE 19 EDGE SETTLEMENT

Edge settlement affects bottom parallel and perpendicular welds in different manners. It affects weld seams that are "parallel" to the shell in a more critical manner that the ones that run "perpendicular".

How to evaluate edge settlement?

<u>STEP 1</u>. Annex B of API 653 separates Edge Settlement evaluations in two separate scenarios:

1. If edge settlement is in an area with a LAP welded seam than runs parallel +-20° to the shell, *B* turns into *Bew*

2. If edge settlement is in an area with a LAP welded seam than runs perpendicular +-20° to the shell,, or a BUTT weld, or an area WITH NO WELDS, *B* turns into *Be*

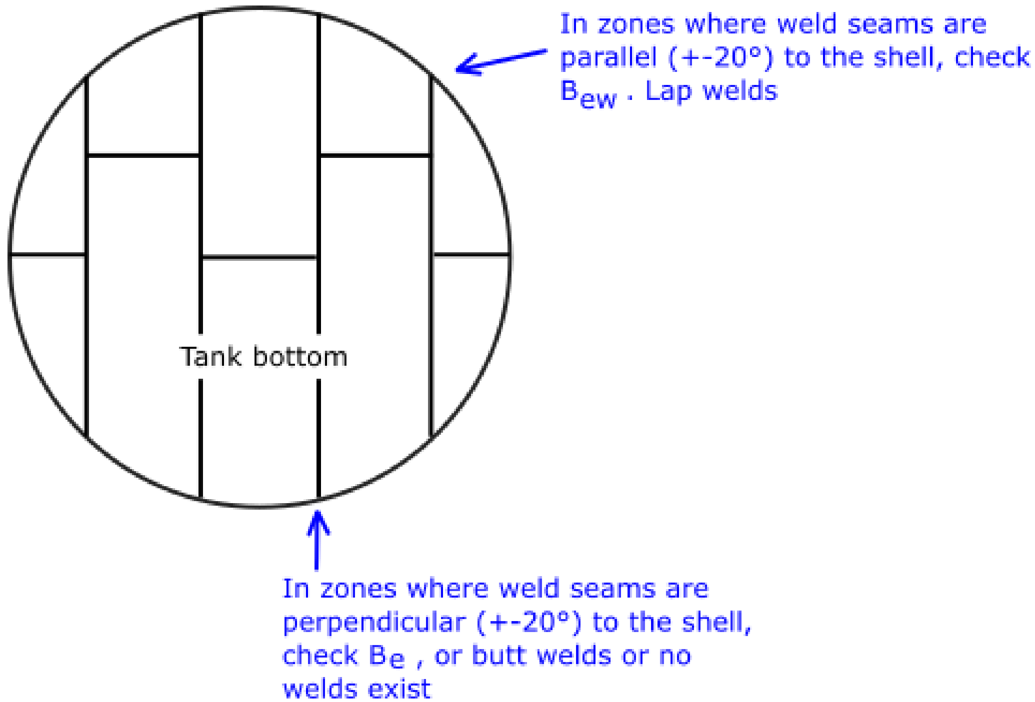


FIGURE 20 EDGE SETTLEMENT EVALUATION

STEP 2. With the value of R, B and the tank diameter, you can check the maximum allowable vertical settlement in figures B-11 of API 653 for B_{ew} or B-12 for B_e. A sample of that diagram you can see next.

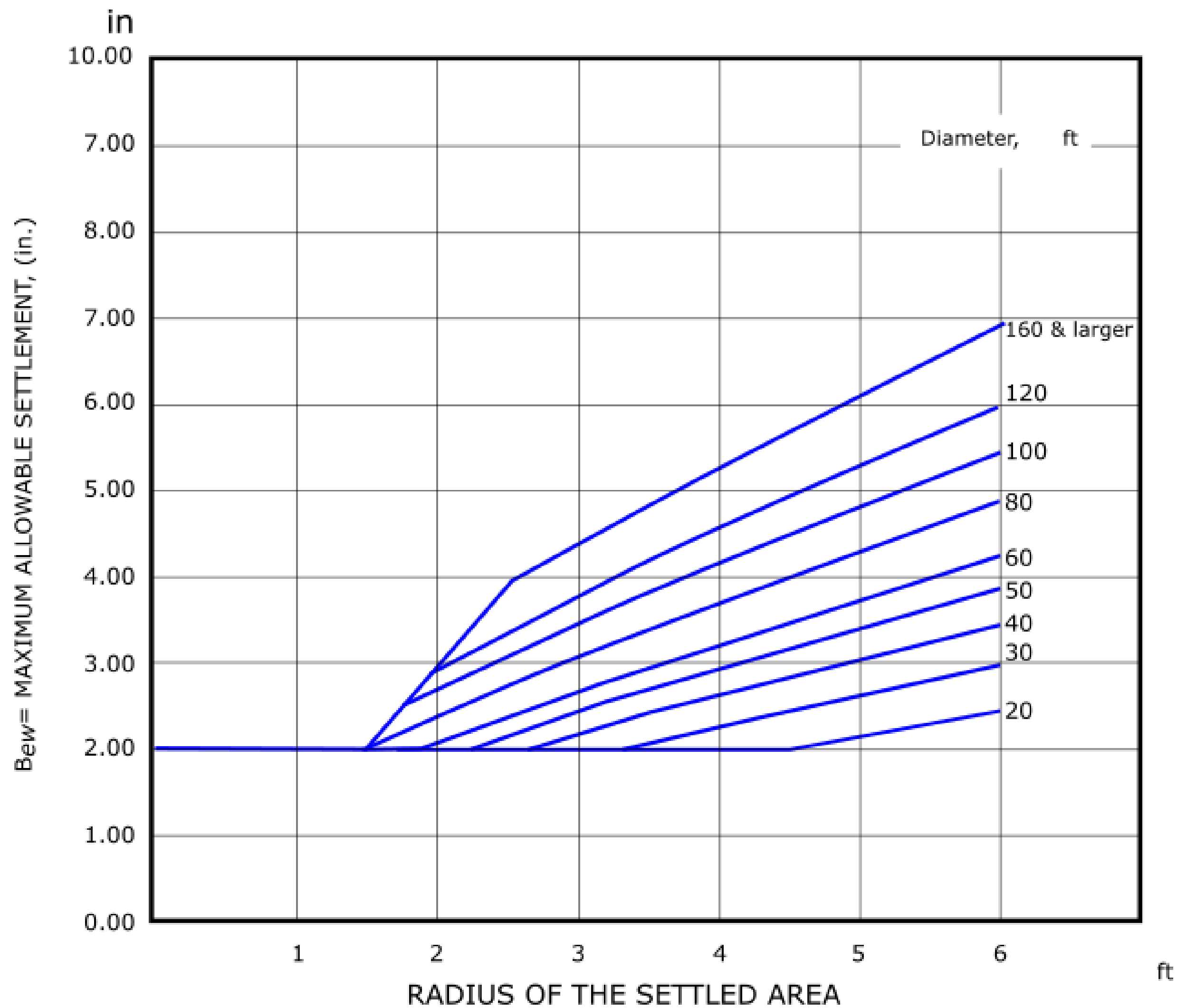


FIGURE 21 FIGURE B.11: MAXIMUM ALLOWABLE SETTLEMENT B_EW

653-FIX | 12/31/2016

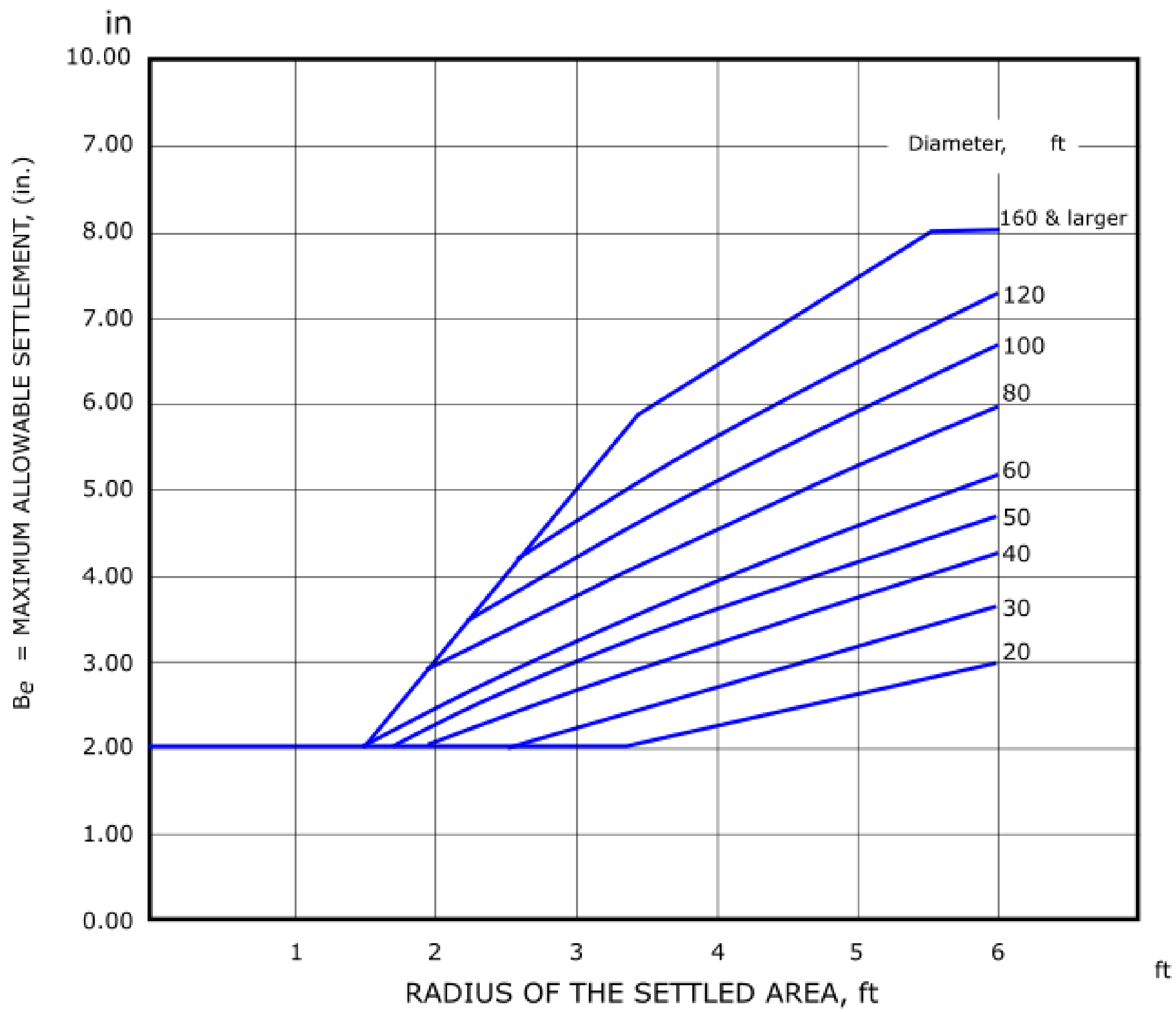


FIGURE 22 FIGURE B.12: MAXIMUM ALLOWABLE SETTLEMENT B_E

See API 653 B-11 and B-12 for the whole details.

Welds in tanks with settlement greater than or equal 75 % of B_{ew} or B_e, and larger than 2 in., are to be inspected with magnetic particle of liquid penetrant method. Additionally, weld seams should be inspected visually and if they show strains bigger than 2%, they should be repaired. Any plate exceeding acceptable plastic strains (typically 2 % to 3 %) should be replaced.

2. Bottom settlement near the tank shell

This kind of settlement can be present in the bottom or in the annular ring zone, if there is one. It occurs when the bottom deforms showing a depression or a convexity in relation with a flat plane bottom. That deformation is caused by stresses in the bottom plate that have to be evaluated.

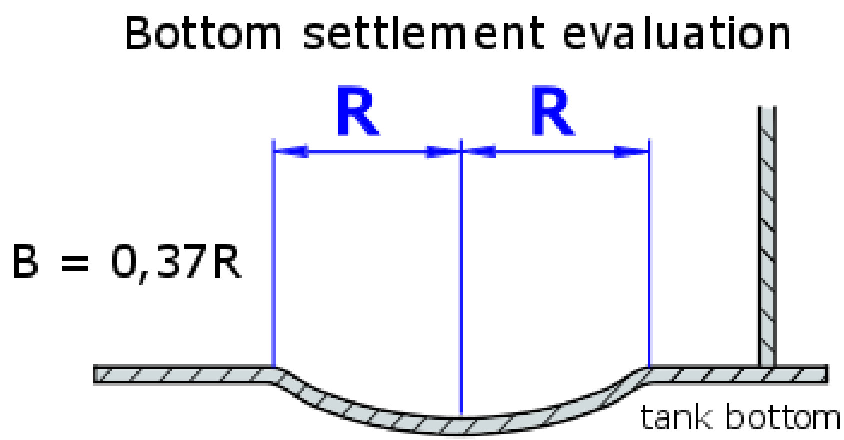


FIGURE 23 BOTTOM SETTLEMENT NEAR THE TANK SHELL

How to evaluate bulges in tank bottoms?

STEP 1. As per API 653 B3.3, measure the bulge or depression in its entire length. The half of that measure is radius R of the bulge.

STEP 2. The maximum dimension for bulges or depressions is given by the following equation:

$$B = 0.37R$$

Where

B is the maximum height of bulge or depth of local depression, in inches;

R is the radius of an inscribed circle in the bulged area or local depression, in feet.

3. Localized bottom settlement remote from the tank shell.

Localized bottom settlement remote from tank shell are depressions (or bulges) that occur in a random manner, remote from the shell. The same equation (B3.3) used for bottom settlement near the tank shell can be used for the evaluation of this kind of settlement, granted the bottom has single-pass welded joints.

RECOMMENDATIONS TO IMPROVE TANK RELIABILITY IN CASE OF SETTLEMENT

1. Leave plenty of free space under any nozzle, to prevent contact with the floor if there is settlement.
2. Settlement occurs to every tank, and it can be different in practice from the measured settlement during and after hydrostatic testing.
3. If there is uniform settled expected (If foundations weren't well built), you can use flexible joints or maritime hoses that can absorb those misalignments.
4. Edge settlement often can be predicted in advance, with sufficient accuracy from soil tests. Anyway, piping (especially buried piping) should be designed with adequate consideration to prevent problems caused by such settlement

If you want to become a certified API 653 inspector, this is what the body of knowledge for the 2015 API 653 certification exam asks from you

The inspector should be able to calculate the number of survey points for determining tank settlement.

At least one question on this matter will show up in the exam. And it is such an easy thing....

DETERMINING THE NUMBER OF POINTS FOR SETTLEMENT MEASUREMENT

In a tank, the number of settlement points around the periphery for external settlement measurement is given by the following formula

Eq. 25. $N = \frac{D}{10}$

where:

N is the minimum required number of settlement measurement points.

D is the tank diameter, in feet (ft).

And the following rules should apply:

1) The maximum spacing between settlement measurement points shall be 32 ft.

2) No less than eight measurement points

Before any hydrostatic test, elevation measurements should be taken inside the tank, as stated in 7.3.6.8 of API 650

Internal bottom elevation measurements shall be made before and after hydrostatic testing. Measurements shall be made at maximum intervals of 3 m (10 ft) measured on diametrical lines across the tank. The diametrical lines shall be spaced at equal angles, with a maximum separation measured at the tank circumference of 10 m (32 ft). A minimum of four diametrical lines shall be used.

There is not much to say about this issue, apart that just having a look at Figure 1 for easiness.

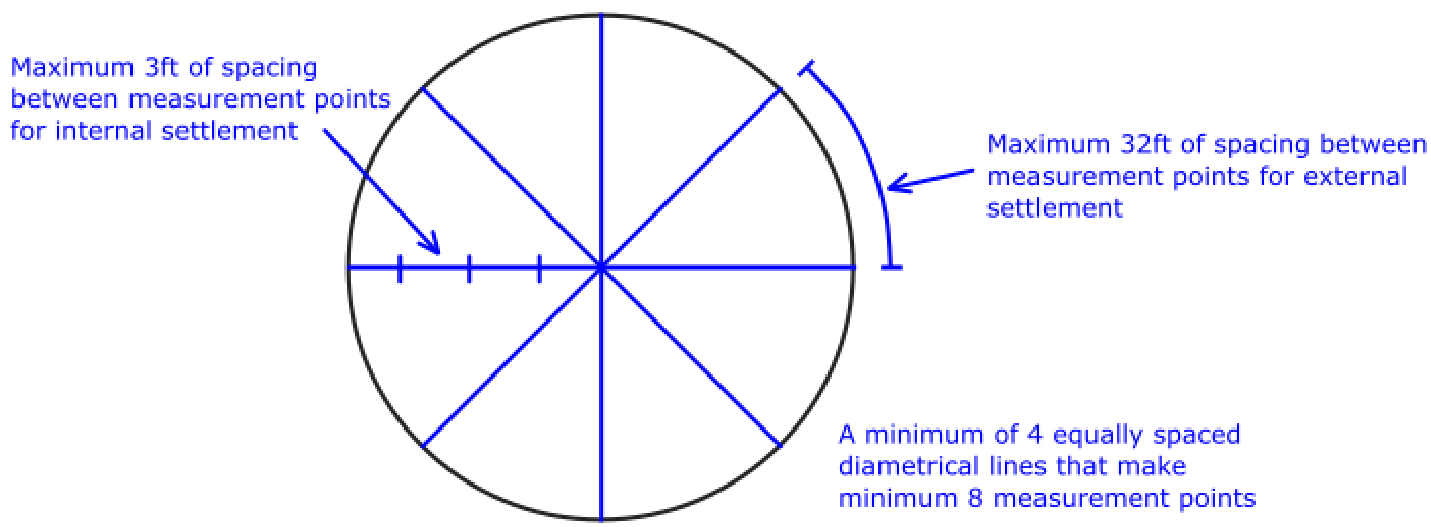


FIGURE 24 MEASUREMENTS OF BOTTOM SETTLEMENT (INTERNAL AND EXTERNAL)

Settlement measurement stations are to be used during hydrostatic test and operation of the tank; settlement measurements should be taken at a planned frequency, based on an assessment of soil settlement predictions (See Annex B of API 653)

Of utmost importance is the maximum allowable differential settlement between 2 consecutive stations that may have several consequences: (a) Out-of plane displacements are induced in the shell in the form of buckling under a displacement-controlled mechanism; (b) High stresses develop at the base of the shell and in the region of the settlement; and (c) High stresses develop in the tank bottom.

Uniform and Rigid body tilting of a tank are too complicated to appear in the exam. Further explanation of tank settlement is found in Annex B, API 653.

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CHAPTER 10: BRITTLE FAILURE ASSESMENT

In terms of risk, catastrophic storage tank failure stands as one of the costliest events that can ever happen. It happens with no warning. It can have huge consequences of everything related to your plant: living beings, property, compliance, stakeholders, processes and finances. It is not something you would want for your facility.

Catastrophic tank failure is usually a consequence of brittle fracture, which is not always understood and is underestimated when making tank repairs and inspections. Given that in some locations aboveground tanks have been in service for more than a few decades, and that is not uncommon to build a tank from parts used in other tanks, catastrophic tank failure is a real concern.

Several questions in the exam will be taken from chapter 5 of API 653, so, be sure to read it.

*References for Tables and figures taken from API 650, twelfth edition, Addendum 1, 2014

BRITTLE FRACTURE

Definition of fracture: Fracture is the separation of an object into pieces due to stress, at a temperature lower than the melting point. In pipes, pressure vessels and tanks, fracture can be ductile or brittle. Both are bad, but brittle fracture is very bad, given that cracks in the stressed material travel so fast that there´s usually no chance to react.

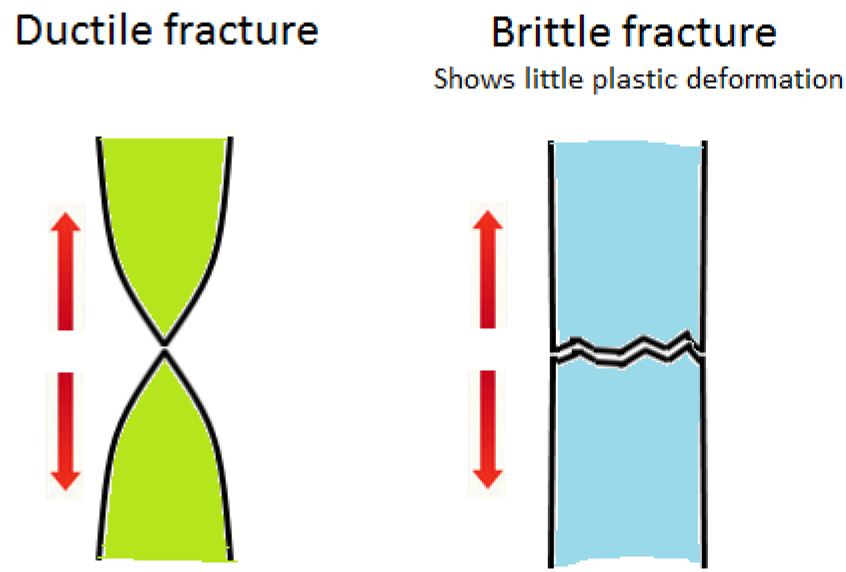


FIGURE 25 DUCTILE AND BRITTLE FRACTURE

Brittle fracture shows no plastic deformation and rather happens if temperature is low, there are tensile stresses applied and if there are stress concentrators as gouges or flaws in the material. Failure is usually catastrophic.

Brittle fracture is more common shortly after erection during hydrostatic testing or on the first filling in cold weather, or in operation, after a change to lower temperature service, or after a repair/alteration. Special care should be taken to not cause overfilling of an old tank. If an old tank has sharp corners or inserts, it could be wise to remove these stress concentrators.

Brittle fracture risk in tanks is minimal if the tank´s shell thickness is no greater than 0.5in. Besides, brittle fracture is very rare if shell metal temperature is over 60°F (Section 5). Older thanks are more susceptible, because manufacturing techniques were deficient.

Sharp cracks and large defects both lower the fracture strength of the material. If a brittle fracture should occur, cracks run almost perpendicular to the applied stress, and with little plastic deformation.

Chapter 5 of API 653 provides a procedure for the assessment of existing tanks for suitability for continued operation or change of service with respect to the risk of brittle fracture.

Be sure to study chapter 5 of API 653 thoroughly. Several questions in the exam are about this subject.

In the following lines, I summarize the decision tree found in Figure 5.1 of API 653. That decision tree gives a step by step assessment procedure. The most important outcome of this decision tree is to check if the tank needs a hydrotest or not, or, if considered necessary, be rerated.

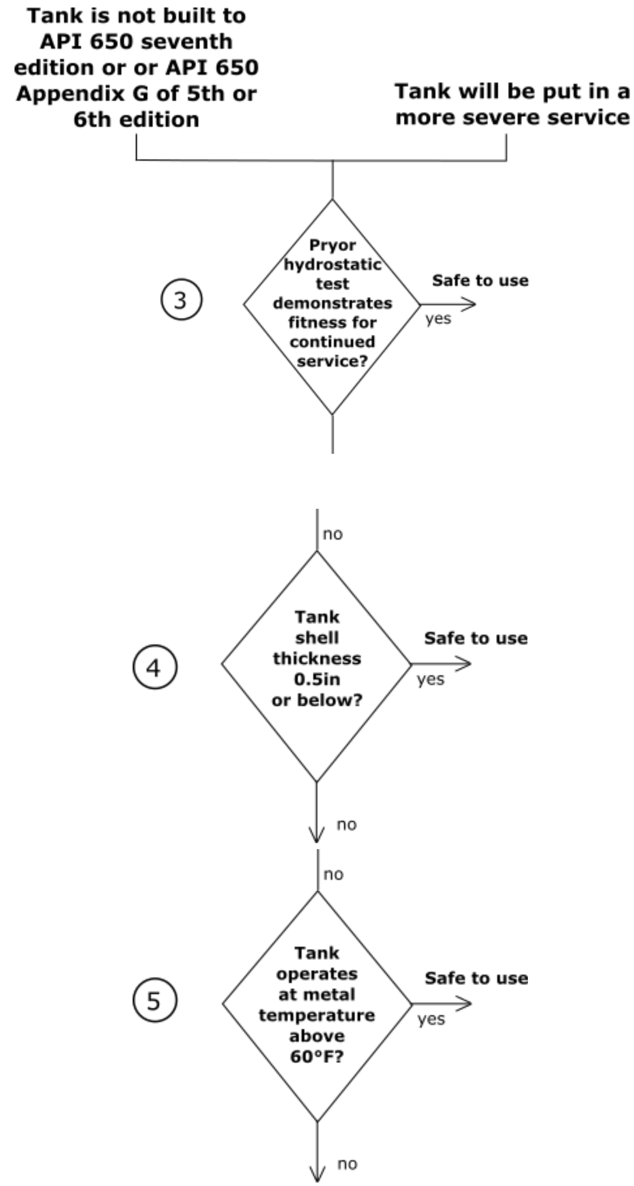
If you are making an internal inspection and the tank will be in the same service than before, and you have the certainty that the tank was built to API 650 seventh edition, then you don´t have to enter the decision tree.

If any of the 2 conditions I just mentioned is met, you enter the decision tree.

Tank is not built to API 650 seventh edition or API 650 Appendix G of 5th or 6th edition ☑

Tank will be put in a more severe service ☑

BRITTLE FRACTURE CRITICAL FACTORS.



The hydrostatic test is the ultimate check of the overall integrity of a tank. API 571 says: “Most processes run at elevated temperature so the main concern is for brittle fracture during startup, shutdown, or hydrotest/tightness testing”. Hydrostatic testing accounts for the stress component out of the 3 things needed for brittle fracture to occur: <u>a low-toughness material, a crack or flaw, and some amount of stress</u>. During hydrotest, the hydrostatic head of the water causes the cracks to separate and grow. The tips of the cracks are placed in tension, and plastically deformed. After the water is removed, the crack (which never failed) close, placing the tip in a state of residual compression. The sharp tip has been "blunted." After hydrotest, the crack will not grow the same. It can continue to operate.

Toughness measured for a particular sized sample of a given material is not valid for a thicker or thinner sample of the same material (notch-toughness is not intrinsic to the material). Check figure 26 to see a graphic comparing absorbed energy vs thickness: the more thickness, the less toughness. The original nominal thickness for the thickest tank shell plate shall be used for this assessment.

In steel, temperature drops can decrease in a very sharp way the ductility of the material. There is a temperature in which the material stops being ductile and becomes fragile. The transition temperature is actually a temperature **RANGE**. Check figure 27 to understand this issue better. Assurance against brittle fracture can be gained by increasing metal temperature, heating the tank.

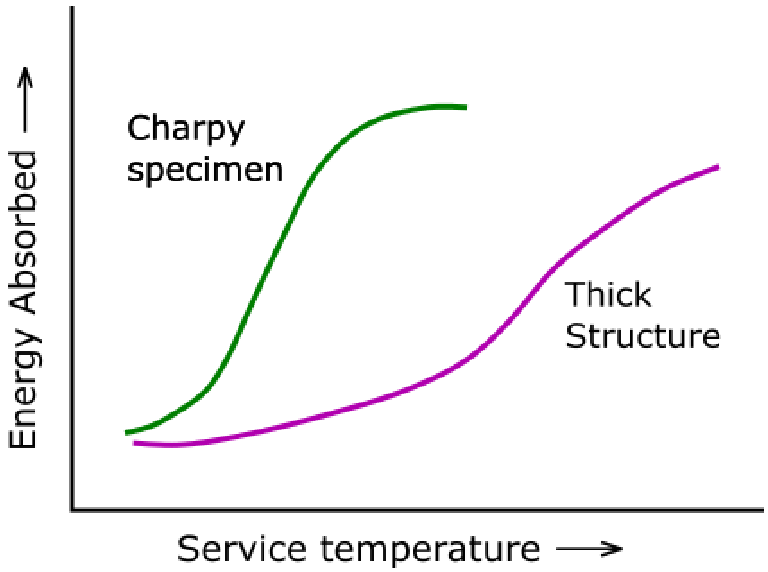


FIGURE 26 EFFECT OF THICKNESS IN DBTT

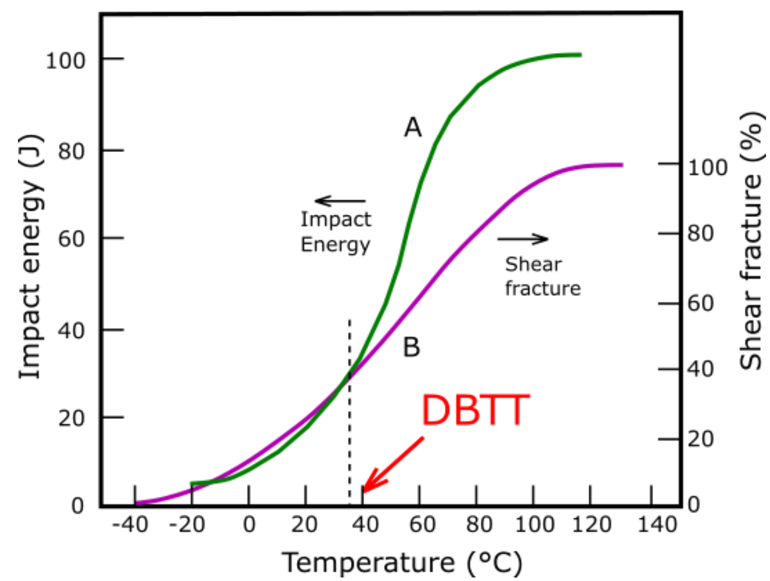
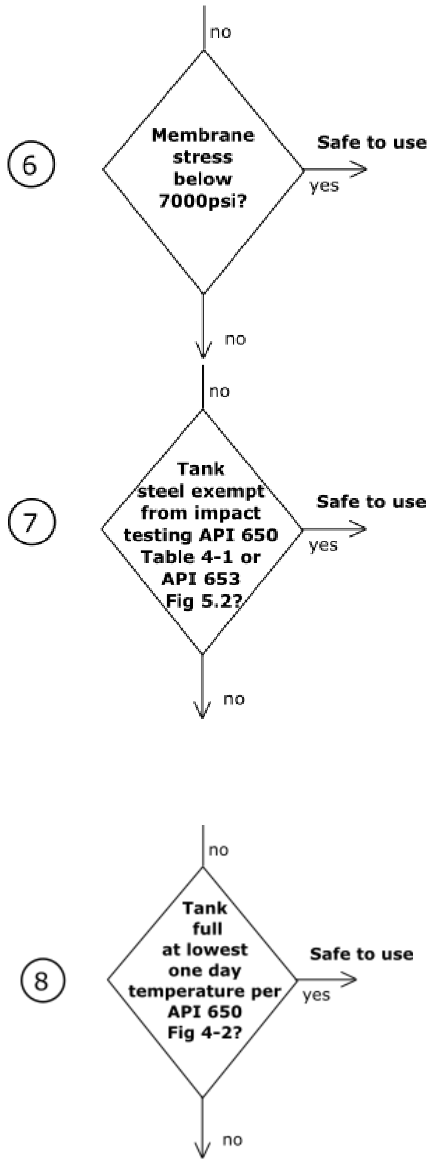


FIGURE 27 DBTT OF A283 STEEL



Industry experience and laboratory tests have shown that a membrane stress in tank shell plates of at least $7ksi$ is required to cause failure due to brittle fracture. Membrane stress is proportional to Diameter D and Liquid Level H. You can calculate stresses from the following equation:

$$S = \frac{2.6DHG}{t}$$

Where t = is the shell thickness at area of interest in inches

API 650 Table 4-1 is for KNOWN materials and API 653 Fig 5.2. is for UNKNOWN materials. Materials listed in API 650 can be used in accordance with their exemption curves, provided that an evaluation for suitability of service in conformance with Section 4 of API 653 has been performed. The test shall be performed on three specimens taken from a single test coupon or test location. The average value of the specimens (with no more than one specimen value being less than the specified minimum value) shall comply with the specified minimum value. If more than one value is less than the specified minimum value, or if one value is less than two-thirds the specified minimum value, three additional specimens shall be tested, and each of these must have a value greater than or equal to the specified minimum value. For UNKNOWN materials, assess using Figure 5.2 of API 653.

Figure 4-2 of API 650 (you can find a version of that in figure 12 in the following page) gives the Lowest One-Day Mean Temperature in the United States. As an example, we see that Houston, Texas, has a Lowest One-Day Mean Temperature of 15°F. If the tank is not heated, as an inspector, you should try ask for the temperature and liquid level records for every day of operation, and, if the 15°F LODT happened at least one time when the tank was full, then it is safe for use. (Don´t forget to check the calibration of the measurement instrument)

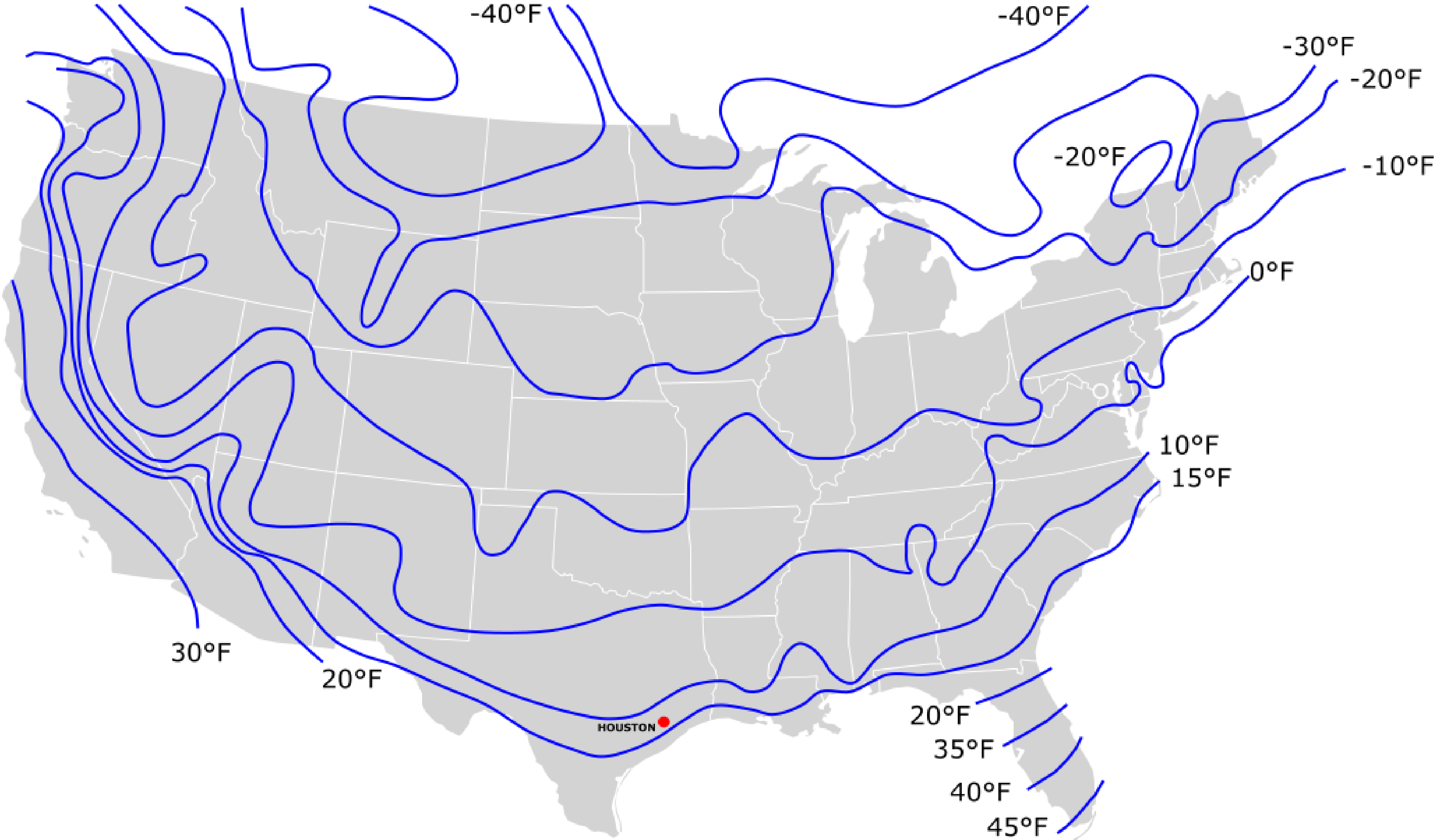


FIGURE 28 LOWEST ONE DAY MEAN TEMPERATURES IN THE UNITED STATES

BRITTLE FRACTURE ASESSMENT BY TYPE OF TANK

Whenever there is doubt about the capabilities of some steel to withstand all the loads present in a tank, maybe because the material is old, or the tank is of unknown steel, or if it is going to operate at low temperatures, impact tests are recommended, and sometimes mandatory according to the standards, to rule out the possibility of brittle fracture.

WHAT THE BOK SAYS

For people studying the API 653 exam, have in mind what the Body Of Knowledge says.

> The inspector should understand the importance of tank materials having adequate toughness. The inspector should be able to determine:
>
> a) Tank design metal temperature (API-650, 4.2.9.3 & Figure 4-2)*
>
> b) Material Group Number for a plate (API-650, Tables 4-3a and 4-3b)*
>
> c) If impact testing is required (API-650, Figure 4-1)
>
> d) If impact test values are acceptable (API-650, Table 4-4)*
>
> *References for Tables and Figures taken from API 650, twelfth edition, 2013

When deciding upon the re-use of an existing tank, the first thing you will take into account will be the exemption curve given in Figure 5.2 of API 653. Existing tanks fabricated from steels of unknown material specifications, thicker than 1/2 in. and operating at a shell metal temperature below 60 °F, can be used if the tank meets the requirements of Figure 5.2. The original nominal thickness for thickest tank shell plate shall be used for the assessment.

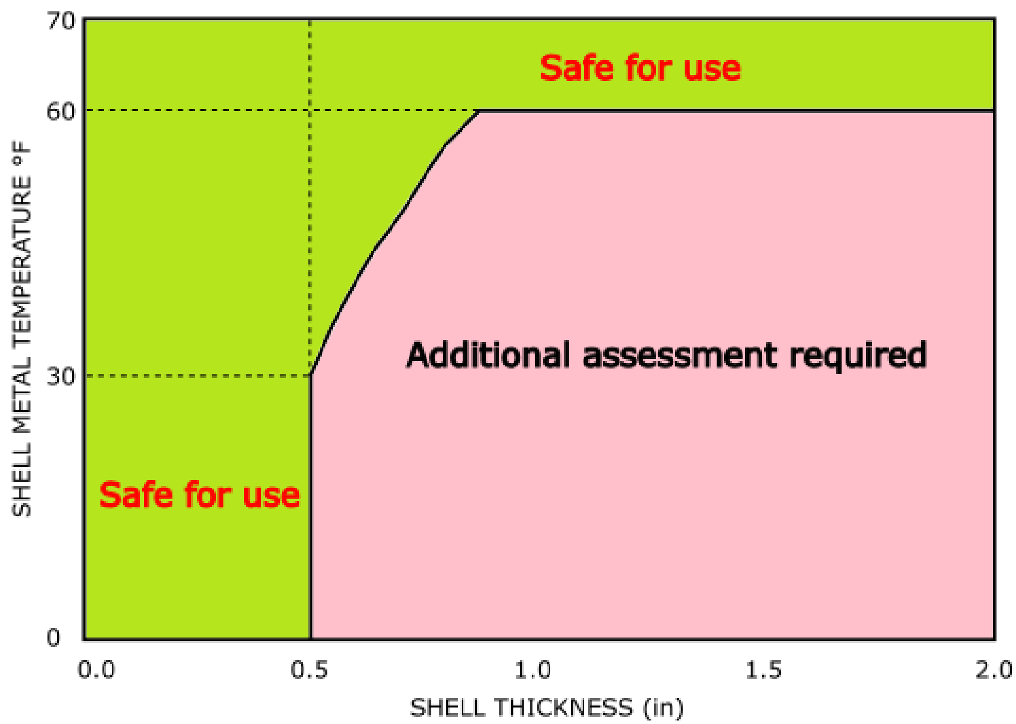


FIGURE 29 EXEMPTION CURVE FOR TANKS CONSTRUCTED FROM CARBON STEEL OF UNKNOWN MATERIAL SPECIFICATION

IMPACT TESTING FOR RECONSTRUCTED TANKS

When a tank is being reconstructed, each individual plate for which adequate identification does not exist shall be subjected to chemical analysis and mechanical tests as required in ASTM A6 and ASTM A370 including Charpy V-notch. Impact values shall satisfy the requirements of API 650

IMPACT TESTING FOR PREHEATED WELDS

Impact testing is required if you are going to apply preheating as an alternative to PWHT, as found in 11.3.1.

IMPACT TESTING TO AVOID HYDROTEST

If you are repairing a tank, and you are short of water for hydrostatic test, make sure to include impact testing in your PQR´s before commencement of work, to make it easier to avoid hydrotest.

12.2.3.2.1 of API 653 says "welds to existing metal, develop welding procedure qualifications based on existing material chemistry, including strength requirements. Welding procedures shall be qualified with existing or similar materials, and shall include impact testing. Impact testing requirements shall follow appropriate portions of API 650, Section 9.2.2 and shall be specified in the repair procedure."

Of course, there are many other requirements to hydrotest exemption, which are described in detail in 12.3.2 of API 653

IMPACT TESTING IN NEW TANKS

Brittle fracture concerns are more critical when dealing with the following parts of a tank shell plates, shell reinforcing plates, shell insert plates, bottom plates welded to the shell, plates used for manhole and nozzle necks, plate-ring shell-nozzle flanges, blind flanges, and manhole cover plates. Bottoms are usually thinner and don´t get as much affected by brittle fracture as the mentioned parts.

If you know the material specification, experience has shown that some materials don´t need impact testing. How to know if you need impact test for a new material? When you have your new plates in location, use figure 4.1a or 4.1b of API 650*. Plates less than or equal to 40 mm (1.5 in.) thick may be used at or above the design metal temperatures indicated in Figure 4.1a and Figure 4.1b without being impact tested.

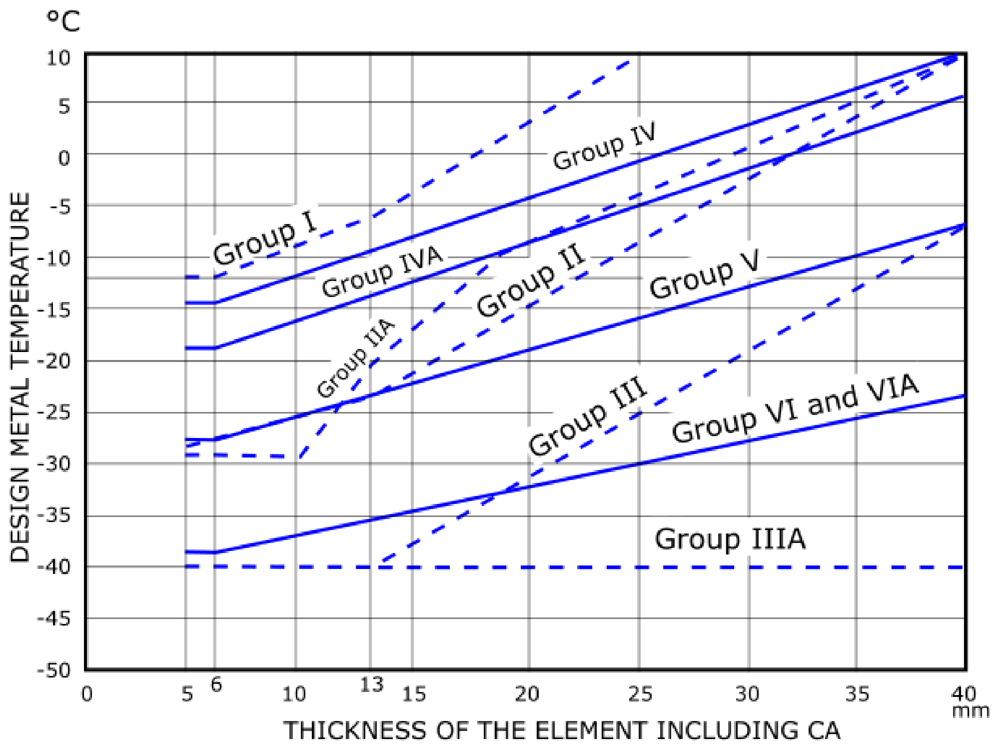


FIGURE 30 MINIMUM PERMISSIBLE DESIGN METAL TEMPERATURE FOR MATERIALS USED IN TANK SHELLS WITHOUT IMPACT TESTING (SI). (USE THIS FIGURE FOR KNOWN MATERIAL SPECIFICATION)

EXAMPLE:

For example, let´s consider an ASTM A36 As Rolled, Semi-Killed plate for a shell 12,5mm thick with a design metal temperature of 10°C. Will it be safe for use?

SOLUTION

API 650 describes three types of steel: Killed, As-rolled and Normalized

KILLED: Killed steel is steel that has been completely deoxidized by the addition of an agent before casting, so that there is practically no evolution of gas during solidification. They are characterized by a high degree of chemical homogeneity and freedom from gas porosity. The steel is said to be "killed" because it will quietly solidify in the mold, with no gas bubbling out. It is marked with a "K" for identification purposes

AS ROLLED: In the event that customers heat-treat their own plates, the product is referred to in as-rolled condition. After being rolled, the plate is cooled in static air. The term as-rolled condition stems from the fact that the product is not heat-treated

NORMALIZED: In this condition, carbon steel is heated to approximately 55 °C above Ac3 or Acm for 1 hour; this ensures the steel completely transforms to austenite. The steel is then air-cooled, which is a cooling rate of approximately 38 °C (100 °F) per minute. This results in a fine perlitic structure, and a more-uniform structure.

In our example, the plate is As-rolled, semikilled material, which makes it a group I, according to Table 4.4a or 4.4b of API 650.

Excerpt of table 4.4a. Material groups (SI)

Group I As Rolled, Semi-Killed	
Material	Notes
A283M C	2
A285M C	2
A131M A	2
A36M	2, 3
Grade 235	3
Grade 250	5

Design Metal Temperature is defined as "the lowest temperature considered in the design, which, unless experience or special local conditions justify another assumption, shall be assumed to be 8 °C (15 °F) above the lowest one-day mean ambient temperature of the locality where the tank is to be installed". The values for mean temperatures in any location in the United States can be found in Figure 4.2—Isothermal Lines of Lowest One-Day Mean Temperatures. Maximum design temperature is 93°C for tanks designed to API 650.

Our design metal temperature is 10°C and our shell thickness is 12,5mm for a group I material. This combination of materials, design, and construction features, makes our steel safe for use (See figure 17)

FIGURE 31 EXAMPLE OF ASSESSMENT FOR BRITTLE FRACTURE

WHEN IMPACT TESTING IS DONE

For a new tank, if required by the Purchaser or if the material falls in an area other than "safe for use", a set of Charpy V-notch impact specimens shall be taken from plates after heat treatment (if the plates have been heat treated), and the specimens shall fulfill the stated energy requirements. Three specimens are needed, and the average value of the three tests should be compared against the minimum requirements of Table 4.5a—Minimum Impact Test Requirements for Plates.

For a new tank, the impact test requirements and the definition of "controlling thickness" for pipings and forgings used as shell nozzles and manholes is found in numeral 4.5 of API 650.

IMPACT TESTS FOR WELDING PROCEDURE SPECIFICATIONS

When a new tank is constructed and impact tests are required by 4.2.9, 4.2.10, or 4.5.4, impact test should follow the guidelines found in numeral 9.2 of API 650.

As you can see, impact testing it is not a very difficult subject to understand. The standards are very clear regarding old and new tanks. Notice that the BOK works exclusively with API 650 and not with API 653.

EXAMPLE:

An Aboveground Storage Tank is to be constructed using ASTM A 516 gr 60 plates. The plates are normalized. The plates were tested for impact value and the following were the test results. The test results are presented for 32 mm thick plates (Lot A) and 30 mm thick plates (Lot B).

A) Longitudinal Specimen:
Three specimens failed at 13 ft-lb, 15 ft-lb and 18 ft-lb respectively

B) Transverse Specimen:
Three specimens failed at 12 ft-lb, 14ft-lb and 14ft-lb respectively

Which of the two plates is OK to use in a new tank?

SOLUTION:

The material belongs to Group III A.
The thicknesses are within acceptable limits. (Ref: 2.2.2, 516 gr60 can be used up to 40 mm thickness)

Plate A (Longitudinal):
Average of 3 specimens =3
13 +15 +16 = 14.66 ft. lb.
Average of 3 specimens, 14.66 ft. lb is less than required average of 15 ft. lb. REJECT.

Plate B (Transverse):
Average of 3 specimens =3
12 +14 +14 = 13.33
Average of 3 specimens, 13.33 is greater than required average of 13 ft. lb.
Also only one specimen (12 ft. lb) is below average and its value is greater than 2/3 x 13, i.e., greater than 8.66. ACCEPT

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CHAPTER 11: RECONSTRUCTED TANKS

First of all, let´s see the definition of a reconstructed tank according to API 653

reconstruction

Any work necessary to reassemble a tank that has been dismantled and relocated to a new site. In short, a reconstructed tank is a tank that has been dismantled and its pieces used together to make a new tank. But this should be made carefully.

The effects of brittle fracture are devastating. *In fact, the Ashland Oil Spill attributed to brittle fracture is credited as the triggering event for the creation of the API 653 and other integrity standards.*

WHAT TO STUDY

The body of knowledge says this about reconstructed tanks:

The inspector should be able to determine the minimum thickness of the shell of a reconstructed tank. The inspector should be able to:

a) Determine "S_d", allowable stress for design condition (API-650, table 5-2, API-653, 8.4.2)

b) Determine "S_t", allowable stress for hydrostatic test condition (API-650, Table 5-2, API-653, 8.4.3)

c) Calculate "t_d", design shell thickness (API-650, 5.6.3.2, for tanks of 200feet diameter and smaller)

d) Calculate "t_t", hydrostatic test shell thickness (API-650, 5.6.3.2)

RECONSTRUCTED TANKS SHELL

The following are the numerals dealing with allowable stresses is reconstructed tanks

8.4.2 The maximum design liquid level for product shall be determined by calculating the maximum design liquid level for each shell course based on the specific gravity of the product, the actual thickness measured for each shell course, the allowable stress for the material in each course, and the design method to be used. The allowable stress for the material shall be determined using API 650, Table 5-2. For material not listed in Table 5-2, an allowable stress value of the lesser of 2/3 of the yield strength or 2/5 of the tensile strength shall be used.

8.4.3 The maximum liquid level for hydrostatic test shall be determined by using the actual thickness measured for each shell course, the allowable stress for the material in each course, and the design method to be used. The allowable stress for the material shall be determined using API 650, Table 5-2. For material not listed in Table 5-2, an allowable stress value of the lesser of 3/4 of the yield strength or 3/7 of the tensile strength shall be used.

Knowing these 2 numerals, let´s go on to the determination of allowable stresses.

DETERMINE ALLOWABLE STRESSES

First, we will see how to determine allowable stresses for reconstructed tanks. If you were going to study by yourself, it will be easy to get confused and use for reconstructed tanks the table 4.1 of API 653 in search of allowable stresses, but that is a mistake. You should use table 5-2 of API 650 instead

The following are 2 questions of the kind that would appear in the open book section of the exam.

DETERMINE ALLOWABLE STRESSES USING TABLE 5-2 OF API 650

QUESTION: For plates of A283 Gr C steel used in a reconstructed tank, determine S_d (allowable stress for the design condition).

ANSWER: You simply go to Table 5.2B of API 650 and read from the sixth column that S_d is 20,000psi.

QUESTION: For plates of A516 Gr 60 steel used in a reconstructed tank, determine S_t (allowable stress for the hydrostatic test condition)

ANSWER: Reading the seventh column, we get a value for S_t of 24,000psi.

And now let´s look at some examples of questions that can be made in the exam.

DETERMINE ALLOWABLE STRESSES USING THE FRACTION VALUES OF SECTION 8.4 OF API 653

QUESTION: For a material not listed in Table 5.2, having Y = 36,000psi and T = 62,000psi, which is the allowable stress for the design condition?

ANSWER: *The lesser* of 2/3*36,000 = 24,000psi or 2/5*62,000 = 24,800psi, then choose 24,000psi

QUESTION: For a material not listed in Table 5.2, having Y = 30,000psi and T = 55,000psi, which is the allowable stress for the hydrostatic condition?

ANSWER: *The lesser* of 3/4*30,000 = 22,500psi or 3/7*55,000 = 23,570psi, then choose 22,500psi

CALCULATION OF DESIGN AND HYDROSTATIC SHELL THICKNESS

Calculation of minimum thicknesses for design and hydrostatic conditions in reconstructed tanks follow the same rules for new tanks. Let´s see a summary.

- Joint efficiency E is 1, as in new tanks. That´s why the E variable won´t show up in the formulas. Note that this is for tanks that have been completely cut apart.
- Values for S_d and S_t are the same as in new tanks. This has to do with the fact that a new and a reconstructed tank haven´t been subjected to a hydrostatic test and hasn´t proved itself against operational conditions. Values of S_d and S_t for new and reconstructed are LOWER than for existing tanks, for the same reason.
- Compare **API 653 8.4.2 to API 650 5.6.2.1** and **API 653 8.4.3 to API 650 5.6.2.2.** The values of the fractions for S_d and $S_t$are the same.
- The values of S_d and S_t for a reconstructed tank are the same for all shell courses, as opposed to API 653, in which this values vary according to shell height for existing tanks. (See table 4.1 of API 653)

The formulas for thickness calculation for reconstructed tanks are found in 5.6.3 of API 650.

FORMULAS FOR THE CALCULATION OF MINIMUM THICKNESS FOR RECONSTRUCTED TANK SHELLS

The minimum thickness of the shell of a reconstructed tank, is given by the following formulas found in

In International System (SI) units

$$t_d = \frac{4.9D(H-0.3)G}{S_d} + CA$$

$$t_t = \frac{4.9D(H-0.3)G}{S_t}$$

In United States Customary System (USC) units

$$t_d = \frac{2.6D(H-1)G}{S_d} + CA$$

$$t_t = \frac{2.6D(H-1)G}{S_t}$$

t_d is the shell design thickness (*mm* and *inches*)

t_t is the hydrostatic test shell thickness (*mm* and *inches*)

D is the nominal tank diameter (*m* and *ft*)

H is the design liquid level (*m* and *ft*)

= is the height from the bottom of the course under consideration to the top of the shell including the top angle, if any; to the bottom of any overflow that limits the tank filling height; or to any other level specified by the Purchaser, restricted by an internal floating roof, or controlled to allow for seismic wave action.

G is the design specific gravity of the liquid to be stored, as specified by the Purchaser

CA is the corrosion allowance (mm and $inches$)

S_d is the allowable stress for the design condition (mpa and psi)

S_t is the allowable stress for the hydrostatic test condition (mpa and psi)

EXAMPLE

Let´s consider the following example

A tank built with A283 Gr C is completely de-seamed and the reconstructed. Product stored is Texas Crude Oil at 60°F (G= 0,918), CA is 1/8", and the diameter of the tank is 28,6m. Design liquid level is 9,5m. Plates to be used are 6ft high. Which are the minimum thicknesses for the first shell course for the design and the hydrostatic test condition?

SOLUTION

t_d=?

t_t=?

D = 28.6m

H = 9.5m

G = 0.918

CA = 0.125"

S_d = 137Mpa

S_t = 154Mpa

E = 1 because the tank is completely de-seamed

Using the formula to calculate the minimum thickness for the design condition, we have:

$$t_d = \frac{4.9 * 28.6(9.5 - 0.3)}{137} + 0.125 * 25.4 = 11.814mm$$

And for the hydrostatic test condition:

$$t_t = \frac{4.9 * 28.6(9.5 - 0.3) * 0.918}{154} = 7.685mm$$

EXAMPLE:

A tank built in 1970 is dismantled and later reconstructed using A283 Gr C steel plates for the shell. Product stored is vehicle gasoline at 60°F (G = 0,739), CA is 3mm, and the diameter of the tank is 15,6m.

Design liquid level is 12,5m. Plates to be used are 6ft high. Which are the minimum thicknesses for each shell course for the design and the hydrostatic test condition if the tank wasn´t completely de-seamed?

SOLUTION:

t_d=?

t_t=?

D = 15.6m

H = 12.5m

G = 0.739

CA = 0"

S_d = 137Mpa

S_t = 154Mpa

E = 0,85 according to Table 4.2 of API 653, given that the tank wasn´t completely de-seamed. This is a hint at the fact that these formulas hide the E variable, because it is 1 for de-seamed tanks as by default in new tanks.

Using the formula to calculate the minimum thickness for the design condition, we have:

$$t_d = \frac{4.9 * 15.6 * (12.5 - 0.3)}{137 * 0.85} + 0 = 5.92mm$$

And for the hydrostatic test condition:

$$t_t = \frac{4.9 * 15.6 * (12.5 - 0.3) * 0.739}{154 * 0.85} = 5.26mm$$

You can see the E variable in the lower portion of the equation.

EXAMPLE:

Example 3. A tank of unknown material was completely de-seamed and reconstructed with the following measures: D = 58m, E = 27ft. Product is water and corrosion allowance is 0,1". Samples of the tank shell material are taken and yield strength is found to be 32000psi, while tensile strength is found to be 56000psi. Which is the minimum thickness for design and hydrostatic conditions? Use USC unit of systems.

SOLUTION:

t_d=?

t_t=?

D = 58m = 190ft

H = 27ft

$G = 1$

$CA = 0.1''$

$E = 1$

For the calculation of S_d, have in mind what API 653 8.4.2 says

For material not listed in Table 5-2, an allowable stress value of the lesser of 2/3 yield strength or 2/5 tensile strength shall be used.

Then

S_d is the lesser of 2/3*32,000 = 21,333psi or 2/5*56,000 = 22,400psi

For tanks of unknown material, have in mind what API 653 8.4.3 says regarding S_t

For material not listed in Table 5-2, an allowable stress value of the lesser of 3/4 yield strength or 3/7 tensile strength shall be used.

Then

S_t is the lesser of 3/4*32,000 = 24,000psi or 3/7*56,000 = 24,000*psi*

With these data, we can solve for the design condition:

$$t_d = \frac{2.6 * 190 * (27 - 1)}{22,333} + 0.1 = 0.675in$$

And for the hydrostatic test condition:

$$t_t = \frac{2.6 * 190 * (27 - 1) * 1}{24{,}000} = 0.525in$$

POINTS TO REMEMBER

Most API 653 exams contain questions that require you to pick out S values from Table 4.1 of API 653 or table 5.2 of API 650. Make sure to use table 5.2 of API 650 for new and reconstructed tanks.

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CHAPTER 12: ASME V RADIOGRAPHY

The BOK for the API 653 exam says:

> The inspector should be familiar with and understand:
>
> 1. The Scope of Article 2 and general requirements [of ASME V].
>
> 2. The rules for radiography as typically applied on butt welded AST horizontal and vertical seams such as, but not limited to:
>
> required marking type.
>
> selection.
>
> number, and placement of IQIs.
>
> allowable density control of backscatter radiation
>
> location markers
>
> 3. Records

I will try to simplify this subject as much as possible for the people who is studying for the API 653 exam.

SCOPE OF ARTICLE 2 AND GENERAL REQUIREMENTS

I don´t want to deal here with this issue, given that it is very broad and ideally should belong to another part of the BOK. Let´s first talk about procedures.

PROCEDURES

Any radiographic testing needs a written procedure approved by a level III supervising inspector, even when the actual test can be done by a level II technician. This is like for any other NDE type, like Penetrant Testing, or Magnetic testing (API 650 Annex U). The procedure shall contain, as a minimum:

1. material type and thickness range
2. isotope or maximum X-ray voltage used
3. source-to-object distance
4. distance from source side of object to film
5. source size
6. film brand and designation
7. screens used

MATERIAL TYPES

There is not much to say here. Industrial radiography can be used in many industries, from concrete to medicine to ceramic aviation components, but mostly it is used for weld inspection. In our case we are talking of course, about carbon steel or stainless steel.

TYPES OF RADIATION FOR INDUSTRIAL RADIOGRAPHY

There are 2 main radiation sources used for industrial radiography.

X-RAY or GAMMA RADIATION

Radiation for industrial radiography is now usually distinguished by their origin: X-rays are emitted by electrons outside the nucleus, while Gamma rays are emitted by the nucleus. X-ray can now be produced by electric means, using x-ray tubes, while gamma rays for industrial radiography will need a radionuclide., as cobalt-60 or iridium-192.

X-RAY TUBES

With isotopes, it is very difficult to achieve a small, compact beam of radiation aimed to your desired location, as you can do with X-ray tubes. Besides, isotopes can´t be turned off for the sake of safety. But X-ray equipment is heavier and requires a power source. The amount of radiation for X-rays depends on the voltage applied.

SOURCE-TO-OBJECT DISTANCE and DISTANCE FROM SOURCE SIDE OF OBJECT TO FILM

The ideal source-to-object distance and the distance from source side of object to film are given by a maximum value of geometric unsharpness present in most radiographies. **Geometric unsharpness** is the loss of definition, mostly of the edges, because of **geometric** factors of the radiographic equipment and setup. It occurs because the radiation does not originate from a single point but rather over an area.

Geometric unsharpness, Ug, can be calculated from the formula in the following equation

$$U_g = \frac{f * b}{a}$$

Check Figure 32 for an explanation

SOURCE SIZE

Source size is important because a bigger source achieves a higher level of geometric unsharpness. For isotopes, source size is just given by a measure in mm or inches, of the diameter of the pellet or pellets used in the source capsule (pellets in the range of 1 or 2 millimeters are common). As for X-rays, several methods have been used to reduce the focal size of the X-rays used, depending on the way the X-rays are created. Usually, reducing the angle of the cathode in the X-ray tube reduces the source area.

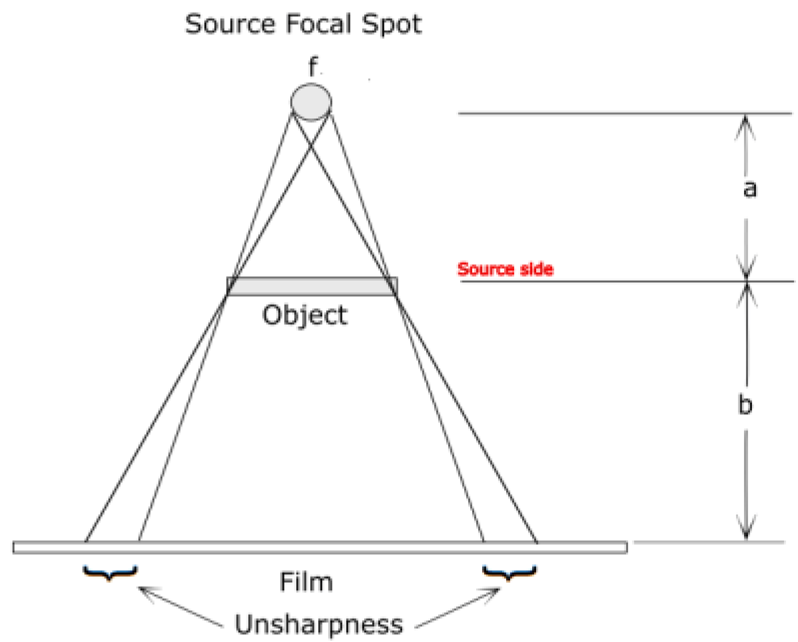

FIGURE 32 GEOMETRIC UNSHARPNESS

FILM BRAND AND DESIGNATION

RT Films Classification is like Class I, II etc. or Type 1,2,3 etc. which is basically denoting the speed of film. Most popular brands for industrial radiography film are AGFA, Fuji and KODAK. There can be different types of films made by the same manufacturer within the same class. Take for example the DR50 and the M100 of Kodak, which are the same class but have different sensitivities. One of the most known films for radiography is the D7 of AGFA. Besides, the same film can have varying speeds depending on the source type. It takes an experienced person to select the right film for the application being. If you wish to review different designations for radiographic films, see the table below.

KODAK FILM	AGFA STRUCTURIX	FUJI (IX)
INDUSTREX CX	D8	150
INDUSTREX AA400	D7	100
INDUSTREX T200	D5	80
INDUSTREX MX125	D4	--
INDUSTREX M110	D3	50
INDUSTREX DR50	D2	25
INDUSTREX SR45	D3-SC	20

SCREENS USED

When we talk here about screens, we are talking about **intensifying screens**. Image in the radiographic film is the result of just 1 % of the amount of radiation energy created. The rest of the energy passes through the film and is not used. Sometimes this is not enough and intensifying screens must be used.

They can be made of several types of material (lead, steel, copper, salt, fluorescent materials, etc.), and basically one front and one back screens are used to sandwich the film and make the image clearer. Fluorescent screens instantly emit light under the influence of electromagnetic radiation. The moment radiation stops, so does the lighting effect. Certain substances, as phosphors (usually rare earths) emit a lot of light when subjected to ionizing radiation, and they have more effect on the light sensitive film than the direct ionizing radiation itself, thus intensifying the image. A side effect of intensifying screens is, of course, a little more unsharpness.

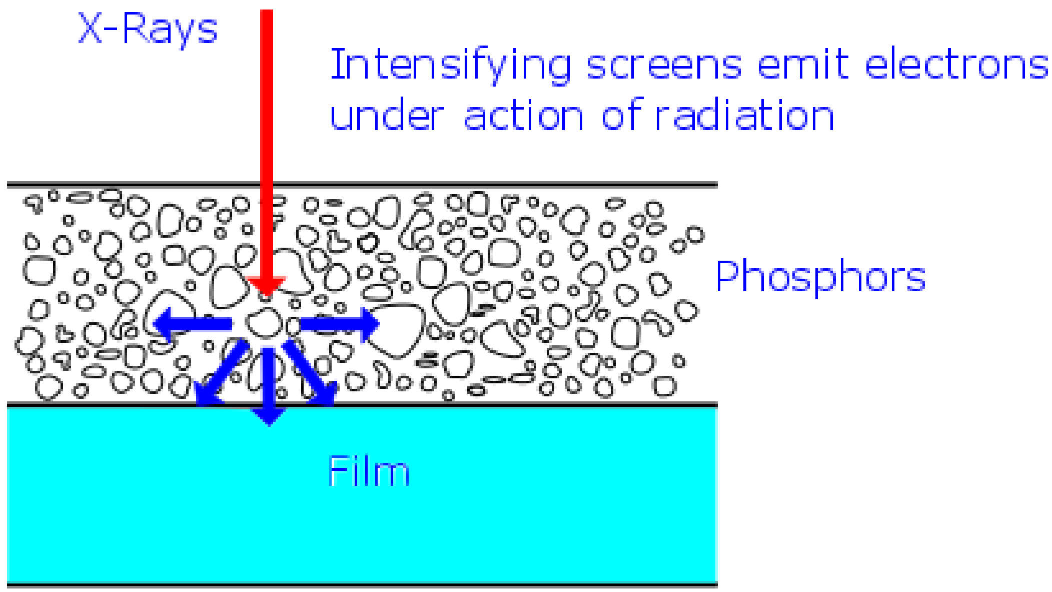

FIGURE 33 INTENSIFYING SCREENS

PROCEDURE DEMONSTRATION

As with any other NDE procedure, a radiographic inspection procedure needs to be demonstrated to know the ability of the performer of the examination. It has, like welding procedures, essential and non-essential variables, depending on the radiographic technique selected. Demonstration of the density and image quality indicator (IQI) image requirements of the written procedure on production or technique radiographs shall be considered satisfactory evidence of compliance with that procedure.

All NDE procedures used on the job shall be approved by an NDE Level III. The NDE Level III shall select a suitable technique according to the job requirement. All essential and non-essential variables shall be mentioned on the procedure. Some values in the procedure may have to be changed after the demonstration.

A test specimen having flaws whose size, location, orientation, quantity and characterization have been determined prior to the demonstration should be known only to the supervising Level III Examiner. The Level III will exercise care to keep the records of those flaws only for himself after demonstration.

Procedure demonstration is defined in article 1 of section V as: A written procedure is demonstrated, to the satisfaction of the Inspector, by applying the examination method using the employer's written nondestructive examination procedure to display compliance with the requirements of this Section.

REQUIRED MARKING

ASME V asks for a system to produce permanent identification on the radiograph traceable to the contract, component, weld or weld seam, or part numbers, as appropriate. The Manufacturer's symbol or name and the date of the radiograph shall be permanently included on the radiograph. The information not necessarily should appear as radiographic images. In any case, this information shall not obscure the area of interest. If a mistake is committed in the film, how can it be fixed? Does the radiography need to be taken again? No. A tape over the mistake will do it, as long as the change is recorded.

A radiographic film for a tank weld has can be like this:

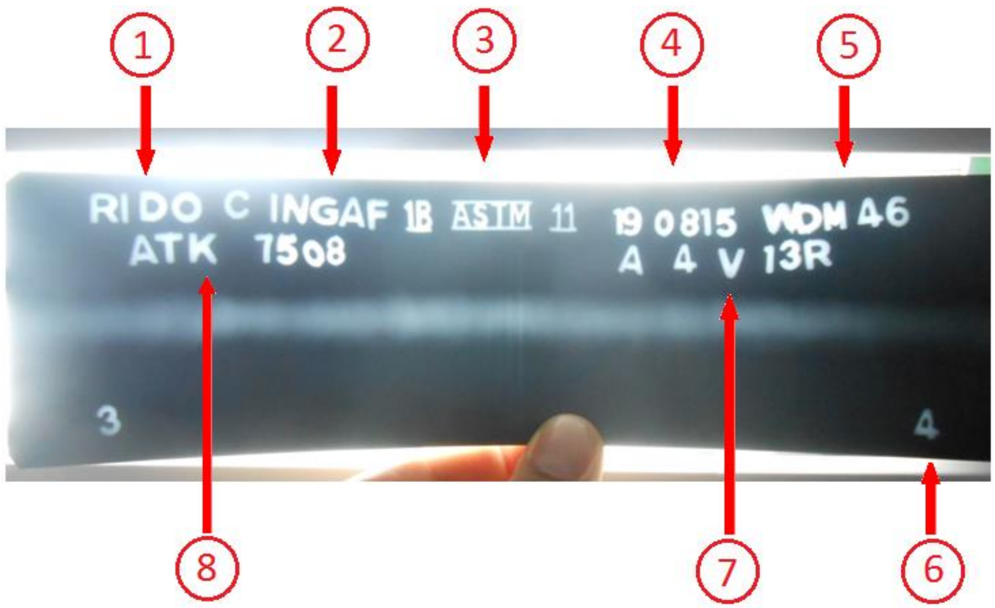

FIGURE 34 EXAMPLE OF A RADIOGRAPHIC FILM TAKEN ON A TANK WELD

1. Name of the radiographic service provider
2. Name of the client
3. The Image Quality indicator (explained below)
4. Date
5. Welder´s ID (We use the welder´s initial plus the last 2 digits of his ID)
6. Location markers
7. Weld ID (When you put this you fulfill the contract, component, weld or weld seam, or part numbers, asked by the standard)
8. Tank´s ID
9.

TYPE, SELECTION, NUMBER, AND PLACEMENT OF IQIS.

WHAT ARE IMAGE QUALITY INDICATORS (IQIs)?

For establishing the quality of an image, an Image Quality Indicator, or penetrameter, is used. The idea is to place a penetrameter (often shortened to “penny”) on a specimen that is being radiographically tested, to evaluate the sensitivity of the radiograph. Radiographic sensitivity is defined as the smallest or thinnest material change that a radiograph reveals.

Again, sensitivity is a measure of the quality of an image, related to the smallest discontinuity it shows. For example, if a radiograph has 2% sensitivity for a material that is 12mm thick, then the smallest defect that can be found would be:

$$0.02*12=0.24mm$$

In the early times of radiographic inspection, you would put, in front of the piece to be inspected, a plate with a perforation the size of the smallest discontinuity you wanted to find in that piece. That was known as a "Hole Type" IQI. However, nowadays the most used type of IQI is the "Wire-type IQI".

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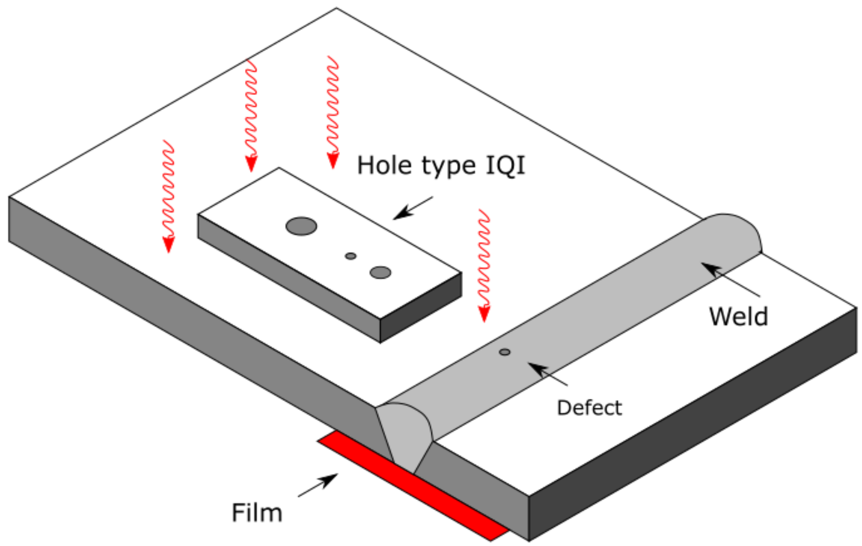

FIGURE 35 HOLE TYPE IQI

Wire-type IQIs come in four sets (Set A, Set B, Set C, Set D) containing six wires each of different diameters. Sets A, B C, D are selected depending on the thickness of the piece to be evaluated. The thickness on which the IQI is based is the nominal single-wall thickness plus the estimated weld reinforcement not to exceed the maximum permitted by the referencing Code Section. If the piece has 2 walls, the IQI is the same (single wall) but exposure time is double. Wire type IQIs should be placed directly across the weld. The IQI shall be made up of the same material as that of the material to be radiographed or the IQI shall be of a radiographically similar material.

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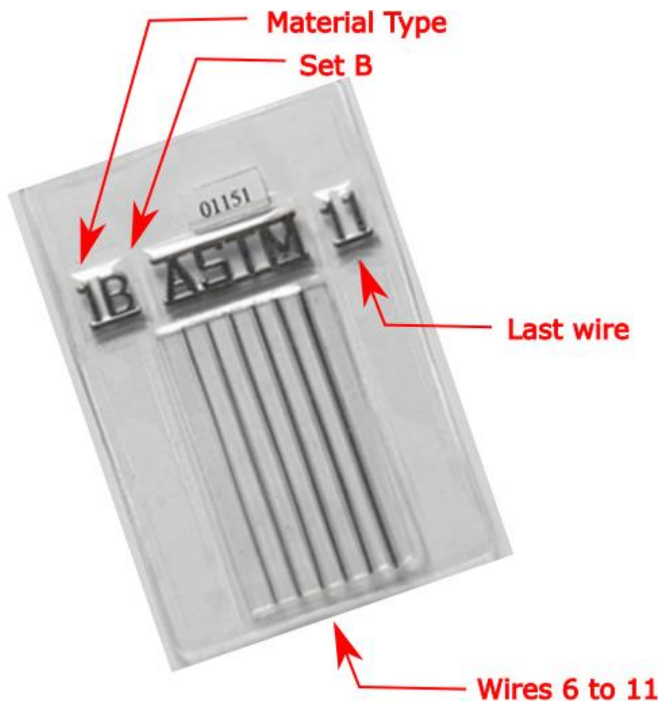

FIGURE 36 WIRE TYPE IQI

EXAMPLE:

Let´s say you need to select a penny for a piece 6,4mm thick with an 1/8" reinforcement in each side (The picture of the radiographic film in this article corresponds to that situation). Then the single wall thickness would be 2/4" = 12,7mm. If you need 2% sensitivity, then multiply 12,7*0,02 = 0,254mm. You go to T-233.2 in ASME V and read through the line of the thickness you need. In this case, the Wire-type essential wire designation is 6. This wire designation corresponds to the set A or B wire type IQI.

Wire IQI designation, Wire diameter, and wire identity					
Set A			Set B		
Wire diameter, in	(mm)	Wire identity	Wire diameter, in	(mm)	Wire identity
0.0032	(0.08)	1	0.010	(0.25)	6
0.004	(0.10)	2	0.013	(0.33)	7
0.005	(0.13)	3	0.016	(0.41)	8
0.0063	(0.16)	4	0.020	(0.51)	9
0.008	(0.20)	5	0.025	(0.64)	10
0.010	(0.25)	6	0.032	(0.81)	11
Set C			Set D		
Wire diameter, in	(mm)	Wire identity	Wire diameter, in	(mm)	Wire identity
0.032	(0.81)	11	0.100	(2.54)	16
0.040	(1.02)	12	0.126	(3.20)	17
0.050	(1.27)	13	0.160	(4.06)	18
0.063	(1.60)	14	0.200	(5.08)	19
0.080	(2.03)	15	0.250	(6.35)	20
0.100	(2.54)	16	0.320	(8.13)	21

If you don´t want to make all of these calculations, go to table T-276 of ASME V, and select directly the wire

ALLOWABLE DENSITY CONTROL OF BACKSCATTER RADIATION

Backscatter radiation happens because some radiation that passes through the piece can rebound in surfaces behind it, and make white zones that should be dark with defects. A lead symbol “B,” with minimum dimensions of 1⁄2 in. (13 mm) in height and 1⁄16 in. (1.5 mm) in thickness, shall be attached to the back of each film holder during each exposure to determine if backscatter radiation is exposing the film, which will render the film useless (See image below). A light image of the B occurs because the lead letter B acts as shielding that prevents scattered radiation from imaging that portion of the film under the B but, the scatter radiation can expose the rest of the film surface. A dark image of a lead letter B could occur too though in rare occasions, when backing screens are not used and the lead from the B acts like a lead intensifier screen.

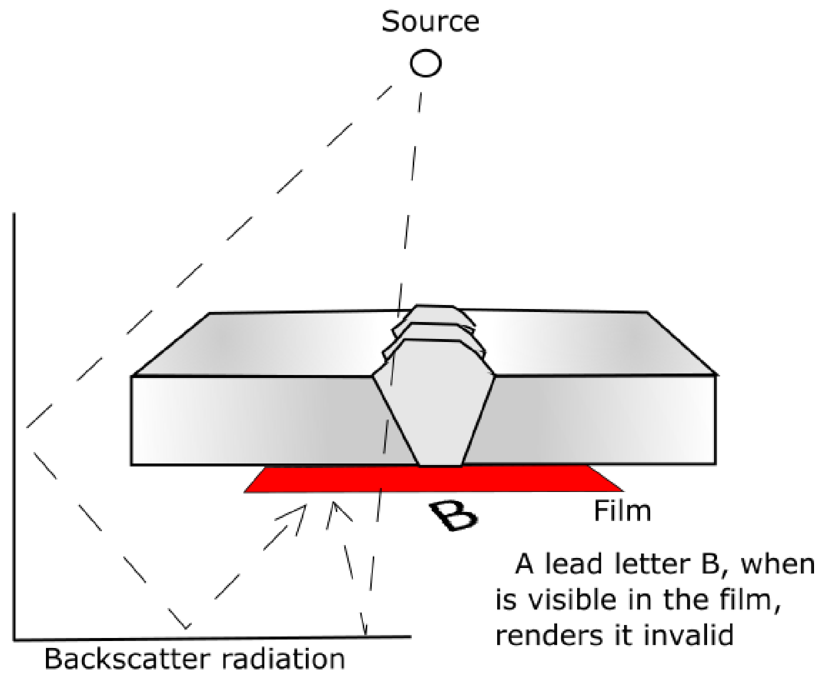

FIGURE 37 BACKSCATTER RADIATION

LOCATION MARKERS

Location markers, which are to appear as radiographic images on the film, shall be placed on the part, not on the exposure holder/cassette. ASME V ask for their locations shall be permanently marked on the surface of the part being radiographed, but this is practically impossible in painted surfaces. Instead you can do a map, in a manner permitting the area of interest on a radiograph to be accurately traceable to its location on the part, for the required retention period of the radiograph. Evidence shall also be provided on the radiograph that the required coverage of the region being examined has been obtained. Example of correct placement of Location Markers can be seen in the figure below. ***There are more configurations in figure T-275 of ASME V***.

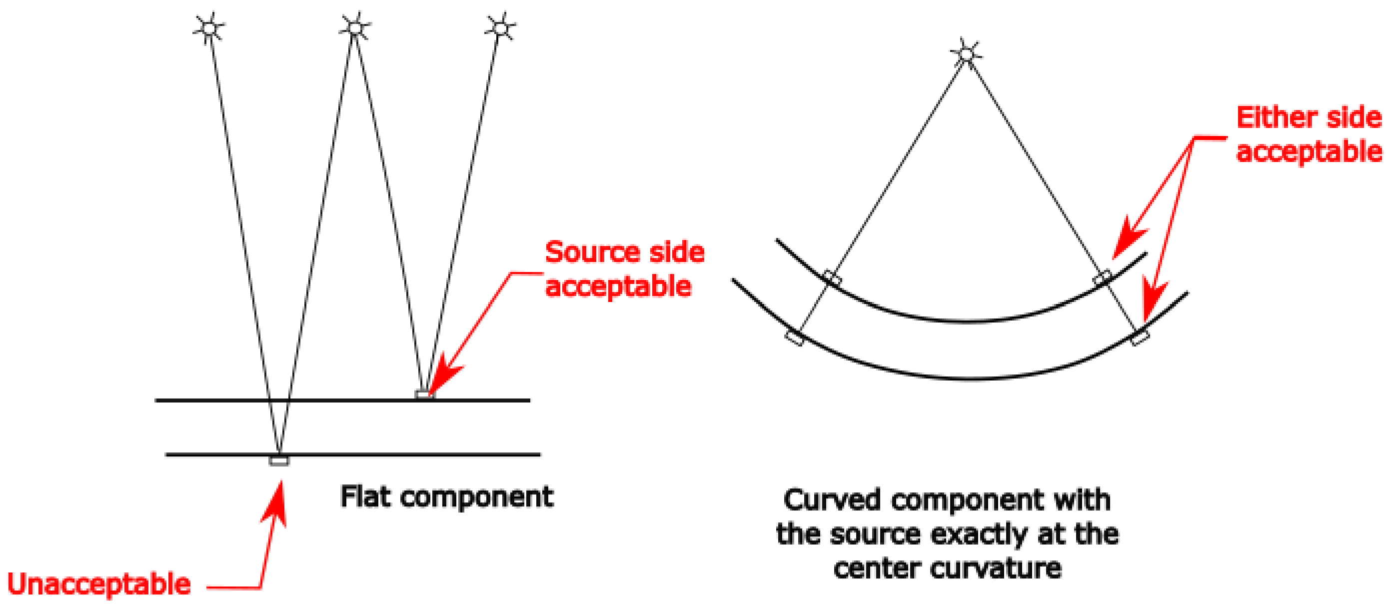

FIGURE 38 EXAMPLES OF LOCATION MARKER PLACEMENT

There is 1 characteristic of a good radiograph that you should control:

FILM DENSITY

According to ASME V,

either (1) a densitometer or (2) step wedge comparison film shall be used for judging film density.

Radiographic density is a measure of the degree of film darkening. Technically it should be called "transmitted density" when associated with transparent-base film since it is a measure of the light transmitted through the film. Radiographic density referred to as the overall blackening of the film. Density is dependent on amount of radiation received by the film, which depends, among other things, on source size and time of exposure.

DENSITOMETERS

A densitometer is a device that measures the amount of light transmitted through an object, in this case a piece of radiographic film. The film is placed between the light source and the sensor and a density reading is produced by the instrument.

When the code says "A national standard step tablet", it is likely talking about a NIST step tablet. Before, NIST created the SRM-1001 step tablet with 17 steps (now 38100C, info for SRM-1001 can be found here) and the SRM-1008 step tablet with 23 steps (now 38120C, info for SRM-1008 can be found here). The instructions on the NIST site state the following regarding densitometer calibration

INSTRUCTIONS FOR USE

Remove the film from its protective sleeve and place the center of a step on the diffuser of the densitometer to be calibrated with the side of the step tablet with the serial number in contact with the diffuser. Calibrate the densitometer using the transmission density of that step, and repeat this procedure with other steps of the step tablet.

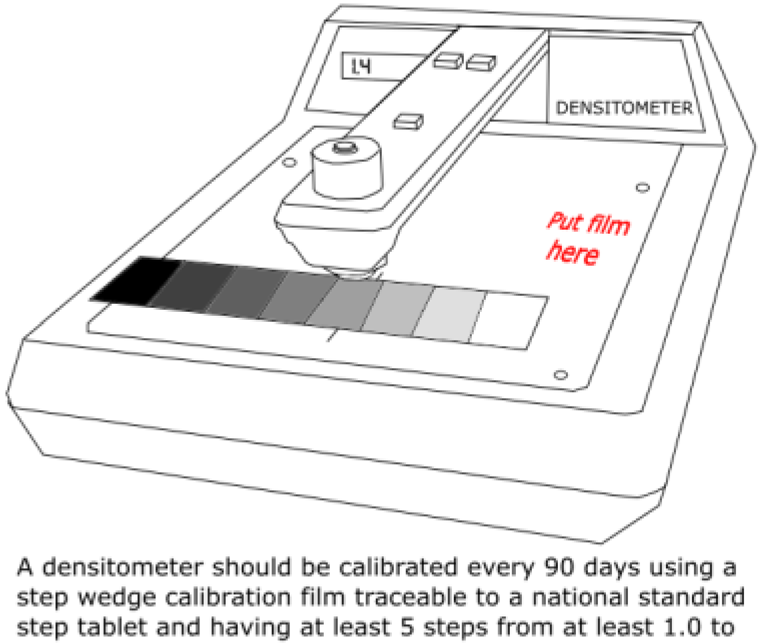

FIGURE 39 DENSITOMETER

Of course, NIST is for US, and most of other countries refer to US standards. For Germany, it exists Physikalisch -Technische Bundesanstalt PTB standard reference X-ray Fil step tablet – calibration mark 3641-02. The national standard step tablet shall be stored properly in between every 90-day calibration.

Step wedge calibration films are processed films with discrete density steps that have been verified by comparison with a national standard step tablet. They can be used for calibration.

STEP WEDGE COMPARISON FILM SHOULD BE VERIFIED

Step Wedge Comparison Films. Step wedge comparison films shall be verified prior to first use, unless performed by the manufacturer, as follows:

(a) The density of the steps on a step wedge comparison film shall be verified by a calibrated densitometer.

(b) The step wedge comparison film is acceptable if the density readings do not vary by more than ±0.1 density units from the density stated on the step wedge comparison film.

Periodic Verification.

(a) Densitometers. Periodic calibration verification checks shall be performed as described in T-262.1 at the beginning of each shift, after 8hr. of continuous use, or after change of apertures, whichever comes first.

(b) Step Wedge Comparison Films. Verification checks shall be performed annually per T-262.2. T-262.4 Documentation.

(a) Densitometers. Densitometer calibrations required by T-262.1 shall be documented, but the actual readings for each step do not have to be recorded. Periodic densitometer verification checks required by T-262.3(a) do not have to be documented.

(b) Step Wedge Calibration Films. Step wedge calibration film verifications required by T-262.1(a) shall be documented, but the actual readings for each step do not have to be recorded.

(c) Step Wedge Comparison Films. Step wedge comparison film verifications required by T-262.2 and T-262.3(b) shall be documented, but the actual readings for each step do not have to be recorded.

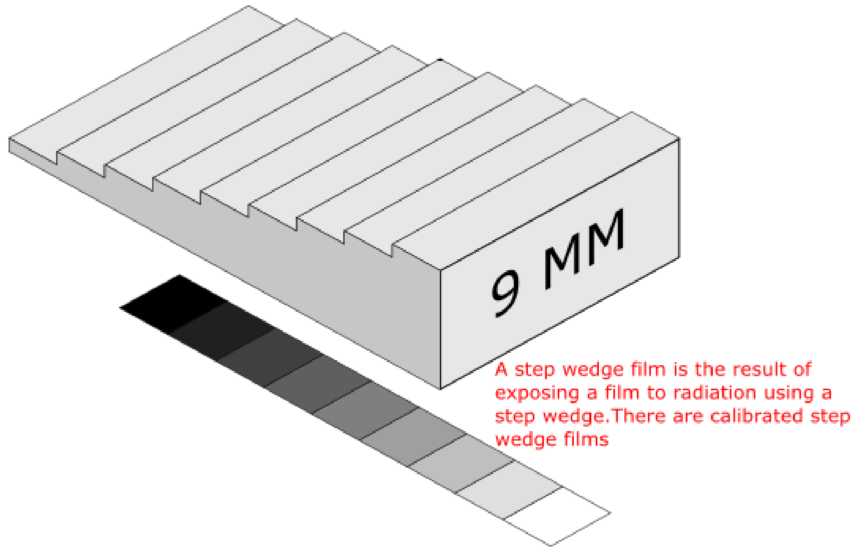

FIGURE 40 STEP WEDGE USED FOR RADIOGRAPHIC CALIBRATION

Step wedge comparison films are processed films with discrete density steps that are to be verified by use of a calibrated densitometer before first use, and that is used to determine if production radiographs meet density limits. This step wedges are needed for the verifications of densitometers that are to be made before and after each use, after every 8 hours of continuous use, and so. Step wedge comparison films need not be calibrated, mostly they are a way to compare a densitometer against itself.

At least once a year, the densities of comparison films are re-measured against the national standard step tablet and the recorded values adjusted as necessary. During these frequency checks, if the readings from the densitometer do not match the recorded densities from the reference comparison film, then you verify the densitometer against the step tablet.

This is my last article about radiology in tanks for readers who are studying for the API 653 exam. We will see

Radiographic Technique

Placement of IQIs

Radiographic density

I make short comments about the parts of interest in the code, given that most of it is self-explanatory. I accompany the comments with valuable images for better understanding

RADIOGRAPHIC TECHNIQUE

According to ASME V T-271

A single-wall exposure technique shall be used for radiography whenever practical. [...]. An adequate number of exposures shall be made to demonstrate that the required coverage has been obtained.

T-271.1 Single-Wall Technique. In the single-wall technique, the radiation passes through only one wall of the weld (material), which is viewed for acceptance on the radiograph.

Radiographs in tanks are single-wall technique. In the excerpt written above, I´ve erased the parts of the code that deal with the double-wall technique (when radiation passes through 2 walls). Usually, the X-Ray technician will have to climb above a scaffold to put the Gamma Ray Camera in position. Some safety measures that need to be taken are the use of a survey meter close to the guide tube of the collimator, and a portable detection device in the technician´s body, along with the rules for working at height of your country. (I say this because I have been in QAQC and HSE roles and actually never technicians did have these safety measures in place)

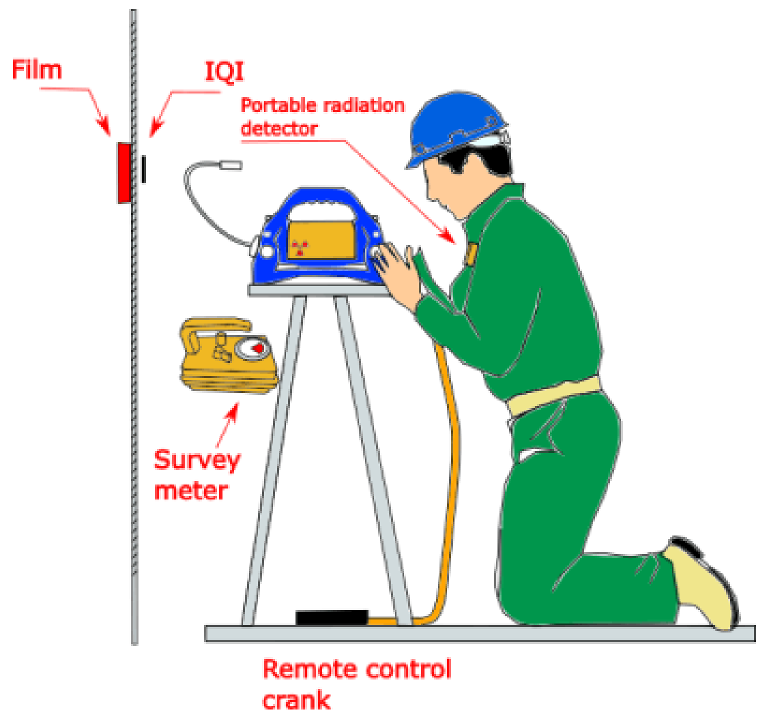

FIGURE 41 RADIOGRAPHY SETUP

PLACEMENT OF IQIs

T-277.1 Placement of IQIs.

653-FIX | 12/31/2016

(a) Source-Side IQI(s). The IQI(s) shall be placed on the source side of the part being examined, except for the condition described in (b).

When, due to part or weld configuration or size, it is not practical to place the IQI(s) on the part or weld, the IQI(s) may be placed on a separate block. Separate blocks shall be made of the same or radiographically similar materials (as defined in SE-1025) and may be used to facilitate IQI positioning. There is no restriction on the separate block thickness, provided the IQI/area-of-interest density tolerance requirements of T-282.2 are met.

(1) The IQI on the source side of the separate block shall be placed no closer to the film than the source side of the part being radiographed.

(b) Film-Side IQI(s). Where inaccessibility prevents hand placing the IQI(s) on the source side, the IQI(s) shall be placed on the film side in contact with the part being examined. A lead letter "F" shall be placed adjacent to or on the IQI(s), but shall not mask the essential hole where hole IQIs are used.

As I said before, you´ll have to keep an eye on technicians. Sometimes they are too lazy to put the IQIs on the source side and instead put it in the film side, but don´t put the lead F letter required by the code.

T-277.2 Number of IQIs. When one or more film holders are used for an exposure, at least one IQI image shall appear on each radiograph [...].

(a) Multiple IQIs. If the requirements of T-282 are met by using more than one IQI, one shall be representative of the lightest area of interest and the other the darkest area of interest; the intervening densities on the radiograph shall be considered as having acceptable density

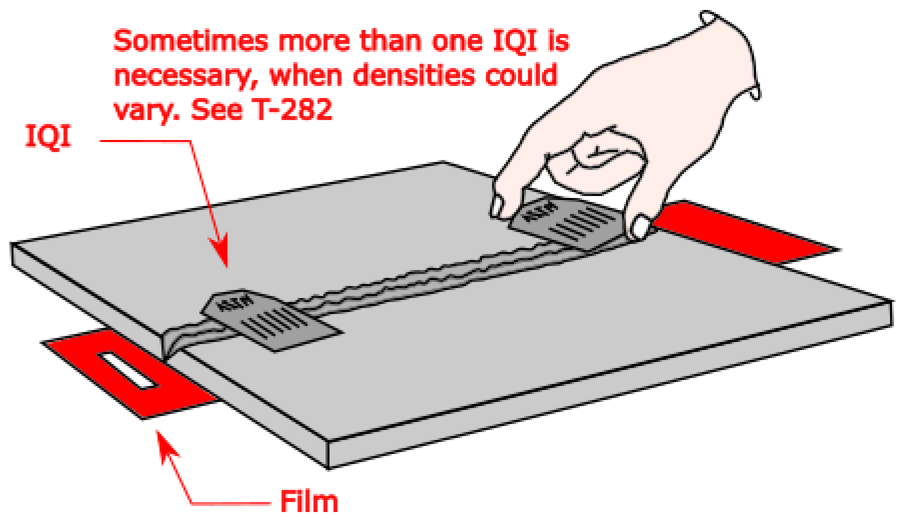

FIGURE 42 RADIOGRAPHIC DENSITY VARIATIONS

RADIOGRAPHIC DENSITY

T-282. Density Limitations. The transmitted film density through the radiographic image of the body of the designated hole-type IQI adjacent to the essential hole or adjacent to the essential wire of a wire-type IQI and the area of interest shall be 1.8 minimum for single film viewing for radiographs made with an X-ray source and 2.0 minimum for radiographs made with a gamma ray source. For composite viewing of multiple film exposures, each film of the composite set shall have a minimum density of 1.3. The maximum density shall be 4.0 for either single or composite viewing. A tolerance of 0.05 in density is allowed for variations between densitometer readings.

T-282.2 Density Variation.

(a) The density of the radiograph anywhere through the area of interest shall not

(1) vary by more than minus 15% or plus 30% from the density through the body of the designated hole-type IQI adjacent to the essential hole or adjacent to the essential wire of a wire-type IQI, and

(2) exceed the minimum/maximum allowable density ranges specified in T-282.1

When calculating the allowable variation in density, the calculation may be rounded to the nearest 0.1 within the range specified in T-282.1.

(b) When the requirements of (a) above are not met, then an additional IQI shall be used for each exceptional area or areas and the radiograph retaken.

(c) When shims are used with hole-type IQIs, the plus 30% density restriction of (a) above may be exceeded, and the minimum density requirements of T-282.1 do not apply for the IQI, provided the required IQI sensitivity of T-283.1 is met.

The following image illustrates point (1) in T-282. Whenever in a radiograph there is a variation of densities in the area of interest minus 15% or plus 30% from the density compared to the density measurable in the IQI, the radiograph should be rejected and it is recommended the use of another set of IQIs

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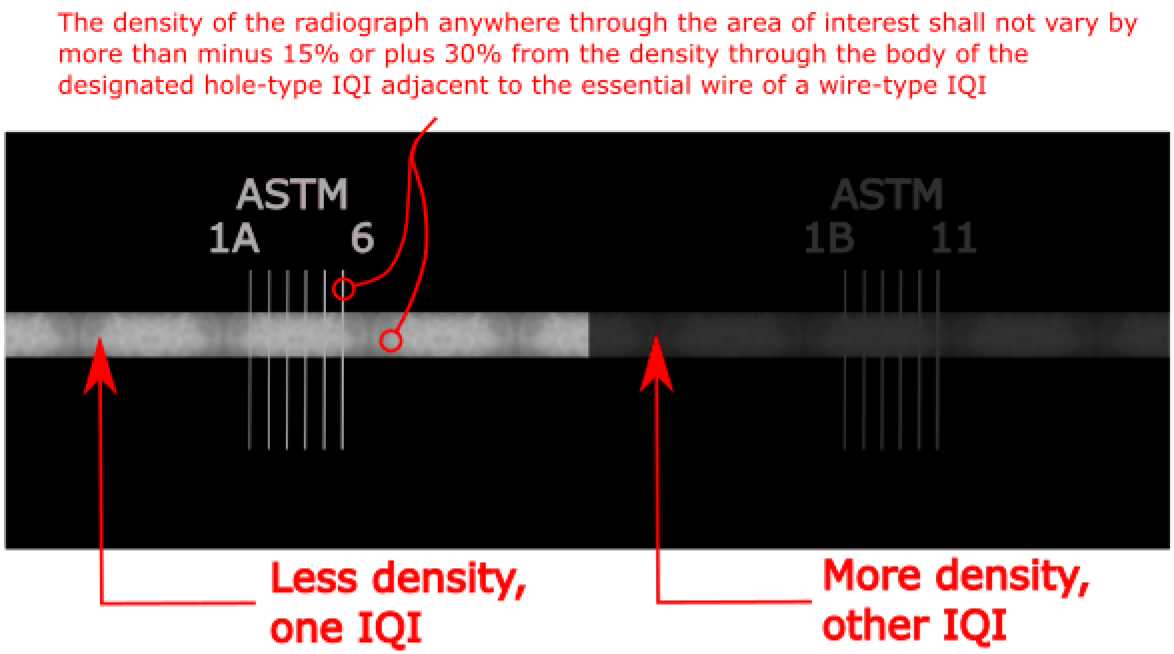

FIGURE 43 RADIOGRAPHIC DENSITY DIFFERENCES IN A FILM

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CHAPTER 13: ASME V ULTRASONIC EXAMINATION

In the Body Of Knowledge for the API 653 exam, Ultrasonic Testing is one of the smallest parts that needs to be studied. This is what the Body Of Knowledge says you need to get:

> E. Article 23, Ultrasonic Standards, Section SE–797 only – Standard practice for measuring thickness by manual ultrasonic pulse-echo contact method:
>
> 1. The Scope of Article 23, Section SE-797
>
> 2. The general rules for applying and using the Ultrasonic method
>
> 3. The specific procedures for Ultrasonic thickness measurement as contained in paragraph 7.

In my opinion, UT will replace radiography in many fabrications, because it is safer and faster, and usually eliminates the need to have access to the opposite surface of the part being inspected.

SCOPE OF ARTICLE 23, SECTION SE-797

This practice

1. […] provides guidelines for measuring the thickness of materials using the contact pulse-echo method at temperatures not to exceed 93°C [200°F].

2. […] is applicable to any material in which ultrasonic waves will propagate at a constant velocity throughout the part, and from which back reflections can be obtained and resolved.

What is pulse-echo? Simply put, pulse-echo is a technique where a source emits a pulse, then that pulse gets reflected (echo), and a search unit detects the echo. By measuring the time between the transmission of the transmit pulse and the reception of that echo, the ultrasound machine can calculate the distance between the probe and the structure that caused that echo. This is essentially the same principle used by bats to catch insects through echo-location.

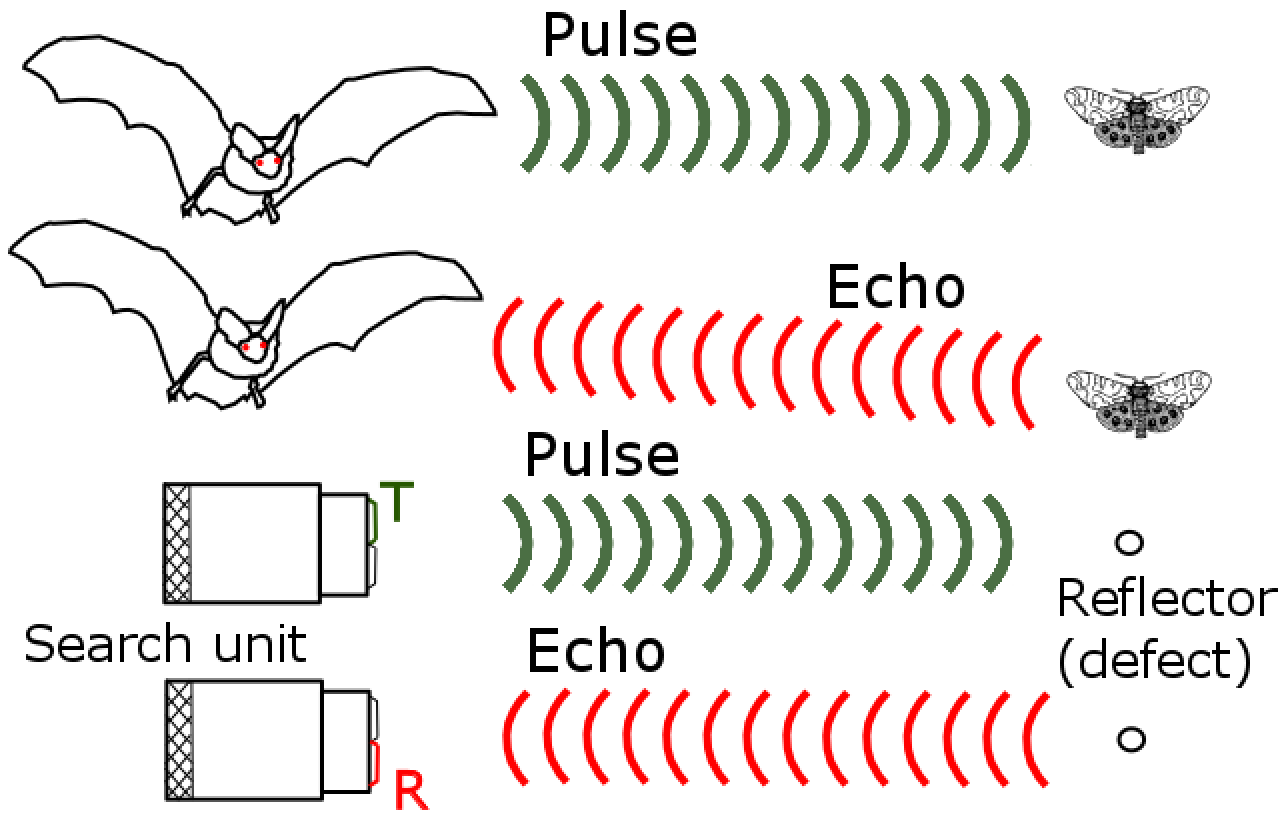


FIGURE 44 ULTRASONIC PULSE ECHO

Temperature of the material being inspected must not to exceed 93°C [200°F]. That is, casually, the maximum design temperature of a tank designed to API 650.

Besides the pulse-echo method, there are other techniques used for NDE, as the impact-echo method, used mostly in concrete, and the TOFD method. The pulse-echo method is the basis for the Phased Array Ultrasonic Technique. It does exist another setup that is called "the through-transmission setup", which requires access to the opposite surface of the part being inspected. ASME V, article 23, only deals with the pulse-echo technique.

GENERAL RULES

When using the pulse-echo technique, thickness is the product between the velocity of sound and half the transit time.

$$T = \frac{Vt}{2}$$

Where

T is the thickness of the material

V is the velocity of sound in the material

t is the transit time

Velocity of sound for different materials can be found in ASTM E494. In steel, longitudinal velocity is 5950m/s and transverse velocity is 3230m/s. With the given data of the velocity of sound in the material, the instrument just needs to measure the transit time to calculate the material thickness. The machine must not transmit again until all detectable echoes caused by the previous transmit pulse have been received.

To verify effectivity of UT measurement, ASME V asks the user to use 2 sizes of reference blocks, one having a similar thickness to the thickness of the part going to be inspected, and the other having the minimum thickness allowable. Reference blocks come in many ways; the code has an appendix showing 2 Typical Multi-Step Thickness Gage Reference Blocks.

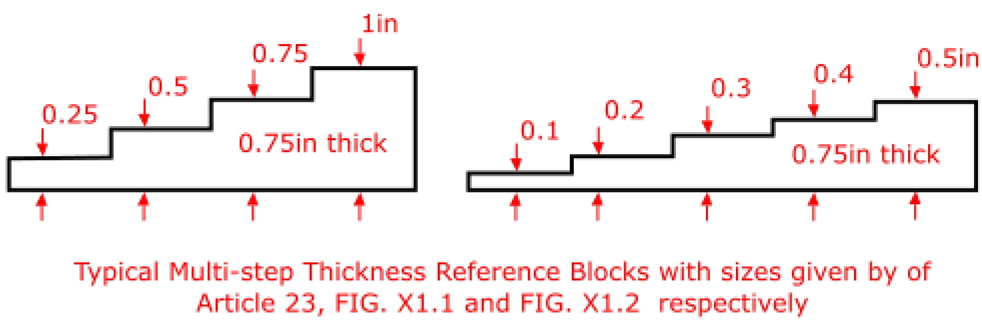


FIGURE 45 A TYPICAL REFERENCE BLOCK

The display element (A-scan display, meter, or digital display) of the instrument must be adjusted to present convenient values of thickness dependent on the range being used.

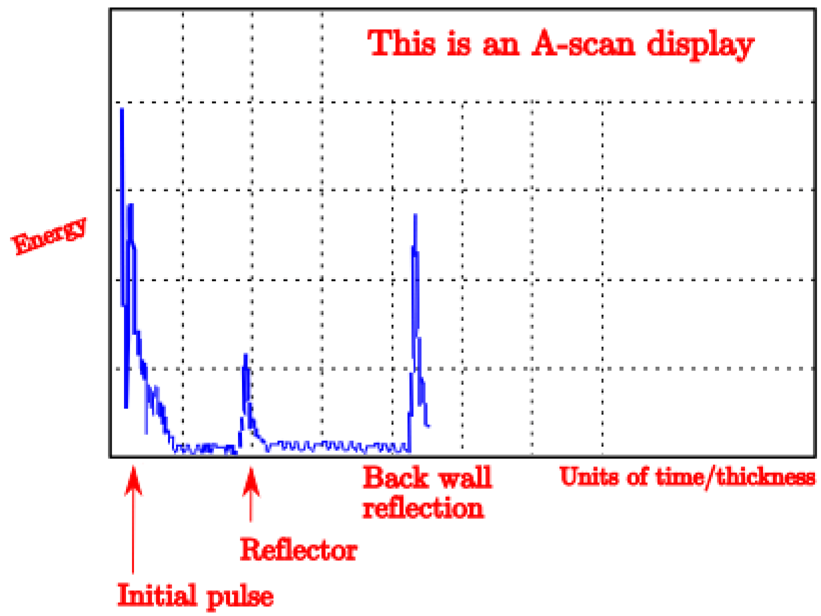


FIGURE 46 A-SCAN DISPLAY

A common method is the so-called time/analog conversion in which the time measured by the instrument is converted into a proportional dc voltage which is then applied to the readout device.

The voltage versus time trace on the oscilloscope screen is an analog signal that must be captured in digital form to allow further processing and manipulation by computer.

Another technique uses a very high-frequency oscillator that is modulated or gated by the appropriate echo indications, the output being used either directly to suitable digital readouts or converted to a voltage for other presentation.

There are the 4 items that need to be subject to contractual agreement according to SE-797: 1) Personnel qualification, 2) Qualification of Nondestructive Agencies, 3) Procedures and techniques, 4) Surface preparation

If specified in the contractual agreement, personnel performing examinations to this standard shall be qualified in accordance with a nationally or internationally recognized NDT personnel qualification practice or standard such as ANSI/ASNT CP-189, SNT-TC-1A, NAS-410, or a similar document and certified by the employer or certifying agency, as applicable. [...] If specified in the contractual agreement, Inspection agencies should be qualified and evaluated by ASTM Specification E543

SPECIFIC PROCEDURES FOR ULTRASONIC THICKNESS MEASUREMENT AS CONTAINED IN PARAGRAPH 7

On the type on measurement instrument.

1. Flaw detectors with A-scan display readouts display time/amplitude information. Thickness determinations are made by reading the distance between the zero-corrected initial pulse and first-returned echo (back reflection), or between multiple-back reflection echoes, on a standardized base line of the A-scan display. The base line of the A-scan display should be adjusted for the desired thickness increments

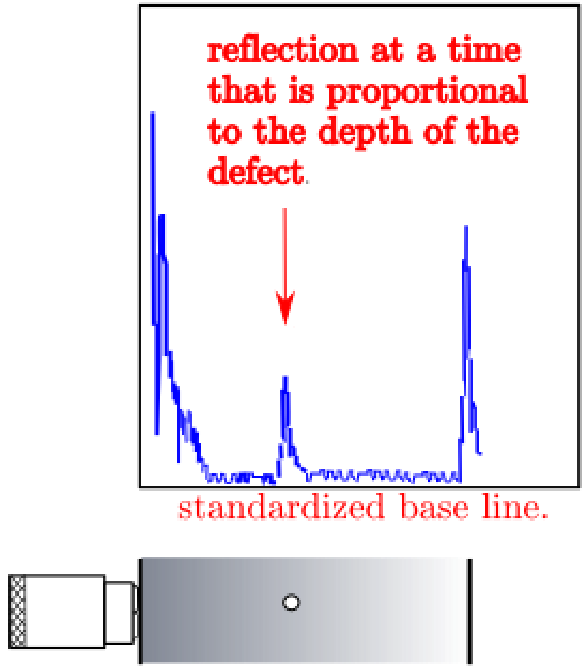
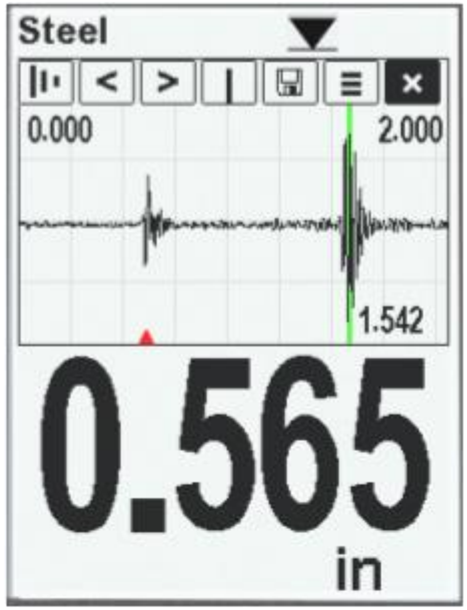


FIGURE 47 A-SCAN DISPLAY FOR THE PULSE-ECHO APPARATUS

2. Flaw detectors with numeric readout are a combination pulse ultrasound flaw detection instrument with an A-scan display and additional circuitry that provides digital thickness information. The material thickness can be electronically measured and presented on a digital readout. The A-scan display provides a check on the validity of the electronic measurement by revealing measurement variables, such as internal discontinuities, or echo-strength variations, which might result in inaccurate readings



The display of an Ultrasonic Instrument, combining A-scan and digital readout

FIGURE 48 A-SCAN WITH DIGITAL READOUT

3. Thickness readout instruments are modified versions of the pulse-echo instrument. The elapsed time between the initial pulse and the first echo or between multiple echoes is converted into a meter or digital readout. The instruments are designed for measurement and direct numerical readout of specific ranges of thickness and material

FIGURE 49 DIRECT NUMERICAL READOUT PULSE-ECHO APPARATUS

This kind of instrument is maybe the first contact UT technicians have with. It requires almost no presentation. It is no flaw detector, but only a thickness measurement instrument. It is used mostly in hulls, bulkheads and girders and rafters in ships in intervals specified by insurers, and in external ultrasonic thickness measurement of tank shells and roofs during external inspections. The figure above shows one belonging to the author)

<u>On the search unit</u>

Contact transducers are available in a variety of configurations to improve their usefulness for a variety of applications. The code mentions “dual element, delay line, straight beam and contact”. All of them can work with flaw detector instruments.

If a thickness readout instrument has the capability to read thin sections, a highly damped, high-frequency search unit is generally used. High-frequency (10 MHz or higher) delay line search units are generally required for thicknesses less than about 0.6 mm [0.025 in.]. Measurements of materials at high temperatures require search units specially designed for the application. When dual element search units are used, their inherent nonlinearity usually requires special corrections for thin sections. (See Fig. 2.) For optimum performance, it is often necessary that the instrument and search units be matched.

WHERE TO USE ULTRASOUND ACCORDING TO STANDARDS?

The manual ultrasonic pulse-echo contact method is used in several occasions during tank building and maintenance:

1. For the detection of laminations in new plates. According to API 650 6.2.4a

    The Manufacturer shall visually inspect all edges of shell and roof plates before installing the plates in the tank or before inserting a nozzle into the plate to determine if laminations are present. If a lamination is visually detected, the Manufacturer shall ultrasonically examine the area to determine the extent of the laminations and shall reject the plate or make repairs in accordance with 6.2.4b. (It says “For laminations found not exceeding 75 mm (3 in.) in length or 25 mm (1 in.) in depth, repairs may be made by edge gouging and rewelding to seal the lamination”. If bigger, reject of submit another procedure)

2. For the evaluation of a tank´s shell according to API 653 3.3.3.1

External, ultrasonic thickness measurements of the shell can be a means of determining a rate of uniform general corrosion while the tank is in service, and can provide an indication of the integrity of the shell. The extent of such measurements shall be determined by the owner/operator.

The frequency of Ultrasonic thickness measurements varies depending if the corrosion rates are known or unknown

3. For the evaluation of a tank´s bottom according to API 653 4.4.4

Magnetic flux leakage (MFL) tools are commonly used, along with ultrasonic (UT) thickness measurement tools, to examine tank bottoms. Ultrasonic thickness measurement techniques are often used to confirm and further quantify data obtained by MFL examination, but these techniques may not be required depending on the specific procedure and application. The quality of data obtained from both MFL and ultrasonic thickness techniques is dependent on personnel, equipment and procedures

MFL is an electromagnetic technique used mostly in tank bottoms and pipes to detect defects. A magnetic flux is induced in the bottom plate. When there is a defect in the plate, magnetic flux “leaks” and a sensor detects the defect (See figure). Usually, MFL is used as a fast way to detect possible defects before further ultrasound examination.

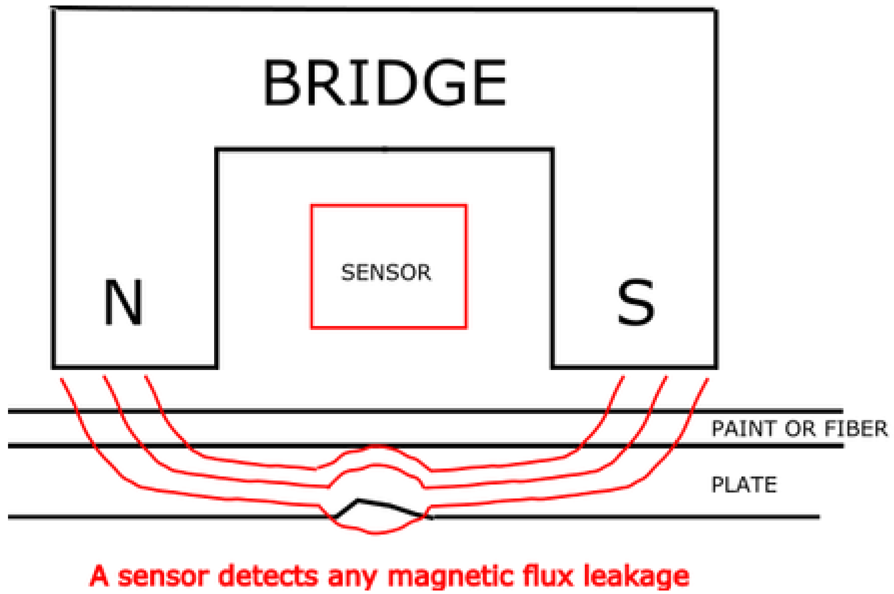


FIGURE 50 MFL TECHNIQUE

4. For shell and annular ring weld inspection according to API 650 8.1

When bottom annular plates are required by 5.5.1, or by M.4.1, the radial joints shall be radiographed as follows: (a) For double-welded butt joints, one spot radiograph shall be taken on 10 % of the radial joints; (b) For single-welded butt joints with permanent or removable back-up bar, one spot radiograph shall be taken on 50 % of the radial joints. Extra care must be exercised in the interpretation of radiographs of single-welded joints that have a permanent back-up bar. In some cases, additional exposures taken at an angle may determine whether questionable indications are acceptable. The minimum radiographic length of each radial joint shall be 150 mm (6 in.). Locations of radiographs shall preferably be at the outer edge of the joint where the shell plate and annular plate join.

Appendix U states that ultrasonic testing cannot be done in lieu of radiography for materials less than 0.375″ in nominal thickness. *However, technology moves quicker than standards*. Today, a combination of Phased array and TOFD has been demonstrated to evaluate efficiently plates of lower thicknesses, and to detect porosity, slag, and other small volumetric indication as well as planar and laminar defects which radiography sometimes has trouble detecting and evaluating, because both techniques complement the capabilities of the other.

5. For tank roof evaluation according to API 653 4.2.1.2

Roof plates corroded to an average thickness of less than 0.09in. in any 100in^2 area or roof plates with any holes through the roof plate shall be repaired or replaced.

6. For the evaluation of thicknesses of components according to API 653 4.3.9.1 and 4.3.9.2.

Components include reinforcement plates, nozzle necks, bolting flanges and cover plates. This also need to be assessed and recorded in an inspection report.

CHAPTER 14: ASME V LIQUID PENETRANT EXAMINATION

Liquid penetrant examination is a NDE technique used many situations. It is an effective means for detecting discontinuities which are open to the surface of nonporous metals and other materials. Typical discontinuities detectable by this method are cracks, seams, laps, cold shuts, laminations, and porosity. In fillet welds of big size (you define big size), it can be used in several stages to make an approximation to a volumetric NDE. It is better used if applied to the root pass of containment welds, although this is not always commanded in the standards.

The Body of Knowledge for the API 653 exam says the following:

C Article 6, Liquid Penetrant Examination, Including Mandatory Appendix II:

The inspector should be familiar with and understand:

1) The Scope of Article 6,

2) The general rules for applying and using the liquid penetrant method such as but not limited to

a) procedures
b) contaminants
c) techniques
d) examination
e) interpretation
f) documentation
g) record keeping

SCOPE

Penetrant testing shall be carried out in conformance with ASTM SE-165, Standard Test Method for Liquid Penetrant Examination. This document provides details to be considered in the procedures used.

PROCEDURES

As with all the other NDT techniques (except Vacuum-Box Testing according to Annex X, API 650) a written procedure is needed for PT when it is to be used in tanks. The procedure shall contain the following essential variables

Essential Variables of a Penetrant Testing procedure

Identification of and any change in type or family group of penetrant materials including developers, emulsifiers, etc.

Surface preparation (finishing and cleaning, including type of cleaning solvent)

Method of applying penetrant

Method of removing excess surface penetrant

Hydrophilic or lipophilic emulsifier concentration and dwell time in dip tanks and agitation time for hydrophilic emulsifiers

Hydrophilic emulsifier concentration in spray applications

Method of applying developer

Minimum and maximum time periods between steps and drying aids

Decrease in penetrant dwell time

Increase in developer dwell time (Interpretation Time)

Minimum light intensity

Surface temperature outside 40°F to 125°F (5°C to 52°C) or as previously qualified

Performance demonstration, when required

CONTAMINANTS

It is essential that the surface of parts be thoroughly dry after cleaning, since any liquid residue inside defects will hinder the entrance of the penetrant. Drying may be accomplished by warming the parts in drying ovens, with infrared lamps, forced hot air, or exposure to ambient temperature.

The inspector usually will need the surface of the weld prepared by grinding, machining, or other methods to avoid irregularities of the weld masking indications. When we are examining nickel base alloys, austenitic or duplex stainless steels, and titanium, we shall obtain certification of contaminant content for all liquid penetrant materials used.

EXAMINATION AND TECHNIQUES

There are 6 different Penetrant Testing methods outlined in SE-165- Essentially, the surface to be examined is first prepared and cleaned, penetrant is applied, then its excess is removed from the surface and a developer is applied which makes indications visible. The following diagram depicts the basics of the operation

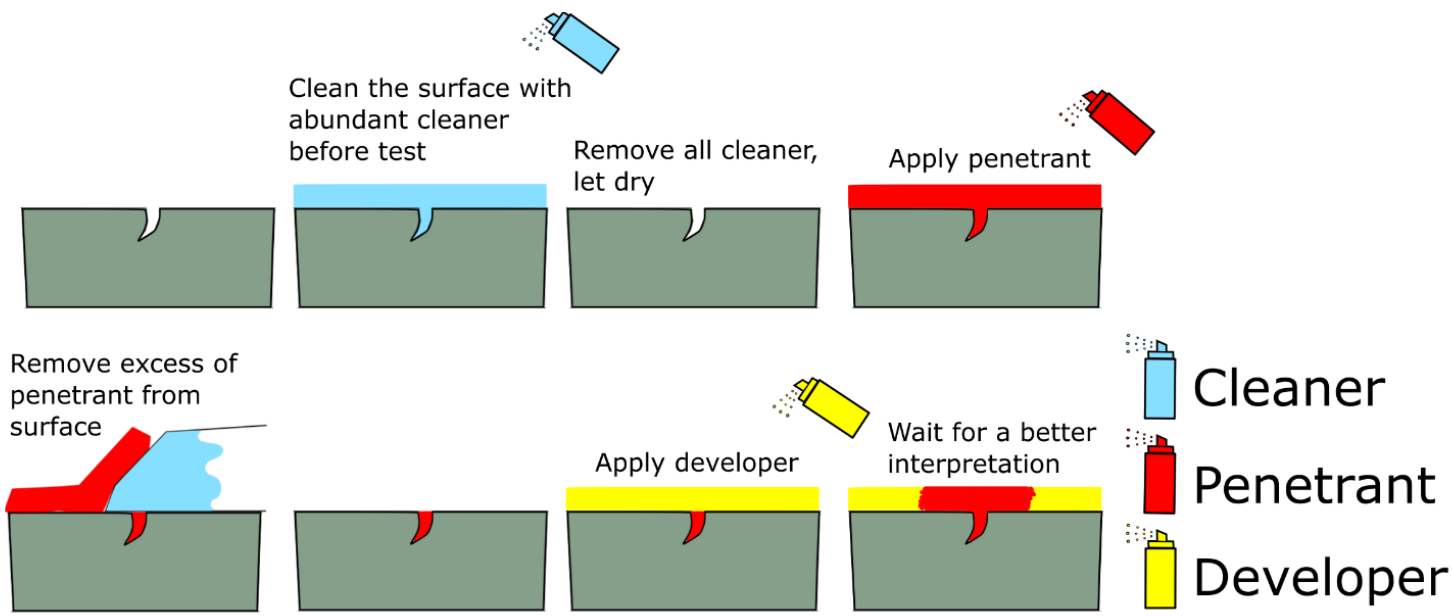


FIGURE 51 PENETRANT TESTING OPERATIONS

The 6 methods outlined in SE-165 are classified according to the characteristics of the materials used. Either a color contrast (visible) penetrant or a fluorescent penetrant shall be used with one of the following three penetrant processes:

(a) water washable

(b) post-emulsifying

(c) solvent removable

The visible and fluorescent penetrants used in combination with these three penetrant processes result in six liquid penetrant techniques. Dwell times for penetrants vary with the chosen method.

INTERPRETATION

Final interpretation shall be made not less than 10 min nor more than 60 min after application of a dry developer or after the developer is dry, although longer periods are permitted. Of course, if you let the examination progress up to the next day, for example, the penetrant will be so extended that you won´t know where it came from.

Discontinuities difficult to evaluate if the penetrant diffuses excessively into the developer as said. If this condition occurs, close observation of the formation of indications during application of the developer may assist in characterizing and determining the extent of the indications.

Color Contrast Penetrants. With a color contrast penetrant, the developer forms a reasonably uniform white coating. Surface discontinuities are indicated by bleed-out of the penetrant which is normally a deep red color that stains the developer. Indications with a light pink color may indicate excessive cleaning. Inadequate cleaning may leave an excessive background making interpretation difficult. A minimum light intensity of 100 fc (1000 lx) is required on the surface to be examined to ensure adequate sensitivity during the examination and evaluation of indications. The light source, technique used, and light level verification is required to be demonstrated one time, documented, and maintained on file.

Fluorescent Penetrants. With fluorescent penetrants, the process is essentially the same as with color contrast penetrants with the exception that the examination is performed using an ultraviolet light, called black light. The examination shall be performed as follows:

(a) It shall be performed in a darkened area.

(b) Examiners shall be in a darkened area for at least 5 min prior to performing examinations to enable their eyes to adapt to dark viewing. Glasses or lenses worn by examiners shall not be photosensitive.

(c) Black lights shall achieve a minimum of 1000 μW/cm2 on the surface of the part being examined throughout the examination.

(d) Reflectors and filters should be checked and, if necessary, cleaned prior to use. Cracked or broken filters shall be replaced immediately.

(e) The black light intensity shall be measured with a black light meter prior to use, whenever the light's power source is interrupted or changed, and at the completion of the examination or series of examinations.

DOCUMENTATION

All indications, Nonrejectable and Rejectable, shall be recorded as specified by the referencing Code Section. In the case of rejectable ones, as a minimum, the type of indications (linear or rounded), location and extent (length or diameter or aligned) shall be recorded.

RECORD KEEPING

For each examination, the following information shall be recorded:

(a) procedure identification and revision;

(b) liquid penetrant type (visible or fluorescent);

(c) type (number or letter designation) of each penetrant, penetrant remover, emulsifier, and developer used;

(d) examination personnel identity and if required by referencing Code Section, qualification level;

(e) map or record of indications per T-691;

(f) material and thickness;

(g) lighting equipment; and

(h) date of examination.

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CHAPTER 15: API RP 652, LININGS

As far as I know, paint is a liquid or paste that, when applied in a substrate, coats a layer over the surface, protects it and then gets to be known as a coating. Any material applied to the internal surfaces of a tank to serve as a barrier to corrosion and/or product, it is known also as a lining. If you are preparing to take the API 653 certification exam, do me a favor and read the 652 RP.

To pass the API 653 exam, you must study API 652 RP Linings of Aboveground Storage Tank Bottoms. Regarding this issue, the BOK for the 2017 exam says:

> The inspector should have a practical understanding and be familiar with the information contained in RP-652 related to:
>
> 1. types of tank bottom linings and advantage and disadvantages of each
> 2. considerations for recommending tank bottom linings
> 3. causes of tank bottom lining failures
> 4. types of tank bottom lining materials
> 5. surface preparation requirements for the installation of tank bottom linings
> 6. issues affecting the application of a tank bottom lining

API 652 RP is a document that is suitable more for the open-book part of the API 653 exam.

IMPORTANT DEFINITIONS

The following are important definitions you should know

holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment
anchor pattern: Surface profile or roughness.
mil: One one-thousandth of an inch (0.001 in.). One mil = 25.4 µm; it is common practice to use 1 mil = 25 µm.
lining: A material applied to the internal surfaces of a tank to serve as a barrier to corrosion and/or product **contamination**. The term coating is also used for the purposes of this document.
thick-film lining: A lining with a dry film thickness of 20 mils (0.51 µm) or more. One of the two types of linings of API RP 652.
thick-film reinforced lining: A thick-film lining reinforced with chopped glass fibers, chopped glass mat, woven glass mat, or organic fibers.
thin-film lining: A lining with a dry film thickness less than 20 mils (0.51 µm). One of the two types of linings of API RP 652.

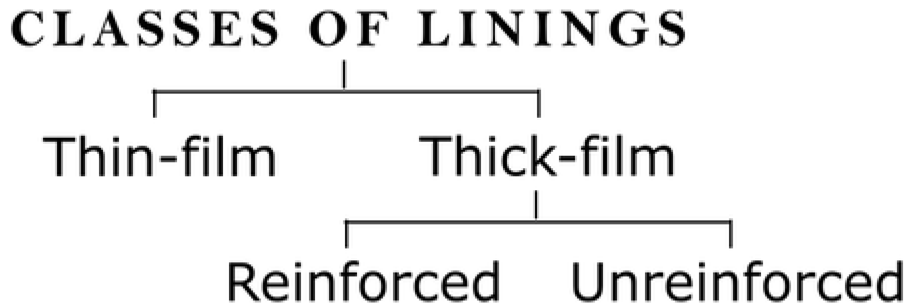
DEFINING THE NEED FOR A LINING

A tank bottom lining may be deemed necessary if inspection shows that the minimum thickness of the bottom steel plate is less than 0.100 in. (2.5 mm), or if corrosion is expected to proceed so that the steel thickness may reach this minimum thickness prior to the next scheduled inspection.

Linings are used to combat corrosive conditions on the product side, as MIC, caustic corrosion, chloride SCC, caustic SCC and sulphuric acid corrosion. There are other Damage mechanisms that are in API RP 652 but not in the BOK. You as a student must read these DM, but not in the same order of importance as the ones mentioned in the BOK.

Linings are listed as one of at least six Release Prevention Systems listed in table 6.1 of API 653 as means to maintain tank integrity and thus protect the environment. They can increase the initial inspection interval from 2 to 5 years.

CLASSES OF LININGS



Tank bottom linings can generally be divided into two classes: thin-films [with a dry film thickness less than 20 mils (0.51 µm)] and thick-films [with a dry film thickness of 20 mils (0.51 µm) or more]. Thin-film linings are applied to tank bottoms that expect or have little corrosion. They are not suitable for heavily pitted tank bottoms.

Thick-film linings can be divided in 2 types: reinforced or unreinforced. Reinforced linings are often used on aged floors that have incurred corrosion and are rough and pitted and thinned tank bottoms.

CONSIDERATIONS IN LINING SELECTION

The following are the advantages of **thin-film linings**

a. Initial cost is typically less than thick-film reinforced linings.
b. Easier to apply.
c. Experience has shown that when properly selected, applied, and not damaged, the life of thin-film linings can be greater than 20 years.
d. Most thin-film epoxy linings exhibit good flexibility.
e. Allows for more accurate MFL floor scans.
f. Easier to remove.

The following are the advantages **thick-film reinforced linings**

a. Easier to achieve coverage over rough, pitted steel and surface irregularities.
b. Proven ability to bridge *future* penetrations in the floor steel.
c. Resistance to mechanical damage.
d. It can be laid by hand or with chopper gun.
e. Few or no discontinuities to repair following the “holiday” test.
f. Long term service–more than 20 years
g. Provides resistance to moisture permeation.

The following are the advantages **thick-film unreinforced linings**

a. Some thick-film linings can be built up to 100 mils (2540μm) in a single coat.
b. Better coverage over rough surfaces.
c. Generally applied in a single coat, there are no issues with contamination between coats.
d. High solids may have better edge retention with reduced material shrinkage.
e. Typically, this linings are fast curing and can be put back in service after 24 hours at normal ambient temperatures.
f. Few or no discontinuities to repair following the “holiday” test.
g. Reduced labor costs compared to multi-coat thin-film or labor-intensive reinforced thick-film linings.
h. Promotes a reduced tank turn around schedule.
i. Long term service-more than 20 years
j. Provides resistance to moisture permeation.

CAUSES OF TANK BOTTOM LINING FAILURES

Regarding the improper application of linings, some experience in coating application comes handy if you are going to take the exam. There are many causes of lining failure, but API 652 RP mentions the following

7.1 Inadequate surface preparation is a major cause of lining failure.
7.2 lack of cleanliness. Prior to abrasive blasting, all hydrocarbon residues such as oil, tar, and grease, must be removed from the area to be lined.
7.2 Presence of salts. The presence of soluble salts on the steel can adversely affect the performance of a lining resulting in blistering by osmosis (because the environment that is saltier “tries” to achieve equilibrium with the exterior, it does so with moisture)
7.4 Environmental conditions during application. As a general rule, the surface temperature must be at least 5°F (3°C) above the dew point temperature in the tank and the relative humidity should be below 80% at the steel surface.
8.1 Failing to meet the manufacturer´s requirements regarding recoat intervals. Subsequent coats must be applied within the recoat interval recommended by the lining manufacturer and/or as determined by the owner’s inspector
8.2 improper mixing
8.4 insufficient coverage. Insufficient film thickness will not provide adequate coverage or protection.
8.4 Too much paint. Excess primer thickness is a common cause of failure of thick-film lining systems. The lining thickness shall be in accordance with the lining specification.
8.5 Inadequate curing time. Refer to the coating manufacturer to determine the proper cure time and temperature
9.3.4 Failing to remove discontinuities from the surface. This is especially true for thin-film linings. Holiday testing of thin-film linings should be performed with a low-voltage (67.5 volts) wet sponge detector

BOTTOM LINING MATERIALS

Material for tank bottom linings are summarized in tables 1 and 2 of API 652. Please study tables 1 and 2 in the RP, as it is probable that questions about this will show up in the exam.

Thin film linings (resin/curative)	**Temperature range °F**	**Limitations**
Coal tar epoxy/amine Epoxy phenolic/amine Epoxy/amine Epoxy/polyamide Epoxy/polyamidoamine	120–170 180–220 160–220 160–180 160–180	a. API Std 653 requires the bottom plate thick ness be a minimum of 0.100 in. (2.5 mm) at the end of the next service interval. b. More susceptible to mechanical damage than thick-film linings. c. Rough weld surfaces and weld spatter can protrude through the finished lining thickness and result in holidays. d. Some thin-film linings require the application of multiple coats. e. Thin-film linings are most often solvent-borne coatings that require the evaporation of solvent from the film to achieve proper cure. If the solvent vapors are not effectively removed from the tank or vessel, because they are heavier than air, they will hover at the floor level and impede the progress of the cure. f. Presence of moisture in the air during the cure can cause amine blush.
Thick-film linings (Glass-reinforced Lining Resins)	**Temperature range °F**	**Limitations**
Isophthalic Polyester Bisphenol-A Polyester Vinyl Ester Epoxy	140-160 160–180 180-220 180	a. They can require more time and effort to apply b. Are normally more expensive to install than thin-film, tank bottom linings c. MFL Floor Scan Inspection of the steel bottom plate through a thick-film, reinforced lining can be more difficult than a thin-film lining. d. Thick-film linings are more prone to cracking if tank bottom plate flexure occurs due to non-uniform soil support, and if the strain at the corner weld caused by hoop stress on the shell (e.g., filling and emptying the tank) exceeds the elastic limits of the lining.
Unreinforced Thick-film linings	**Temperature range °F**	**Limitations**
Same resins as reinforced ones	Same ranges as reinforced ones	a. Typically requires the use of plural component spray equipment. b. Difficult to install on complex geometry due to plural component application. c. Contractor experience level should be a consideration. d. MFL Floor Scan Inspection of underlying steel condition may be limited on linings of very high thickness. e. Depending on resin type and thickness, cracking due to plate flexure may be a concern.

Table x. Summary of tables 1 and 2 in API RP 652

SURFACE PREPARATION

Generally, abrasive blast cleaning to a white metal finish (NACE No. 1/SSPC-SP5) is desired. Abrasive blast cleaning to a near-white metal finish (NACE No. 2/SSPC-SP10) is often specified as the minimum degree of surface cleanliness. For small areas, SSPC SP 11 is often desirable to avoid damage to the surrounding lining that may be in very good condition. The anchor pattern required for linings is typically 1.5 to 4.0 mils and generally increases with the thickness of the lining", the API RP 652 states. "To achieve adhesion necessary for long-term performance, it is important that the anchor pattern is sharp and angular".

ISSUES AFFECTING APPLICATION OF LININGS

Most of the quality control in lining applications can be controlled having in mind the following controls.

1. **Lining system.** The recommendations of the lining manufacturer should be followed at all times to avoid risk of lining malfunction or lack of guarantee. After sufficient curing of the completed lining system, holiday testing should be carried out
2. **Guidelines for lining application**. A procedure stablishing proper on-site storage conditions, mixing, applying, and curing of the lining are necessary, and the lining manufacturer's recommendations should be followed. Any differences between the owner's specification and the lining manufacturer's technical data sheet should be resolved before beginning the job.
3. **Temperature and humidity control**. With the use of a thermohigrometer, you need to control ambient temperature and humidity. You need to control the surface´s temperature too. As said earlier, the surface temperature must be at least 5°F (3°C) above the dew point temperature in the tank and the relative humidity should be below 80% at the steel surface.
4. **Lining thickness**. As the lining is being applied, wet film thickness measurements should be made.
5. **Lining curing**. Thin film linings are higher VOC than thick-film linings. Independently, any lining should be allowed a proper cure time and temperature. The proper curing conditions should be ensured for the full duration of the cure time, or forced-curing of the lining may be accomplished by circulating warmed, dehumidified air.

RELATIONSHIP WITH API 653

API Standard 653 states that if a tank has an applied tank bottom reinforced lining that is thicker than 50mils, the MRT of the bottom at the end of the next inspection interval is 0.05in (remember table 4.1 of API 653, below). When determining the next inspection interval, also the internal corrosion rate (*StPr*) of a tank with an internal lining can be assumed to be zero. This assumption can be made provided that the lining is in acceptable condition and suitable for the intended service, without regard of the type of lining.

Minimum Bottom Plate Thickness at next inspection	Tank Bottom/Foundation design
0.10	Tank bottom/foundation design with no means for detection and containment of a bottom leak
0.05	Tank bottom/foundation design with means to provide detection and containment of a bottom leak.
0.05	Applied tank bottom reinforced lining, > 0.05 in. thick, in accordance with API 652

TABLE 8 (TABLE 4.4 OF API 653)—BOTTOM PLATE MINIMUM THICKNESS

The reason the MRT is lower for thick film reinforced linings is that they have **future** hole-bridging capabilities (Figure 52). (*Not related, but I guess the fact that coatings can seal a hole demonstrates that you should consider always, in the present, to carry your hydrostatic test before you paint!*) Thick film linings are also used in present thin areas of the bottom, and they can be applied if there is suspicion of heavy soil side corrosion.

Inspection of the lining is part of any internal inspection of the tank. If you want to comply with the Quality Control requirements present in API 652 RP 9.1, that "Records should be made to briefly describe the products and procedures that were used during installation of the lining", take a look at an strategy that has served me well before to record all the information produced in a painting project.

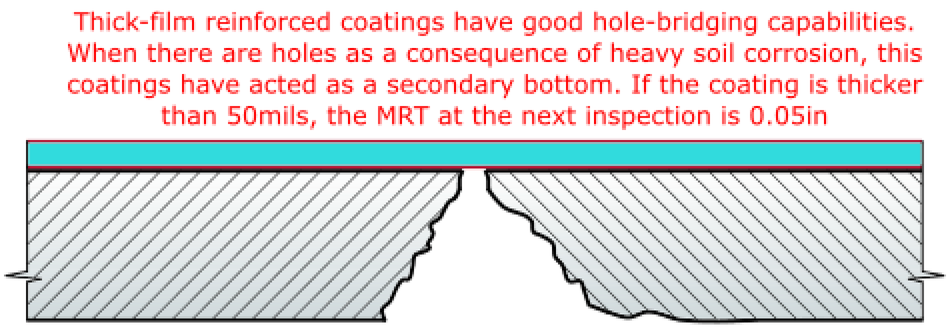


FIGURE 52 HOLE BRIDGING CAPABILITIES OF THICK-FILM REINFORCED LININGS

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CHAPTER 16: API RP 651 CATHODIC PROTECTION

To protect metal from corrosion, there are several things that can be made

- Coat the surface with paint so there is no contact between the metal and the electrolyte.
- Coat the surface with another metal that is a sacrificial metal that protects the steel.
- Passivation.
- Anodization.
- Cathodic protection from sacrificial anodes - no power supplied.
- Cathodic protection using an impressed current from an electrical source.

A tank bottom can make good use of cathodic protection and coatings. The most effective protection for a tank bottom is a combination of a corrosion resistant coating and a cathodic protection system (says API 571 and NACE RP0193). The provision of an insulating coating to the structure will greatly reduce the current demand for cathodic protection.

API 651 - CATHODIC PROTECTION OF ABOVEGROUND STORAGE TANK BOTTOMS

Let´s concentrate in what you should study for the API 653 exam (due March 17, 2017). API 651 RP was created in 1997 to present procedures and practices for achieving effective corrosion control on aboveground storage tank bottoms using cathodic protection. It is currently in the fourth edition.

The following is what the Body of knowledge for the 2017 exam says

The inspector should have a practical understanding and be familiar with the information contained in RP-651related to:

1. Corrosion of Aboveground Steel Storage Tanks
2. Determination of Need for Cathodic Protection
3. Methods of Cathodic Protection for Corrosion Control
4. Operation and Maintenance of Cathodic Protection Systems

DEFINITIONS

The following definitions of section 1 are necessary

anode: The electrode of an electrochemical cell at which oxidation (corrosion) occurs.

cathode: The electrode of an electrochemical cell at which a reduction reaction occurs

electrolyte: A chemical substance containing ions that migrate in an electric field. For the purposes of this recommended practice, electrolyte refers to the soil or water adjacent to and in contact with the bottom of an aboveground petroleum storage tank, including the contaminants and chemicals contained therein.

oxidation: The loss of electrons by a constituent of a chemical reaction

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CORROSION OF TANKS

ELECTROCHEMICAL CELL

API-651 RP defines corrosion as the deterioration of a metal resulting from a reaction with its environment. Corrosion of steel structures is an electrochemical process. For the corrosion process to occur, areas with different electrical potentials must exist on the metal surface. These areas must be electrically connected and in contact with an electrolyte.

There are four components required for a corrosion cell: an anode, a cathode, a metallic path connecting the anode and cathode, and an electrolyte. The role of each component in the corrosion cell is as follows:

a. At the anode, the metal corrodes by releasing electrons and forming positive metal ions. For steel, the anodic reaction is:

$$Fe \rightarrow Fe^{+2} + 2e^{-}$$

b. At the cathode, chemical reactions take place using electrons released at the anode. No corrosion takes place at the cathode. One common cathodic reaction is:

$$O_2 + 2H_2O + 4e^{-} = 4OH^{-}$$

c. The metallic path serves as a way for electrons released at the anode to flow to the cathode.

d. The electrolyte contains ions and conducts current from the anode to the cathode by ionic movement. The electrolyte contains both negatively charged ions called anions and positively charged ions called cations that are attracted to the anode and cathode, respectively. Moist soil is the most common electrolyte for external surfaces of the tank bottom, while water and sludge generally are the electrolytes for the internal surfaces.

If you have difficulty remembering the 4 elements of an electrochemical cell, use the acronym ACME. A - Anode, C - Cathode, M - Metallic Path, E - Electrolyte.

There are many forms of corrosion. The two most common types relative to tank bottoms are general and localized (pitting) corrosion. In general corrosion, thousands of microscopic corrosion cells occur on an area of the metal surface resulting in relatively uniform metal loss. In localized (pitting) corrosion, the individual corrosion cells are larger and distinct anodic and cathodic areas can be identified. Metal loss in this case may be concentrated within relatively small areas with substantial areas of the surface unaffected by corrosion.

FACTORS AFFECTING THE RATE OF CORROSION

-The composition of the metal is a factor in determining which areas on a metal surface become anodes or cathodes. Differences in electrochemical potential between adjacent areas can result from uneven distribution of alloying elements or contaminants within the metal structure. Potential and physical differences between the weld metal, the heat affected zone and the base metal are the riving fore behind preferential weld corrosion, with mechanisms such as galvanic corrosion, stress corrosion, etc.

-Physical and chemical properties of the electrolyte influence the location of cathodic and anodic areas on the metal surface. Just like potential differences in a metal can generate corrosion, also Ion concentration gradients in the electrolyte can provide a potential. Differential aeriation can also generate corrosion. The part of the metal exposed to higher oxygen concentration acts as cathodic region and part of the metal exposed lower oxygen concentration acts as anodic region. Consequently, poorly oxygenated region undergoes corrosion. Differential aeriation under a tank bottom can happen if the soil has clay, debris, or other type of contamination.

On the other side, if you can change the composition of an electrolyte adding a corrosion inhibitor, that would reduce the corrosion rate, but this is not used much in tank bottoms and not the subject of API - 651.

-Soil characteristics. Soil corrosion is a damage mechanism affected by a lot of parameters. Soil resistivity is the most common used parameter to determine corrosivity. Salts present in the soil electrolyte affects the current carrying capacity of the soil and therefore corrosion rates. moisture content, pH, oxygen concentration, and other factors interact in a complex fashion to influence corrosion.

Stray currents (also known as interference currents) travel through the soil electrolyte and on to structures for which they are not intended (Figure 53). Usually, the affected structure collects the interference currents from the electrolyte; the source of these currents is not electrically connected to the affected structure. As shown in Figure 3, stray current may enter an unprotected tank bottom and travel through the low resistance path of the metal to an area on the tank closer to the protected structure (pipeline). At this location, the current discharges back into the electrolyte (soil) at point B with resultant metal loss. The most common, and potentially the most damaging, stray currents are direct currents. These currents are generated from grounded DC electric power systems including electric railroads, subways, welding machines, impressed current cathodic protection systems, and thermoelectric generators.

The severity of corrosion (metal loss) resulting from interference currents depends on several factors:

a. separation and routing of the interfering and affected structures and location of the interfering current source;

b. magnitude and density of the current;

c. quality or absence of a coating on the affected structures;

d. the presence and location of mechanical joints having high electrical resistance;

e. temperature.

Further information related to proper design to avoid stray currents, and detection and control of stray current corrosion, can be found in Sections 7 and 10.

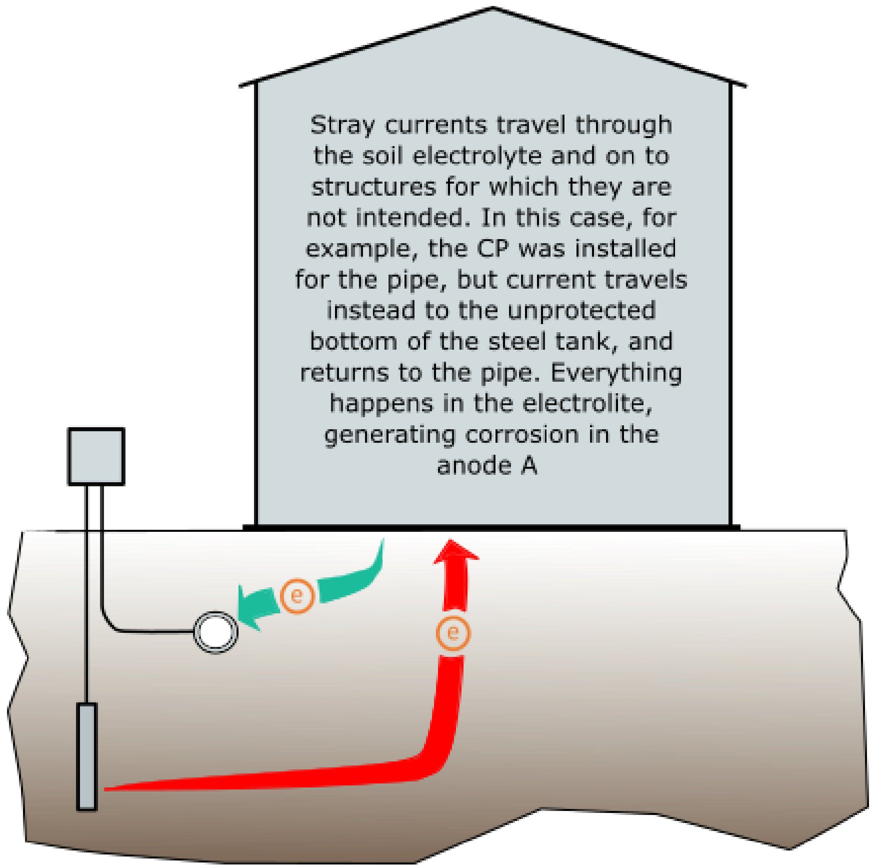


FIGURE 53 STRAY CURRENTS

Galvanic corrosion occurs when two metals with different compositions (thus, different electrolytic potentials) are connected in an electrolyte (usually soil). Current will flow from the more active metal (anode) to the less active metal (cathode) with accelerated attack at the anodic metal. For example, galvanic corrosion can occur when a bronze check valve is joined to carbon steel piping or where stainless steel, copper pipe or a copper ground rod is connected to a carbon steel tank (Figure 54). In the pipe/steel tank example, the stainless steel or copper pipe becomes the cathode and the steel tank is the anode. Since current takes the path of least resistance, the most severe corrosion attack will occur in the area on the steel tank immediately adjacent to the stainless steel or copper pipe as shown in Figure 4. The extent of such a problem is dependent on several factors.

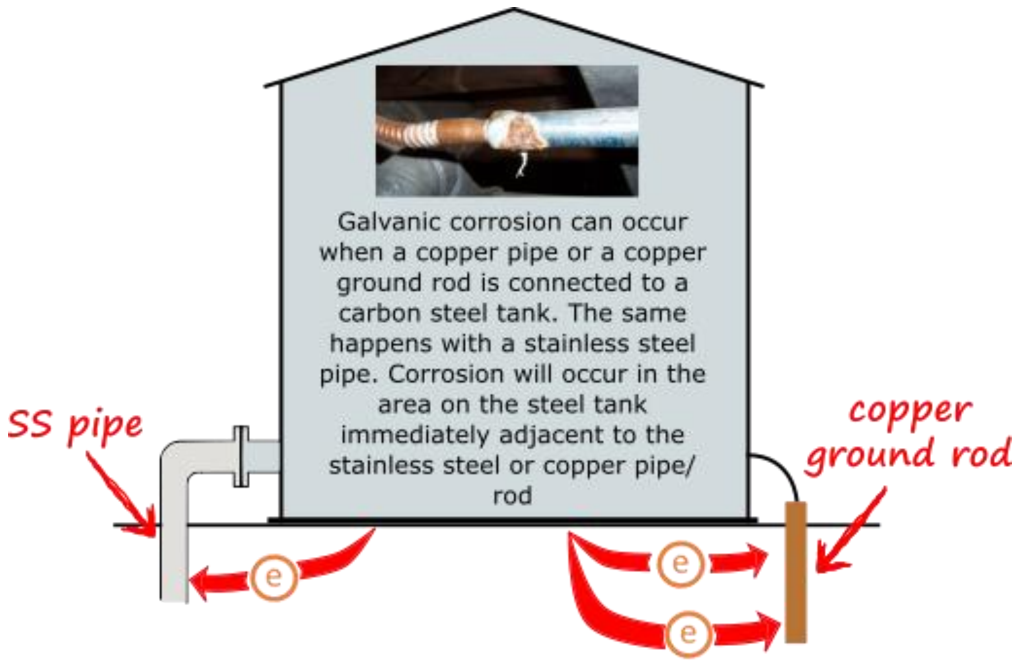


FIGURE 54 GALVANIC CORROSION

The most significant factors are:

a. the relative surface areas of the cathode and anode,

b. the relative potential difference between the two materials as determined by their position in the galvanic series, and

c. temperature.

Corrosion tends to be more severe when the anodic area is small with respect to the cathode surface and the two metals are far apart in the galvanic series.

NEW ABOVEGROUND STORAGE TANKS

Cathodic protection must be "ON" all hours of the day and all the year around. Little interruptions won´t do harm.

Corrosion control by cathodic protection for new aboveground storage tanks should be evaluated in the initial design, and if applied, should be maintained during the service life of the tank.

EXISTING ABOVEGROUND STORAGE TANKS

> "Studies should be made within a suitable time frame in accordance with API Std 653 concerning the possible need for cathodic protection. When these studies indicate that corrosion will affect the safe or economic operation of the system, adequate corrosion control measures should be used."

Some thought goes here to the concept of "Suitable time frame", that is not clear. Actually, API 653 re-sends you to API 651 when talking about CP surveys. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed. Survey intervals should be close enough to detect any malfunction/turning off. If a tank bottom is already corroded, the use of a new cathodic protection system can be harmful.

INTERNAL CATHODIC PROTECTION

If the product you are going to store is a pure hydrocarbon, which usually is not corrosive, there will be no need to use internal cathodic protection. But sometimes hydrocarbons traces of water or sediments in the bottom, or in an emulsion, so sacrificial anodes will be needed.

Limitations of External Cathodic Protection

> “Cathodic protection is an effective means of corrosion control only if it is possible to pass electrical current between the anode and cathode (tank bottom)”

How to reconcile this fact with the statement of API 571 that the best protection is a combination of coating and CP? Some coatings act as an isolation for electric current from the cathodic protection system. To avoid it, you can select a coating that doesn´t act as electrical shielding.

The following are potential problems that can affect CP

a. tank pads such as concrete, asphalt, or oiled sand (oiled sand won´t allow precise current measuring);

b. an impervious external liner between the tank bottom and anodes;

c. high resistance soil or rock aggregate pads;

d. old storage tank bottoms left in place when a new bottom is installed.

METHODS OF CATHODIC PROTECTION

API RP 651 list 2 methods of cathodic protection: galvanic and impressed current. Galvanic cathodic protection relies solely in the natural differences in electronegativity of the cathodic protection system vs the protected steel. Impressed current uses DC electrical current instead.

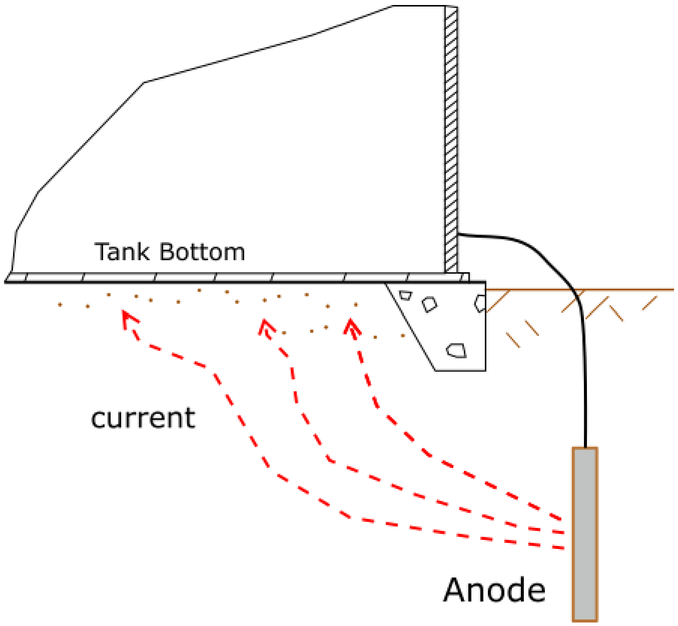


FIGURE 55 GALVANIC CATHODIC PROTECTION WITHOUT TEST STATION

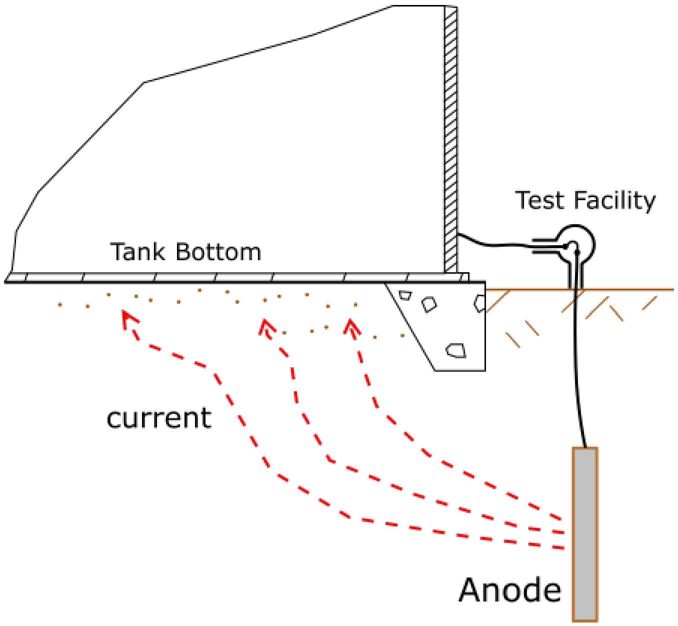


FIGURE 56 GALVANIC CATHODIC PROTECTION WITH TEST STATION

Galvanic anodes (Figure 56) are limited in current output by driving voltage and the circuit resistance. Galvanic cathodic protection systems may be more economical on small diameter tanks (less than 60 ft. [18 m]; see NACE RP0193). In large, poorly coated structures, it is better an impressed current-type system.

Impressed current cathodic protection (Figure 57) consists of anodes connected to a DC power source, and, often, a transformer-rectifier connected to AC power. In the absence of an AC supply, alternative power sources may be used, such as solar panels, wind power or gas powered thermoelectric generators

ADVANTAGES OF GALVANIC CP SYSTEMS	DISADVANTAGES OF GALVANIC CP SYSTEMS
No external power supply	Potential is limited
Installation is easy	Current output is low
Capital investment is low for small diameter tanks	Use is limited to low-resistivity soils (too picky)
Maintenance costs are minimal	Not practical for large bare structures. Work better with coated surfaces
Interference problems (stray currents) are rare	Short anode life (Added by author)
Less frequent monitoring is required	

TABLE 9 ADVANTAGES AND DISADVANTAGES OF GALVANIC CATHODIC PROTECTION

ADVANTAGES OF IMPRESED CURRENT CP SYSTEMS	DISADVANTAGES OF IMPRESED CURRENT CP SYSTEMS
Large potential (minimum 50 times that of galvanic CP systems)	Stray current may be an issue
Capability of variable current output	Loss of AC power causes loss of protection
Applicability to almost any soil resistivity	Higher maintenance and operating costs
	More frequent monitoring
	High anode life (Added by the author)
	Higher initial investment

TABLE 10 ADVANTAGES AND DISADVANTAGES OF IMPRESSED CURRENT CATHODIC PROTECTION

TYPES OF ANODE INSTALLATION

Current from an anode in a cathodic protection system is like light from a lightbulb. Several anodes will make a "light field" over the surface to be protected, instead of light, with electrons. And as with light, the surface can be shadowed, or things we don´t want to become lighted will become lighted. Your CP specialist will have that I mind when deciding what type of anode installation is best for you.

SHALLOW BED INSTALLATION

Shallow means "of little depth". Shallow bed installation can be horizontal or vertical, being horizontal the first choice when trying to control exactly where your current is going. It is used where soil resistance is high.

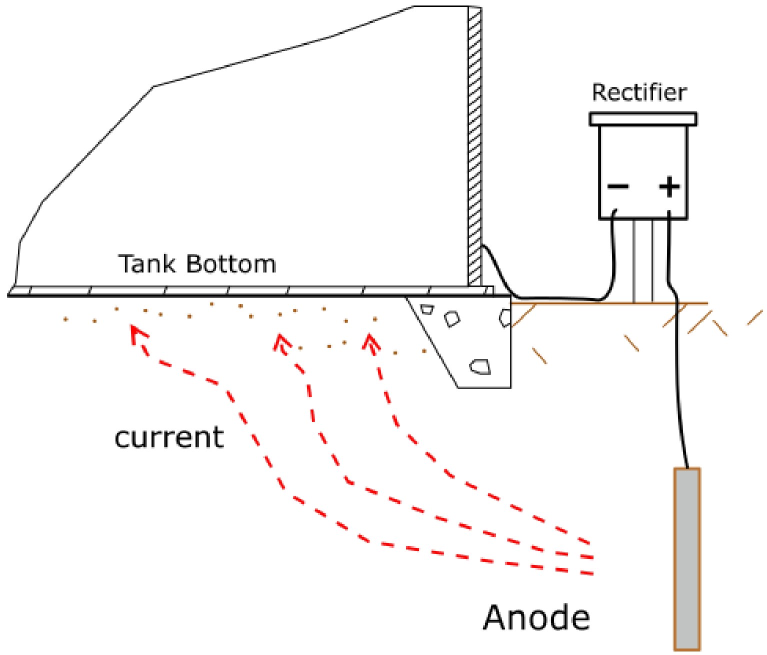


FIGURE 57 IMPRESSED CURRENT CATHODIC PROTECTION

DEEP BED INSTALLATION

In this type of installation, an anode is buried deep in the ground, sometimes protected by a steel casing, and protects a range of equipment (Figure 58). Works good in remote plants where nothing else is buried, and where soil resistance is low.

OPERATION AND MAINTENANCE OF CATHODIC PROTECTION SYSTEMS

CATHODIC PROTECTION SURVEYS

There are several cathodic protection surveys to be made. Surveys should include one or more of the following types of measurements:

a. structure-to-soil potential;
b. anode current;
c. native structure-to-soil potentials;
d. structure-to-structure potential;
e. piping-to-tank isolation if protected separately;
f. structure-to-soil potential on adjacent structures;
g. continuity of structures if protected as a single structure;
h. rectifier DC volts, DC amps, efficiency, and tap settings.
When in the exam, remember the following types of surveys and their timeframes

DESCRIPTION	TIME FRAME
Check all electrical parameters of the soil	Before energizing the CP system
Survey of the cathodic protection system to determine that it operates properly	Immediately after the system is energized or repaired
Survey of the cathodic protection system to verify that it satisfies applicable criteria	After adequate polarization
Survey of cathodic protection systems without regard of the type	Every year
Survey of Impressed Current sources	Every 2 months
Survey of Impressed current protective facilities	Every year
Records demonstrating the need for cathodic protection	Keep as long at the facility is in service
Records of the effectiveness of the CP system	Keep 5 years

TABLE 11. TIMEFRAMES FOR CATHODIC PROTECTION SURVEYS AND RECORDKEEPING

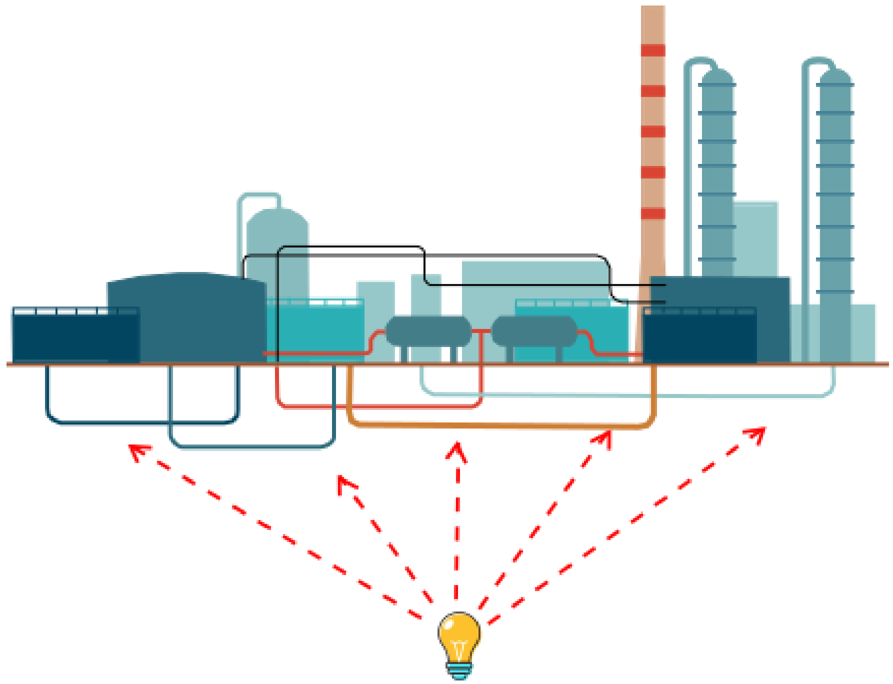


FIGURE 58 DEEP BED ANODES WORK LIKE BIG BURIED LIGHT BULBS

Bottom-to-electrolyte potential readings may indicate adequate cathodic protection for the portion of the tank bottom in contact with the soil but when the tank is full and all the tank bottom is in contact with the soil, protection may be insufficient. Therefore, potential surveys should be conducted with an adequate level in the tank to maximize contact of the tank bottom with the pad material

CHAPTER 17: RISK BASED INSPECTION

RISK is such a lovely concept.

Everybody should now about Risk and apply it. Every decision in life has an inherent risk. Yes, you could drink your milk in the morning and face the risk of having gases in the afternoon.

I don´t know why engineers don´t talk more about risk. Oh, yes, …I now. The gurus in our trade have made risk something complicated whit all their fluffy names and charts, slides, etc. But risk is simple.

Risk = Consequence x probability

I love the concept of risk.

Have you heard someone say “There are no words to describe this”? Well, I think that with Risk, that becomes true. There are no words to describe Risk, because it is a mathematical concept. It is an equation. Whoever realized this is a genius and should be awarded the engineering nobel.

You can put any units you want to Risk. It may be dollars, barrels, equity, tears, whatever.

Risk involves something that might happen in the future. Is a concept that exists in the mind. It can be applied to finances, safety, public relations, health, etc.

However being something that exists in the mind, you can take steps to reduce it. The document that caters most to risk in the API publications is “API RP 580, Risk-Based Inspection” The RBI methodology provides the basis for managing risk by making informed decisions on the inspection method, coverage required, and frequency of inspections.

RISK ASSESSMENT MATRIX					
		CONSEQUENCES			
		Catastrophic	Critical	Marginal	Negligible
PROBABILITY	Frequent	High	High	Serious	Medium
	Probable	High	High	Serious	Medium
	Occasional	High	Serious	Medium	Low
	Remote	Serious	Medium	Medium	Low
	Improbable	Medium	Medium	Medium	Low
	Eliminated	Eliminated			

FIGURE 59 AN EXAMPLE OF A RISK ASSESSMENT MATRIX

DECISION MAKING

API 653 and API 650 are standards. If you have a good reason to avoid any of the requirements of API 653, you may do so, provided that reason is written and approved by the client. Risk level is a major factor in decision making.

A risk assessment matrix (Figure 59) can be used for any procedure or possible expected failure in a process or item, and consider consequences in areas of finance, personal safety, public relations, etc. (Figure 60)

You put your value of tolerable Risk in this cells

CONSEQUENCES					
Environment					
Financial					
Death/injury		Death	Permanent Incapacitating	Temporary Incapacitating	Minor Injury
Public relations					
		Catastrophic	Critical	Marginal	Negligible
PROBABILITY	Frequent	High	High	Serious	Medium
	Probable	High	High	Serious	Medium
	Occasional	High	Serious	Medium	Low
	Remote	Serious	Medium	Medium	Low
	Improbable	Medium	Medium	Medium	Low
	Eliminated	Eliminated	Eliminated	Eliminated	Eliminated

FIGURE 60 AN ENHANCED RISK ASSESSMENT MATRIX

RBI IN TANKS

The RBI acronym is used 18 times in the API 653 standard. It stands for Risk Based Inspection. In the standard, RBI appears as a mean to shorten or lengthen inspection intervals, which would be useful, having in mind that scheduled inspections of a tank can be a costly and risky task. Consider what 6.4.2.4 has to say:

API 6.4.2.4 *As an alternative to the procedures in 6.4.2.3, an owner/operator may establish the internal inspection interval using RBI procedures in accordance with this section*

In any way, an RBI analysis shall be carried on by a group of individuals form a range of disciplines and with the skills to conduct the assessment. If different teams make RBI assessment for the same tank, inspection recommendations may vary.

And about the principles of RBI, you can find them in API 580 RP, intended to supplement API 510, API 570, and API 653. A good summary of reasons for tank deterioration can be found in API 571 RP "Damage Mechanisms Affecting Fixed Equipment in the Refining Industry".

API 6.4.2.4. *RBI assessment shall be performed by an individual or team of individuals knowledgeable in the proper application of API 580 principles to aboveground storage tanks, and experienced in tank design, construction details, and reasons for tank deterioration, and shall be reviewed and approved by an authorized inspector and a storage tank engineer. The initial RBI assessment shall be re-assessed at intervals not to exceed 10 years, at the time of a premature failure, and at the time of proposed changes in service or other significant changes in conditions.*

API 653 also enlists a set of minimum likelihood factors and consequence factors that should be taken into account for the analysis. In a tank, likelihood factors you would consider would be those related to shell, and bottom thickness and weld quality, and things like soil resistivity, quality of lining, etc. Regarding consequence factors, you should consider Safety, Health, and Environmental Consequences.

API 6.4.2.4. *RBI assessment shall consist of a systematic evaluation of both the likelihood of failure and the associated consequence of failure, utilizing the principles of API 580. RBI assessment shall be thoroughly documented, clearly defining all factors contributing to both likelihood and consequence of tank leakage or failure.*

Requirements of the standards are clearly risk driven, and represent a minimum consensus between members of the API committees. For example, the requirement for hydrostatic testing of tanks can be avoided only when there is difficult access to water for the test, the standard asking for other means of testing when this is the case. However, making the hydrostatic test to detect leaks before initial operation, although expensive, is way much less expensive than having to do it after operation. The members of the committee surely consider the other testing alternatives to be too costly or too unreliable for both all leak, settlement and weld strength testing

Another example is that when you make a hydrostatic test, according to the design, the standard asks the test to be made to design level. If you test a tank that will contain water, you will surely do it until design level, but if it contains oil, you better try to make the test above the roof-to-shell joint even if the tank doesn´t ask, because you consider the risk of failure too high and the cost of testing relatively low.

Besides, RBI is useful for tank repair or construction in other terms. Well, have you been around one of those tank projects were there are endless discussion about some little non-compliance with the standards? RBI can help you decide more easily on any subject.

FOR THE API 653 EXAM

In the examination, rather one or two questions are based in inspections intervals related to API 580. Don´t forget to study numerals 6.4.2.1 through 6.4.2.2.2.2 of API 653.

Summary

This is a schedule that will help you pass your exam with no hassle

Start six months in advance.

6 MONTHS IN ADVANCE

Start reading this manual.

Start reading the API 653 and API 650 standards

4 MONTHS IN ADVANCE

Start creating Q&A sets and feed them to your Spaced Repetition Software

3 MONTHS IN ADVANCE

Start reading the ASME IX Standard.

1 MONTH BEFORE THE EXAM

Read API 575 and all the other standards

1 WEEK BEFORE THE EXAM

Intensify your study the week before the exam so the contents are still hot in your mind when you are being administered the exam. Ask for permission in your job to attain complete dedication to the subject. Study in groups

Resources

- https://archive.org/details/reportofinvestig00penn_1; Ashland Spill Investigation report
- www.apiexam.com

  carlos@apiexam.com

  +573154212502.

ANNEX 1

FORM QW-482 FORMAT FOR WELDING PROCEDURE SPECIFICATION (WPS)
(See QW-200,1, Section iX, ASME Boiler and Pressure Vessel Code)

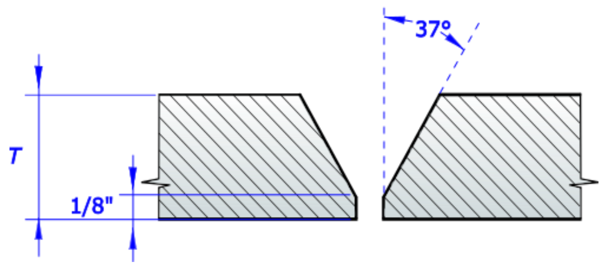
Organization Name: WELDING COMPANY, INC — By: JOHN SMITH
Welding Procedure Specification No.: SMAW - 001 — Date: 12/31/16 — Supporting PQR No(s): PQR - 001
Revision No.: 0

Welding Process(es): SMAW — Type: MANUAL

JOINTS(QW-402) — DETAILS

Joint design: Singe V, double V, J and U, All fillets
Backing: Yes X No X
Backing Material (Type): Weld Metal
Refer to both backing amd retainers

[X] Metal — [ ] Nonfusing Metal
[ ] Nonmetallic — [ ] Other



BASE METALS (QW-403)

P-No. 1 — Group No. 1 — to P-No. 1 — Group No. 1
OR
Specification and type/grade or UNS number: A36
to Specification and type/grade or UNS number: A36
OR
Chem. Analysis and Mech. Prop.:
to Chem. Analysis and Mech. Prop.:
Thickness Range:
Base Metal: Groove 1/16 to 3/4 — Fillet All
Maximum Pass Thickness <= 1/2 in. (13mm) — Yes X — No
Other:

FILLER METALS (QW-404)	1	2
Spec. No (SFA)	5.1	5.1
AWS No. (Class)	E6010	E7018
F-No	3	4
A-No	1	1
Size of filler metals	3/32" - 1/8"	3/32" , 1/8" , 5/32"
Filler Metal product form	Mild Steel, Cellulosic	Mild Steel, Low hydrogen
Supplemental Filler Metal	--	--
Weld Metal		
Deposited thickness:		
Groove	1/4"	5/8"
Fillet	All	All
Electrode-Flux (Class)	--	--
Flux Type	--	--
Flux Trade Name	--	--
Consumable Insert	--	--

Other: --

FORM QW-482 (back)

POSITIONS (QW-405)
Position(s) of groove: All
Welding progression: Up X Down X
Position(s) of fillet: All positions
Other

POST WELD HEAT TREATMENT (QW-407)
Temperature range: None
Time Range: --
Other: --

PREHEAT (QW-406)
Preheat temperature, Minimum: 50 °F
Interpass temperature, Maximum: --
Preheat Maintenance: Yes, preheat during 5minutes
Other
(Continuous or special heating, where applicable, should be recorded)

GAS (QW-408)

	Gas(es)	Percent composition Mixture	Flow rate
Shielding	N/A	N/A	N/A
Trailing	N/A	N/A	N/A
Backing	N/A	N/A	N/A
Other	N/A	N/A	N/A

ELECTRICAL CHARACTERISTICS (QW-409)

Weld Passes	Process	Filler metal Classifi-cation	Filler metal Diameter	Current Type and Polarity	Amps (Range)	Wire Feed Speed (Range)	Energy or Power (Range)	Volts (Range)	Travel Speed (Range)	Other (e.g., Remarks, Comments, Hot Wire Addition, Technique, Torch Angle, etc.)
1	SMAW	E6010	3/32" - 1/8"	**DCEP**	40-70, 80-120	N/A	N/A	26-29	2 - 51 ipm	--
2-n	SMAW	E7018	3/32" , 1/8" , 5/32"	**DCEP**	70-110, 90-160, 130-210	N/A	N/A	19-27	2 - 81 ipm	--

Amps and vots, or power or energy range, should be recorded for each electrode size, position, and thickness,etc.

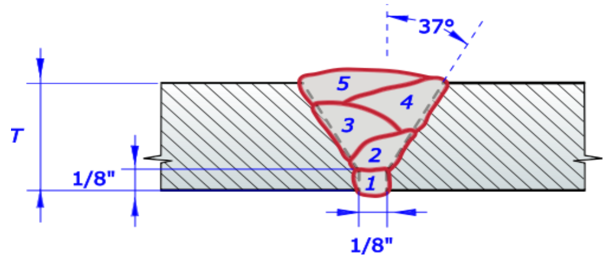
Pulsing current: N/A　　Heat Input Max: N/A
Tungsten electrode Size and type: N/A
(Pure tungsten, 2% thoriated, etc.)
Mode of Metal Transfer for GMAW: N/A
(Spray Arc, Short Circuiting Arc, etc.)
Other: --

TECHNIQUE (QW-410)
String or Weave Bead: String or weave
Orifice, nozzle, or gas Cup Size: N/A
Initial and Interpass Cleaning (Brushing, grinding, etc.): Hand or power tools may be used
--
Method of Back Gouging: Angle grinder
Oscillation: --
Contact Tube to Work Distance: --
Nultiple or Single Pass (per side): E-6010 SINGLE　E-7018 MULTIPLE
Multiple or Single Electrodes: --
Electrode Spacing: --
Peening: NO PEENING
Other

FORM QW-483 SUGGESTED FORMAT FOR PROCEDURE QUALIFICATION RECORDS (PQR)
(See QW-200.2, Section IX, ASME Boiler and Pressure Vessel Code)
Record Actual Variables Used to Weld Test Coupon

Organization Name: WELDING COMPANY, INC
Procedure Qualification Record No.: PQR - 001 Date: 12/31/16
WPS No.: SMAW - 001
Welding Process(es): SMAW
Types (Manual, Automatic, Semi-Automatic): Manual

JOINTS (QW-402)



Groove Design of Test Coupon
(For combination qualifications, the deposited weld metal thickness shall be recorded for each filler metal and process used.)

BASE METALS (QW-403)
Material Spec.: A283
Type/Grade, or UNS Number: C
P-No. 1 Group No 1 to P-No. 1 Gr 1
Thickness of Test Coupon: 1/2"
Diameter of Test Coupon: N/A
Maximum Pass Thickness:
Other: --
--
--
--
--

POSTWELD HEAT TREATMENT (QW-407)
Temperature: No PWHT
Time: --
Other: --
--
--
--

GAS (QW-408)

	Gases	Mixture (Percent Composition)	Flow rate
Shielding	--	--	--
Trailing	--	--	--
Backing	--	--	--
Other	--	--	--

FILLER METALS (QW-404)

SFA Specification	A5.1	A5.1
AWS Classification	E6010	E7018
Filler Metal F-No	3	4
Weld Metal Analysis A-No	1	1
Size of Filler Metal	1/8"	1/8"
Filler Metal Product Form	Cellulosic	Low Hydrogen
Supplemental Filler Metal	--	--
Electrode Flux Classification	--	--
Flux Type	--	--
Flux Trade Name	--	--
Weld Metal Thickness	0.125"	0.375"
Other		

ELECTRICAL CHARACTERISTICS (QW-409)
Current: DCEP
Polarity: DCEP
Amps.: 100 and 125amps Volts: 27 and 25volts
Tungsten Electrode Size: --
Mode of Metal Transfer for GMAW (FCAW): --
Heat Input: --
Other: --

POSITION (QW-405)
Position of Groove: 1F
Weld Progression (Uphill, Downhill): --
Other: --
--

TECHNIQUE (QW-410)
Travel Speed: 6ipm and 7ipm
String or Weave Bead: Weave
Oscillation: 3d
Multipass or Single Pass (Per Side): Both
Single or Multiple Electrodes: Single
Other: --
--
--
--

PREHEAT (QW-406)
Preheat Temperature: 50°F
Interpass Temperature: --
Other: --

FORM QW-483 (Back)

PQR No WPS-001

Tensile Test (QW-150)

Specimen No.	Width	Thickness	Area	Ultimate Total Load	Ultimate Unit Stress (psi)	Type of failure and location
1	1,5"	1/2"	3/4"	97,600	76,200	BASE
--	--	--	--	--	--	--
--	--	--	--	--	--	--
--	--	--	--	--	--	--

Guided-Bend Tests (QW-160)

Type and Figure No.	Result
Side Bend	Good
Side Bend	Good
Side Bend	Good
Root Bend	Good

Thoughness Tests (QW-170)

Specimen No.	Notch Location	Specimen size	Test temperature	Impact Values			Drop Weight Break (Y/n)
				ft-lb or J	% Shear	Mils (in) or mm	
--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--

Comments

Fillet Weld Test (QW-180)

Result - Satisfactory: Yes -- No -- Penetration into parent metal: Yes -- No --

Macro-Results --

Other Tests

Type of Test Radiographic Test - Good

Deposit Analysis --

Other --

Welder´s Name JOHN SMITH Clock No WC-035 Stamp No. JS23

Test Conducted by NDT COMPANY Laboratory Test No LAB-252-TT-01

We certify that the statements in this record are correct and that the test welds were prepared, welded, and tested in accordance with the requirements of Section IX of the ASME Boiler and Pressure Vessel Code.

Organization WELDING COMPANY, INC

Date 12/31/16 Certified By

(Detail of record of tests are illustrative only and may be modified to conform to the type and number of tests required by the Code.)

ANNEX 2

The following questions were extracted from the standards by me, or remembered by me or other students that took the exam before. The format is a Q&A one, different from the multiple choice question format from other courses I have seen online. I prefer this method because it takes away all the clutter that leads to confusion when treating these standards. I advise you to copy this info and paste it in a spaced repetition software like Anki or Supermemo, as the Q&A format allows, and start studying right away. You could choose to print flashcards too. When days pass by, you will see who you remember all of the information with no problem.

1 Q: What is the minimum thickness for a tank floor plate with no means for leak detection or secondary containment if an RBI program is not in place?
A: 0,1 inches — Ref: Table 4.4 API 653

2 Q: When a full hydrostatic test is required, it shall be held for ________
A: 24 hours. — Ref: 12.3.1 API 653

3 Q: How many radiographs shall be taken in a square 12” x 24” butt welded insert plate in a shell over 1" thick?
A: 100% — Ref: 12.2.1.6.2 API 653

4 Q: Minimun number of radiographs that shall be taken to a circular butt welded insert plate in a shell 1/2" thick?
A: 1 — Ref: 12.2.1.6.1 API 653

5 Q: How much time do you need to keep the radiographs of a reconstructed tank?
A: 1 year — Ref: 13.2.3 API 653

6 Q: Who should conduct visual inspection and review NDE results?
A: The authorized inspector — Ref: 6.4.1.2 API 653

7 Q: How much time should the operator keep the cathodic protection records?
A: 5 years — Ref: 11.4.7 API 571

8 Q: Minimum diagnostic length of a radiograph is _________
A: 6 inches Ref: 12.2.1.7 API 653

9 Q: The total metal loss divided by the period of time over which the metal loss occurred is the _________________
A: Corrosion rate Ref: 3.9 API 653

10 Q: The presence of rock under the steel bottom of an AST would have what effect
A: Promote sever underside corrosion Ref: C.1.1.4 API 653

11 Q: When do you use thin film linings?
A: When the tank is new or has light corrosion Ref: 6.1 API 652

12 Q: A formal visual external inspection by an Authorized Inspector shall be made
A: at least every 5 years or RCA/4N years, whichever is less Ref: 6.3.2.1 API 653

13 Q: Radiographic film density shall be checked by a densitometer calibrated on a step wedge film traceable to
A: A national standard Ref: T-262 ASME SEC V

14 Q: A welder deposits more weld metal than allowed by the WPS. What should be done?
A: Re-qualify the welder Ref: ASME IX

15 Q: What is the maximum critical length for plate thickness determination?
A: 40 inches Ref: 4.3.2.1 API 653

16 Q: When it is necessary hydrostatic test for a reconstructed tank?
A: Always Ref: 12.3.1 API 653

17 Q: How much more corrosion rate do rafters and girders can get with respect to roofs and shells?

A: Twice the speed — Ref: 7.4.8 API 575

18 Q: Between Thin film and thick film linings, which lining is best for a crude oil tank that operates at 190F
A: Thin-film — Ref: 6 Tank Bottom Lining Selection API 652

19 Q: What is the maximum spacing for MT prods?
A: 8 inches — Ref: T-752.3 ASME SEC V

20 Q: What is the height of the lead symbol "B" that shall be attached to the back of each film holder during each exposure to determine if backscatter radiation is exposing the film?
A: 1/2" — Ref: T-223 ASME SEC V

21 Q: Any work on a tank that changes its physical dimensions or configuration is called an?
A: Alteration — Ref: 3.1 API 653

22 Q: Which annex of API 653 provides guides about Aboveground tanks inspector certification?
A: Annex D — Ref: API 653

23 Q: The maximum permissible limit for exposure to organic lead in a normal 8 hour work day is ____
A: 2 micrograms of organic lead per cubic feet — Ref: 3.2.38 API 2015

24 Q: The maximum horizontal dimension for shell repair plates as per API 653 shall be
A: 72 in — Ref: 9.3.1.7 API 653

25 Q: In accordance with API Standard 653, Critical Zone for repairs to a Tank Bottom is that portion, which is ___________________________________
A: Measured radially inward, within 3” of the inside edge of the shell. — Ref: 3.10 API 653

26 Q: As per API Standard 653, a routine, in-service, visual external inspection of an above ground storage tank (AST) shall be done every ____________

A: 1 month Ref: 6.3.1.2 API 653

27 Q: How many types of authorized inspection agencies can exist?
A: 4 types Ref: 3.3 API 653

28 Q: Who has the ultimate responsibility for complying with the provisions of API 653 standard?
A: The owner/operator Ref: 1.2 API 653

29 Q: What RBI means?
A: Risk Based Inspection Ref: 6.4.2.1 API 653

30 Q: Jacking of a tank is an alteration or a repair?
A: A repair Ref: 3.24 API 653

31 Q: In which case is external inspection permitted in lieu of internal inspection?
A: When you have access to the underside of the bottom Ref: 6.5 API 653

32 Q: A relocated tank needs hydrostatic testing?
A: Yes

33 Q: Which NDE technique is used to fully check shell welds?
A: Hydrostatic testing Ref: 12.3 API 653

34 Q: Reinforcement pad welds should be pneumatically tested at which pressure?
A: 15 psig Ref: 7.3.4 API 650

35 Q: During a hydrostatic test, at least how many measurement points shall be surveyed?
A: 8 points Ref: 12.5.1.2 API 653

36 Q: During a hydrostatic test for a new tank, at least how many measurement sets shall be taken?

A: At least 6 sets Ref: 7.3.6.5 API 650

37 Q: Which types of tanks use windgirders?
A: Open top tanks Ref: 5.9.1 API 650

38 Q: The total resistance from tank to earth should not exceed approximately ______
A: 25 ohms Ref: 7.2.5 API 575

39 Q: Vacuum box testing requires how many psig of vacuum minimum?
A: 3psig Ref: 8.6.3 API 650

40 Q: API 653 standard covers maintenance, repair, relocation and reconstruction of tanks constructed according to what standards?
A: API 650 and API 12C Ref: 1.1.1 API 653

41 Q: Guided bend test are used to _______________________________
A: determine the degree of soundness and ductility of groove-weld joints Ref: QW-141.2 ASME IX

42 Q: Tension tests are used to __________________________________
A: to determine the ultimate strength of groove-weld joints Ref: QW-141.1 ASME IX

43 Q: How many tension tests are required for procedure qualification?
A: 2 tension tests Ref: QW-450 SME IX

44 Q: Which NDE techniques are volumetric?
A: Radiography and ultrasound Ref: QW-191 ASME IX

45 Q: Radiography can be used to qualify welding procedures and welder´s performance?
A: Yes Ref: QW-304 ASME IX

46 Q: Apart from 6G, which pipe position can be used to qualify a welder for all other positions?
A: 2G and 5G Ref: QW-461.9 ASME IX

47 Q: The 1-foot method design shall not be used in tanks over which diameter?

A: 200ft Ref: 5.6.3.1 API 650

48 Q: Maximum design internal pressure in an AST is not exceeding _______
A: 2.5psig Ref: 5.2.1 API 650

49 Q: At which temperature risk of brittle fracture is considered minimal?
A: 60F Ref: 5.3.6 API 653

50 Q: In case of tank shell thickness above 1/2", is there risk of brittle failure?
A: No, it is minimal Ref: 5.3.5 API 653

51. Q: A penetrameter is used to
A: Determine the image quality of a radiograph Ref: V-230 ASME SEC V

52. Q: API 650 limits design temperature to be no more than
A: 93°C Ref: 1.1.1 API 650

53. Q: In reconstructed tanks, how much time before relocation must have been done the thickness measurement of the plates?
A: 180 days Ref: 8.4.1 API 653

54. Q: If impact test was not done on original tank material of unknown toughness, the hot taps shall be limited to what diameter?
A: 4NPS Ref: 9.14.1.1 API 653

55. Q: In a tank alteration, what is the minimum size of a nozzle installed below liquid level that makes the hydrostic test obligatory?

A: 12NPS bellow liquid level Ref: 9.14.1.1 API 653

56. Q: It is permitted the use of Cast iron in the pressure parts of a tank?
A: No Ref: 4.1.1.3 API 650

57. Q: A new A36 tank is to be hydrostatically tested. What maximun allowable stress should be used to determine the maximum hydrostatic height?
A: 24900psi Ref: Table 5-2b API 650

58. Q: Routine visual in-service inspections of aboveground storage tanks from the ground may be done by ?
A: Owner/operator Ref: 6.3.1 API 653

59. Q: Penetrameters are usually placed in which side of the radiographic arrangement?
A: Source side Ref: VIII-277.1 ASME SEC V

60. Q: If a welder test for a 6G position, he qualifies for
A: all positions Ref: QW-461.9 ASME IX

61. Q: If a repair of shell plate thicker than 1 inch, the base metal within 3 inches of the repair shall be heated to how much degrees?
A: 140 °F Ref: 10.4.2.3 API 653

62. Q: The maximum spacing of measurement points around the circumference of a tank for an hydrostatic test is?
A: 32ft Ref: 12.5.1.2 API 653

63. Q: The maximum acceptable undercutting of vertical butt welds in a recosntructed tank shall be limited to what?
A: 1/64" Ref: 8.5.1.b API 650

64. Q: How many tensile tests are required to qualify a 1/4" plate groove weld?
A: 2 Ref: QW-450 SME IX

65. Q: For what diameter tank is the variable design method for calculating shell thickness mandatory?
A: 200ft Ref: 5.6.3.1 API 650

66. Q: At the maximum pole spacing, a magnetic Yoke is expected to lift at least
A: 10 lb Ref: T-762 ASME SEC V

67. Q: The magnetizing power of permanent magnetic yokes shall be checked every
    A: Prior to use Ref: T-762 ASME SEC V

68. Q: When there is no RBI assessment, the internal inspection interval of an aboveground storage tank shall not exceed
    A: 20 years Ref: 6.4.2.2 API 653

69. Q: The minimum number of settlement points around a tank periphery is?
    A: 8 Ref: 12.5.1.2 API 653

70. Q: If corrosion rates are not known, external UT measurements of a new tank shell shall be made not later than how many years?
    A: 5 Ref: 6.3.3.2 API 653

71. Q: Welders participating in tank construction should be tested according to which standard?
    A: ASME IX Ref: 7.2.1.1 API 650

72. Q: A welder is qualified to B31.3. Is he authorized to weld in the tank?
    A: No Ref: 7.2.1.1 API 650

73. Q: What is the minimum amount of manholes a single deck external floating roof 15m diameter?
    A: 2 Ref: C.3.11 API 650

74. Q: A riveted tank shell with a butt joint has 3 rows at each side of the joint center line. What is the joint efficiency?
    A: 0,85 Ref: Table 4-3 API 653

75. Q: What is the value used for joint efficiency in API 650 shell design calculations?

A: 1 Ref: Table 4-2 API 653

76. Q: Since which edition of API 650 joint efficiency has a 1 value?
A: Seventh Ref: Table 4-2 API 653

77. Q: Is PT required for areas where temporary attachments have been removed, if the shell is A36 steel?
A: No Ref: 7.2.3.5 API 650

78. Q: Essential variables for procedure qualification are summarized in which numeral od ASME IX?
A: QW-253 Ref: ASME IX

79. Q: Essential variables for performance qualification are summarized in which numeral od ASME IX?
A: QW-353 Ref: ASME IX

80. Q: Opening in tank shells larger than required to accommodate a _____ inch standard-weight coupling shall be reinforced
A: 2NPS Ref: Table 5-6a API 650

81. Q: It is allowed to have in a course plates thinner than those in the course above it?
A: No 5.6.1.3 API 650

82. Q: The minimum allowable thickness of an annular plate ring is
A: 0,1" Ref: 4.4.6.1 API 653

83. Q: Misalignment in completed vertical joints for shell plates greater than 16 mm should not exceed
A: 3mm Ref: 7.2.3.1 API 650

84. Q: Is API 653 used to inspect refrigerated tanks?
A: No Ref: 1.1.1 API 650

85. Q: To be a major alteration a nozzle installed below liquid level must be what size?

A: Larger than 12NPS Ref: 3.18 API 653

86. Q: UT examination methods shall be in accordance with ______________
A: ASME Boiler and Pressure vessel code SEC 5 Ref: Chapter 8 API 650

87. Q: Vertical welds on new tanks must be fully radiographed if the shell thickness exceeds which thickness?
A: 1 inches Ref: Figure 8-1 API 650

88. Q: Is welder identification required for roof welds?
A: No Ref: 9.4 API 650

89. Q: Welder or welding operator's identification marks shall be located adjacent to completed welds at intervals not exceeding
A: 3 feet Ref: 9.4 API 650

90. Q: Which standard is mandatory for new material to be used in an existing tank?
A: The current aplicable standard Ref: 7.2 API 653

91. Q: Which is the maximum allowable slope of a frangible roof of a tank 15m or greater?
A: 2:12 Ref: 5.10.2.6 API 650

92. Q: Which type of roof is used to reduce vapor space and product loss?
A: Floating roof tank Ref: General Knowledge

93. Q: The area on a tank bottom where settlement begins
A: Breakover point Ref: 3.5 API 653

94. Q: A tank for which corrosion rates and service history are not known and documented is known as?
A: A candidate Tank Ref: 3.6 API 653

95. Q: A procedure for installing a nozzle in the shell of a tank that is in service
A: Hot tap Ref: 3.14 API 653

96. Q: Installing a shell penetration 6NPS in size 24" above the bottom is considered a major alteration?
    A: No Ref: 3.18 API 653

97. Q: A tank for which corrosion rates and service history are known and documented is known as?
    A: A control tank Ref: 3.8 API 653

98. Q: Any work necessary to maintain or restore a tank to a condition suitable for safe operation is called a…
    A: Repair Ref: 3.24 API 653

99. Q: Should you consider jacking of a tank shell a major alteration/repair?
    A: Yes Ref: 3.20 API 653

100. Q: An authorized ____________ is representative of an organization's integrity department
    A: inspector Ref: 3.16 API 653

101. Q: When the results of a tank inspection show that a change has occurred from the original physical condition of that tank, should it be repaired?
    A: No, an examination shall be made for suitability of service Ref: 4.1.1 API 653

102. Q: Roof plates to be repaired are those with an average thickness of less than ____ in any 100 in^2
    A: 0.09in Ref: 4.2.1.2 API 653

103. Q: Before changing the service of a tank to operation at temperatures above 200 °F, the requirements of which appendix shall be considered?
    A: Appendix M of API 650 Ref: 4.2.4.3 API 653

104. Q: The evaluation of the existing tank shell shall be conducted by a ____________________
    A: Storage tank engineer Ref: 4.3.1.2 API 653

105. Q: When there is a shell corroded area with a thickness lower than allowed, there are 3 options, which are…

A: damaged areas shall be repaired, or the allowable liquid level of the tank reduced, or the tank retired Ref: 4.3.1.5 API 653

106. Q: How many types of shell distortion does API 653 consider
A: 5 types. out-of-roundness, buckled areas, flat spots, and peaking and banding at welded joints Ref: 4.3.5.1 API 653

107. Q: Cracks in the shell-to-bottom weld are allowed under which condition?
A: None. They are never allowed Ref: 4.3.6 API 653

108. Q: If a repair is needed, what is the first step you have to tke? ?
A: a repair procedure shall be developed and implemented Ref: 4.3.6 API 653

109. Q: The condition of wind girders is part of the shell analysis?
A: Yes Ref: 4.3.7 API 653

110. Q: Grinding to eliminate weld defects is permissible?
A: Yes, if the resulting profile satisfies base thickness and weld size requirements Ref: 4.3.9.1 API 653

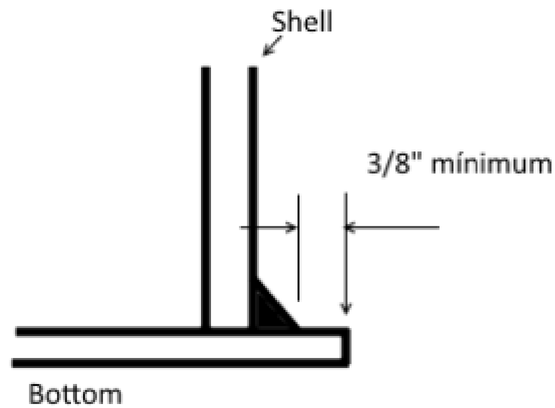
111. Q: In the evaluation of a tank shell for a tank at elevated temperature, the value of allowable stress for each sheel course should be ____ minimum yield strength?
A: 0.8 Ref: 4.3.10.1.1 API 653

112. Q: When evaluating a shell of a tank at elevated temperature, what value of yield strength should be assumed if the material is not known?
A: 30.000 lb/pulg2 Ref: 4.3.10.1.1 API 653

113. Q: Which RP covers a selection basis for cathodic protection?
A: API 651 Ref: 4.4 API 653

114. Q: Plate thickness in the critical zone of the bottom of a tank in no case shall be less than _______
A: 0,1inch Ref: 4.4.5.4 API 653

115. Q: The projection of the bottom plate beyond the outside toe of the shell-to-bottom weld shell shall be at least ______
A: 3/8 inch Ref: 4.4.5.7 API 653



Q.115 Minimum bottom projection

116. Q: Unless special reasons indicate different, the interval between inspections of a tank (both internal and external) should be determined by ______________________
A: its service history Ref: 6.2.2. API 653

117. Q: If inspecting an insulated tank during the five-year external inspection, do you need to remove all of the isolation?
A: No. You only need to remove isolation to the extent necessary. Ref: T-762 ASME SEC V

118. Q: During a five-year external inspections, to what extent shall be tank grounding systems inspected?
A: Visually inspected Ref: 6.3.1.3 API 653

119. Q: If corrosion rates are known, external UT measurements of a new tank shell shall be made
A: the smaller of RCA/2N years or 15 years Ref: 6.3.3.2 API 653

120. Q: When a new tank has no Release Prevention Systems, the interval from initial service until the initial internal inspection shall not exceed ____ years.

A: 10 Ref: 6.4.2.1 API 653

121. Q: When a tank has an RPS consisting of an original bottom corrosion allowance of 0.2in,and the CR is 0.03in, which is the initial internal inspection interval?

A: 11.66 years Ref: 6.4.2.1 API 653

122. Q: When a tank has an RPS consisting of Cathodic protection of the soil-side of the primary tank bottom, which is the initial internal inspection interval?

A: 15 years Ref: 6.4.2.1 API 653

123. Q: When a tank has an RPS consisting of a thin-film lining of the product-side of the tank bottom, which is the initial internal inspection interval?

A: 12 years Ref: 6.4.2.1 API 653

124. Q: When a tank has an RPS consisting of fiberglass-reinforced lining of the product-side of the tank bottom, which is the initial internal inspection interval?

A: 15 years Ref: 6.4.2.1 API 653

125. Q: When a tank has an RPS consisting of cathodic protection plus a thin-film lining, which is the initial internal inspection interval??

A: 17 years Ref: 6.4.2.1 API 653

126. Q: When a tank has an RPS consisting of cathodic protection plus fiberglass-reinforced lining, which is the initial internal inspection interval?

A: 20 years Ref: 6.4.2.1 API 653

127. Q: When a tank has an RPS consisting of a release prevention barrier and a similar service assessment, which is the initial internal inspection interval?
A: 20 years Ref: 6.4.2.1 API 653

128. Q: When a tank has an RPS consisting of a release prevention barrier and a Risk based Inspection was performed, which is the initial internal inspection interval?
A: 25 years Ref: 6.4.2.1 API 653

129. Q: RBI assessment shall consist of a systematic evaluation of both the ___________________________________ and the associated consequence of failure
A: Likelihood of failure Ref: 6.4.2.4 API 653

130. Q: RBI assessment shall consist of a systematic evaluation of both the likelihood of failure and the associated _______________________
A: Consequence of failure Ref: 6.4.2.4 API 653

131. Q: How many types of records should an operator keep at all times?
A: 3 types. Construction records, inspection history and repair/alteration history Ref: 6.8.1. API 653

132. Q: All new shell joints shall be _________ joints with complete penetration and complete fusion
A: Butt-welded Ref: 8.2.2. API 653

133. Q: Each existing shell joint should comply with _________________
A: The as-built standard Ref: 8.3. API 653

134. Q: Who can authorize a repair?
A: The inspector or an engineer experienced in storage tank design Ref: 9.1.3 API 650

135. Q: The minimum dimension for a replacement shell plate is _____
A: 12inches Ref: 9.2.2.1. API 653

136. Q: When welding shell seams, which seams should go first: horizontal or vertical?
A: Vertical Ref: 9.2.2.2. API 653

Questions 137 through 143 are for all kinds of repairs using lapped patch shell plates.

137. Q: Lapped patch shell repairs shall not be used on any shell course thickness that exceeds ________
A: 1/2 in Ref: 9.3.1.2 API 653

138. Q: Lapped patch shell repair plates shall not be less than _______
A: 3/16 Ref: 9.3.1.3 API 653

139. Q: The shape of the repair plate may be circular, oblong, square, or rectangular. All corners, except at the shell-to-bottom joint, shall be rounded to a minimum radius of _____
A: 2 inches Ref: 9.3.1.4. API 653

140. Q: Lapped patch repair plates positioned on the shell interior shall be located such that the toe-to-toe weld clearances are a minimum of ____ to the shell-to-bottom weld
A: 6 inches Ref: 9.3.1.6. API 653

141. Q: The minimum lapped patch repair plate dimension is ______
A: 4 inches Ref: 9.3.1.7 API 653

142. Q: What is the maximum vertical dimension of a lapped patch repair plate?
A: 48 inches Ref: 9.3.1.7 API 653

143. Q: What is the maximum horizontal dimension of a lapped patch repair plate?
A: 72 inches Ref: 9.3.1.7 API 653

Questions 144 through 146 are for a repair using lapped patch shell plates for the closure of holes caused by the removal of existing shell openings or the removal of severely corroded or eroded areas.

144. Q: Can you put a patch plate over a ½" diameter hole, then weld the inner perimeter of the hole?
A: No. The hole must be at least 2" diameter Ref: 9.3.2.1 API 653

145. Q: The repair plate thickness selection shall be used a joint efficiency not exceeding ______
A: 0.7 Ref: 9.3.2.3. API 653

146. Q: Can you use a 3/8" patch plate over an existing ¼" shell?
A: No Ref: 9.3.2.4. API 653

Questions 147 through 149 are lapped patch shell plates used to reinforce areas of severely deteriorated shell plates that are not able to resist the service loads or that are below the retirement thickness.

147. Q: The repair plate thickness selection shall be used a joint efficiency not exceeding ______
A: 0.35 Ref: 9.3.3.1. API 653

148. Q: Lapped patch shell plates shall not exceed ________
A: 1/2 in Ref: 9.3.3.2. API 653

149. Q: The repair plate thickness shall not exceed ______
A: One third of the shell plate or 1/8" maximum Ref: 3.18 API 653

The following questions are for lapped patch shell plates used to repair small shell leaks

150. Q: If there is a leak and the product stored is corrosive, can you use this method?
A: No Ref: 9.3.4 API 653

The following questions correspond to Brittle fracture

151. Q: _______ __________ is the sudden rapid fracture under stress where the material exhibits little or no evidence of ductility or plastic deformation
A: Brittle fracture Ref: API 571 4.2.7.1

152. Q: Which 3 types of steel are susceptible to Brittle fracture?
A: Carbon, low alloy and 400 series SS steels Ref: API 571 4.2.7.2

153. Q: First of five critical factors that make a material susceptible to brittle fracture
A: Existence of flaws in the material Ref: API 571 4.2.7.3

154. Q: In materials with flaws, the most important variable in resistance to brittle fracture is
A: Material fracture toughness Ref: API 571 4.2.7.3

155. Q: Give an example of an embrittlement phase, which raises a material´s susceptibility to brittle fracture
A: Cementite Ref: API 571 4.2.7.3

156. Q: A lower grain size affects brittle fracture by lowering _____________
A: Ductile-brittle transition temperature Ref: API 571 4.2.7.3

157. Q: Thicker material sections have a higher/lower resistance to brittle fracture
A: Lower Ref: API 571 4.2.7.3

158. Q: Brittle fracture occurs at temperatures ______ the ductile-brittle transition temperature
A: Below Ref: API 571 4.2.7.3

159. Q: Let´s review all 5 critical factors affecting brittle fracture
A: Flaws, embrittling phases, steel cleanliness and grains size, thickness and temperature Ref: API 571 4.2.7.3

160. Q: Which type of damage mechanism can be present at equipment manufactured prior to 1987 and designed according to the ASME BPVC Section VIII, div 1?
A: Brittle fracture Ref: API 571 4.2.7.4

161. Q: After the 1987 Section VIII, div 1 addenda, equipment made to this code was also subject to the requirements of ______

A: UCS 66 (impact exemption curves) Ref: API 571 4.2.7.4

162. Q: Main concern of brittle fracture is during which events in an equipment´s life cycle?
A: Start-up, shutdown or hydrotest/tightness testing Ref: API 571 4.2.7.4

163. Q: Why is susceptible an equipment to brittle fracture during ambient temperature hydrotesting?
A: Due to high stresses and low toughness at the testing temperature Ref: API 571 4.2.7.4

164. Q: Brittle fracture can be present in units processing light hydrocarbons because of ___________________
A: Autorefrigeration Ref: API 571 4.2.7.4

165. Q: Brittle fracture cracks tend to be _________
A: Straight, non branching and without plastic deformation Ref: API 571 4.2.7.5

166. Q: Preventative measures against brittle fracture can be taken in several parts of an equipment´s ______ ______
A: Life Cycle Ref: API 571 4.2.7.6

167. Q: Brittle fracture is an "_______ _______" damage mechanism, meaning that
A: Event driven Ref: API 571 4.2.7.6

168. Q: If the morphology of a fracture surface is composed largely of cleavage, with limited intergranular cracking an little microvoid coalescence, then the damage mechanism is
A: Brittle fracture Ref: API 571 4.2.7.6

169. Q: Performing a PWHT will improve/worsen the resistance to brittle fracture
A: Improve Ref: API 571 4.2.7.6

170. Q: For existing equipment, resistance to brittle fracture of existing carbon and low alloy steel can be evaluated with

A: Api 579-1 section 3 level 1 or 2 Ref: API 571 4.2.7.6

171. Q: Can inspection mitigate brittle fracture?
A: No Ref: API 571 4.2.7.7

The following questions correspond to Mechanical fatigue

172. Q: Fatigue cracking is a mechanical form of degradation that occurs when a component is exposed to ____________ _______ for an extended period
A: Cyclical stresses Ref: API 571 4.2.16.1

173. Q: Mechanical loading can cause Mechanical Fatigue. Which other phenomena causes Mechanical Fatigue.
A: Thermal cycling Ref: API 571 4.2.16.1

174. Q: Which materials can suffer mechanical fatigue?

A: All engineering alloys Ref: API 571 4.2.16.2

175. Q: What is the most important factor in determining a component´s resistance to fatigue cracking?

A: Design of the component Ref: API 571 4.2.16.3

176. Q: Which materials exhibit and endurance limit to mechanical fatigue cracking?
A: Carbon steel an d titanium Ref: API 571 4.2.16.3

177. Q: Does 300 series SS exhibit endurance limit to mechanical fatigue cracking?
A: No Ref: API 571 4.2.16.3

178. Q: For alloys with endurance limit to mechanical fatigue cracking, the ratio of endurance limit over Ultimate Tensile Strength is between ___ and _____
A: 0,4 and 0,5 Ref: API 571 4.2.16.3

179. Q: Inclusions in metal decelerate/accelerate fatigue cracking
A: Accelerate Ref: API 571 4.2.16.3

180. Q: How does heat treatment improve the toughness of a metal?
A: Reducing grain size and eliminating embrittlement phases — Ref: API 571 4.2.16.3

181. Q: In mechanical fatigue, the finer the grain, the worst/better for mechanical fatigue resistance
A: Better — Ref: API 571 4.2.16.3

182. Q: Which are the 2 types of load that originate mechanical fatigue?
A: Thermal cycling and mechanical loading — Ref: API 571 4.2.16.4

183. Q: If you see fracture and a "clam shell" type fingerprint with "beach marks" emanating from the crack initiation, that is _________________ _________________
A: Mechanical fatigue — Ref: API 571 4.2.16.5

184. Q: Definition of endurance limit in mechanical fatigue
A: An amplitude value under which fatigue cracking will not occur, regardless of the number of cycles — Ref: API 571 4.2.16.3

185. Q: What is the best defense against mechanical fatigue cracking of components in cyclic service?
A: Good design that reduces stress concentration — Ref: API 571 4.2.16.6

186. Q: Use of low stress stamps and marking tools is a measure you would take to prevent ______________
A: Mechanical fatigue — Ref: API 571 4.2.16.6

187. Q: Besides PT and MT, what other NDE can be used to detect fatigue cracks in stress concentration areas?
A: SWUT — Ref: API 571 4.2.16.7

188. Q: Which are the 3 NDE methods you can use to detect fatigue cracks in stress concentration areas?

A: PT, MT and SWUT Ref: API 571 4.2.16.7

The following questions correspond to Atmospheric Corrosion

189. Q: Atmospheric corrosion occurs from _______ associated with atmospheric conditions
A: Moisture Ref: API 571 4.3.2.1

190. Q: Atmospheric corrosion can affect which materials?
A: Carbon steels, low alloy steels and copper alloyed aluminum Ref: API 571 4.3.2.2

191. Q: Which is the most important measure against atmospheric corrosion?
A: Surface preparation an proper coating application Ref: API 571 4.3.2.6

192. Q: Atmospheric corrosion can affect which kind of metallic connections?
A: Bimetallic connections, such as copper to aluminum electrical connections Ref: API 571 4.3.2.4

193. Q: What is the average corrosion rate in marine environments?
A: 20mpy Ref: API 571 4.3.2.3

194. Q: What is the average corrosion rate in industrial environments that contain acids or sulfur compounds that can form acid?
A: 5-10mpy Ref: API 571 4.3.2.3

195. Q: As opposed to corrosive marine environments, what is the average corrosion rate in inland locations?
A: 1 to 3mpy Ref: API 571 4.3.2.3

196. Q: What is the average corrosion rate in dry rural environments?
A: Less than 1mpy Ref: API 571 4.3.2.3

197. Q: Corrosion rates increase with proximity with which equipment?
A: Cooling towers and furnace stacks Ref: API 571 4.3.2.3

198. Q: Corrosion rates increase with temperature up to _______
A: 250°F Ref: API 571 4.3.2.3

199. Q: Over 250°F, why is atmospheric condition less probable?
A: Over that temperature, surfaces are too dry for corrosion to occur Ref: API 571 4.3.2.3

200. Q: Designs that trap water or moisture in crevices are prone to __________ _________________
A: Atmospheric corrosion Ref: API 571 4.3.2.3

201. Q: Which are the 2 NDE techniques you can use to detect atmospheric corrosion?
A: VT and UT Ref: API 571 4.3.2.7

202. Q: Can UT be used to detect atmospheric corrosion? (Yes/no)
A: Yes Ref: API 571 4.3.2.7

The following questions correspond to Corrosion Under Insulation

203. Q: Damage mechanisms resulting from water entrapment under insulation or fireproofing:
A: Corrosion Under Insulation Ref: API 571 4.3.3

204. Q: The 4 materials that can be affected by CUI are _______ ____, low alloy steel, 300 Series SS and duplex stainless steel
A: Carbon steel Ref: API 571 4.3.3

205. Q: The 4 materials that can be affected by CUI are Carbon steel, _______ ____ _______, 300 Series SS and duplex stainless steel
A: Low alloy steels Ref: API 571 4.3.3

206. Q: The 4 materials that can be affected by CUI are Carbon steel, low alloy steel, _______ ____ and duplex stainless steel
A: 300 series SS Ref: API 571 4.3.3

207. Q: The 4 materials that can be affected by CUI are Carbon steel, low alloy steel, 300 Series SS and _______ ____ ______.
A: Duplex Stainless steels Ref: API 571 4.3.3

208. Q: Let´s review all 4 steels prone to Corrosion Under Insulation
A: Carbon steel, low alloy steel, 300 series SS and duplex stainless steel Ref: API 571 4.3.3

209. Q: Carbon Steel and Low alloy steels are more affected by CUI mainly in which temperature range?
A: -12°C and 175°C Ref: API 571 4.3.3

210. Q: Austenitic steels (300 series) and duplex stainless steels are more affected by CUI mainly in which temperature range?
A: 60°C and 205°C Ref: API 571 4.3.3

211. Q: In CUI, if metal temperature increases, corrosion rates increase/decrease
A: Increase Ref: API 571 4.3.3

212. Q: When do corrosion rates stop increasing when there is Corrosion Under Insulation?
A: Until water evaporates quickly Ref: API 571 4.3.3

213. Q: For insulated components, what is the metal temperature range when corrosion under insulation is more severe?
A: Between the boiling point (100°C) and 121°C Ref: API 571 4.3.3

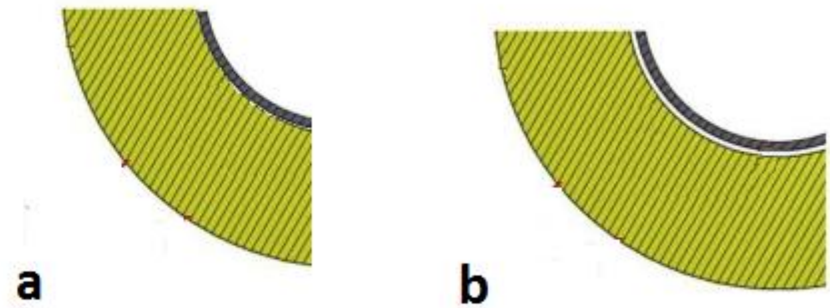
214. Following metal surface temperature, the most critical factor that promotes CUI is ……
Design of the insulation system Ref: API 571 4.3.3

215. Q: If an insulation material absorbs water, corrosion rates (CUI) increase/decrease
A: Increase Ref: API 571 4.3.3

216. Q: Why pyrogel is better that calcium silicate insulation?
A: Calcium Silicate absorbs water (Illustrating None

the point in 4.3.3.3.e)

217. Q: Look at the image. Why material A insulates better than material B?
A: Because it leaves no annular space to water to become entrapped — None



218. Q: Which type of contaminant can be present in insulation that is corrosive to 300 series SS?
A: Chlorides — Ref: API 571 4.3.3.3.h

219. Q: Cyclic thermal operation can increase/decrease corrosion
A: Increase — Ref: API 571 4.3.3

220. Q: When does condensation happen on a metal surface?
A: When temperature is below the dew point — Ref: API 571 4.3.3

221. Q: Inland locations are more prone to CUI tan marine locations. True/False
A: False — Ref: API 571 4.3.3

222. Q: API 571 mentions 2 airborne contaminants typical of marine locations and cooling tower drift. What are they?
A: Chlorides and SO2 (Sulfur dioxide causes acid rain) — Ref: API 571 4.3.3

223. Q: Which equipment is susceptible to Corrosion Under Insulation?
A: All insulated piping and equipment — Ref: API 571 4.3.3

224. Q: Which materials mainly show localized pitting and localized loss in thickness when subject to CUI?

A: Carbon steels and low alloy steels Ref: API 571 4.3.3

225. Q: If chlorides are present and there exists CUI, which other damage mechanism can be promoted in 300 series SS?
A: Stress Corrosion Cracking (SCC) Ref: API 571 4.3.3

226. Q: Between 300Series SS and duplex SS, which one is more susceptible to Stress Corrosion Cracking (SCC)?
A: Duplex SS Ref: API 571 4.3.3

227. Q: Which of all of the 4 materials prone to CUI are susceptible to localized pitting?

A: All of them Ref: API 571 4.3.3

228. Q: Name one insulation material that was known for containing chlorides

A: Calcium Silicate Ref: API 571 4.3.3

229. Q: For 300 series SS, specifically in older calcium silicates, which t2 phenomena can occur?
A: Localized pitting and chloride stress corrosion cracking (Cl-SCC) Ref: API 571 4.3.3

230. Q: What is usually the appearance of CUI I carbon and ow alloy steels?
A: Loose, flaky scale Ref: API 571 4.3.3

231. Q: In some localized cases, CUI can appear to be ______________ ______ ________

A: Carbuncle type pitting Ref: API 571 4.3.3

232. Q: Which is the best defense against CUI?
A: Using ***Appropriate coatings*** and *Maintaining the insulation barriers* Ref: API 571 4.3.3

233. Q: What metal coating is useful in protecting carbon steel from CUI?
A: Flame-sprayed aluminum coatings Ref: API 571 4.3.3

234. Q: What form of corrosion acts over aluminum coatings? (Intergranular/Galvanic/Crevice/Uniform)
A: Galvanic Ref: API 571 4.3.3

235. Q: Thin foils of which metal are used on stainless pipes and equipment to reduce Corrosion Under Insulation?
A: Aluminum thin foils Ref: API 571 4.3.3

236. Q: Why closed cell foam glass is better than mineral wool as an insulating material?
A: Because it holds less water against the pipe or equipment Ref: API 571 4.3.3

237. Q: If heat conservation is not important, what should a designer do to reduce probabilities of CUI?
A: Remove the insulation Ref: API 571 4.3.3

238. Q: Low chloride insulation should be used on ___ ______ __ to minimize the potential for pitting and Cl-SCC
A: 300 series SS Ref: API 571 4.3.3

239. Q: If an equipment is suspected of having Corrosion Under Insulation, all the insulation should be removed for inspection. True/False
A: False. It should be removed only to the extent necessary Ref: API 571 4.3.3

240 Q: Can guided Wave UT help in inspecting for CUI? Yes/No
A: Yes Ref: API 571 4.3.3

The following questions correspond to Microbiologically Induced Corrosion. I´ve begun to make research and convert that into questions for you, as a way to make you really remember the knowledge. You will find that those questions have no reference

241. Q: Name of the form of corrosion caused by living organisms such as bacteria, algae or fungi.
A: Microbiologically Induced Corrosion (MIC) Ref: API 571 4.3.8.1

242. Q: How many types of materials can be affected by MIC?
A: 7 according to API 571 (and many others) Ref: API 571 4.3.8.2

243. Q: Which kinds of stainless steels are affected by MIC?
A: 300 series SS and 400 series SS Ref: API 571 4.3.8.2

244. Q: Inconel is an example of a metal that can be affected by MIC because it is a ________________________
A: Nickel base alloy

245. Q: Early jet aircraft fuel tanks were affected by MIC because they were made of ___________
A: Aluminum

246. Q: Are cold water copper plumbing systems affected by microbiologically induced corrosion? Yes/No
A: Yes

247. Q: What is the single most critical factor that will contribute to MIC
A: Aqueous environment Ref: API 571 4.3.8.3

248. Q: Where is there more probability of MIC: Systems with high water flow or systems with low water flow?
A: Low water flow Ref: API 571 4.3.8.3

249. Q: Name three substances we as humans need that are needed by microorganisms to produce MIC
A: All organisms require a source of carbon, nitrogen and phosphorous for growth. Ref: API 571 4.3.8.3

250. Q: In-leakage of process contaminants such as hydrocarbons or H_2S may lead to a massive increase/decrease in biofouling and corrosion.
A: Increase Ref: API 571 4.3.8.3

251. Q: MIC is the most common in ________ _____________
A: Heat exchangers Ref: API 571 4.3.8.4

252. MIC is commoner in crude oil tank roofs that any other tank component. True/False
False. It is more common in tank bottoms Ref: API 571 4.3.8.4

253. Q: If the hydrotest water is not drained after use, it can lead to which equipment damage mechanism?
A: Microbiologically Induced Corrosion Ref: API 571 4.3.8.4

254. Q: MIC can cause rapid development of pinhole-sized leaks in _____ _________ __________
A: Fire water systems Ref: API 571 4.3.8.4

255. Q: Name of damage mechanism usually observed as localized pitting under deposits or tubercles that shield organisms
A: MIC Ref: API 571 4.3.8.5

256. Q: In carbon steel, microbiologically induced corrosion damage is characterized by ____ _____ ____ ____ ___________ pits within pits
A: Cup-shaped pits within pits Ref: API 571 4.3.8.5

257. Q: In stainless steels, microbiologically induced corrosion damage is characterized by ______________ ________________
A: Subsurface cavities Ref: API 571 4.3.8.5

258. Q: To avoid MIC, systems that contain water (cooling water, storage tanks, etc.) should be treated with _________
A: Biocides Ref: API 571 4.3.8.6

259. Q: Can you eliminate microorganisms using biocide only once in still water?
A: No. Continued treatment is necessary Ref: API 571 4.3.8.6

260. Q: Maintaining water flow velocities above minimum levels will avoid
A: Microbiologically induced corrosion Ref: API 571 4.3.8.6

261. Q: What should you do after draining hydrotest water to better improve the chances of getting no MIC?

A: Blow and dry the equipment Ref: API 571 4.3.8.6

262. Q: In systems not intended for water, you still have to keep equipment _____ ____ ______ in order to avoid Microbiologically induced corrosion
A: Clean and dry Ref: API 571 4.3.8.6

263. Q: A combination of pigging, blasting, chemical cleaning and biocide treatment is useful in __________ __ _____________ __________
A: Mitigation of established organisms Ref: API 571 4.3.8.6

264. Q: Between UT, RT, MT, PT, which is mentioned in API 571 as a way to inspect for MIC?
A: None Ref: API 571 4.3.8.7

265. Q: Foul smelling water may be a sign of ___

A: Microbiologically induced corrosion MIC Ref: API 571 4.3.8.7

266. Q: What is the thickness of the lead symbol "B" that shall be attached to the back of each film holder during each exposure to determine if backscatter radiation is exposing the film?
A: 1/16 Ref: T-223 ASME V

267. Q: If a densitometer is not used, what shall be used instead for judging film density?
A: A step wedge Ref: T-225 ASME V

268. Q: If a step wedge is not used, what shall be used instead for judging film density?
A: A densitometer Ref: T-225 ASME V

269. Q: Wire-type IQIs shall be manufactured and identified in accordance with the requirements of
A: SE-747 Ref: T-233.1 ASME V

270. Q: Hole-type IQIs shall be manufactured and identified in accordance with the requirements of
A: SE-1025 Ref: T-233.1 ASME V

271. Q: Which standard is used for calibration step tablets to be used in United States?
A: NIST Ref: T-262.1 ASME V

272. Q: Densitometers shall be calibrated at least every ___ days during use
A: 90 Ref: T-262.1 ASME V

273. Q: How many steps minimum shall a national standard step tablet used for densitometer calibration have?
A: 5 Ref: T-262.1 ASME V

274. Q: Neutral densities of any national step tablet used for densitometer calibration should be between 1 and ___
A: 4 Ref: T-262.1 ASME V

275. Q: Neutral densities of any national step tablet used for densitometer calibration should be between ___ and 4
A: 1 Ref: T-262.1 ASME V

276. Q: The densitometer used for film evaluation is acceptable if the density readings do not vary by more than _____ density units from the actual density stated on the national standard step tablet or step wedge calibration film
A: 0.05 Ref: T-262.1 ASME V

277. Q: Step wedge comparison films shall be verified ____________________
A: Prior to first use Ref: T-262.2 ASME V

278. Q: The step wedge comparison film is acceptable if the density readings do not vary by more than ___ density units from the density stated on the step wedge comparison film
A: 0.01 Ref: T-262.2 ASME V

279. Q: The density of the steps on a step wedge comparison film shall be verified by ______________________________
A: a calibrated densitometer Ref: T-262.2 ASME V

280. Q: Periodic calibration verification of densitometers shall be performed at the beginning of each shift, after 8hr of continuous use, or ____, whichever comes first

A: after change of apertures — Ref: T-262.3 ASME V

281. Q: Periodic calibration verification of densitometers shall be performed at the beginning of each shift, after ________________________________, or after change of apertures, whichever comes first

A: 8hr of continuous use — Ref: T-262.3 ASME V

282. Q: Periodic calibration verification of densitometers shall be performed at ____, after 8hr of continuous use, or after change of apertures, whichever comes first

A: the beginning of each shift — Ref: T-262.3 ASME V

283. Q: Periodic densitometer verification needs to be documented. True or false?

A: False — Ref: T-262.4 ASME V

284. Q: Location markers shall be placed on __________________

A: The part — Ref: T-275 ASME V

285. Q: Maximum value for geometric unsharpness in a film used to evaluate a material under 2 inches thick

A: 0.020 in — Ref: T-274.2 ASME V

286. Q: If an IQI is going to be used on a weld with a reinforcement, the thickness on which the IQI is based is ___________________________________

A: the nominal single-wall thickness plus the estimated weld reinforcement — Ref: T-276.ASME V

287. Q: The transmitted film density trough the radiographic image of the body of the designated hole-type IQI adjacent to the essential hole or adjacent to the essential wire of a wire-type IQI and the area of interest shall be ___ minimum for radiographs made with an X-ray source

A: 1.8 Ref: T-282.1 ASME V

288. Q: The transmitted film density trough the radiographic image of the body of the designated hole-type IQI adjacent to the essential hole or adjacent to the essential wire of a wire-type IQI and the area of interest shall be ___ minimum for radiographs made with a gamma ray source

A: 2.0 Ref: T-282.1 ASME V

289. Q: The maximum density in a radiographic image shall be ____

A: 4 Ref: T-282.1 ASME V

290. Q: For composite viewing of multiple film exposures, each film of the composite set shall have a minimum density of ___

A: 1.3 Ref: T-282.1 ASME V

291. Q: The density of the radiograph anywhere through the area of interest shall not vary vs the density of the essential IQI component in which way?

A: vary more than minus 15% or plus 30% from the density through the body of the designated hole-type IQI adjacent to the essential hole or adjacent to the essential wire of a wire-type IQI Ref: T-282.2 ASME V

293. Q: When a radiograph has areas with density variation of more than minus 15% or plus 30% from the essential hole or wire, what should be done?

A: an additional IQI shall be used for each exceptional area and the radiography retaken Ref: T-282.2 ASME V

294. Q: Material thickness for recommended geometric unsharpness limitation is based in ____________________________
A: The thickness on which the IQI is based   Ref: T-274.2 ASME V

295. Q: Source size verification can be made by ____________________
A: checking the equipment manufacturer´s or supplier´s publications, documenting actual or maximum source size or focal spot   Ref: T-261.1 ASME V

296. Q: Maximum weld reinforcement for a weld to be radiographed in 3/8 inch plate according to API 650
A: 1.5mm (1/16")   Ref: 8.1.3.4 API 650

297. Q: Definition of inspection
A: the observation of any operation performed on materials and/or components to determine its acceptability in accordance with given criteria   Ref: I-130 ASME V

298. Q: The term inspection applies to
A: the functions performed to the Authorized inspector   Ref: T-170 ASME V

299. Q: Examination applies to
A: those quality control functions performed by personnel employed by the manufacturer   Ref: T-170 ASME V

300. Q: Which section of the ASME BPVC code contains requirements and methods for nondestructive examination
A: ASME V

301. Q: The employer´s written practice for NDE personnel qualification must be in accordance with which ANSI standard?
A: ANSI/ASNT CP-189   Ref: T-120 ASME V

302. Q: How many copies of each NDE procedure shall be available to the NDE personnel?
A: 1 Ref: T-150 ASME V

303. Q: All nondestructive examination procedures shall be ____________________________
A: demonstrated to the satisfaction of the Inspector Ref: T-150 ASME V

304. Q: When qualification of the written NDE procedure is needed, it shall be demonstrated
A: on a minimum of one test specimen having flaws whose size, location, orientation, quantity and carachterization have been determined prior to the demonstration and are known only by the supervising Level III Examiner, by a Level II or Level III, under observation of the supervising Level III Ref: T-150 ASME V

305. Q: Who must sign the procedure qualification record of NDE examinations?
A: The supervising level III and the witnessing Inspector Ref: T-150 ASME V

306. Q: Non Destructive Examination is
A: the development and application of technical methods to examine materials in ways that do not impair future usefulness and serviceability, in order to detect, locate, measure, interpret and evaluate flaws Ref: I-130 ASME V

307. Q: Indication is
A: the response or evidence from a NDE that requires interpretation to determine relevance Ref: I-130 ASME V

308. Q: At least how many steps national standard step tablets or step wedge calibration films should have?
A: 5 Ref: T-262.1 ASME V

309. Q: A lead letter F shall be used in a radiography when:
A: the IQI is placed in the film side Ref: T-277.1 ASME V

310. Q: What is the minimum amount of IQIs that shall appear in any radiographic film?
A: 1 minimum Ref: T-277.2 ASME V

311. Q: Who is responsible for the review, interpretation, evaluation and acceptance of the completed radiographs to assure compliance with the requirements of article 2 of ASME V?
A: The manufacturer Ref: T-285 ASME V

312. Q: The radiographic review form required by T-292 shall be completed
A: during evaluation Ref: T-285 ASME V

The following questions correspond to ASME V, Article 23, SE-797

313. Q: Article 23, SE-797, provides guidelines for measuring the thickness of materials using the contact pulse-echo method at temperatures not to exceed ____
A: 93°C (200°F) Ref: ASME V, Article 23

314. Q: Which condition must be met in regard to wave speed of ultrasonic pulses in any material to be inside SE-797´s scope?
A: Constant velocity Ref: ASME V, Article 23

315. Q: Which ultrasound technique is considered in SE-797?
A: Pulse-echo method Ref: ASME V, Article 23

316. Q: Which types of display elements exists for ultrasonic instruments? _________________________
A: A-scan display, meter or digital display Ref: ASME V, Article 23

317. Q: Ultrasonic measurements in the pulse echo-technique are made from both sides of the object. True/False___________
A: False Ref: ASME V, Article 23

318. Q: Regarding surface for ultrasonic examination, which condition shall be specified in the contractual agreement?
A: Surface preparation Ref: ASME V, Article 23

319. Q: Besides 1) Flaw detectors with an A-scan display readout, 2) Flaw detectors with an A-scan display and direct thickness readout and [...], which other thickness-measurement instrument group exists?
A: Direct thickness readout Ref: ASME V, Article 23

320. Q: Besides 1) Flaw detectors with an A-scan display readout, [...] and 3) Direct thickness readout, which other thickness-measurement instrument group exists?
A: Flaw detectors with an A-scan display and direct thickness readout Ref: ASME V, Article 23

321. Q: Besides [...], 2) Flaw detectors with an A-scan display and direct thickness readout and 3) Direct thickness readout, which other thickness-measurement instrument group exists?
A: Flaw detectors with an A-scan display readout Ref: ASME V, Article 23

322. Q: Thickness, when measured by the pulse-echo ultrasonic method, is a product of velocity of sound x ________________________________
A: one half the transit time through the material Ref: ASME V, Article 23

323. Q: How many items, according to Article 23, SE-797, are subject to contractual agreement between the parties?
A: 4 Ref: ASME V, Article 23

324. These are the 4 items that need to be subject to contractual agreement according to SE-797 1) __________, 2) Qualification of Nondestructive Agencies, 3) Procedures and techniques, 4) Surface preparation
Personnel Qualification Ref: ASME V, Article 23

325. Q: These are the 4 items that need to be subject to contractual agreement according to SE-797 1) Personnel qualification, 2) __________, 3) Procedures and techniques, 4) Surface preparation
A: Qualification of Nondestructive Agencies Ref: ASME V, Article 23

326. Q: These are the 4 items that need to be subject to contractual agreement according to SE-797 1) Personnel qualification, 2) Qualification of Nondestructive Agencies, 3) __________,4) Surface preparation
A: Procedures and techniques Ref: ASME V, Article 23

327. Q: These are the 4 items that need to be subject to contractual agreement according to SE-797 1) Personnel qualification, 2) Qualification of Nondestructive Agencies, 3) Procedures and techniques, 4) __________
A: Surface preparation Ref: ASME V, Article 23

328. Q: For thicknesses less than about 0.6mm, what is the minimum frequency of the delay line search unit?
A: 10MHz or higher Ref: ASME V, Article 23

329. Q: Highest accuracy for ultrasonic examination can be obtained from materials with ____________ or ____________ surfaces
A: parallel or concentric Ref: ASME V, Article 23

330. Q: The apparent ultrasonic thickness measurement reading obtained from steel walls having elevated temperatures is high by a factor of about ___% per 55°C
A: 1 Ref: ASME V, Article 23

331. Q: The apparent ultrasonic thickness measurement reading obtained from steel walls having elevated temperatures is high by a factor of about 1% per ____ °C
A: 55 Ref: ASME V, Article 23

The following questions correspond to SOIL CORROSION

332. Q: What is the name of the damage mechanism present when there is deterioration of metals exposed to soils?
A: Soil corrosion Ref: API 571 4.3.9

333. Q: API 571 lists 3 affected materials that suffer soil corrosion. Besides carbon steel and cast iron, it also affects _______________
A: Ductile iron Ref: API 571 4.3.9

334. Q: API 571 lists 3 affected materials that suffer soil corrosion. Besides carbon steel and ductile iron, it also affects _______________
A: Cast iron Ref: API 571 4.3.9

335. Q: API 571 lists 3 affected materials that suffer soil corrosion. Besides carbon steel and cast iron, it also affects _______________
A: Carbon steel Ref: API 571 4.3.9

336. Q: Which parameter is frequently used to estimate soil corrosivity?

A: Soil resistivity Ref: API 571 4.3.9

337. Q: When there is soil corrosion, is there a correlation between corrosion rate and temperature?
A: Yes, there is more corrosion the higher the temperature Ref: API 571 4.3.9

338. Q: Name the damage mechanism that affects underground piping and equipment as well as buried tanks, the bottoms of above ground storage tanks, and ground supported metal structures.
A: Soil corrosion Ref: API 571 4.3.9

339. Q: Where is soil corrosion more likely?
A: At the soil-to-air interface Ref: API 571 4.3.9

340. Q: What is the appearance of soil corrosion?
A: external thinning with localized losses due to pitting Ref: API 571 4.3.9

341. Q: Soil corrosion of carbon steel can be minimized through the use of ____________, coatings and cathodic protection.
A: Special backfill Ref: API 571 4.3.9

342. Q: Soil corrosion of carbon steel can be minimized through the use of special backfill, __________ and cathodic protection.
A: Coatings Ref: API 571 4.3.9

343. Q: Soil corrosion of carbon steel can be minimized through the use of special backfill, coatings and ___________________
A: Cathodic Protection Ref: API 571 4.3.9

344. Q: The most effective protection against soil corrosion is ________________
A: a combination of a corrosion resistant coating and a cathodic protection system. Ref: API 571 4.3.9

345. Q: The most common method used for monitoring underground structures against soil corrosion is _______________
A: measuring the structure to soil potential using dedicated reference electrodes near the structure Ref: API 571 4.3.9

345. Q: Cathodic protection to reduce soil corrosion should be performed and monitored in accordance with which RP?
A: NACE RP 0169 Ref: API 571 4.3.9

347. Q: To estimate the probability of soil corrosion, several characteristics must be combined to estimate the corrosion in particular soil as outlined in __________ as well as API RP 580 and Publ 581.
A: ASTM STP 741 Ref: API 571 4.3.9

348. Q: To estimate the probability of soil corrosion, several characteristics must be combined to estimate the corrosion in particular soil as outlined in ASTM STP 741 as well as ___________ and Publ 581.
A: API RP 580 Ref: API 571 4.3.9

349. Q: To estimate the probability of soil corrosion, several characteristics must be combined to estimate the corrosion in particular soil as outlined in ASTM STP 741 as well as API RP 580 and _____________.
A: Publ 581 Ref: API 571 4.3.9

350. Q: Poor condition of a protective coating in a buried or ground supported structure is a telltale sign of potential __________ damage
A: Soil corrosion Ref: API 571 4.3.9

The following questions correspond to CAUSTIC CORROSION

351. Q: Caustic corrosion usually occurs under _____________________ or high heat transfer conditions.

A: Evaporative Ref: API 571 4.3.10

352. Q: Caustic corrosion usually occurs under evaporative or __________ conditions.
A: high heat transfer Ref: API 571 4.3.10

353. Q: Caustic corrosion mostly creates localized corrosion, but can cause general corrosion depending on ____________________
A: Caustic solution strength. Ref: API 571 4.3.10

354. Q: Caustic corrosion affects primarily _______________, low alloy steels and 300 Series SS.
A: Carbon steels Ref: API 571 4.3.10

355. Q: Caustic corrosion affects primarily carbon steel, ______________ and 300 Series SS.
A: Low alloy steels Ref: API 571 4.3.10

356. Q: Caustic corrosion affects primarily carbon steel, low alloy steels and _________________.
A: 300 series SS Ref: API 571 4.3.10

357. Q: Which damage mechanisms are mostly associated with the presence of NaOH?
A: Caustic corrosion and Caustic Stress Corrosion Cracking Ref: API 571 4.3.10

358. Q: Which damage mechanisms are mostly associated with the presence of KOH?
A: Caustic corrosion and Caustic Stress Corrosion Cracking Ref: API 571 4.3.10

359. Q: Caustic corrosion is most often associated with ______ and steam generating equipment including heat exchangers.
A: boilers Ref: API 571 4.3.10

360. Q: Caustic corrosion is most often associated with boilers and steam generating equipment including ________________
A: Heat exchangers Ref: API 571 4.3.10

361. Q: The concentrating effects of caustic may occur ____________
A: where caustic is added to crude unit charge Ref: API 571 4.3.10

362. Q: Preheat exchangers, furnace tubes and transfer lines can suffer __________________________________ related to caustic corrosion
A: Accelerated localized corrosion Ref: API 571 4.3.10

363. Q: How can you avoid caustic accelerated localized corrosion in preheat exchangers, furnace tubes and transfer lines
A: Achieving effective mixture in the oil stream Ref: API 571 4.3.10

364. Q: To remove sulfur compounds from product streams you can use
A: Caustic products Ref: API 571 4.3.10

365. Q: Caustic corrosion in a boiler tube appears as
A: Localized metal loss that may appear as grooves Ref: API 571 4.3.10

366. Q: Caustic corrosion is typically characterized by localized metal loss which may appear as grooves in a boiler tube or _____ ___________________ _________
A: Locally thinned areas under insulating deposits Ref: API 571 4.3.10

367. Q: You would use a sharp instrument to probe suspect areas of ________________, because it generates deposits that may fill corroded depressions
A: Caustic corrosion Ref: API 571 4.3.10

368. Q: In a vertical tube, caustic corrosion can appear as ___________________
A: A circumferential groove Ref: API 571 4.3.10

369. Q: Along a waterline, caustic corrosion causes

A: Localized gouging Ref: API 571 4.3.10

370. Q: In horizontal tubes, caustic corrosion can appear as ________________
A: grooves in opposite sides of the tube Ref: API 571 4.3.10

371. Q: In carbon steel, exposure to high solution strength caustic causes general corrosion, in temperatures between
A: 175°F and 200°F Ref: API 571 4.3.10

372. Q: In carbon steel, exposure to high solution strength caustic causes very high general corrosion rates, in temperatures above
A: 200°F Ref: API 571 4.3.10

373. Q: Which of the following best reduces caustic corrosion
A: Reducing the amount of free caustic inside the equipment Ref: API 571 4.3.10

374. Q: In process equipment, caustic injection facilities should be designed to allow
A: Proper mixing of caustic Ref: API 571 4.3.10

375. Q: Injection points should be inspected in accordance with ______
A: API 570 Ref: API 571 4.3.10

376. Q: For the detection of caustic corrosion, __________________ equipment may require visual inspection with the use of a boroscope
A: Steam generation Ref: API 571 4.3.10

377. Q: Which of the following is a good measure for reducing caustic corrosion in steam generating equipment
A: Minimizing the ingress of alkaline producing salts into condensers. Ref: API 571 4.3.10

378. Q: Carbon steel and 300 Series SS have serious corrosion problems in high strength caustic solutions above about
A: 150°F Ref: API 571 4.3.10

379. Q: Alloy 400 and some other _____ base alloys exhibit little caustic corrosion
A: Nickel Ref: API 571 4.3.10

380. Q: ________ and some other nickel base alloys exhibit little caustic corrosion
A: Alloy 400 Ref: API 571 4.3.10

381. Q: In steam generating equipment, caustic corrosion is best prevented
A: Through proper design Ref: API 571 4.3.10

382. Q: In steam generating equipment, which of the following actions can better prevent caustic corrosion?
A: Minimize hot spots on heater tubes Ref: API 571 4.3.10

383. Q: In process equipment, caustic injection facilities should be designed to
A: avoid the concentration of caustic on hot metal surfaces Ref: API 571 4.3.10