TUGAS AKHIR – ME 184834

ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

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BACHELOR THESIS – ME 184834

INSPECTION SCHEDULING PROGRAMS ANALYSIS OF AMINE REBOILER HEAT EXCHANGER USING RISK-BASED INSPECTION API 581 METHOD

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TUGAS AKHIR

Diajukan Untuk Memenuhi Salah Satu Syarat
Memperoleh Gelar Sarjana Teknik
pada
Bidang Studi Digital Marine Operation and Maintenance (DMOM)
Program Studi S-1 Departemen Teknik Sistem Perkapalan
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JULI, 2020

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ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

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ABSTRAK

Pada industri pengolahan minyak dan gas, untuk pemurnian dan pengolahan minyak dan gas bumi dibutuhkan proses penukaran kalor untuk memisahkan H_2S dan CO_2 dari gas alam dengan larutan amina. Proses tersebut terjadi di dalam *amine reboiler* yang merupakan *shell and tube heat exchanger.* Fluida proses yang mengalir pada *Amine Reboiler* memiliki komposisi kimia Air, CO_2, H_2S dan MDEA dengan pH 7.83 pada *shell side* (HEXSS) dan Therminol-55 pada *tube side* (HEXTS). Dengan komposisi kimia tersebut, ditambah dengan tekanan dan temperatur operasi yang tinggi, membuat fluida menjadi lingkungan yang korosif bagi *Amine Reboiler*. Sehingga diperlukan program inspeksi dan penjadwalan yang akurat untuk menjamin umur peralatan, memastikan instalasi aman dan keamanan pekerja. Oleh karena itu perlu untuk melakukan evaluasi risiko untuk peralatan *shell and tube heat exchanger* menggunakan metode Risk Based Inspection (RBI) yang mengacu pada API RP 581. Risiko *Amine Reboiler* merupakan kombinasi dari *Probability of Failure* (PoF) dan Consequence of Failure (CoF). Dari hasil analisis, nilai PoF pada saat RBI *date* yang didapatkan adalah sebesar 2.080E-03 untuk HEXSS dan 4.758E-03 untuk HEXTS. PoF pada saat RBI *plan date* didapatkn sebesar 4.646E-03 untuk HEXSS dan 8.454E-03 untuk HEXTS Sedangkan analisis CoF menunjukkan bahwa area yang terdampak apabila terjadi kerusakan adalah 4.56 m^2 untuk konsekuensi HEXSS dan \$218,675.43 untuk HEXTS. Dari PoF dan CoF yang didapatkan, level risiko HEXSS pada matriks risiko saat RBI *date* adalah 9.48E-03 m^2/tahun yang dikategorikan sebagai Low Risk dan saat RBI *plan date* 2.12E-02 03 m^2/tahun yang dikategorikan sebagai Medium Risk. Sedangkan level risiko HEXTS pada matriks risiko saat RBI date adalah 1040.49 \$/tahun yang dikategorikan sebagai Medium-High Risk dan saat RBI *plan date* adalah 1848.59 \$/tahun yang dikategorikan sebagai Medium-High Risk. Kemudian waktu yang disarankan untuk melaksanakan inspeksi adalah pada tanggal 1 Januari 2020.

Kata kunci: (RBI, Amine Reboiler, PoF, CoF, Risiko)

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INSPECTION SCHEDULING PROGRAMS ANALYSIS OF AMINE REBOILER HEAT EXCHANGER USING RISK-BASED INSPECTION API 581 METHOD

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ABSTRACT

In the oil and gas processing industry, for the purification and processing of oil and natural gas, the process of heat conversion is needed to separate the H_2S and CO_2 from natural gas with amine solution. The process takes place inside the amine reboiler which is a shell and tube heat exchanger. Process fluid flowing in the Amine Reboiler has the chemical composition of water, CO_2, H_2S, and MDEA with a pH of 7.83 on the shell side (HEXSS) and Therminol-55 on the tube side (HEXTS). With such chemical composition, operated with high pressure and temperature, makes the fluid into a corrosive environment for Amine Reboiler. Therefore, an accurate inspection and scheduling program is required to ensure equipment life, ensuring the safe installation and safety of workers. Therefore, it is necessary to conduct a risk evaluation for shell and tube heat exchanger equipment using the Risk-Based Inspection (RBI) method which refers to the API RP 581. The risk of Amine Reboiler is a combination of the Probability of Failure (PoF) and the Consequence of Failure (CoF). From the results of the analysis, the PoF value at the time of RBI date obtained is 2.080E-03 for HEXSS and 4.758E-03 for HEXTS. PoF at the RBI plan date is obtained at 4.646E-03 for HEXSS and 8.454E-03 for HEXTS. While the CoF analysis showed that the affected area in case of damage is 4.56 m^2 for the consequences of HEXSS and \$218,675.43 for HEXTS. From the PoF and CoF obtained, the HEXSS risk level on the risk matrix at the RBI date is 9.48E-03 m^2 / year is categorized as Low Risk and at RBI plan date is 2.12E-02 03 m^2 / year which is categorized as Medium Risk. While the risk level of HEXTS on risk matrix at RBI date is 1040.49 \$ / year which is categorized as Medium-High Risk and at RBI plan date is 1848.59 \$ / year which is categorized as Medium-High Risk. Then the recommended date to carry out the inspection is January 1, 2020.

Keywords: (RBI, Amine Reboiler, PoF, CoF, Risk)

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Penulis berharap bahwa tugas akhir ini dapat bermanfaat dan memberikan informasi kepada pembaca. Karena keterbatasan penulis, kritik dan saran yang membangun sangat diperlukan untuk kesempurnaan dalam tugas akhir ini

Surabaya, Juli 2020

Penulis

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DAFTAR ISI

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DAFTAR GAMBAR

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DAFTAR TABEL

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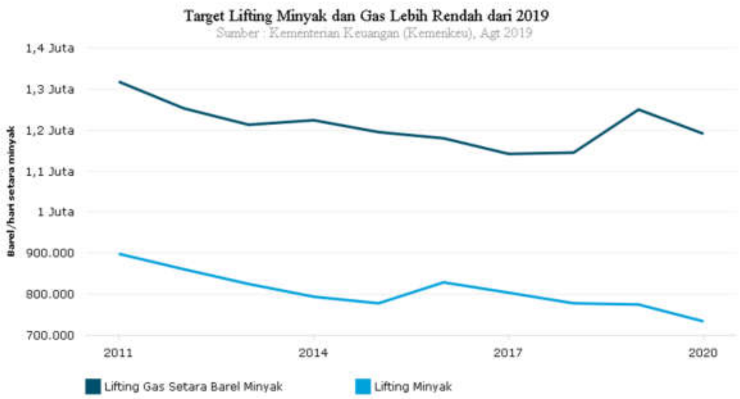
BAB 1
PENDAHULUAN

1.1 Latar Belakang

Industri pengolahan minyak dan gas bumi di Indonesia merupakan salah satu industri yang menyumbang hingga 215 triliun rupiah pada tahun 2018. Dimana pendapatan tersebut melampaui target yang ditetapkan sebesar 160.6 triliun rupiah dengan jumlah 800,000 barel per hari. Merujuk pada Gambar 1.1, di tahun 2020 pemerintah menargetkan untuk sektor migas memproduksi sebesar 734,000 barel minyak per hari dan produksi 1.19 juta barel setara minyak per hari (Kementerian Keuangan, 2019). Meskipun, saat ini masyarakat dunia sedang mengeksplorasi dan mengembangkan energi terbarukan, namun peran dari minyak dan gas bumi di dunia terutama di Indonesia tidak dapat diabaikan. Bahan bakar fosil tetap menjadi sumber energi yang penting bagi masyarakat Indonesia.



Gambar 1.1 Target Lifting Minyak dan Gas 2020
Sumber: Kementerian Keuangan, 2019

Salah satu peralatan penting yang digunakan dalam proses pengilangan pada pabrik pengolahan minyak dan gas bumi adalah *amine reboiler. Amine reboiler* merupakan *heat exchanger* jenis *shell and tube.* Alat ini berfungsi untuk menghilangkan hidrogen sulfida (H_2S) dan karbondioksida (CO_2) dari gas alam meggunakan larutan amina. *Amine reboiler* adalah item yang sangat penting dikarenakan bekerja pada tekanan dan temperatur yang tinggi dengan fluida yang mudah meledak. Apabila terjadi kegagalan, maka akan menyebabkan sistem *shutdown* dan membahayakan lingkungan sekitar hingga karyawan yang bekerja di sekitarnya (Ramesh, *et al*., 2003).

Contoh peristiwa ledakan di industri minyak dan gas yang disebabkan oleh *heat exchanger* gagal bekerja adalah peristiwa ledakan di Tesoro Refinery Anacortes, Washington pada tanggal 2 April 2010. Dari peristiwa tersebut, tujuh karyawan meninggal dunia. Berdasarkan laporan investigasi, ditemukan bahwa penyebab ledakan adalah *shell and tube heat exchanger* yang sudah beroperasi selama 38 tahun (CSB, 2014). Dua *heat exchanger* yang saling berdekatan pecah (ruptured). Penyebab pecahnya *heat exchanger* adalah *High Temperature Hydrogen Attack* (HTHA) yang terjadi dikarenakan material terpapar hydrogen pada temperatur dan tekanan tinggi. HTHA mengakibatkan material dari *heat exchanger* (carbon steel) mengalami retak (fracture) di area *heat affected zone* pengelasan. Ledakan terjadi di bagian *shell* dan menyebabkan hydrogen dan naphtha dengan suhu lebih dari 500°F keluar ke atmosfer dimana kedua gas tersebut akan langsung tersulut sesaat setelah kontak dengan udara di sekitarnya (CSB, 2014).

Oleh karena itu, industri pengolahan minyak dan gas bumi merupakan salah satu industri yang memerlukan perhatian yang cukup ketat dalam hal keselamatan. Salah satu contoh aturan mengenai pengelolaan minyak bumi adalah Peraturan Pemerintah No. 11 Tahun 1979 yang mengontrol keselamatan kerja di perumahan dan pemrosesan minyak dan gas harus dipatuhi. Selanjutnya, berdasarkan Peraturan Menteri Energi dan Sumber Daya Mineral (ESDM) No. 18 Tahun 2018 menunjukkan bahwa peralatan yang dipasang di pabrik gas harus melakukan inspeksi baik berdasarkan inspeksi waktu atau pencegahan. Menurut revisi terbaru Pedoman Tata Kerja (PTK)-041 SKK Migas Indonesia tentang pemeliharaan fasilitas produksi minyak dan gas dengan menerapkan inspeksi terjadwal dan pemeliharaan terencana.

Untuk memenuhi peraturan terkait industri minyak dan gas serta mengurangi risiko terjadinya kerusakan yang terjadi pada *amine reboiler* adalah dengan melakukan analisa risiko dan melaksanakan inspeksi secara terjadwal. Salah satu metode pendekatan dalam menentukan interval inspeksi dan jenis inspeksi adalah *Risk Based Inspection* (RBI). Metode RBI mendefinisikan risiko sebagai hasil kombinasi antara nilai peluang terjadinya kegagalan (Probability of Failure) dan konsekuensi yang diterima saat terjadi kegagalan (Consequence of Failure) (API RP 580, 2016). Metode RBI digunakan karena metode inspeksi berdasarkan waktu sudah tidak relevan digunakan sebagai kontrol kualitas. Hal ini disebabkan karena setiap peralatan memiliki masalah yang berbeda dan berubah terhadap waktu, sehingga penurunan kualitas dari peralatan tidak dapat diprediksi secara tepat (Murariu dan Pasca, 2013). Perencanaan inspeksi pada metode RBI difokuskan untuk mengklasifikasikan apa yang harus dilakukan saat inspeksi, metode inspeksi, lokasi inspeksi dan interval inspeksi yang tepat (Priyanta, *et al,* 2017).

1.2 Rumusan Masalah

Berdasarkan uraian di atas, permasalahan utama yang akan dianalisa adalah sebagai berikut:

1. Bagaimana cara menghitung *Probability of Failure* (POF) dan *Conseuence of Failure* (COF) pada *amine reboiler heat exchanger* menggunakan metode Risk-Based Inspection?
2. Bagaimana menentukan level risiko pada *amine reboiler heat exchanger* dengan menggunakan metode Risk-Based Inspection?
3. Bagaimana menentukan perencanaan inspeksi yang tepat pada *amine reboiler heat exchanger* menggunakan metode Risk-Based Inspection?

1.3 Batasan Masalah

Batasan masalah pada penelitian ini adalah:

1. *Heat exchanger* yang akan dilakukan analisa adalah tipe *shell and tube* untuk *equipment amine reboiler*.
2. Analisa risiko pada penelitian ini berpedoman pada *code* API RP 581.
3. Bencana alam tidak dimasukkan dalam perhitungan.

1.4 Tujuan Penelitian

Tujuan dilakukannya analisa pada penulisan tugas akhir ini adalah:

1. Menentukan *Probability of Failure* (POF) dan *Conseuence of Failure* (COF) pada *amine reboiler heat exchanger* berdasarkan metode Risk-Based Inspection (RBI).
2. Memberikan informasi analisa level risiko dari *amine reboiler heat exchanger* berdasarkan metode RBI.
3. Memberikan informasi mengenai metode inspeksi dan penjadwalan inspeksi yang sesuai pada *amine reboiler heat exchanger* menggunakan metode RBI berdasarkan American Petroleum Institution (API) 581.

1.5 Manfaat Penelitian

Manfaat yang dapat diperoleh dari hasil penelitian tugas akhir ini adalah:

1. Memberikan informasi mengenai risiko yang akan berpengaruh pada *amine reboiler heat exchanger* sehingga kemungkinan terjadinya kegagalan dapat dikurangi.
2. Menjadi bahan pertimbangan untuk menentukan prioriatas pelaksanaan inspeksi berdasarkan informasi level risiko
3. Menjadi bahan pertimbangan bagi perusahaan untuk menerapkan jenis program inspeksi yang tepat dan penjadwalan inspeksi *amine reboiler heat exchanger* di fasilitas Central Processing Plant (CPP).

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BAB 2
KAJIAN PUSTAKA

2.1 Kajian Penelitian Terkait

Tesoro Refinery Anacortes Industry adalah perusahaan yang bergerak dibidang eksplorasi dan produksi minyak dan gas. Tesoro Refinery Anacortes Industry merupakan penyuplai utama untuk produk *gasoline, jet fuel* dan diesel di Washington dan Oregon. Produk lain yang dihasilkan oleh perusahaan ini adalah *heavy fuel oils, liquefied petroleum gas* dan aspal.

Pada tanggal 2 April tahun 2010, terjadi sebuah ledakan dan kebakaran yang menewaskan tujuh karyawan di Tesoro Refinery Anacortes, Washington. Berdasarkan laporan investigasi, ditemukan bahwa penyebab ledakan adalah dua unit *shell and tube heat exchanger* yang saling berdekatan dan telah beroperasi selama 38 tahun.

Diketahui bahwa selama proses produksi, *heat exchanger* A/B/C dan D/E/F semuanya dioperasikan. Selama proses produksi, akan terjadi *fouling* di dalam *heat exchanger. Foul* akan menghambat perpindahan panas di dalam *heat exchanger* sehingga mengurangi efisiensi perpindahan panas. Oleh karena itu, dibutuhkan pembersihan setiap enam bulan sehingga efisiensi perpindahan panas dapat dipertahankan. Saat melakukan proses pembersihan, satu *bank heat exchanger* akan diambil dan dibersihkan sementara *bank heat exchanger* lainnya akan terus beroperasi. Setelah proses pembersihan, *heat exchanger* akan dipasang kembali lalu dilakukan proses *start-up* dengan memasukkan memasukkan naphta panas dan hydrogen secara perlahan ke dalam unit.

Pada saat proses *start-up heat exchanger A/B/C,* terjadi dua kebocoran. Namun proses *start-up* tidak dihentikan karena berdasarkan histori laporan perawatan, kebocoran pada saat proses pemasangan dan *start-up heat exchanger* sering terjadi sehingga dianggap normal. Kebocoran diperkirakan akan berhenti ketika *heat exchanger* mencapai temperature operasi. Ketika proses *start-up heat exchanger A/B/C* sedang berlangsung, *heat exchanger E* yang sedang beroperasi secara normal tiba-tiba pecah.

Diketahui penyebab pecahnya *heat exchanger* adalah *High Temperature Hydrogen Attack* (HTHA) yang terjadi dikarenakan material terpapar hydrogen pada temperatur dan tekanan tinggi. HTHA timbul ketika hydrogen berdifusi ke dalam dinding *heat exchanger*. Hydrogen bereaksi dengan karbon pada material *carbon steel*, menghasilkan gas metana. Reaksi ini disebut sebagai dekarburasi dan menghilangkan karbon dari material *carbon steel.* Semakin banyak gas metana terbentuk, tekanan metana akan meningkat dan dapat membentuk celah pada dinding material dari *heat exchanger*. Seiring dengan tekanan yang diterima, maka celah akan terhubung membentuk *microcracks* yang selanjutnya membentuk retakan lebih besar dan menyebabkan pecahnya *heat exchanger* di area *heat affected zone* pengelasan. Ledakan terjadi di bagian *shell* dan menyebabkan hydrogen dan naphtha dengan suhu lebih dari 500°F keluar ke atmosfer dimana kedua gas tersebut akan langsung tersulut sesaat setelah kontak dengan udara di sekitarnya.

Setelah dilakukan simulasi yang disesuaikan dengan kondisi operasional *heat exchanger,* hasilnya menunjukkan bahwa *heat exchanger* yang mengalami *rupture* diperkirakan telah beroperasi di bawah kurva Nelson yang berlaku. Kurva Nelson digunakan untuk memprediksi terjadinya HTHA pada berbagai material berdasarkan temperature operasi dan tekanan parsial hydrogen. Material *carbon steel* merupakan material yang paling rentan terhadap HTHA. Semakin tinggi temperatur operasi akan meningkatkan kemungkinan munculnya HTHA.

Dalam laporan investigasi US Chemical Safety Board (CSB) yang dirilis pada Mei 2014, memberikan rekomendasi bahwa tidak diperbolehkan untuk penggunaan material *carbon steel* pada unit yang beroperasi di atas 400°F dan tekanan parsial hydrogen lebih dari 50 psia (CSB,2014).

CSB juga memberikan rekomendasi untuk jenis inspeksi yang dilakukan. Non-destrcutive examination (NDE) adalah pemeriksaan visual yang dapat memberikan informasi mengenai kerusakan fisik seperti penyok, retak, perubahan warna atau korosi. Teknik-teknik NDE meliputi:

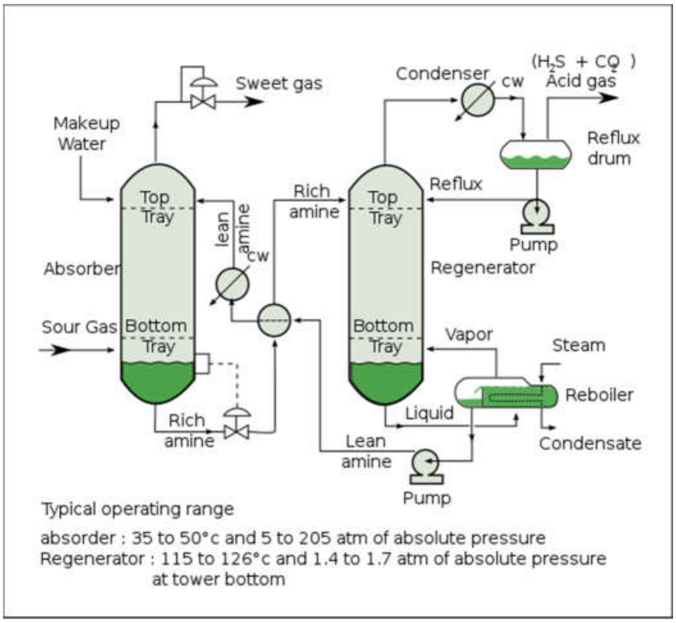
- *Ultrasonic Technique (UT)*
- *Radiographic Technique (RT)*
- *Dye Penetrant Inspection (DPI)*
- *Magnetic Particle (MT)*
- *Ultrasonic Shear Wave (Angled Beam Ultrasonic Technique)*
- *Phased Array Ultrasonic Technology (PAUT)*
- *Advanced Ultrasonic Backscatter Technique (AUBT)*

2.2 Proses *Gas Sweetening*

Pada industri pengolahan minyak dan gas, terutama dalam mengolah gas alam yang didapatkan, pabrik perlu dilengkapi dengan *sweetening unit* untuk melakukan proses *gas sweetening.* Proses penghilangan zat-zat yang mengandung asam pada gas alam menggunakan larutan pengabsorpsi disebut sebagai proses *gas sweetening*. *Gas sweetening* diperlukan karena zat yang mengandung asam bersifat korosif bagi logam.

Pada penelitian ini, proses *gas sweetening* menggunakan metode *chemical absorption,* yaitu amina untuk menghilangkan hidrogen sulfida (H_2S) dan/atau karbondioksida (CO_2) dari gas alam. Jenis larutan amina yang digunakan dapat disesuaikan dengan komposisi gas dan kondisi operasi. Larutan amina dikategorikan menjadi primer, sekunder dan tersier amine. Amine primer akan bereaksi secara langsung dengan H_2S, CO_2 dan karbonil sulfida (COS) yaitu Monoethanolamine (MEA) dan Diglycolamine (DGA). Amine sekunder bereaksi langsung dengan H_2S, CO_2 dan sebagian gas COS yaitu diisopropanolamine (DIPA). Amine tersier bereaksi langsung dengan H_2S yaitu yaitu Triethanolamine (TEA) dan Methyldiethanolamine (MDEA).

Proses *sweetening gas* secara umum dapat dilihat pada Gambar 2.1, dimana untuk menghilangkan zat asam digunakan reaktan amine. Proses diawali dengan *feed gas* atau gas yang mengandung H_2S dan CO_2 masuk melalui bagian *bottom absorber.* Sementara itu, larutan pengabsorpsi dimana dalam penelitian ini adalah larutan amina, akan masuk dari bagian *top absorber.* Di dalam *absorber* akan terjadi reaksi kimia antara larutan amina dengan *feed gas* sehingga larutan amina tersebut dapat mengabsorpsi zat asam dalam gas. Selama reaksi kimia berlangsung, kalor yang dihasilkan akan menyebabkan temperatur gas akan naik. *Treated gas* yang sedikit mengandung gas asam keluar dari *top absorber.* Sedangkan larutan amina yang kaya akan gas asam atau disebut sebagai *rich solvent* akan keluar dari *bottom absorber.*



Gambar 2.1 *Shell and Tube Heat Exchanger*
Sumber: Saeid, et al., 2006

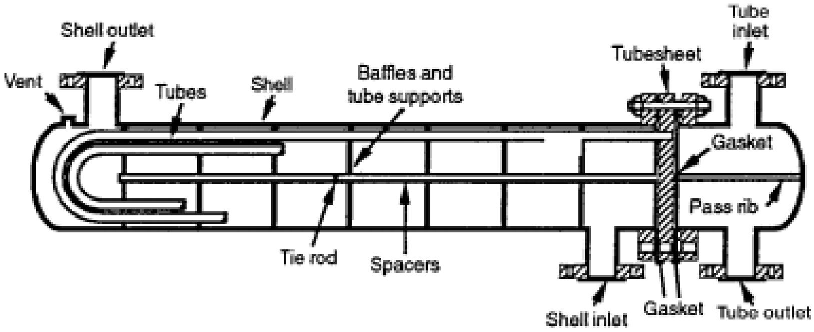
Rich solvent kemudian ditransfer menuju *flash vessel. Flash vessel* berfungsi untuk menguapkan hidrokarbon yang terikut dalam proses absorbsi. Hidrokarbon dihilangkan, karena senyawa tersebut dapat menyebabkan peristiwa terbentuknya busa (*foaming*) pada larutan amina dan mengganggu proses absorbsi. Setelah *rich solvent* melalui *flash vessel,* selanjutnya akan dilakukan *pre-heating* dengan *lean-rich heat exchanger,* dimana media yang menjadi pemanas adalah larutan amina yang mengandung sedikit zat asam (*lean solvent*) yang dialirkan dari regenerator.

Setelah *rich solvent* dipanaskan, larutan kemudian masuk ke regenerator. Regenerator berfungsi menghasilkan *lean solvent* yang bsia digunakan kembali untuk proses absorbsi. Pada regenerator, terdapat *heat exchanger* jenis *shell and tube* yang disebut sebagai *reboiler. Reboiler* berfungsi untuk menguapkan air yang terkandung di dalam larutan amina. Pada regenerator, zat asam yang terkandung dalam *rich solvent* diproses sehingga didapatkan *lean solvent.* Setelah itu, *lean solvent* digunakan kembali dalam proses absorbsi.

2.3 Shell and Tube Heat Exchanger

Pressure vessel memiliki beragam jenis desain bentuk. Dapat berupa silinder, *spherical, spheroidal, boxed* atau *lobed. Cylindrical pressure vessel* dapat berupa penukar panas dan kondensor baik didesain secara vertical maupun horizontal (API RP 572, 2001).

Heat exchanger atau dalam Bahasa Indonesia disebut sebagai penukar panas merupakan alat yang digunakan untuk menghasilkan proses pepindahan panas antara dua atau lebih fluida yang memiliki perbedaan temperatur. Selain itu, *heat exchanger* juga dapat berfungsi sebagai alat untuk menguapkan fluida, pembangkit daya, menkondensasikan uap, memanfaatkan panas buang dan memperoleh aliran fluida pada temperatur yang tepat untuk proses selanjutnya.



Gambar 2.2 *Shell and Tube Heat Exchanger*
Sumber: Ramesh, et al., 2003

Berdasarkan jenis fluida yang digunakan, *heat exchanger* terbagi menjadi dua, yaitu dengan media udara atau fluida cair. Untuk *heat exchanger* dengan media udara disebut sebagai *finfan*. Sedangkan *heat exchanger* yang menggunakan fluida cair berdasarkan konstruksinya terbagi menjadi dua jenis, yaitu jenis *shell and tube* dan jenis *plate.* Seperti yang ditunjukkan pada Gambar 2.2, *Shell and tube heat exchanger* terdiri dari sebuah *shell* yaitu tabung atau silinder besar dimana didalamnya terdapat suatu kumpulan pipa (tube) dengan diameter yang relatif kecil. Satu jenis fluida mengalir di dalam pipa-pipa sedangkan fluida lainnya mengalir diluar pipa tetapi masih didalam *shell*.

2.3.1 Komponen Utama Shell and Tube Heat Exchanger

2.3.1.1 Shell

Konstruksi *shell* sangat ditentukan oleh kapasitas dan keadaan *tubes* yang akan ditempatkan didalamnya. *Shell* ini dapat dibuat dari pipa yang berukuran besar atau pelat baja yang dirol. *Shell* merupakan badan dari alat penukar kalor, dimana terdapat *tube bundle*.

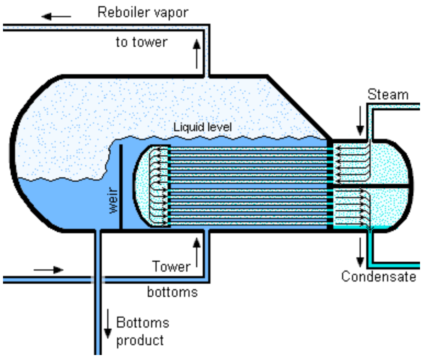
2.3.1.2 Tube

Tube merupakan bidang pemisah antara dua fluida yang mengalir, dan sekaligus sebagai bidang perpindahan panas. Pada umumnya aliran fluida yang mengalir di dalam *tube* lebih kecil dibandingkan dengan aliran fluida yang mengalir di dalam *shell*. Ketebalan dan material *tube* harus dipilih berdasarkan tekanan operasi dan jenis fluidanya. Agar tidak mudah bocor dan korosi akibat aliran fluida yang mengalir di dalam *tube*.

2.4 Amine Reboiler

Pada industri minyak dan gas, dalam proses pemurnian gas alam dan minyak mentah, gas yang memiliki sifat korosif yaitu hidrogen sulfida (H_2S) dan karbon dioksida (CO_2) harus dihilangkan dari aliran hidrokarbon sebelum masing-masing bahan bakar dapat disimpan atau dialirkan pada *pipeline*.

Gas tersebut merupakan gas yang bersifat asam, senyawa yang dihasilkan bergantung pada lokasi sumur atau lokasi sumber fluida. Untuk toleransi maksimum dari senyawa yang terdapat pada hasil pemurnian gas diatur oleh pemerintah. Untuk menghilangkan gas asam tersebut, dilakukan pemurnian dengan senyawa amina yang akan menyerap H_2S dan CO_2.



Gambar 2.3 *Reboiler Heat Exchanger*
Sumber: Fadilah, 2012

Dalam proses pengolahan gas amina, *reboiler* berfungsi sebagai alat untuk mendidihkan kembali (reboil) serta menguapkan sebagian cairan yang diproses (Saeid, *et al.,* 2006). *Reboiler* dapat dilihat dari Gambar 2.3. Adapaun media pemanas yang sering digunakan adalah uap atau zat panas yang sedang diproses itu sendiri. Dalam penelitian ini media yang digunakan adalah larutan amina.

Aliran dari larutan amina perlu untuk dipanaskan sampai suhu tertentu agar amina dapat bekerja untuk menghilangkan gas asam tanpa perlu memanaskan gas alam atau minyak mentah. Namun larutan amina yang terlalu panas akan menyebabkan penurunan kualitas amina sehingga amina tidak dapat menyerap gas asam dan air dengan sempurna. Menggunakan sistem penukar panas tidak langsung adalah cara yang ideal untuk menjaga temperatur larutan amina dan menjaga efisiensi dari *reboiler*.

2.5 Peraturan Terkait

Perusahaan minyak dan gas, wajib untuk menerapkan peraturan keselamatan untuk setiap proses, yang mengacu pada Pemerintah Indonesia, pembuat peraturan, dan memastikan bahwa semuanya berjalan dengan baik di jalur dan di bawah kendali. Setiap pekerja berhak mendapatkan perlindungan dan keselamatan dalam setiap detail pekerjaan. Oleh karena itu, implementasi setiap peraturan yang mengacu pada keselamatan dan kesehatan kerja, perlu untuk mencegah kegagalan atau kecelakaan dalam setiap operasi.

2.5.1 Peraturan No. 1, 1970

Peraturan ini memberikan alasan keamanan. Seperti yang dapat kita lihat dalam Bab III, Pasal 3, paragraf 1, menjelaskan bahwa untuk mewujudkan keselamatan kerja, kita perlu:

1. Mencegah dan kurangi kemungkinan kecelakaan
2. Mencegah, mengurangi, dan memadamkan api
3. Mencegah dan mengurangi bahaya ledakan

2.5.2 Peraturan Pemerintah No.11, 1979

Peraturan ini mengontrol keselamatan kerja dalam proses pemurnian minyak dan gas. Ini terdiri dari 31 bab dan 58 artikel yang mengatur administrasi dan pengawasan keselamatan kerja pada proses pemurnian industri minyak dan gas, wewenang dan tanggung jawab pertambangan menteri, dan dalam pelaksanaan pengawasan disampaikan kepada Direktur Jenderal (Dirjen) dengan hak substitusi sementara tugas dan pekerjaan pengawasan dilakukan oleh kepala inspeksi. Menurut Bab IV Artikel, 14 dan 15 membahas penggunaan dan program inspeksi yang akan dilakukan untuk mencegah kemungkinan bahaya yang mungkin terjadi selama pemrosesan minyak bumi.

2.5.3 Peraturan Menteri Energi dan Sumber Daya Mineral Republik Indonesia No. 38, 2017

Peraturan ini menetapkan peraturan Menteri Energi dan Sumber Daya Mineral tentang inspeksi instalasi dan peralatan keselamatan dalam bisnis industri minyak dan gas. Beberapa artikel terkait meliputi:

1. **Pasal 5 Ayat 1**
   Untuk jaminan desain, konstruksi, operasi dan pemeliharaan, pengujian, inspeksi dan implementasi instalasi dan peralatan, setiap fasilitas dan peralatan yang digunakan dalam kegiatan bisnis minyak dan gas bumi harus memeriksa dan diperiksa dengan baik.
2. **Pasal 11 Ayat 2**
   Pemeriksaan dan inspeksi keselamatan pada instalasi dan peralatan yang dioperasikan dapat dilakukan secara berkala berdasarkan periode atau waktu tertentu serta hasil analisis risiko.
3. **Pasal 17 Ayat 1 dan 3**
   Persetujuan penggunaan pemeriksaan keamanan berkala berdasarkan periode tertentu berlaku untuk maksimum empat tahun atau kurang dari periode tersebut jika instalasi dan peralatan berubah atau ragu-ragu dengan kemampuannya.

2.5.4 Peraturan Menteri Energi dan Sumber Daya Mineral Republik Indonesia No. 18, 2018

Peraturan Menteri Energi dan Sumber Daya Mineral ini menetapkan aturan dan undang-undang tentang inspeksi keselamatan instalasi dan peralatan yang terlibat dalam kegiatan minyak dan gas yang terkait dengan Peraturan Menteri Energi dan Sumber Daya Mineral No. 38 Tahun 2017. Isi spesifik dari peraturan ini lebih lanjut kemungkinan mengarah pada prosedur tentang bagaimana melakukan inspeksi keselamatan dan pihak-pihak yang bertanggung jawab melaksanakan inspeksi ini, sebagaimana disebutkan di bawah ini:

1. **Bab III Pasal 6 Ayat 1 dan 2**
   (1) Setiap instalasi atau peralatan yang digunakan dalam industri minyak dan gas harus melakukan inspeksi dan pemeriksaan keamanan.
   (2) Jenis peralatan yang bergerak dalam industri minyak dan gas yang harus termasuk dalam inspeksi terdiri dari bejana tekan, peralatan berputar (pompa dan kompresor), pembangkit listrik, transformator daya, panel distribusi, tangki atmosfer, dll.
2. **Bab III Pasal 10 Ayat 1 dan 2**
   (1) Kepala Teknik mengeluarkan informasi tentang hasil inspeksi.

(2) Kepala Teknik mengeluarkan informasi tentang hasil inspeksi.

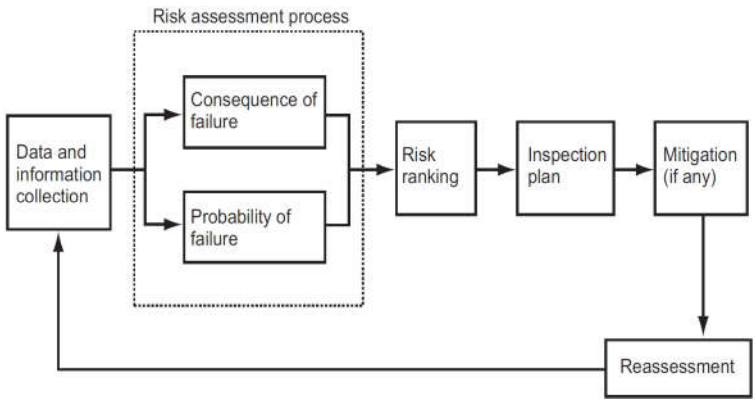
2.5.5 Pedoman Kerja 041 SKK MIGAS

SKK Migas adalah lembaga yang didirikan oleh pemerintah Republik Indonesia melalui Peraturan Presiden (Perpres) No. 9 tahun 2013 yang membahas implementasi manajemen dalam kegiatan minyak dan gas. SKK Migas adalah tugas dengan menjalankan administrasi bisnis hulu minyak dan gas di bawah kontrak kerja sama dan juga mengeluarkan peraturan dan prosedur sebagai Pedoman Tata Kerja (PTK). Salah satu PTK yang harus diperhatikan oleh perusahaan minyak dan gas di Indonesia adalah tentang "Pemeliharaan Fasilitas Minyak dan Produksi". Menurut PTK-041 / SKKMA000 / 2018 / S0, Bab II "Prinsip Manajemen Pemeliharaan", Setiap data dan dokumen yang terkait dengan program maintenane diperiksa secara berkala oleh KKKS dan disimpan dalam sistem manajemen data yang dapat diperbarui dan diakses kapan saja. Data dan dokumen yang terkait dengan program pemeliharaan termasuk integritas dan keandalan data, termasuk Risk Based Inspection (RBI).

2.6 Risk-Based Inspection

RBI adalah proses mengembangkan skema inspeksi berdasarkan pengetahuan tentang risiko kegagalan. Proses penting adalah analisis risiko. Kombinasi penilaian *Probability of Failure* (PoF) karena kerusakan, atau degradasi kecacatan dengan evaluasi *Consequences of Failure* (CoF). Program RBI mengidentifikasi jenis kerusakan yang mungkin ada, lokasi kerusakan terjadi, laju kerusakan mungkin berkembang, dan lokasi kegagalan akan menimbulkan bahaya. RBI diterapkan di sektor industri apa saja, sebagian besar di sektor pembangkit listrik dan petrokimia. Penerapan metode RBI dengan mengkompromikan bahaya peralatan, dan risiko. Peringkatan risiko dengan memprioritaskan peralatan secara sistematis pada tingkat risiko tinggi untuk mendapatkan program inspeksi pertama.

Gambar 2.4 menunjukkan proses perencanaan RBI. Mulai dari mengumpulkan data tentang peralatan dan menginspeksi, seperti karakteristik material, riwayat kegagalan, kondisi saat ini, dan data lainnya. Kemudian, probabilitas kegagalan dan konsekuensi kegagalan dihitung. Keduanya dapat menentukan tingkat risiko masing-masing komponen. Setelah mengetahui risikonya, perencanaan dan mitigasi inspeksi (jika ada) ditetapkan.



Gambar 2.4 Metode Perencanaan *Risk Based Inspection*
Sumber: API RP 580, 2016

Secara umum tujuan dari Risk-Based Inspection adalah sebagai berikut (Wicaksana, 2019):

1. Mengelompokkan peralatan yang sedang beroperasi sehingga area yang memiliki tingkat risiko tinggi dapat teridentifikasi,
2. Mengetahui nilai risiko peralatan berdasarkan matriks risiko,
3. Adanya prioritas peralatan berdasarkan perhitungan risiko,
4. Merancang perencanaan inspeksi yang tepat,
5. Mengetahui risiko kegagalan dan mengatur mitigasi pada saat peralatan mengalami kegagalan.

2.6.1 *Probability of Failure* (PoF)

Probabilitias atau kemungkinan terjadinya sebuah kegagalan ditunjukkan oleh persamaan (2.1).

$$P_f\ (t) = gff.D_f\ (t).F_{MS} \qquad (2.1)$$

Dimana :

$P_f\ (t)$ = *Probability of Failure*

gff = *Total Generic Failure Frequency*

$D_f\ (t)$ = *Damage Factor*

F_{MS} = *Management System Factor*

2.6.1.1 *Generic Failure Frequency*

Generic failure frequency (g_{ff}) atau frekuensi kegagalan secara umum merupakan frekuensi kegagalan yang muncul sebelum terjadi kegagalan yang disebabkan oleh lingkungan operasi dari *equipment.* Frekuensi kegagalan umum sebuah komponen diperkirakan menggunakan catatan dari peralatan-peralatan dalam sebuah perusahaan atau dari berbagai pabrik dalam sebuah industri, dari sumber literatur, dan data keandalan komersial.

Nilai frekuensi kegagalan umum digunakan sebagai nilai representatif dari kegagalan dan disediakan untuk beberapa ukuran lubang diskrit untuk berbagai jenis peralatan pengolahan (yaitu *process vessel*, *drum*, *towers*, sistem perpipaan, tangki, dll.). Frekuensi kegagalan umum diasumsikan mengikuti distribusi log-normal, dan memiliki tingakt kesalahan 3% sampai 10%.

2.6.1.2 *Damage Factor*

Damage factor (D_f) atau faktor kerusakan disebabkan oleh berbagai macam faktor dan ditentukan dari mekanisme kerusakan (korosi, retak, dll.) yang sebanding dengan pemeliharaan material konstruksi dan proses servis. Menurut API RP 581, ada 21 jenis faktor kerusakan:

1. *Thinning Damage Factor*
2. *Component Lining Damage Factor*
3. *SCC Damage Factor – Caustic Cracking*
4. *SCC Damage Factor – Amine Cracking*
5. *SCC Damage Factor – Sulfide Stress Cracking*

6. *SCC Damage Factor – HIC / SOHIC – H2S*
7. *SCC Damage Factor – Alkaline Carbonate Cracking*
8. *SCC Damage Factor – PTA Cracking*
9. *SCC Damage Factor – CLSCC*
10. *SCC Damage Factor – HSC-HF*
11. *SCC Damage Factor – HIC / SOHIC – HF*
12. *External Corrosion Damage Factor – Ferritic Component*
13. *External CLSCC Damage Factor Austenitic Component*
14. *CUI Damage Factor – Ferritic Component*
15. *External CUI CLSCC Damage Factor – Austenitic Component*
16. *High Temperature Hydrogen Attack Damage Factor*
17. *Brittle Damage Factor*
18. *Temper Embrittlement Damage Factor*
19. *Embrittlement Damage Factor*
20. *Sigma Phase Embrittlement Damage Factor*
21. *Piping Mechanical Fatigue Damage Factor*

Setiap jenis kerusakan umumnya disebabkan oleh satu atau beberapa faktor kerusakan. Sementara itu, *damage mechanism* (DM) atau mekanisme kerusakan terjadi karena kombinasi material, faktor lingkungan, dan kondisi operasi. *Damage mechanism* biasanya bersifat kumulatif, *incremental* dan dalam beberapa kasus tidak dapat dipulihkan.

Damage mechanism yang sedang aktif terjadi pada sebuah system tergantung dari beberapa faktor antara lain komposisi kimia fluida, lingkungan, material dari *equipment* (piping, pressure vessel, tangka timbun, dll.) dimana fluida mengalir, temperatur, tekanan maupun kecepatan dari fluida yang berada di dalam *equipment*.

2.6.1.3 *Management System Factor*

Management system factor (F_{MS}) adalah faktor yang disesuaikan dan dipengaruhi oleh *management system* pada *mechanical integrity* sebuah *plant*. *Management system factor* menunjukkan kualitas dari program proses *safety management* sebuah fasilitas. Evaluasi *management system* terdiri dari pertanyaan-pertanyaan yang dijabarkan dalam API RP 581 Annex 2.A. Skor maksimal yang dapat diperoleh adalah 1000. Skor yang didapatkan suatu fasilitas kemudian dimasukkan ke persamaan (2.2) berikut:

$$pscore = \frac{Score}{1000}\,100\;[unit\;os\%] \quad \text{.......................................} (2.2)$$

Untuk mendapatkan nilai F_{MS}, nilai *pscore* dimasukkan ke persamaan (2.3) berikut:

$$F_{MS} = 10^{(-0.02\,pscore+1)} \quad \text{.......................................} (2.3)$$

2.6.2 *Consequence of Failure* (CoF)

Consequence of Failure (CoF) yang disajikan dalam Bagian 3 dari American Petroleum Recommended Practice 581 (API RP 581) yang nantinya akan digabungkan dengan perhitungan *Probability of Failure* (PoF) untuk memberikan peringkat risiko dan rencana inspeksi untuk komponen yang tunduk pada proses dan kondisi lingkungan biasanya ditemukan di industri pengilangan, petrokimia dan eksplorasi, dan produksi.

CoF dihitung untuk membantu dalam menetapkan peringkat *equipment* berdasarkan risiko dan juga digunakan untuk menetapkan prioritas untuk program inspeksi.

Konsekuensi didefinisikan sebagai akibat yang terjadi apabila kegagalan muncul pada suatu *equipment.* Analisa konsekuensi perlu dilakukan untuk mengestimasikan konsekuensi yang akan terjadi akibat *failure modes* dari *damage mechanism* yang telah teridentifikasi.

Berdasarkan API RP 581, terdapat dua level konsekuensi, yaitu Level 1 dan Level 2. Analisis konsekuensi Level 1dapat digunakan untuk fluida representatif yang disebutkan pada API RP 581 Part 3. Sedangkan analisis konsekuensi Level 2 digunakan pada kasus dimana asumsi pada analisis konsekuensi Level 1 tidak valid. Analisis konsekuensi. Analisis konsekuensi Level 1 dan Level 2 tidak mempertimbangkan pelepasan produk beracun selama reaksi pembakaran.

Kategori konsekuensi dianalisis menggunakan metode berbeda yang akan dijelaskan di bawah ini:

2.6.2.1 *Flammable and Explosive Consequence*

Konsekuensi yang mudah terbakar dan meledak dihitung dengan menggunakan event tress untuk menentukan probabilitas berbagai hasil (mis. Kebakaran kumpulan, kebakaran kilat, ledakan awan uap), dikombinasikan dengan pemodelan komputer untuk menentukan besarnya konsekuensi. Area konsekuensi dapat ditentukan berdasarkan cedera personil yang serius dan kerusakan komponen akibat radiasi termal dan ledakan. Kerugian finansial ditentukan berdasarkan area yang terkena dampak rilis.

2.6.2.2 *Toxic Consequence*

Konsekuensi toksik dihitung dihitung dengan menggunakan pemodelan komputer untuk menentukan besarnya area konsekuensi sebagai akibat paparan berlebih kepada personel terhadap konsentrasi toksik dalam awan uap. Jika cairan mudah terbakar dan beracun, probabilitas kejadian toksik mengasumsikan bahwa pelepasannya dinyalakan, konsekuensi toksik dapat diabaikan (mis. Racun dikonsumsi dalam api). Kerugian finansial ditentukan berdasarkan area yang terkena dampak rilis.

2.6.2.3 *Non-Flammable, Non-Toxic Consequence*

Pelepasan yang tidak mudah terbakar, tidak beracun dipertimbangkan karena masih dapat menimbulkan konsekuensi serius. Konsekuensi dari percikan kimiawi dan luka bakar uap suhu tinggi ditentukan berdasarkan cedera serius pada personel. Ledakan fisik dan *Boiling Liquid Expanding Vapor Explosions* (BLEVE) juga dapat menyebabkan cedera serius pada personil dan kerusakan komponen.

2.6.2.4 *Financial Consequence*

Konsekuensi finansial termasuk kerugian karena gangguan bisnis dan biaya yang terkait dengan pelepasan lingkungan. Konsekuensi gangguan bisnis diperkirakan sebagai fungsi dari hasil area konsekuensi yang mudah terbakar dan tidak mudah terbakar. Konsekuensi lingkungan ditentukan langsung dari massa pelepasan dan laju pelepasan fluida.

2.7 Risiko dan Level Risiko

2.7.1 Definisi Risiko

Risiko adalah kombinasi dari kemungkinan suatu peristiwa yang terjadi selama periode waktu tertentu dan konsekuensi yang berkaitan dengan kejadiannya. Sebuah risiko dapat dikalkulasikan sebagai fungsi waktu. Ekuasi ini menggabungkan probabilitas kegagalan dan konsekuensi kegagalan.

$$R(t) = P_f(t).C(t) \quad \text{...(2.4)}$$

Dimana :
$R\ (t)$ = Risk
$P_f\ (t)$ = Probability of Failure
$C(t)$ = Total Generic Failure Frequency

Dalam API RP 581, konsekuensi kegagalan *C(t)* yang diasumsikan tidak relevan dalam waktu, dan dapat diubah tergantung pada risiko yang di asumsikan, bisa pada berbasis area atau financial.

$$R(t) = P_f(t).CA \quad \text{untuk risiko berbasis area ....(2.5)}$$

$$R(t) = P_f(t).FC \quad \text{untuk risiko berbasis financial. .... (2.6)}$$

Penilaian risiko yang efektif harus merupakan proses yang rasional, logis, terstruktur dengan baik yang mengandung setidaknya dua langkah penting sebagai berikut:

1. Tentukan seberapa signifikan risikonya, dan
2. Tentukan apakah risikonya dapat diterima.

2.7.2 Level Risiko

Level risiko dari sebuah *equipment* dapat ditentukan menggunakan metode matriks risiko (risk matrix). Matriks risiko adalah sebuah diagram kotak 5x5 dengan kategori pemetaan risiko. Level risiko dapat disimbolkan menggunakan warna yang ditunjukkan pada Gambar 2.5 dengan deskripsi sebagai berikut:

1. Merah digunakan untuk *high-risk* level,
2. Oranye digunakan untuk *medium high-risk* level,
3. Kuning digunakan untuk *medium-risk* level, dan
4. Hijau digunakan untuk *low-risk* level.

Gambar 2.5 Risk Matrix
Sumber: API RP 581, 2016

Pada gambar 2.5, sumbu horizontal adalah tingkatan dari *consequence of failure*, dan sumbu vertikal adalah tingkatan dari *probability of failure* atau *damage factor*. Untuk pengklasifikasian nilai risiko berbasis area dapat dilihat pada Tabel 2.1 yang merupakan kutipan dari Table 4.1M API RP 581 Part 1. Sedangkan pengklasifikasian nilai risiko berbasis finansial dapat dilihat pada Tabel 2.2 yang merupakan kutipan dari Table 4.2 API RP 581 Part 1.

Tabel 2.1 Tingkatan Nilai Untuk Matriks Risiko Berbasis Area

Category	Probability Category		Consequence Category	
	Probability range	Damage factor range	Category	Range (m²)
1	$P_f(t, I_E) \leq$ 3.06E-05	$D_{f-total} \leq 1$	A	CA≤9.29
2	3.06E-05 < $P_f(t, I_E)$ ≤3.06E-04	$1 < D_{f-total} \leq 10$	B	9.29<CA≤92.9
3	3.06E-04 < $P_f(t, I_E)$ ≤3.06E-03	$10 < D_{f-total} \leq 100$	C	92.9<CA≤929
4	3.06E-03 < $P_f(t, I_E)$ ≤3.06E-02	$100 < D_{f-total} \leq 1000$	D	929<CA≤9290
5	$P_f(t, I_E) >$ 3.06E-02	$D_{f-total} > 1000$	E	CA>9290

Tabel 2.2 Tingkatan Nilai Untuk Matriks Risiko Berbasis Finansial

Category	Probability Category		Consequence Category	
	Probability range	Damage factor range	Category	Range ($)
1	$P_f(t, I_E) \leq$ 3.06E-05	$D_{f-total} \leq 1$	A	FC≤10,000
2	3.06E-05 < $P_f(t, I_E)$ ≤3.06E-04	$1 < D_{f-total} \leq 10$	B	10,000 < FC ≤ 100,000
3	3.06E-04 < $P_f(t, I_E)$ ≤3.06E-03	$10 < D_{f-total} \leq 100$	C	100,000 < FC ≤ 1,000,000
4	3.06E-03 < $P_f(t, I_E)$ ≤3.06E-02	$100 < D_{f-total} \leq 1000$	D	1,000,000<FC≤ 10,000,000
5	$P_f(t, I_E) >$ 3.06E-02	$D_{f-total} > 1000$	E	FC>10,000,000

2.8 Manajemen Risiko

Manajemen risiko, adalah proses untuk menilai risiko, untuk menentukan apakah pengurangan risiko diperlukan dan untuk mengembangkan rencana untuk mempertahakan risiko pada tingkat yang dapat diterima. Dalam manajemen risiko, terdapat unsur pengurangan/minimalisasi risiko. Pengurangan risiko adalah tindakan mitigasi suatu risiko yang dianggap terlalu tinggi ke yang lebih rendah, sehingga tingkat dengan level risiko yang dapat diterima dengan beberapa bentuk kegiatan pengurangan risiko. Dengan menggunakan manajemen risiko, beberapa risiko dapat diidentifikasi sebagai diterima sehingga tidak ada pengurangan risiko (mitigasi) yang diperlukan.

2.9 Perencanaan Program Inspeksi

Inspeksi merupakan evaluasi kualitas dari beberapa karakteristik yang berhubungan dengan standart atau spesifikasi. Terdapat beberapa komponen mendasar pada sebuah inspection plan, antara lain *inspection task, scope of inspection,* dan jadwal pelaksanaan untuk memonitor *damage mechanishm* dan memastikan status *mechanical integrity* pada setiap komponennya. Untuk jenis inspeksi berupa inspeksi visual pada *teknik intrusive* dan *teknik non-intrusive* yang definisikan sebagai teknik *nondestructive evaluation* (NDE), *nondestructive testing* (NDT), atau *nondestructive Inspection* (NDI) (Pierre, 2007).

Inspection plan didesain untuk mendeteksi dan mengukur spesifik tipe dari korosi yang mungkin terjadi seperti *local corrosion* atau *general corrosion*, *cracking*, atau tipe kerusakan yang lainnya. Setiap jenis kerusakan memiliki metode tersendiri untuk mendekteksi dan mengukurnya. Sehingga *inspection plan* dikatakan efektif jika metode inspeksi dan luasan daerah yang di inspeksi mewakili jenis kerusakan yang mungkin terjadi.

2.9.1 Kategori Inspeksi

Pada suatu *equipment* terdapat peluang beberapa *damage mechanism* yang akan terjadi. Diantaranya adalah *thinning, stress corrosion cracking* (SCC) dan *corrosion under insulation* (CUI). Kategori dari *inspection effectiveness* secara umum dijelaskan pada Tabel 2.3.

Tabel 2.3 Kategori *Inspection Effectiveness*

Kategori Inspeksi	Kategori	Deskripsi
A	Highly Effective	Metode inspeksi akan mengidentifikasi keadaan kerusakaan dengan tepat pada hampir setiap kasus (atau 80-100% *confidence*)
B	Usually Effective	Metode inspeksi akan mengidentifikasi keadaan kerusakaan dengan tepat pada sebagian besar kasus (atau 60-80% *confidence*)
C	Fairly Effective	Metode inspeksi akan mengidentifikasi keadaan kerusakaan dengan tepat pada sebagian kasus (atau 40-60% *confidence*)
D	Poorly Effective	Metode inspeksi akan memberikan sedikit informasi mengidentifikasi keadaan kerusakaan dengan tepat (atau 20-40% *confidence*)
E	Ineffective	Metode inspeksi tidak akan memberikan atau hampir tidak ada informasi yang akan mengidentifikasi keadaan kerusakaan yang sebenarnya dan dianggap tidak efektif untuk mendeteksi *damage mechanism* (kurang dari 20% *confidence*)

2.9.1.1 Kategori Inspeksi untuk Thinning

Semua peralatan yang memiliki potensi terkorosi pasti mengalami *thinning* (penipisan). Penipisan tersebut diakibatkan oleh berbagai macam faktor mulai dari faktor korosi yang diakibatkan oleh senyawa yang terkandung dalam fluida yang mengalir (semisal CO_2, H_2S, H_2O, CL_2, Amine), sampai dengan faktor *erosion* yang diakibatkan oleh perpaduan antara kecepatan aliran fluida dan besarnya partikel dalam fluida.

Berdasarkan API RP 581, terdapat 2 jenis *thinning* antara lain *general* dan *localized*. *General thinning* merupakan korosi dengan ciri-ciri area terkorosi melebih 10% dan kedalaman kurang dari 1.27 mm. *Localized thinning* merupakan korosi dengan ciri-ciri area terkorosi kurang dari 10% dan kedalaman lebih dari dari 1.27 mm.

Dikarenakan *equipment* belum pernah dilakukan inspeksi, maka *thining* yang terjadi diasumsikan bersifat *localized thinning.* Tabel 2.4 adalah deskripsi *inspection effectiveness* untuk *local thinning.*

Tabel 2.4 *Inspection Effectiveness* untuk *Local Thinning*

Kategori Inspeksi	Kategori	Inspeksi Intrusif	Inspeksi Non-Intrusif
A	Highly effective	Untuk area permukaan total: • 100% pemeriksaan visual. • 100% follow up di area local thinning.	Untuk total area yang dicurigai: • Cakupan 100% dari CML menggunakan ultrasonic scanning atau *profile radiography*.
B	Usually effective	Untuk area permukaan total: • >75% pemeriksaan visual. • 100% follow up di area local thinning.	Untuk total area yang dicurigai: • >75% dari CML menggunakan ultrasonic scanning atau profile radiography.
C	Fairly effective	Untuk area permukaan total: • >50% pemeriksaan visual. • 100% follow up di area local thinning.	Untuk total area yang dicurigai: • >50% dari CML menggunakan ultrasonic scanning atau profile radiography.
D	Poorly effective	Untuk area permukaan total: • >20% pemeriksaan visual. • 100% follow up di area local thinning.	Untuk total area yang dicurigai: • >20% dari CML menggunakan *ultrasonic scanning* atau *profile radiography*.
E	Ineffective	• Teknik inspeksi yang tidak efektif	• Teknik inspeksi yang tidak efektif

Inspeksi intrusif diartikan sebagai inspeksi yang memerlukan masuk ke dalam *equipment*. Sedangkan non-intrusif diartikan sebaliknya.

2.9.1.2 Kategori Inspeksi untuk Stress Corrosion Cracking

Stress Corrosion Cracking (SCC) merupakan fenomena keretakan pada sebuah logam dikarenakan kombinasi dari *tensile stress* dan korosi dalam waktu yang bersamaan. Beberapa s*tress corrosion cracking* (SCC) yang mungkin terjadi pada logam/metal adalah *Amine stress corrosion cracking, sulfide stress cracking* (SSC) dan HIC/SOHIC – H_2S *cracking.*

Amine- stress corrosion cracking (SSC) merupakan SCC yang terjadi karena terdapat *aqueous alkanomine* pada suhu tertentu. *Aqueous alkanomine* terjadi pada *amine* *treating unit* baik yang menggunakan *monoethanolamine* (MEA), *disopropanolamine* (DIPA), *diethanolamine* (DEA), dan *methyldiethanoamine* (MDEA). Peluang terjadinya Amine-SCC jika menggunakan MDEA relatif lebih kecil dari pada jenis Amine yang lain.

Sulfide stress cracking (SSC) merupakan *stress corrosion cracking* yang terjadi karena terdapat air dan H_2S pada waktu yang bersamaan pada permukaan sebuah *equipment* yang terpapar fluida tersebut.

HIC/SOHIC – H_2S *cracking* merupakan singkatan dari *hydrogen-induced cracking* dan *stress oriented hydrogen-induced cracking* karena pengaruh H_2S. HIC didefinisikan sebagai retakan internal bertahap yang menghubungkan hidrogen blister yang berdekatan pada bidang yang berbeda dalam logam, atau ke permukaan logam. HIC terjadi bukan karena stress eksternal, namun karena penumpukan tekanan internal dari hidrogen blister. Interaksi bidang dengan stress tinggi cenderung mengakibatkan keretakan yang menghubungkan hidrogen blister di bidang berbeda pada logam. Kerentanan terhadap HIC utamanya dipengaruhi oleh kadar sulfur pada logam tersebut. Semakin tinggi kadarnya, maka semakin rentan. Pun kerentanan terhadap HIC juga dipengaruhi (bukan yang utama) oleh pH dan konsentrasi H_2S di air. Semakin jauh dari pH netral dan/atau semakin tinggi konsentrasi H_2S, maka akan semakin rentan terhadap HIC.

Tabel 2.3 menjelaskan kategori *inspection effectiveness* untuk *Amine Stress Corrosion Cracking,* Tabel 2.4 menjelaskan kategori *inspection effectiveness* untuk *Sulfide stress cracking* (SSC), dan Tabel 2.5 menjelaskan kategori *inspection effectiveness* untuk HIC/SOHIC – H_2S *Stress Corrosion Cracking* secara instrusif maupun non-intrusif.

Tabel 2.5 *Inspection Effectiveness* untuk *Amine Stress Corrosion Cracking*

Kategori Inspeksi	Kategori	Inspeksi Intrusif	Inspeksi Non-Intrusif
A	Highly Effective	Untuk las / area las yang dipilih: 100% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: 100% ultrasonic scanning secara otomatis atau manual.
B	Usually Effective	Untuk las / area las yang dipilih: >75% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: >75% ultrasonic scanning secara otomatis atau manual. **ATAU** >75% AE testing dengan follow up di seluruh indikasi relevan.
C	Fairly Effective	Untuk las / area las yang dipilih: >35% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: >35% ultrasonic scanning secara otomatis atau manual. **ATAU** >35% tes radiographic.

Kategori Inspeski	Kategori	Inspeksi Intrusif	Inspeksi Non-Intrusif
D	Poorly Effective	Untuk las / area las yang dipilih: >10% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: >35% ultrasonic scanning secara otomatis atau manual. **ATAU** >10% tes radiographic.
E	Ineffective	Teknik inspeksi yang tidak efektif	Teknik inspeksi yang tidak efektif

(Lanjutan Tabel 2.5 *Inspection Effectiveness* untuk *Amine Stress Corrosion Cracking*)

Tabel 2.6 *Inspection Effectiveness* untuk *Sulfide Stress Cracking*

Kategori Inspeski	Kategori	Inspeksi Intrusif	Inspeksi Non-Intrusif
A	Highly Effective	Untuk las / area las yang dipilih: 100% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: 100% ultrasonic scanning secara otomatis atau manual.
B	Usually Effective	Untuk las / area las yang dipilih: >75% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: >75% ultrasonic scanning secara otomatis atau manual. **ATAU** >75% AE testing dengan follow up di seluruh indikasi relevan.
C	Fairly Effective	Untuk las / area las yang dipilih: >35% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: >35% ultrasonic scanning secara otomatis atau manual. **ATAU** >35% tes radiographic.
D	Poorly Effective	Untuk las / area las yang dipilih: >10% WFMT / ACFM dengan follow up terhadap seluruh indikasi relevan.	Untuk las / area las yang dipilih: >35% ultrasonic scanning secara otomatis atau manual. **ATAU** >10% tes radiographic.
E	Ineffective	Teknik inspeksi yang tidak efektif	Teknik inspeksi yang tidak efektif

Tabel 2.7 *Inspection Effectiveness* untuk HIC/SOHIC – H_2S *Cracking*

Kategori Inspeski	Kategori	Inspeksi Intrusif	Inspeksi Non-Intrusif
A	Highly Effective	Untuk total area permukaan: • >95% A atau C scan dengan straight beam. • Diikuti dengan TOFD / Shear wave. • 100% visual.	Untuk total area permukaan: • >90% C scan dari logam dasar dengan UT tingkat lanjut. • Untuk area las dan HAZ – 100% shear wave dan TOFD. • HIC: 1 area 0.5 ft^2, C scan logam

Kategori Inspeksi	Kategori	Inspeksi Intrusif	Inspeksi Non-Intrusif
			dasar dengan UT tingkat lanjut pada tiap plat dan heads
B	Usually Effective	Untuk total area permukaan: • >75% A atau C scan dengan straight beam. • Diikuti dengan TOFD / Shear wave. • 100% visual.	Untuk total area permukaan: • >65% C scan dari logam dasar dengan UT tingkat lanjut. • HIC: 2 area 0.5 ft^2, C scan logam dasar dengan UT tingkat lanjut pada tiap plat dan heads
C	Fairly Effective	Untuk total area permukaan: • >35% A atau C scan dengan straight beam. • Diikuti dengan TOFD / Shear wave. • 100% visual. **ATAU** • >50% WFMT / ACFM. • Follow up UT pada indikasi. • 100% Visual dari total area permukaan.	Untuk total area permukaan: • >35% C scan dari logam dasar dengan UT tingkat lanjut. • HIC: 1 area 0.5 ft^2, C scan logam dasar dengan UT tingkat lanjut pada tiap plat dan heads
D	Poorly Effective	Untuk total area permukaan: • >10% A atau C scan dengan straight beam. • Diikuti dengan TOFD / Shear wave. • 100% visual. **ATAU** • >25% WFMT / ACFM. • Follow up UT pada indikasi. • 100% Visual dari total area permukaan.	Untuk total area permukaan: • >5% C scan dari logam dasar dengan UT tingkat lanjut. • HIC: 1 area 0.5 ft^2, C scan logam dasar dengan UT tingkat lanjut pada tiap plat dan heads
E	Ineffective	Teknik inspeksi yang tidak efektif	Teknik inspeksi yang tidak efektif

(Lanjutan Tabel 2.7 *Inspection Effectiveness* untuk HIC/SOHIC – H_2S *Cracking*)

2.9.1.3 Kategori Inspeksi untuk Corrosion Under Insulation (CUI)

Corrosion under Insulation (CUI) terjadi karena adanya air yang terkumpul pada ruang antara *insulation* dan permukaan *equipment*. Air tersebut bisa berasal dari air hujan, rembesan air, kondensasi, *deluge system*, dan *steam tracing leak*. CUI dapat muncul pada temperatur antara -12° C dan 175° C. Pada rentan suhu 77° C sampai 110° C, CUI akan terjadi dengan laju yang lebih signifikan.

Tabel 2.6 merupakan deskripsi *inspection effectiveness* untuk *corrosion under insulation* (CUI) baik dengan cara melepas insulasi terlebih dahulu maupun tanpa melepas insulasi.

Tabel 2.8 *Inspection Effectiveness* untuk *Corrosion Under Insulation* (CUI)

Kategori Inspeski	Kategori	Tanpa Insulasi	Dengan Insulasi
A	Highly Effective	Untuk total area permukaan: • Inspeksi visual 100% sebelum insulasi dilepas **DAN** • Melepaskan inslulasi >100% dari total luas permukaan termasuk area yang rusak atau berpotensi rusak **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang tereskpos menggunakan UT, RT atau pit gauge	Untuk total area permukaan: • Inspeksi visual 100% **DAN** • Follow-up dengan profil atau real-time radiography >100% dari total luas permukaan termasuk area yang dicurigai. **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang tereskpos menggunakan UT, RT atau pit gauge
B	Usually Effective	Untuk total area permukaan: • Inspeksi visual 100% sebelum insulasi dilepas **DAN** • Melepaskan inslulasi >50% dari total luas permukaan termasuk area yang rusak atau berpotensi rusak **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang tereskpos menggunakan UT, RT atau pit gauge	Untuk total area permukaan: • Inspeksi visual 100% **DAN** • Follow-up dengan profil atau real-time radiography >65% dari total luas permukaan termasuk area yang dicurigai. **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang tereskpos menggunakan UT, RT atau pit gauge
C	Fairly Effective	Untuk total area permukaan: • Inspeksi visual 100% sebelum insulasi dilepas **DAN** • Melepaskan inslulasi >25% dari total luas permukaan termasuk area yang rusak atau berpotensi rusak **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang tereskpos menggunakan UT, RT atau pit gauge	Untuk total area permukaan: • Inspeksi visual 100% **DAN** • Follow-up dengan profil atau real-time radiography >35% dari total luas permukaan termasuk area yang dicurigai. **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang tereskpos menggunakan UT, RT atau pit gauge
D	Poorly Effective	Untuk total area permukaan: • Inspeksi visual 100% sebelum insulasi dilepas **DAN**	Untuk total area permukaan: • Inspeksi visual 100% **DAN**

Kategori Inspeksi	Kategori	Tanpa Insulasi	Dengan Insulasi
		• Melepaskan inslulasi >5% dari total luas permukaan termasuk area yang rusak atau berpotensi rusak **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang terekspos menggunakan UT, RT atau pit gauge	• Follow-up dengan profil atau real-time radiography >5% dari total luas permukaan termasuk area yang dicurigai. **DAN** • Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang terekspos menggunakan UT, RT atau pit gauge
E	Ineffective	Teknik inspeksi yang tidak efektif	Teknik inspeksi yang tidak efektif

(Lanjutan Tabel 2.8 *Inspection Effectiveness* untuk HIC/SOHIC – H_2S *Cracking*)

2.9.2 Metode Inspeksi

Metode inspeksi yang tepat sesuai dengan mekanisme kerusakan peralatan yang dianalisa akan memberikan data yang lebih akurat untuk mengetahui kondisi peralatan yang sebenarnya. Beberapa metode inspeksi yang dapat dilaksanakan adalah sebagai berikut (API RP 571, 2011):

2.9.2.1 Metode Inspeksi Thinning

a. Inspeksi Visual (VT)

Inspeksi visual adalah metode inspeksi paling sederhana tanpa menggunakan alat. Kerusakan secara visual dapat diketahui dari metode ini baik secara internal maupun eksternal permukaan.

- *Direct Visual Examination*
- *Remote Visual Examination*
- *Translucent Visual Examination*

b. Ultrasonic Testing (UT)

Metode inspeksi ini merupakan metode non-destruktif (NDE) yang memanfaatkan gelombang ultrasonik berfrekuensi tinggi (>20,000 Hz). Dengan memancarkan gelombang ultrasonik pada peralatan, ketebalan dan cacat pada peralatan dapat diidentifikasi. Terdapat beberapa tipe UT, yaitu:

- *Automated Ultrasonic Backscatter Technique* (AUBT)

  Tipe UT yang menggunakan frekuensi tinggi, broadband UT probes dan osiloskop digital. Metode ini dikembangan untuk mendeteksi kerusakan terutama pada *High-Temperature Hydrogen Attack* (HTHA).
- *Phased Array Ultrasonic Testing* (PAUT)

  Metode yang menggunakan serangkaian probe UT yang terbuat dari banyak elemen kecil dan masing-masing menghasilkan getaran dimana perhitungan waktu dilakukan oleh komputer.

- *Long Range Ultrasonic Testing* (LRUT)
  Metode yang dikembangakan untuk pengujian pada peralatan berukuran besar atau pipa panjang dengan memasang cincin transducer secara merata disekitar peralatan. Gelombang berfrekuensi rendah disebarkan oleh cincin transducer.
- *Internal Rotating Inspection Systems* (IRIS)
  Metode yang dikembangkan untuk mendeteksi korosi pada pipa dan tabung. Metode ini menggunakan probe yang dimasukkan ke dalam sebuah peralatan yang memancarkan gelombang ultrasonik. Metode IRIS dapat mendeteksi cacat seperti erosi internal dan eksternal, korosi, *pitting*, *denting, fretting* dan mengetahui ketebalan dinding.
- *Time of Flight Diffraction* (TOFD)
  Merupakan metode pengujian cacat las dengan menggunakan waktu pergerakan (*time of flight*). Untuk menemukan waktu pergerakan, metode ini menggunakan sepasang transduser ultrasonik. Apabila terdapat cacat, pemanca akan mengembalikan gelombang.
- *Dry-Coupled Ultrasonic Testing* (DCUT)
  Metode yang digunakan untuk memeriksa peralatan dengan material metalik dan non-metalik tanpa menggunakan *liquid couplant*. Metode ini menggunakan gelombang ultrasonik frekuensi tinggi untuk mengidentifikasi cacat.
- *External Shear Wave Ultrasonic Testing* (SWUT)
  SWUT adalah metode menggunakan gelombang ultrasonik *shear* yang dapat mendeteksi besar dan volume suatu keretakan.

c. *Radiographic Testing (*RT)
   Radiography test merupakan sebuah metode inspeksi non-destruktif yang menggunakan sinar-x (x-rays) atau sinar gama untuk melihat struktur bagian dalam dari sebuah peralatan. Metode ini dapat mengidentifikasi cacat pada material, objek asing di dalam sistem, memeriksa perbaikan las, dan *Corrosion Under Insulation* (CUI).

d. *Magnetic Particle Testing* (MT)
   Metode ini digunakan untuk mengidentifikasi cacat dan keretakan pada peralatan.Metode MT menggunakan serbuk magnetik pada permukaan benda yang akan diuji. Apabila terdapat cacat maka partikel magnetik akan terkumpul pada lokasi cacat. Tipe-tipe metode inspeksi ini adalah:
   - *Wet Fluorescent Magnetic Test* (WFMT)
     Inspeksi dengan menggunakan fluorescent dapat mendeteksi cacat dan keretakan lebih detail dibanding menggunakan serbuk. Cairan fluorescent memungkinkan untuk meningkatkan visibilitas keretakan pada permukaan material.
   - *Alternating Current Field Measurement* (ACFM)
     Metode elektromagnetik yang menggunakan arus bolak-balik pada permukaan peralatanuntuk mendeteksi keretakan pada material. Adanya keretakan akan mengganggu medan

elektromagnetik dan memberikan sinyal yang telah dikonversi sehingga inspektor dapat mengetahui adanya keretakan atau cacat.

e. *Eddy Current* (EC)

Metode EC dilaksanakan dengan mengalirkan arus listrik pada kumparan hingga medan magnet terbentuk. Jika medan magnet ditempelkan pada material yang diinspeksi akan terbentuk arus eddy.

f. *Thermographic Inspection*

Metode inspeksi ini digunakan untuk mengidentifikasi kondisi temperature abnormal pada peralatan. Peningkatan temperature dapat menjad indikasi terjadinya kegagalan atau terdapat cacat.

g. *Acoustic Emission Testing* (AET)

Metode ini mengukur gelombang emisi akustik yang dihasilkan material karena pelepasan energi yang cepat. Metode AET digunakan untuk memonitoring pertumbuhan crack serta lokasinya.

h. *Neutron Backscatter*

Metode ini menggunakan neutron sebagai pendeteksi adanya CUI. Sumber radioaktif memancarkan neutron dengan energy yang tinggi (cepat) ke daerah yang akan di ukur (daerah isolasi yang di inginkan). Sepanjang perjalanan, neutron akan dipantau melalui detektor sensitif parsial untuk neutron energi rendah. Apabila energi neutron tersebut bertabrakan dengan hidrogen maka neutron tersebut akan berkurang (energi rendah). Hal tersebut akan terdeteksi oleh alat detektor. Semakin rendah energi neutron yang terdeteksi, maka semakin banyak hidrogen diarea tersebut.

Metode ini memiliki fleksibilitas yang baik, karena dapat menjangkau daerah yang sempit serta dapat mendeteksi lapisan yang terdapat hidrogen secara akurat. Namun, metode ini tidak dapat mendeteksi daerah korosi, hanya mendeteksi daerah yang kemungkinan besar mengandung air (hidrogen).

2.9.3 Perencanaan Inspeksi *Heat Exchanger*

Heat exchanger diklasifikasikan sebagai salah satu jenis *pressure vessel* (API STD 510, 2014). Sehingga dalam menyusun perencanaan inspeksi pada *heat exchanger* perlu untuk memperhatikan hal-hal berikut (API RP 572, 2011):

a. Pengukuran *thickness*
   - *Wall thickness tube shell and tube heat exchanger*
   - Pengambilan *thickness* pada titik yang terkorosi
b. *External inspection*
   - *Ladder, stairways, platform, dan walkways*
   - *Foundation and support*
   - *Anchor bolt*
   - *Concrete support*

- *Steel support*
- *Nozzles*
- *Grounding connection*
- *Auxiliary equipment*
- *Protective coating dan insulation*
- *External metal surface*

c. *Internal inspection*
- *Visual inspection inside shell*
- *Trays*
- *Linings*
- *Nozzle (inside shell side)*

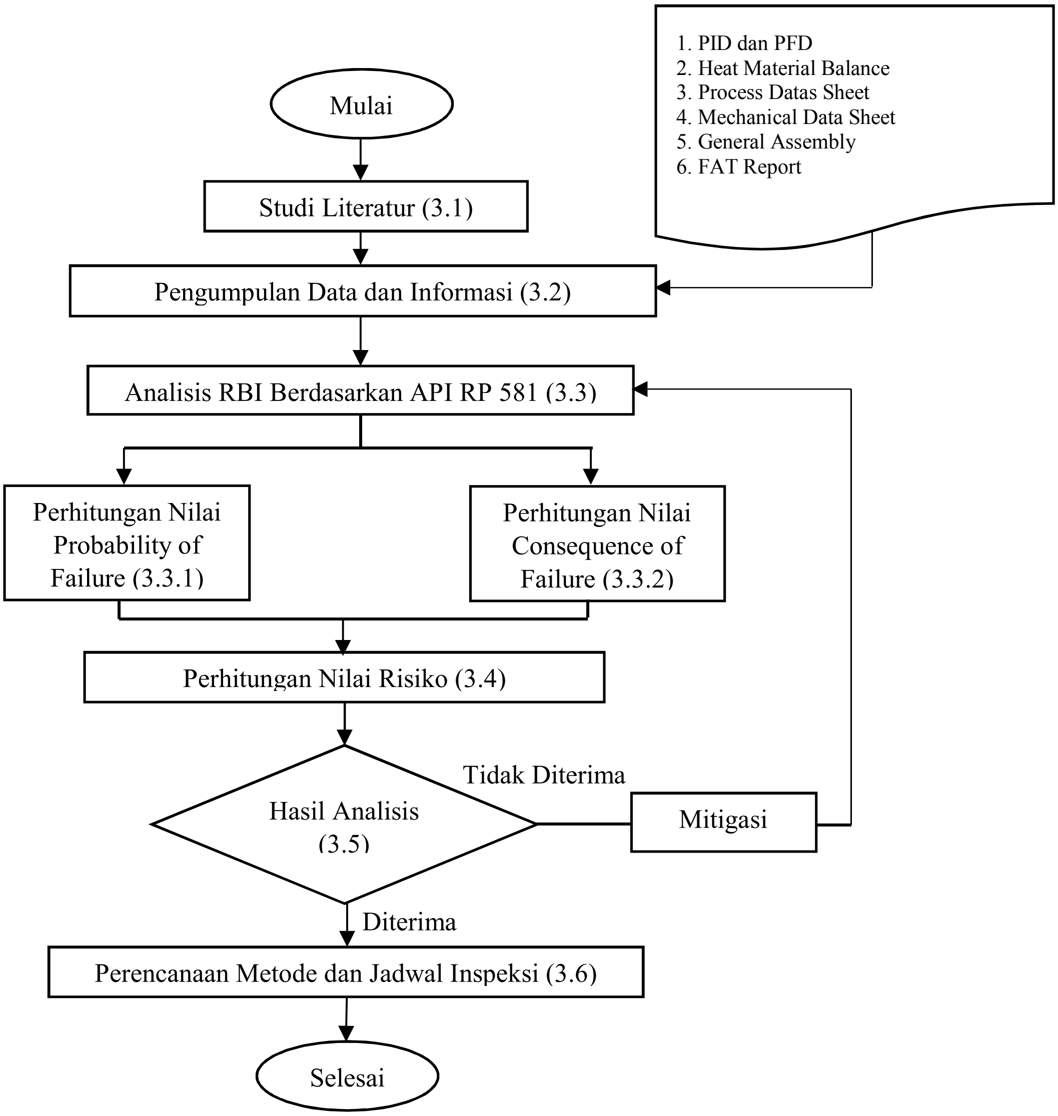
2.10 Keuntungan Metode Risk Based Inspection (RBI)

Penerapan metode RBI memiliki beberapa manfaat dalam meningkatkan efisiensi dan efektivitas inspeksi seperti (Mohamed, 2012):

1. Mengoptimalkan jadwal perbaikan dan pergantian *equipment.*
2. Mengurangi kegiatan inspeksi yang tidak perlu dalam interval isnpeksi berdasarkan tingkat risiko dari *equipment.*
3. Mengurangi *downtime* dari *plant*.
4. Memperbaiki manajemen keselamatan dan kesehatan kerja.
5. Menghemat biaya dikarenakan sumber daya inspeksi akan fokus pada *equipment* dengan risiko tinggi.

BAB 3
METODOLOGI PENELITIAN

Untuk menyelesaikaan masalah diatas akan dilakukan langkah-langkah secara sistematis baik dalam perhitungan, analisa, maupun pembahasannya. Gambar 3.1 menunjukkan diagram alur pengerjaan yang akan dilakukan.



Gambar 3.1 Flowchart Pengerjaan

3.1 Studi Literatur

Studi literatur dilakukan untuk membuat ringkasan teori fundamental baik secara umum maupun khusus. Studi literatur ini dilakukan dengan membaca dan meringkas jurnal, buku teks, database perusahaan, tesis lain yang dilakukan dengan baik, dan bahkan dari internet tentang segala sesuatu yang berkaitan dengan tugas akhir. Pada Tabel 3.1 menunjukkan hasil studi literatur yang telah dilakukan oleh penulis.

Tabel 3.1 Hasil Studi Literatur

Referensi	Hasil yang didapatkan
Kajian Penelitian Terkait: Tesoro Anacortes Refinery Investigation Report,	Sebagai landasan penyebab perlunya dilakukan penelitian ini untuk menyusun latar belakang dan referensi.
Peraturan Pemerintah	Sebagai landasan hukum pada penelitain untuk tugas akhir ini yang membantu untuk menyusun teori latar belakang, dan referensi.
Textbook: International Journal of Chemical Industry	Referensi tambahan dalam menyusun teori latar belakang, dan studi literatur.
Guidelines : API 510 API 571 API 580 API 581	Recommended Practice (RP) memberikan pedoman untuk memesan persyaratan program minimum untuk memenuhi syarat untuk menetapkan interval inspeksi berdasarkan analisis Risk Based Inspection (RBI) dan memberikan pedoman tambahan yang disarankan pada analisis risiko untuk mengembangkan rencana inspeksi yang efektif.
Pustaka Internet	Memberikan definisi istilah-istilah yang digunakan dalam penelitian ini.

3.2 Pengumpulan Data dan Informasi

Pengumpulan data kondisi desain dan operasional sebagai kelengkapan penelitian. Data yang diperlukan dalam penelitian ini adalah sebagai berikut:

- PID dan PFD dari *amine reboiler heat exchanger*
- *General Assembly* dari *amine reboiler heat exchanger*
- *Heat Material Balance* (HMB) untuk *amine reboiler heat exchanger*
- *Process data sheet amine reboiler heat exchanger*
- *Mechanical data sheet amine reboiler heat exchanger*
- *Factory Accepatance Test* (FAT) *Report amine reboiler heat exchanger*

Data yang dikumpulkan selanjutnya akan diproses untuk menentukan probabilitas kegagalan dan konsekuensi dari kegagalan agar program inspeksi dapat dilakukan dengan tepat dan penjadwalan perencanaan inspeksi dapat dijalankan pada waktu yang tepat sebelum instalasi mengalami *shutdown*.

3.3 Analisis RBI Berdasarkan API RP 581

Semua pemrosesan data, berdasarkan Rekomendasi API 581 yang memberikan dasar untuk mengelola risiko dengan membuat keputusan berdasarkan informasi tentang tingkat frekuensi detail perincian dan jenis *Non-Destructive Examination* (NDE). Setelah data didapatkan, tahap selanjutnya yaitu menentukan *damage mechanism* dari equipment yang akan dianalisa.

Damage mechanism yang sedang aktif pada sebuah sistem tergantung dari beberapa faktor antara lain, komposisi kimia fluida, lingkungan, material dari *equipment* dimana fluida mengalir, temperatur, tekanan maupun kecepatan dari fluida yang berada di dalam *equipment*.

Dari 21 jenis *damage factor,* API RP 581 mengelompokkan mekanisme kerusakan yang terjadi pada *heat exchanger* sebagai berikut:

1. *Thinning*
2. *Stress corrosion cracking (SCC)*
3. *External damage*
4. *Hihg temperature hydrogen attack*
5. *Mechanical fatigue (piping only)*
6. *Brittle fracture*

Setelah itu, *damage mechanism* diseleksi berdasarkan pertanyaan-pertanyaan *screening* pada API 581. *Damage mechanism* yang dipilih adalah *damage mechanism* yang memiliki risiko tertinggi penyebab kegagalan pada *equipment.*

3.3.1 Perhitungan Probability of Failure (PoF)

Metode untuk menghitung *Probability of Failure* (PoF) untuk *shell and tube heat exchanger* tercantum pada Recommended Practice API 581 Part 2. Nilai PoF didapatkan berdasarkan jenis komponen dan mekanisme kerusakan yang ada, sebagaimana dimaksud:

- Karakteristik fluida
- Kondisi desain
- Bahan konstruksi
- Dan *code construction* asli

Ketepatan dan akurasi sebuah informasi digunakan untuk lebih memahami kondisi sebuah equipment sehingga mampu mengurangi ketidakpastian (*uncertainty*) dalam analisa PoF. Secara matematis, PoF dapat dihitung menggunakan persamaan (2.1).

Tahapan-tahapan dalam melakukan analisa PoF adalah:

Langkah 1. Menentukan nilai frekuensi kegagalan umum (gff)

Nilai frekuensi kegagalan umum atau *generic failure frequency* yang direkomendasikan tercantum pada API RP 581 Part 2 untuk tiap kegagalan komponen yang terjadi pada industri pengolahan minyak dan gas.

Langkah 2. Menghitung nilai faktor kerusakan (Df)

Nilai faktor kerusakan atau *damage factor* ditentukan dari hasil analisa beberapa parameter pada *damage mechanism*. Jika pada komponen mempunyai *multiple damage factor*, perlu untuk menghitung masing-masing nilai *damage factor*. Selanjutnya nilai *total damage factor* akan dihitung dan digunakan dalam analisa PoF.

Langkah 3. Menghitung nilai faktor sistem manajemen (F_{MS})

Nilai faktor sistem manajemen atau *management system factor* ditentukan dengan melakukan penilaian berdasarkan daftar pertanyaan pada Annex 2.A API RP 581 Part 2.

3.3.1.1 Analisis Thinning Damage Factor

Langkah-langkah dalam menghitung nilai *thinning damage factor* pada suatu komponen yang tercantum pada API RP 581 Part 2 adalah sebagai berikut:

Langkah 1. Menentukan nilai *furnished thickness,* t, dan usia komponen, *age,* berdasarkan waktu instalasi komponen.

Langkah 2. Menentukan nilai laju korosi untuk *base material*, $C_{r,bm}$, berdasarkan material dan lingkungan. Dalam menentukan nilai laju korosi berdasarkan data komposisi kimia sesuai dengan Annex 2B. Untuk komponen dengan *cladding/weld overlay*, nilai laju korosi *cladding/weld overlay* juga perlu untuk ditentukan.

Langkah 3. Menentukan nilai *time in service*, age_{tk}, dan *thickness* komponen berdasarkan data inspeksi terakhir, tr_{di}.

Langkah 4. Menghitung nilai *age required to corroded away*, age_{rc}, pada *cladding/weld overlay* menggunakan persamaan berikut.

$$age_{rc} = \max\left[\left(\frac{t_{rdi}-t_{bm}}{C_{r,cm}}\right),\ 0.0\right] \tag{3.1}$$

Langkah 5. Menentukan nilai *minimum required wall thickness,* t_{min}, untuk komponen dengan bentuk *cylindrical, spherical atau head*, t_{min} dihitung berdasarkan *original design code* atau API 579-1/ASME FFS-1.

Langkah 6. Menentukan parameter A_{rt} untuk komponen tanpa cladding/weld overlay dan age_{rc}=0.0 menggunakan persamaan (3.2).

$$A_{rt} = \left(\frac{Crb,m\ .\ age_{tk}}{t_{tdi}}\right) \tag{3.2}$$

Langkah 7. Menghitung nilai Flow Stress, FS^{Thin}, menggunakan persamaan (3.3).

$$FS^{Thin} = \frac{(YS+TS)}{2} \cdot E\ \cdot 1.1 \tag{3.3}$$

Langkah 8. Menghitung nilai *strength ratio parameter*, SR_P^{Thin}, menggunakan persamaan (3.4)

$$SR_P^{Thin} = \frac{S \cdot E}{FS^{Thin}} \cdot \frac{Max\,(t_{min}, t_c)}{t_{rdi}} \tag{3.4}$$

Langkah 9. Menentukan jumlah inspeksi yang telah dilakukan berdasarkan *inspection effectiveness*, N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}, berdasarkan Tabel 2.1 kategori *inspection effectiveness* pada Bab 2.

Langkah 10. Menghitung nilai *inspection effectiveness factor*, I_1^{Thin}, I_2^{Thin}, I_3^{Thin}, menggunakan parameter *prior probabilities*, Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}, berdasarkan Table 4.1.9 Lampiran 4, parameter *conditional probabilities*, Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}, berdasarkan Table 4.1.10 Lampiran 4 dan jumlah inspeksi yang telah ditentukan pada Langkah 9 menggunakan persamaan (3.5), (3.6), dan (3.7).

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}} \tag{3.5}$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_D^{Thin}} \quad (3.6)$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_D^{Thin}} \quad (3.7)$$

Langkah 11. Menghitung nilai *posterior probability,* $Po_{p1}^{extcorr}$, $Po_{p2}^{extcorr}$, $Po_{p3}^{extcorr}$, menggunakan persamaan (3.8), (3.9) dan (3.10).

$$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin}+I_2^{Thin}+I_3^{Thin}} \quad (3.8)$$

$$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin}+I_2^{Thin}+I_3^{Thin}} \quad (3.9)$$

$$Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin}+I_2^{Thin}+I_3^{Thin}} \quad (3.10)$$

Langkah 12. Menghitung nilai parameter, $ß_1^{Thin}, ß_2^{Thin}, ß_3^{Thin}$ menggunakan persamaan (3.11), (3.12), dan (3.13) dengan asumsi nilai $COV_{\Delta t} = 0.2$, $COV_{sf} = 0.2$, dan $COV_P = 0.05$.

$$ß_1^{Thin} = \frac{1-D_{S1}\,.\,A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.\,A_{rt}{}^2.\,COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad (3.11)$$

$$ß_2^{Thin} = \frac{1-D_{S2}\,.\,A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.\,A_{rt}{}^2.\,COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad (3.12)$$

$$ß_3^{Thin} = \frac{1-D_{S3}\,.\,A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.\,A_{rt}{}^2.\,COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad (3.13)$$

Langkah 13. Menghitung *base damage factor for thinning* untuk komponen *tank bottom* menggunakan Table 4.8 pada API RP 581 Part 2 dan parameter A_{rt} dari STEP 6.

Langkah 14. Menghitung *base damage factor,* D_{fB}^{Thin} untuk semua komponen (kecuali *tank bottom*) menggunakan persamaan (3.14)

$$D_{fb}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi\left(-\beta_1^{Thin}\right)\right)+\left(Po_{P2}^{Thin}\Phi\left(-\beta_2^{Thin}\right)\right)+\left(Po_{P3}^{Thin}\Phi\left(-\beta_3^{Thin}\right)\right)}{1.56E-0.4} \quad (3.14)$$

Langkah 15. Menentukan *damage factor for thinning,* D_f^{Thin}, menggunakan persamaan (3.15)

$$D_f^{Thin} = \text{Max}[(\frac{(D_{fb}^{Thin}.\ F_{IP}\,.\ F_{DL}\,.\,F_{WD}.\,F_{AM}\,.\,F_{SM})}{F_{OM}}),0.1] \quad (3.15)$$

3.3.1.2 Analisis Stress Corrosion Cracking Damage Factor – Amine Cracking

Langkah-langkah dalam menghitung nilai *SCC-Amine Cracking damage factor* pada suatu komponen yang tercantum pada API RP 581 Part 2 adalah sebagai berikut:

Langkah 1. Menentukan *susceptibility* untuk keretakan menggunakan Figure 7.1. Perlu diperhatikan bahwa *HIGH susceptibility* harus digunakan jika dipastikan ada retak.

Langkah 2. Menentukan *severity index,* S_{VI}, berdasarkan *susceptibility* pada Langkah 3 dari Table 4.1.14 Lampiran 4.

Langkah 3. Menentukan nilai *time in service*, age_{tk}, sejak inspeksi Level A, B atau C terakhir dilaksanakan tanpa keretakan yang terdeteksi atau keretakan sudah diperbaiki. Keretakan yang terdeteksi tetapi tidak diperbaiki harus dievaluasi dan rekomendasi inspeksi di masa mendatang berdasarkan evaluasi FFS.

Langkah 4. Menentukan jumlah inspeksi dan kategori efektivitas inspeksi yang sesuai berdasarkan Section 7.6.2 untuk inspeksi yang sebelumnya dilakukan selama *in-service*. Untuk menentukan kategori efektivitas tertinggi dari beberapa inspeksi yan telah ditentukan menggunakan Section 3.4.3.

Langkah 5. Menentukan *base damage factor* untuk *amine cracking*, D_{fB}^{Amine} menggunakan Table 4.1.15 Lampiran 4 berdasarkan jumlah dan efektivitas inspeksi tertinggi yang sudah ditentukan dalam Langkah 4, dan *severity index*, S_{VI}, dari Langkah 2.

Langkah 6. Menghitung *damage factor* (DF), D_f^{Amine}, berdasarkan waktu *in-service* sejak inspeksi terakhir menggunakan *age* pada Langkah 3 dan persamaan (3.16). Pada persamaan ini diasumsikan bahwa probabilitas untuk keretakan akan meningkat seiring waktu sejak inspeksi terakhir sebagai akibat dari meningkatnya paparan kondisi non-normal.

$$D_f^{amine} = D_{fB}^{Amine} \cdot \left(Max\,[age, 1.0]\right)^{1.1} \tag{3.16}$$

3.3.1.3 Analisis Stress Corrosion Cracking Damage Factor – Sulfide Stress Cracking

Langkah-langkah dalam menghitung nilai *SCC-Sulfide Stress Cracking damage factor* pada suatu komponen yang tercantum pada API RP 581 Part 2 adalah sebagai berikut:

Langkah 1. Menentukan *environmental severity* (tingkat potensi fluks hidrogen) untuk keretakan berdasarkan kandungan H_2S dalam air dan pH menggunakan Table 4.1.18 Lampiran 4.

Langkah 2. Menentukan *susceptibility* untuk keretakan menggunakan Figure 8.1 dan Table 4.1.19 Lampiran 4 berdasarkan *environmental severity* dari Langkah 1, *maximum Brinell hardness*, dan apakah komponen tersebut melalui PWHT. Perlu diperhatikan bahwa *HIGH susceptibility* harus digunakan jika dipastikan ada retak.

Langkah 3. Menentukan *severity index,* S_{VI}, berdasarkan *susceptibility* pada Langkah 3 menggunakan Table 4.1.20 Lampiran 4.

Langkah 4. Menentukan nilai *time in service*, age_{tk}, sejak inspeksi Level A, B atau C terakhir dilaksanakan tanpa keretakan yang terdeteksi atau keretakan sudah diperbaiki. Keretakan yang terdeteksi tetapi tidak diperbaiki harus dievaluasi dan rekomendasi inspeksi di masa mendatang berdasarkan evaluasi FFS.

Langkah 5. Menentukan jumlah inspeksi dan kategori efektivitas inspeksi yang sesuai berdasarkan Section 8.6.2 untuk inspeksi yang sebelumnya dilakukan selama *in-service*. Untuk menentukan kategori efektivitas tertinggi dari beberapa inspeksi yan telah ditentukan menggunakan Section 3.4.3.

Langkah 6. Menentukan *base damage factor* untuk *sulfide stress cracking,* D_{fB}^{SSC} menggunakan Table 4.1.21 Lampiran 4 berdasarkan jumlah dan efektivitas inspeksi tertinggi yang sudah ditentukan dalam Langkah 5, dan *severity index*, S_{VI}, dari Langkah 3.

Langkah 7. Menghitung *damage factor* (DF), D_f^{SSC}, berdasarkan waktu *in-service* sejak inspeksi terakhir menggunakan *age* pada Langkah 4 dan persamaan (3.17). Pada persamaan ini diasumsikan bahwa probabilitas untuk keretakan akan meningkat seiring waktu sejak inspeksi terakhir sebagai akibat dari meningkatnya paparan kondisi non-normal.

$$D_f^{SCC} = D_{fB}^{SCC} \cdot \left(Max\,[age, 1.0]\right)^{1.1} \quad (3.17)$$

3.3.1.4 Analisis Stress Corrosion Cracking Damage Factor – HIC/SOHIC-H_2S Cracking

Langkah-langkah dalam menghitung nilai *SCC-HIC/SOHIC-H_2S damage factor* pada suatu komponen yang tercantum pada API RP 581 Part 2 adalah sebagai berikut:

Langkah 1. Menentukan *environmental severity* (tingkat potensi fluks hidrogen) untuk keretakan berdasarkan kandungan H_2S dalam air dan pH menggunakan Table 4.1.24 Lampiran 4. Perlu diperhatikan bahwa *HIGH susceptibility* harus digunakan jika dipastikan ada retak.

Langkah 2. Menentukan *susceptibility* untuk keretakan menggunakan Figure 9.1 dan Table 4.1.25 Lampiran 4 berdasarkan *environmental severity* dari Langkah 1, kandungan sulfur dari *carbon steel*, bentuk produk dan apakah komponen tersebut melalui PWHT. Perlu diperhatikan bahwa *HIGH susceptibility* harus digunakan jika dipastikan ada retak.

Langkah 3. Menentukan *severity index,* S_{VI}, berdasarkan *susceptibility* pada Langkah 2 menggunakan Table 4.1.26 Lampiran 4.

Langkah 4. Menentukan nilai *time in service*, age_{tk}, sejak inspeksi Level A, B atau C terakhir dilaksanakan tanpa keretakan yang terdeteksi atau keretakan sudah diperbaiki. Keretakan yang terdeteksi tetapi tidak diperbaiki harus dievaluasi dan rekomendasi inspeksi di masa mendatang berdasarkan evaluasi FFS.

Langkah 5. Menentukan jumlah inspeksi dan kategori efektivitas inspeksi yang sesuai berdasarkan Section 9.6.2 untuk inspeksi yang sebelumnya dilakukan selama *in-service*. Untuk menentukan kategori efektivitas tertinggi dari beberapa inspeksi yan telah ditentukan menggunakan Section 3.4.3.

Langkah 6. Menentukan *base damage factor* untuk HIC/SOHIC-H_2S*,* $D_{Fb}^{HIC/SOHIC-H2S}$ menggunakan Table 4.1.27 Lampiran 4 berdasarkan jumlah dan efektivitas inspeksi tertinggi yang sudah ditentukan dalam Langkah 5, dan *severity index*, S_{VI}, dari Langkah 3.

Langkah 7. Menentukan *on-line adjustment factor*, F_{OM}, menggunakan Table 4.1.28 Lampiran 4.

Langkah 8. Menghitung *damage factor* (DF), $D_f^{HIC/SOHIC-H2S}$, berdasarkan waktu *in-service* sejak inspeksi terakhir menggunakan *age* pada Langkah 4 dan persamaan (3.18). Pada persamaan ini diasumsikan bahwa probabilitas untuk keretakan akan meningkat seiring waktu sejak inspeksi terakhir sebagai akibat dari meningkatnya paparan kondisi non-normal. Persamaan ini juga menerapkan *adjustment factor* untuk *online monitoring.*

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} . (Max[age, 1.0])^{1.1}}{Fom} \quad (3.18)$$

3.3.1.5 Corrosion Under Insulation Damage Factor – Ferritic Component

Langkah-langkah dalam menghitung nilai *CUI damage factor* pada suatu komponen yang tercantum pada API RP 581 Part 2 adalah sebagai berikut:

Langkah 1. Menentukan nilai *furnished thickness,* t, dan usia komponen, *age,* berdasarkan waktu instalasi komponen.

Langkah 2. Menentukan nilai *base corrosion rate,* C_{rB}, berdasrakn *driver* dan temperatur operasi menggunakan Table 4.1.31 Lampiran 4.

Langkah 3. Menghitung *final corrosion rate* menggunakan persamaan (3.19).

$$C_r = C_{rB} \cdot F_{INS} \cdot F_{CM} \cdot F_{IC} \cdot \max[F_{EQ}, F_{IF}] \quad (3.19)$$

Langkah 4. Menentukan nilai *time in service*, age_{tk}, dan *thickness* komponen berdasarkan data inspeksi terakhir, tr_{de}. tr_{de} adalah ketebalan awal sehubungan dengan berkurangnya ketebalan dinding yang terkait dengan korosi eksternal. Jika tidak ada ketebalan yang diukur saat inspeksi, $t_{rde} = t$ dang $age_{tk} = age$.

Langkah 5. Menentukan nilai *in-service time,* age_{coat}, sejak *coating* diinstal menggunakan persamaan (3.20)

$$age_{coat} = Calculation\ Date\ - Coating\ Installation\ Date \quad (3.20)$$

Langkah 6. Menentukan nilai *coating adjustment,* $coat_{adj}$, menggunakan persamaan pada API RP 581 Part 2 Section 16.

Langkah 7. Menentukan nilai *in-service time,* age, dimana CUI mungkin telah terjadi menggunakan persamaan (3.21).

$$age = age_{tk} - Coat_{adj} \quad (3.21)$$

Langkah 8. Menentukan nilai *allowable stress,* S, *weld joint efficiency,* E, dan *minimum required wall thickness,* t_{min}, per *design code* atau API 579-1/ASME FFS-1.

Langkah 9. Menentukan parameter A_{rt} menggunakan persamaan (3.22) berdasarkan age dan t_{rde} dari Langkah 4 dan Cr dari Langkah 3.

$$A_{rt} = \frac{C_r \cdot age}{t_{rde}} \quad (3.22)$$

Langkah 10. Menghitung *flow stress*, FS^{CUIF}, menggunakan E dari Langkah 8 dan persamaan (3.23).

$$FS^{CUIF} = \frac{(YS+TS)}{2} \cdot E \cdot 1.1 \quad (3.23)$$

Langkah 11. Menghitung parameter *strength ratio,* SRPThin, menggunakan salah satu persamaan (3.24) dan (3.25).

$$SR_P^{CUIF} = \frac{S \cdot E}{FS^{CUIF}} \cdot \frac{Min\,(t_{min}, t_c)}{t_{rde}} \quad (3.24)$$

$$SR_P^{CUIF} = \frac{P \cdot D}{\alpha \cdot FS^{CUIF} \cdot t_{rde}} \quad (3.25)$$

Langkah 12. Menentukan jumlah inspeksi yang telah dilakukan berdasarkan *inspection effectiveness*, N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}, berdasarkan Section 16.6.2 API RP 581 Part 2.

Langkah 13. Menghitung nilai *inspection effectiveness factor*, I_1^{CUIF}, I_2^{CUIF}, I_3^{CUIF}, menggunakan parameter *prior probabilities*, Pr_{p1}^{CUIF}, Pr_{p2}^{CUIF}, Pr_{p3}^{CUIF}, berdasarkan Table 4.1.33 Lampiran 4, parameter *conditional probabilities*,

Pr_{p1}^{CUIF}, Pr_{p2}^{CUIF}, Pr_{p3}^{CUIF}, berdasarkan Table 4.1.34 Lampiran 4 dan jumlah inspeksi yang telah ditentukan pada Langkah 12 menggunakan persamaan (3.26), (3.27), dan (3.28).

$$I_1^{CUIF} = Pr_{p1}^{CUIF} \left(Co_{p1}^{CUIF}\right)^{N_A^{CUIF}} \left(Co_{p1}^{CUIF}\right)^{N_B^{CUIF}} \left(Co_{p1}^{CUIF}\right)^{N_C^{CUIF}} \left(Co_{p1}^{CUIF}\right)^{N_D^{CUIF}} \quad (3.26)$$

$$I_2^{CUIF} = Pr_{p2}^{CUIF} \left(Co_{p2}^{CUIF}\right)^{N_A^{CUIF}} \left(Co_{p2}^{CUIF}\right)^{N_B^{CUIF}} \left(Co_{p2}^{CUIF}\right)^{N_C^{CUIF}} \left(Co_{p2}^{CUIF}\right)^{N_D^{CUIF}} \quad (3.27)$$

$$I_3^{CUIF} = Pr_{p3}^{CUIF} \left(Co_{p3}^{CUIF}\right)^{N_A^{CUIF}} \left(Co_{p3}^{CUIF}\right)^{N_B^{CUIF}} \left(Co_{p3}^{CUIF}\right)^{N_C^{CUIF}} \left(Co_{p3}^{CUIF}\right)^{N_D^{CUIF}} \quad (3.28)$$

Langkah 14. Menghitung nilai *posterior probability,* Po_{p1}^{CUIF}, Po_{p2}^{CUIF}, Po_{p3}^{CUIF}, menggunakan persamaan (3.29), (3.30) dan (3.31).

$$Po_{p1}^{CUIF} = \frac{I_1^{CUIF}}{I_1^{CUIF}+I_2^{CUIF}+I_3^{CUIF}} \quad (3.29)$$

$$Po_{p2}^{CUIF} = \frac{I_2^{CUIF}}{I_1^{CUIF}+I_2^{CUIF}+I_3^{CUIF}} \quad (3.30)$$

$$Po_{p3}^{CUIF} = \frac{I_3^{CUIF}}{I_1^{CUIF}+I_2^{CUIF}+I_3^{CUIF}} \quad (3.31)$$

Langkah 15. Menghitung nilai parameter, β_1^{CUIF}, β_2^{CUIF}, β_3^{CUIF} menggunakan persamaan (3.32), (3.33), dan (3.34) dengan asumsi nilai $COV_{\Delta t} = 0.2$, $COV_{sf} = 0.2$, dan $COV_P = 0.05$

$$\beta_1^{CUIF} = \frac{1-D_{S_1}\cdot A_{rt}-SR_P^{CUIF}}{\sqrt{D_{S_1}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_1}\cdot A_{rt}\right)^2\cdot COV_{Sf}{}^2+\left(SR_P^{CUIF}\right)^2\cdot COV_P{}^2}} \quad (3.32)$$

$$\beta_2^{CUIF} = \frac{1-D_{S_2}\cdot A_{rt}-SR_P^{CUIF}}{\sqrt{D_{S_2}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_2}\cdot A_{rt}\right)^2\cdot COV_{Sf}{}^2+\left(SR_P^{CUIF}\right)^2\cdot COV_P{}^2}} \quad (3.33)$$

$$\beta_3^{CUIF} = \frac{1-D_{S_3}\cdot A_{rt}-SR_P^{CUIF}}{\sqrt{D_{S_3}{}^2\cdot A_{rt}{}^2\cdot COV_{\Delta t}{}^2+\left(1-D_{S_3}\cdot A_{rt}\right)^2\cdot COV_{Sf}{}^2+\left(SR_P^{CUIF}\right)^2\cdot COV_P{}^2}} \quad (3.34)$$

Dimana, $D_{s1} = 1$, $D_{s2} = 2$, $D_{s3} = 4$ merupakan faktor laju korosi untuk kondisi kerusakan 1, 2 dan 3. Perlu diperhatikan bahwa perhitungan DF sangat sensitif terhadap nilai yang digunakan untuk koefisien *variance for thickness*, $COV_{\Delta t}$. $COV_{\Delta t}$ berkisar $0.10 \leq COV_{\Delta t} \leq 0.20$ dengan rekomendasi *conservative value* $COV_{\Delta t} = 0.20$.

Langkah 16. Menghitung D_f^{CUIF} menggunakan persamaan (3.35).

$$D_f^{CUIF} = \left[\frac{\left(Po_{p1}^{CUIF}\phi(-\beta_1^{CUIF})\right)+\left(Po_{p2}^{CUIF}\phi(-\beta_2^{CUIF})\right)+\left(Po_{p3}^{CUIF}\phi(-\beta_3^{CUIF})\right)}{1.56E-0.4}\right] \quad (3.35)$$

3.3.2 Perhitungan Consequence of Failure (CoF)

Metode untuk menghitung *Consequence of Failure* (CoF) untuk *shell and tube heat exchanger* tercantum pada Recommended Practice API 581 Part 3. Perhitungan CoF dilakukan untuk membantu dalam menetapkan peringkat item peralatan berdasarkan risiko dan juga dimaksudkan untuk digunakan untuk menetapkan prioritas untuk program inspeksi. Pada penelitian ini, CoF menggunakan pendekatan area terdampak yang dikategorikan dalam: (1) luas area terbakar; (2) luas area radiasi panas yang berdampak terhadap manusia; dan (3) luas area terdampak racun.Sedangkan CoF menggunakan pendekatan finansial dikategorikan dalam: (1) biaya hilangnya pendapatan produksi karena *downtime*; (2) biaya dampak terhadap lingkungan; (3) biaya pemeliharaan; dan (4) biaya penggantian peralatan.

3.3.2.1 Tahapan-tahapan Perhitungan CoF Berbasis Area

Langkah 1. Menentukan jenis fluida dan propertinya termasuk *release phase*.

1.1 Memilih fluida representative.
1.2 Menentukan fase fluida pada saat penyimpanan.
1.3 Menentukan sifat-sifat fluida saat berdasarkan fasenya.
1.4 Menentukan fase fluida pada saat setelah terlepas ke atmosfer.

Langkah 2. Menentukan ukuran lubang (release hole size area) yang mungkin akan terjadi (*small, medium, large, dan rupture*).

2.1 Menentukan diameter untuk setiap *release hole*, d_n.
2.2 Menentukan *generic failure frequence*, gff_n, untuk setiap n^{th} release hole dan total *generic failure frequency*.

Langkah 3. Menghitung laju pelepasan.

3.1. Memilih persamaan laju pelepasan yang sesuai dengan fase fluida penyimpanan yang telah ditentukan pada Langkah 1.2.
3.2. Menghitung release hole size area, A_n, menggunakan persamaan (3.36) berdasarkan d_n.

$$An = \frac{\pi d_n^2}{4} \tag{3.36}$$

3.3. Menghitung nilai viscocity correction factor, $K_{v,n}$, untuk tipe pelepasan liquid pada masing-masing *release hole* menggunakan persamaan (3.37).

$$K_{v,n} = \left(0.9935 + \frac{2.878}{Re_n^{0.5}} + \frac{342.75}{Re_n^{1.5}}\right)^{-1.0} \tag{3.37}$$

3.4. Menghitung laju pelepasan, W_n, untuk tiap *release hole size* dan tiap *release area,* A_n, yang telah ditentukan pada Langkah 3.2 menggunakan persamaan (3.38).

$$Wn = \frac{Cd}{C2} \,.\, An \,.\, Ps \sqrt{\left(\frac{MW \,.\, gc}{R \,.\, Ts}\right)\left(\frac{2.k}{k+1}\right)\left(\frac{P_{atm}}{P_S}\right)^{\frac{2}{k}}\left(1 - \left(\frac{P_{atm}}{P_S}\right)^{\frac{k-1}{k}}\right)} \tag{3.38}$$

Langkah 4. Menghitung estimasi total fluida yang dikeluarkan.

4.1 Mengelompokkan komponen dan item komponen pada *inventory groups* berdasarkan Annex 3.A API RP 581.
4.2 Menghitung massa fluida, $mass_{comp}$, pada komponen yang sedang dianalisa.
4.3 Menghitung massa fluida pada peralatan lainnya yang termasuk dalam *inventory group*, $mass_{comp,i}$.
4.4 Menghitung massa fluida pada *inventory group* menggunakan persamaan (3.39).

$$\sum mass_{inv} = \sum_{i=1}^{n} mass_{comp,i} \quad (3.39)$$

4.5 Menghitung laju aliran untuk diameter untuk lubang dengan diameter 203 mm (8 inch), W_{max8}, menggunakan persamaan untuk menghitung laju pelepasan pada Langkah 3.4, dengan nilai A_n = A_8 = 32.450 mm^2 (50.3 $inch^2$).

4.6 Menghitung massa fluida tambahan, $W_{add,n}$, untuk tiap *release hole,* yang dapat menambah jumlah massa fluida dalam komponen selama 3 menit menggunakan persamaan (3.40).

$$Mass_{add,n} = 180 \cdot \min[W_n, W_{max8}] \quad (3.40)$$

4.7 Menghitung *available mass*, $mass_{avail,n}$, untuk tiap *release hole* menggunakan persamaan (3.41).

$$Mass_{avail,n} = \min[\{Mass_{comp} + Mass_{add,n}\}, Mass_{inv}] \quad (3.41)$$

Langkah 5. Menentukan tipe pelepasan, *continuous* atau *instantaneous*.

Tipe Pelepasan:

a. ***Instantaneous Release*** – pelepasan sesaat atau *puff release* adalah pelepasan yang terjadi dengan sangat cepat sehingga cairan menyebar seperti awan yang besar atau pool.

b. ***Continuous Release*** – pelepasan terus-menerus atau *plume release* adalah pelepasan yang terjadi selama jangka waktu yang lama, yang memungkinkan cairan untuk menyebar dalam bentuk elips memanjang (tergantung kondisi cuaca).

5.1 Menghitung waktu yang dibutuhkan untuk melepaskan 4536 kgs (10,000 lbs) dari fluida untuk tiap *release hole* menggunakan persamaan (3.42)

$$t_n = \frac{C_3}{W_n} \quad (3.42)$$

5.2 Menentukan tipe pelepasan, *continuous* atau *instantaneous* untuk tiap *release hole size* berdasarkan kriteria berikut:

a. Apabila ukurang lubang pelepasan (*release hole*) adalah 6.35 mm (0.25 inch) atau kurang maka tipe pelepasan adalah *continuous*.

b. Apabila tn ≤180 detik dan massa pelepasan lebih besar dari 4536 kg (10,000 lbs), maka jenis pelepasannya adalah *instantaneous*; jika tidak maka jenis pelepasannya *continuous*.

Langkah 6. Menentukan sistem deteksi dan isolasi.

6.1 Menentukan sistem deteksi dan isolasi yang terdapat pada komponen.

6.2 Memilih klasifikasi sistem deteksi (A,B,C) yang sesuai berdasarkan Tabel 5.6 pada Lampiran 5.

6.3 Memilih klasifikasi sistem isolasi (A,B,C) yang sesuai berdasarkan Tabel 5.6 pada Lampiran 5.

6.4 Memilih faktor reduksi, $fact_{di}$, yang sesuai berdasarkan Tabel 5.7 pada Lampiran 5.

6.5 Menentukan total durasi kebocoran, $ld_{max,n}$, untuk tiap *release hole* menggunakan Tabel 5.8 pada Lampiran 5.

Langkah 7. Menentukan laju pelepasan dan massa fluida yang terlepas untuk analisa konsekuensi.

7.1 Menghitung laju pelepasan yang disesuaikan, $rate_n$, untuk tiap *release hole*, menggunakan persamaan (3.43).

$$Rate_n = W_n\ (1\text{-}fact_{di}) \tag{3.43}$$

7.2 Menghitung durasi kebocoran, ld_n, untuk setiap *release hole* menggunakan persamaan (3.44).

$$ldn = min\ .\ [\{\frac{Mass_{avail,n}}{Rate_n}\},\{60\ .\ ld_{max,n}\} \tag{3.44}$$

7.3 Menghitung release mass, massn, untuk setiap *release hole* menggunakan persamaan (3.45).

$$Mass_n = min\ .\ [\{Rate_n\ .\ ld_n\},Mass_{avail,n}\ ] \tag{3.45}$$

Langkah 8. Menghitung nilai *flammable* dan *explosive consequence*.

8.1 Memilih *reduction factor*, $fact_{mit}$, menggunakan Tabel 5.9 pada Lampiran 5.

8.2 Menghitung *energy efficiency correction factor*, $eneff_n$, untuk tiap *release hole* menggunakan persamaan (3.46).

$$eneff_n = 4.\ log_{10}\left[C_{4A}\ .\ mass_n\right] - 15 \tag{3.46}$$

8.3 Menentukan tipe fluida, apakah termasuk TYPE 0 atau TYPE 1 berdasarkan Tabel 5.2 pada Lampiran 5.

8.4 Menghitung nilai *component damage consequence area* untuk tiap *release hole*, untuk Auto-Ignition Not Likely, Continuous Release (AINL-CONT), $CA^{AINL\text{-}CONT}$ menggunakan persamaan (3.47).

$$CA_{cmd,n}^{AINL-CONT} = \alpha(rate_n)^b\ .\ (1 - fact_{mit}) \tag{3.47}$$

8.5 Menghitung nilai *component damage consequence area* untuk tiap *release hole*, untuk Auto-Ignition Likely, Continuous Release (AIL-CONT), $CA^{AIL\text{-}CONT}$ menggunakan persamaan (3.48).

$$CA_{cmd,n}^{AIL-CONT} = \alpha(rate_n)^b\ .\ (1 - fact_{mit}) \tag{3.48}$$

8.6 Menghitung nilai *component damage consequence area* untuk tiap *release hole*, untuk Auto-Ignition Not Likely, Instantaneous Release (AINL-INST), $CA^{AINL\text{-}INST}$ menggunakan persamaan (3.49).

$$CA_{cmd,n}^{AINL-INST} = \alpha(mass_n)^b\ .\ \left(\frac{1 - fact_{mit}}{eneff_n}\right) \tag{3.49}$$

8.7 Menghitung nilai *component damage consequence area* untuk tiap *release hole*, untuk Auto-Ignition Likely, Instantaneous Release (AIL-INST), $CA^{AIL\text{-}INST}$ menggunakan persamaan (3.50).

$$CA_{cmd,n}^{AIL-INST} = \alpha(mass_n)^b\ .\ \left(\frac{1 - fact_{mit}}{eneff_n}\right) \tag{3.51}$$

8.8 Menghitung nilai *personnel injury consequence area* untuk tiap *release hole*, untuk Auto-Ignition Not Likely, Continuous Release (AINL-CONT), $CA^{AINL\text{-}CONT}$ menggunakan persamaan (3.52).

$$CA_{inj,n}^{AINL-CONT} = [\alpha.(rate_n^{AINL-CONT})^b].(1 - fact_{mit}) \tag{3.52}$$

8.9 Menghitung nilai *personnel injury consequence area* untuk tiap *release hole*, untuk Auto-Ignition Likely, Continuous Release (AIL-CONT), $CA^{AIL\text{-}CONT}$ menggunakan persamaan (3.53).

$$CA_{inj,n}^{AIL-CONT} = [\alpha.(rate_n^{AINL-CONT})^b].(1 - fact_{mit}) \tag{3.53}$$

8.10 Menghitung nilai *personnel injury consequence area* untuk tiap *release hole*, untuk Auto-Ignition Not Likely, Instantaneous Release (AINL-INST), $CA^{AINL\text{-}INST}$ menggunakan persamaan (3.54).

$$CA_{inj,n}^{AINL-INST} = \alpha(mass_n)^b \cdot \left(\frac{1-fact_{mit}}{eneff_n}\right) \tag{3.54}$$

8.11 Menghitung nilai *component damage consequence area* untuk tiap *release hole*, untuk Auto-Ignition Likely, Instantaneous Release (AIL-INST), $CA^{AIL\text{-}INST}$ menggunakan persamaan (3.55).

$$CA_{cmd,n}^{AIL-INST} = \alpha(mass_n)^b \cdot \left(\frac{1-fact_{mit}}{eneff_n}\right) \tag{3.55}$$

8.12 Menghitung nilai *blending factor*, $fact_n^{IC}$, untuk tipe pelepasan *instantaneous/continuous* untuk tiap *release hole* menggunakan persamaan (3.56) untuk *continuous release* dan persamaan (3.57) untuk *instantaneous release*.

$$fact_n^{IC} = \min\left[\left\{\frac{rate_n}{C_5}\right\}, 1.0\right] \tag{3.56}$$

$$fact_n^{IC} = 1.0 \tag{3.57}$$

8.13 Menghitung nilai AIT *blending factor,* $fact^{AIT}$, menggunakan persamaan (3.58), (3.59), atau (3.60) yang sesuai.

$$fact^{AIT} = 0 \qquad \text{untuk } T_S + C_6 \leq AIT \tag{3.58}$$

$$fact^{AIT} = \frac{(T_S - AIT + C_6)}{2 \cdot C_6} \qquad \text{untuk } T_S + C_6 > AIT > T_S - C_6 \tag{3.59}$$

$$fact^{AIT} = 1 \qquad \text{untuk } T_S - C_6 \geq AIT \tag{3.60}$$

8.14 Menghitung nilai *blended consequence area* untuk tipe pelepasan *continuous/instantaneous* tiap *release hole* pada komponen menggunakan persamaan berikut.

$$CA_{cmd,n}^{AIL} = CA_{cmd,n}^{AIL-INST} \cdot fact_n^{IC} + CA_{cmd,n}^{AIL-CONT} \cdot (1 - fact_n^{IC}) \tag{3.61}$$

$$CA_{inj,n}^{AIL} = CA_{inj,n}^{AIL-INST} \cdot fact_n^{IC} + CA_{inj,n}^{AIL-CONT} \cdot (1 - fact_n^{IC}) \tag{3.62}$$

$$CA_{cmd,n}^{AINL} = CA_{cmd,n}^{AINL-INST} \cdot fact_n^{IC} + CA_{cmd,n}^{AINL-CONT} \cdot (1 - fact_n^{IC}) \tag{3.63}$$

$$CA_{inj,n}^{AINL} = CA_{inj,n}^{AINL-INST} \cdot fact_n^{IC} + CA_{inj,n}^{AINL-CONT} \cdot (1 - fact_n^{IC}) \tag{3.64}$$

8.15 Menghitung nilai AIT *blended consequence area* pada komponen untuk tiap *release hole* berdasarkan hasil perhitungan *component damage consequence area* dan *personnel injury consequence area*.

a. Menghitung nilai AIT *blended consequence area* untuk *component damage*.

$$CA_{cmd,n}^{flam} = CA_{smd,n}^{AIL}.\, fact^{AIT} + CA_{cmd,n}^{AINL}.\, (1 - fact^{AIT}) \quad (3.65)$$

b. Menghitung nilai AIT *blended consequence area* untuk *personnel injury*.

$$CA_{inj,n}^{flam} = CA_{inj,n}^{flam-AIL}.\, fact^{AIT} + CA_{inj,n}^{AINL}.\, (1 - fact^{AIT}) \quad (3.66)$$

8.16 Menghitung nilai *consequence area* untuk *component damage* dan *personnel injury*.

a. Menghitung nilai *consequence area* untuk *component damage.*

$$CA_{cmd}^{flam} = \left(\frac{\Sigma gff_n \cdot CA_{cmd,n}^{flam}}{gff_{total}} \right) \quad (3.67)$$

b. Menghitung nilai *consequence area* untuk *personnel injury.*

$$CA_{inj}^{flam} = \left(\frac{\Sigma gff_n \cdot CA_{inj,n}^{flam}}{gff_{total}} \right) \quad (3.68)$$

Langkah 9. Menghitung nilai *toxic consequence.*

9.1 Menghitung *effective duration of release* untuk tiap *release hole* menggunakan persamaan (3.69).

$$ld_n^{tox} = \min\left(3600\,,\ \left\{\frac{mass_n}{W_n}\right\},\ \left\{60.\, ld_{max,n}\right\}\right) \quad (3.69)$$

9.2 Menentukan persentase toksik dari komponen, $mfrac^{tox}$, pada material rilis. Jika fluida yang dikeluarkan adalah fluida murni, $mfrac^{tox}=1.0$. Jika ada lebih dari satu komponen toksik dalam campuran fluida yang dikeluarkan, prosedur ini dapat diulang untuk setiap komponen toksik.

9.3 Menghitung laju pelepasan, $rate_n^{tox}$, dan massa pelepasan, $mass_n^{tox}$, untuk tiap *release hole* menggunakan persamaan (3.70) untuk *continuous release* dan persamaan (3.71) untuk *instantaneous release*.

$$rate_n^{tox} = mfrac^{tox}.\, W_n \quad (3.70)$$

$$mass_n^{tox} = mfrac^{tox}.\, mass_n \quad (3.71)$$

9.4 Menghitung *toxic consequence area* untuk tiap *release hole*.

a. HF Acid dan H_2S – Menghitung $CA_{inj,n}^{tox}$, menggunakan persamaan (3.72) untuk *continuous release* atau persamaan (3.73) *instantaneous release*.

$$CA_{inj,n}^{toxCONT} = C_8.\, 10^{(c.log_{10}[C_{4B}.rate_n^{tox}]+d)} \quad (3.72)$$

$$CA_{inj,n}^{toxINST} = C_8.\, 10^{(c.log_{10}[C_{4B}.mass_n^{tox}]+d)} \quad (3.73)$$

b. Ammonia and Chlorine – Menghitung $CA_{inj,n}^{tox}$, menggunakan persamaan (3.74) untuk *continuous release* atau persamaan (3.75) *instantaneous release*.

$$CA_{inj,n}^{toxCONT} = e(Rate_n^{tox})^f \quad (3.74)$$

$$CA_{inj,n}^{toxINST} = e(Mass_n^{tox})^f \tag{3.75}$$

9.5 Menghitung *additional toxic consequence area* untuk tiap *release hole* apabila terdapat *toxic component* lainnya dengan mengulang Langkah 9.2 sampai Langkah 9.3.

9.6 Menghitung nilai *final toxic consequence areas* untuk *personnel injury.*

$$CA_{inj}^{tox} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{tox}}{gff_{total}}\right) \tag{3.76}$$

Langkah 10. Menghitung nilai *non-flammable* dan *non-toxic consequences*.

10.1 Menghitung *non-flammable* dan *non-toxic consequences area* untuk tiap *release hole*.

10.1.1. Menghitung $CA_{inj,n}^{CONT}$ menggunakan persamaan (3.77) untuk *continuous release* dan $CA_{inj,n}^{INST}$ menggunakan persamaan (3.78) untuk *instantaneous release* pada *steam.*

$$CA_{inj,n}^{CONT} = C_9 \cdot Rate_n \tag{3.77}$$

$$CA_{inj,n}^{INST} = C_{10} \cdot (Mass_n)^{0.6384} \tag{3.78}$$

10.1.2. Menghitung $CA_{inj,n}^{CONT}$ menggunakan persamaan (3.79) untuk *continuous release* dan $CA_{inj,n}^{INST}$ menggunakan persamaan (3.80) untuk *instantaneous release* pada *acids* atau *caustics.*

$$CA_{inj,n}^{CONT} = 0.2 \cdot C_8 \cdot g(C_4 \cdot Rate_n)^h \tag{3.79}$$

$$CA_{inj,n}^{INST} = 0 \tag{3.80}$$

10.2 Menghitung nilai *instantaneous/continuous blending factor*, $fact_n^{IC}$, untuk tiap *release hole* menggunakan persamaan (3.81) untuk *steam* dan untuk *acids atau caustics*, $fact_n^{IC} = 0$.

$$fact_n^{IC} = min\left[\left\{\frac{rate_n}{C_5}\right\}, 1.0\right] \tag{3.81}$$

10.3 Menghitung nilai *blended non-flammable, non-toxic personnel injury consequence area*, $CA_{inj,n}^{leak}$, menggunakan persamaan (3.82).

$$CA_{inj,n}^{leak} = CA_{inj,n}^{INST} \cdot fact_n^{IC} + CA_{inj,n}^{CONT} \cdot (1 - fact_n^{IC}) \tag{3.82}$$

10.4 Menghitung nilai *final blended non-flammable, non-toxic personnel injury consequence area* untuk *personnel injury* menggunakan persamaan (3.83).

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}}\right) \tag{3.83}$$

Langkah 11. Menentukan nilai total luasan *final component damage* dan *personnel injury consequences*.

11.1 Menghitung area *final component damage consequence* menggunakan persamaan (3.84) berikut:

$$CA_{cmd} = \max\left[CA_{cmd}^{flam}, CA_{cmd}^{tox}, CA_{cmd}^{nfnt}\right] \tag{3.84}$$

Karena area *component damage consequence* untuk *toxic release,* CA_{cmd}^{tox}, dan *non-flammable,non-toxic releases,* CA_{cmd}^{nfnt}, keduanya bernilai nol. Sehingga final component damage sama dengan nilai *flammable component damage consequence area*.

$$CA_{cmd} = CA_{cmd}^{flam} \tag{3.85}$$

11.2 Menghitung area *final personnel injury consequence* CA_{inj}, menggunakan persamaan (3.86) berikut:

$$CA_{inj} = \max\left[CA_{inj}^{flam},\ CA_{inj}^{tox},\ CA_{inj}^{nfnt}\right] \tag{3.86}$$

11.3 Menghitung *final consequence area,* CA, menggunakan persamaan (3.87)

$$CA = \max\left[CA_{cmd}, CA_{inj}\right] \tag{3.87}$$

3.3.2.2 Tahapan-tahapan Perhitungan CoF Berbasis Finansial

Untuk menentukan nilai konsekuensi dari kegagalan *tube bundle* yang mengakibatkan *shutdown* tanpa penjadwalan, digunakan persamaan (3.88) berikut:

$$C_f^{tube} = Cost_{prod} + Cost_{env} + Cost_{bundle} + Cost_{maint} \tag{3.88}$$

Dimana unit produksi atau peluang hilangnya produksi ($Cost_{prod}$) ditentukan menggunakan persamaan (3.89) berikut:

$$Cost_{prod} = Unit_{prod} \cdot \left(\frac{Rate_{red}}{100}\right) \cdot D_{sd} \tag{3.89}$$

Dimana :

$Rate_{red}$ = *bypass with rate reduction*

$Unit_{prod}$ = biaya unit produksi

D_{sd} = waktu (hari) untuk perbaikan selama kegagalan yang tidak direncanakan

Biaya penggantian peralatan ($Cost_{bundle}$) dapat diasumsikan menggunakan persamaan (3.90) berikut:

$$Cost_{bundle} = \frac{22000 \cdot \left(\frac{\pi D_{shell}^3}{4}\right) \cdot L_{tube} \cdot M_f}{C_1} \tag{3.90}$$

Dimana :

D_{shell} = outside diameter (inch)

L_{tube} = panjang equipment (feet)

M_f = *tube material cost factors*

Biaya perawatan ($Cost_{maint}$) diasumsikan sama dengan biaya penggantian peralatan.

3.4 Perhitungan Nilai Risiko

Perhitungan *Probability of Failure* (PoF) dan *Consequence of Failure* (CoF) tidak dapat dipisahkan dalam menentukan analisis risiko dan program perencanaan inspeksi. Risiko didapatkan dengan mengkombinasikan nilai PoF dan CoF seperti yang tercantum pada persamaan (2.5) untuk konsekuensi berbasis area dan persamaan (2.6) untuk konsekuensi berbasis finansial.

Hasil risiko yang telah dihitung akan ditentukan level risikonya. Level risiko dapat dipresentasikan dengan menggunakan matriks risiko berdasarkan Gambar 2.5. Dalam menentukan tingkatan risiko pada matriks risiko, digunakan Tabel 2.1 untuk risko dengan konsekuensi berbasis area dan Tabel 2.2 untuk risiko dengan konsekuensi berbasis finansial.

3.5 Hasil Analisis

Setelah menghitung *Probability of Failure* (PoF) dan *Consequence of Failure* (CoF), akan didapatkan nilai risiko. Jika hasil dari perhitungan risiko berada dibawah target, perusahaan dapat terus melakukan perencanaan inspeksi menggunakan metodologi perawatan yang tepat.

Target-target yang dapat ditentukan dengan RBI untuk tindakan mitigasi adalah:

1. Target Risiko – tingkat risiko minimum untuk mengadakan perencanaan inspeksi. Dapat berupa area per tahun (m^2/tahun) atau finansial per tahun ($/tahun)
2. Target PoF – batas maksimum frekuensi kegagalan yang dapat diterima.
3. Target DF - batas maksimum nilai kerusakan yang dapat diterima atau dapat memicu penjadwalan inspeksi
4. Target CoF – tingkatan *consequence area* (CA) atau *financial consequence* (FA) yang dapat diterima.
5. Target *Thickness* – ketebalan minimum yang dapat diterima atau dapat memicu penjadwalan inspeksi.
6. Target Interval – rentang waktu maksimum seperti yang ditentukan dalam kode dan standar.

Apabila hasil perhitungan risiko melebih target risiko yang telah ditentukan, perlu untuk melakukan mitigasi dan menghitung risiko setelah mitigasi dilakukan hingga hasil dari perhitungan risiko dapat diterima.

3.6 Perencanaan Metode dan Penjadwalan Inspeksi

Merancang jadwal inspeksi dengan memperhatikan level risiko dari sebuah *equipment*. *Equipment* dengan level risiko yang lebih tinggi akan diprioritaskan untuk diinspeksi. Inspeksi dilaksanakan apabila risiko atau kondisi *equipment* sudah melebihi target yang dipasang oleh perusahaan.

Dalam merancang pelaksanaan dan penjadwalan inspeksi, beberapa hal yang perlu dipertimbangkan adalah:

1. Tipe kerusakan dari komponen yang dianalisa

   Tipe kerusakan dapat dilihat pada API 581 berdasarkan *damage factor* dan mempertimbangkan juga API 571 untuk karakteristik *damage mechanism*.
2. Metode NDE yang dapat mengidentifikasi kerusakan sesuai faktor kerusakannya.
3. Interval inspeksi maksimum yang ditetapkan pada *code* dan standart.

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BAB 4
PEMBAHASAN

4.1 Data Heat Exchanger

Berdasarkan American Petroleum Institution (API) 580 Chapter 7, kumpulan data yang dibutuhkan untuk menghitung Risk-Based Inspection (RBI) pada *Heat Exchanger* adalah:

- Desain dan konstruksi dari Amine Reboiler (PFD,P&ID dan General Assembly),
- Kondisi operasional Amine Reboiler (Process datasheet dan mechanical data sheet)
- Data komposisi kimia Amine Reboiler (Heat Material Balance),
- Laporan inspeksi Amine Reboiler (FAT Report)

Dari data-data yang disebutkan, kemudian diolah dan diproses sesuai dengan langkah-langkah yang terdapat dalam API 581. **Tabel 4.1** menunjukkan data yang dibutuhkan dalam analisa. Berikut merupakan penjelasan detail tentang data yang akan dianalisis:

4.1.1 General Data

General data adalah data umum yang berisi informasi dasar dan spesifikasi umum tentang Heat Exchanger mulai dari Nomor Tag, Kuantitas, Manufaktur, Nomor Seri, Jenis *heat exchanger*, dan *Code of Heat Exchanger* yang dijelaskan pada ASME VIII DIV 1, 2010 Edition.

Untuk *date of installation* dan *RBI date* masing masing menggunakan tanggal 1 Juni 2014 untuk *date of installation* dan 1 Januari 2020 untuk *RBI date*. Isian ini digunakan untuk analisis risiko Amine Reboiler.

4.1.2 Kondisi Desain

Pada data ini menunjukkan kondisi desain dan karakteristik dari *heat exchanger* ketika dirancang dan diproduksi oleh pabrik seperti informasi tentang tekanan desain dan suhu desain.

4.1.3 Kondisi Operasi

Kondisi operasi adalah suatu kondisi untuk mengoperasikan sistem atau proses tertentu, dalam hal ini akan tercapai ketika Heat Exchanger sedang dioperasikan. Seperangkat data ini berisi tekanan operasi, suhu operasi, *maximum allowable working pressure* (MAWP), c*orrosion allowance*, *geometry type*, volume, dan sebagainya.

4.1.4 Material

Material adalah komponen dasar dar bahan logam yang digunakan untuk membuat *Heat Exchanger* berdasarkan beberapa faktor dan pertimbangan. Pada penelitian ini, material dari *Amine Reboiler Heat Exchanger* adalah SA-516 GR.70N (Carbon Steel).

Tabel 4.1 *Amine Reboiler General Specification*

General Specification			
Tag Number		ABC-E-0101	
Process Unit		Amine Reboiler	
Manufactured by		Samsung Engineering Co., Ltd.	
TEMA Type *)		BKU	
TEMA Class *)		R	
Code		ASME Section VIII Division 1 Edition 2010	
Exchanger Type		Reboiler	
Geometry Type		Elliptical Head	
Dimension		508 mm (ID) / 914.4 mm (ID) X 5486.4 mm (L)	
Insulation		Yes	
Postweld Heat Treatment		Yes	
Install Date		June 1, 2014	
Tube Joint Design		Plain Type	
Quantitiy	Shell	1	
	Tube	224	
Material	Shell	SA-516 Gr.70N	
	Tube	SA-179 Smls	
Diameter	Shell (ID)	36.00	inch
		914.40	mm
	Tube (OD)	0.75	inch
		19.05	mm
Thickness	Shell	0.472	inch
		12.00	mm
	Tube	0.083	inch
		2.11	mm
Fluid Category	Shell	Lean Amine	
	Tube	Hot Oil (Therminol 55)	
Fluid Phase	Shell	Liquid	
	Tube	Liquid	
Design Pressure	Shell	85	psig
		586.08	Kpa
	Tube	210	psig
		1447.95	Kpa
Operating Pressure	Shell	20.7	psig
		142.73	Kpa
	Tube	65	psig
		448.18	Kpa
Design Temperature	Shell	300	°F
		148.89	°C
	Tube	450	°F
		232.22	°C

General Specification			
Operating Temperature	Shell	264	°F
		128.67	°C
	Tube	350	°F
		176.67	°C
Minimum Wall Thickness per Code	Shell	6.98	mm
	Tube	0.28	mm
Corrosion Allowance	Shell	5.02	Mm
	Tube	1.83	Mm
Allowable Stress (S)	Shell	138000	Kpa
	Tube	132000	Kpa

(Lanjutan Tabel 4.1 *Amine Reboiler General Specification*)

TEMA (Tubular Exchanger Manufacturers Assosciation) yaitu standar yang mengklasifikasikan bentuk dan toleransi dalam manufaktur *heat exchanger*. BKU adalah jenis *reboiler* dengan *U-tube bundle* yang dapat dilepaskan. TEMA Class R adalah *exchanger* dioperasikan untuk layanan pengilangan minyak (refinery service).

Dokumen PFD, P&ID dan General Assembly dapat dilihat pada **Lampiran 1**.

4.2 Komposisi Fluida

Komposisi dari fluida yang diproses dalam *equipment* Amine Reboiler dapat dilihat pada Tabel 4.2. Data yang ditampilkan pada Tabel 4.2 diambil dari dokumen *Heat Material Balance*(HMB) yang tercantum pada **Lampiran 2**.

Tabel 4.2 Komposisi Fluida

Stream Number	Stream Name	Composition	Symbol	Amount	Unit
158	Liquid to Amine Regenerator Reboiler	Hydrogen Sulfide	H_2S	0.0119	% mole
		Carbondioxide	CO_2	0.2894	% mole
		Water	H_2O	90.5763	% mole
		Methyl diethanolamine	aMDEA	9.1224	% mole
117A	Hot Oil to LP Fuel Gas Treatment Reboiler 1	Therminol 55	-	100.0000	% mole

Dari Tabel 4.2 terlihat bahwa air merupakan fluida paling dominan dari seluruh aliran fluida pada bagian *shell.* Namun berdasarkan API RP 581 Annex 3.A, jika fluida dominan adalah senyawa *inert* seperti CO_2 atau air, maka fluida representatif dipilih berdasarkan senyawa yang mudah terbakar atau beracun. Oleh karena itu, fluida representatif pada bagian *shell* adalah **H_2S**. Sedangkan fluida representatif pada bagian *tube* adalah **Therminol-55.**

4.3 Analisis RBI Berdasarkan API RP 581

4.3.1 Perhitungan Nilai Probability of Failure (PoF)

Nilai *probability of failure* (PoF) merupakan kombinasi dari nilai frekuensi kegagalan umum (gff), faktor kerusakan (Df) dan faktor sistem manajemen (F_{MS}) sesuai dengan persamaan (2.1). Perhitungan nilai PoF untuk Amine Reboiler secara detail dapat tercantum pada **Lampiran 4**.

4.3.1.1 Perhitungan Nilai Frekuensi Kegagalan Umum (gff)

Dalam melakukan perhitungan nilai frekuensi kegagalan umum atau *general failure frequency* (gff) menggunakan daftar rekomendasi dari Tabel 4.3 (mengacu pada Table 3.1 pada API RP 581).

Tabel 4.3 Rekomendasi Frekuensi Kegagalan Umum pada Komponen

Tipe Equipment	Tipe Komponen	*gff* as a Function of Hole Size (failures/yr)				gff_{total} (failures/yr)
		Small	Medium	Large	Rupture	
Heat Exchanger	HEXSS HEXTS	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

Dari Tabel 4.3, berdasarkan tipe *equipment* dan tipe komponen nilai gff_{total} sebesar **3.06E-05**.

4.3.1.2 Perhitungan Nilai Damage Factor (Df) Shell Side Amine Reboiler

Kriteria dalam menentukan faktor kerusakan atau *damage factor* yang berpengaruh pada *equipment* dapat dilihat pada **Lampiran 3** tentang d*amage factor screening questions*. Faktor kerusakan yang dapat mempengaruhi *shell side heat exchanger* berdasarkan kondisi operasi Amine Reboiler tercantum pada Tabel 4.3 berikut.

Tabel 4.4 Faktor Kerusakan (Damage Factor) Shell Side Amine Reboiler

No.	**Faktor Kerusakan**	**Kriteria *Screening***	**Ya / Tidak**
1	Thinning	Semua *equipment* perlu dievaluasi terhadap indikator kerusakan *thinning*.	Ya
2	Stress Corrosion Cracking – Amine Cracking	Jika konstruksi *equipment* dibangun dari material *carbon steel* dan fluida proses mengandung amina untuk *gas sweetening* (MEA, DEA, DIPA, MDEA, dll.) maka *equipment* harus dievaluasi untuk kerentanannya terhadap keretakan amina.	Ya
3	Stress Corrosion Cracking – Sulfide Stress Cracking	Jika konstruksi *equipment* dibangun dari material *carbon steel* dan fluida proses mengandung air dan H_2S maka *equipment* harus dievaluasi untuk kerentanan terhadap keretakan sulfida.	Ya
4	Stress Corrosion Cracking – HIC/SOHIC-H_2S	Jika konstruksi *equipment* dibangun dari material *carbon steel* dan fluida proses mengandung air dan H_2S maka *equipment* harus dievaluasi untuk kerentanan terhadap keretakan karena HIC/SOHIC-H_2S.	Ya

No.	Faktor Kerusakan	Kriteria *Screening*	Ya / Tidak
5	Corrosion Under Insulation - Ferritic Commponent	Jika *equipment* diinsulasi dan memenuhi salah satu dari beberapa faktor pada Lampiran 3, maka *equipment* harus dievaluasi untuk kerentanan terhadap korosi eksternal.	Ya

(Lanjutan Tabel 4.4 Faktor Kerusakan (Damage Factor) Shell Side Amine Reboiler)

Berikut merupakan perhitungan faktor kerusakan total pada *shell side* Amine Reboiler ABC-E-0101. Perhitungan nilai faktor kerusakan pada *shell side* Amine Reboiler ABC-E-0101 secara detail dicantumkan pada **Lampiran 4.1**.

1. **Perhitungan Thinning Damage Factor**

   Semua *equipment* perlu dievaluasi terhadap indikator kerusakan *thinning* atau penipisan. Thinning disebabkan oleh berbagai macam mekanisme seperti faktor korosi dan erosi. Faktor korosi disebabkan oleh senyawa yang terkandung pada fluida proses seperti CO_2, H_2S, H_2O, CL_2, dan amina. Faktor erosi disebabkan oleh kombinasi antara kecepatan aliran fluida dan besarnya partikel dalam fluida.

   Untuk perhitungan *thinning* pada *shell side* Amine Reboiler ABC-E-0101, berdasarkan hasil *screening criteria* pada API RP 581 Part 2 Annex 2.A, faktor korosi disebabkan oleh *sour water corrosion, amine corrosion* dan CO_2 *corrosion*. *Sour water corrosion* disebabkan adanya kandungan H_2S pada fluida proses. *Amine corrosion* disebabkan karena *equipment* terpapar *gas treating amine* (MDEA) dalam proses *sweetening gas*. *CO_2 corrosion* disebabkan oleh adanya kandungan CO_2 dan air pada fluida proses dan material konstruksi adalah SA-516 GR.70N yang merupakan *carbon steel* dengan kadar Cr <13%.

   Berdasarkan API RP 581, terdapat 2 jenis *thinning* antara lain *general* dan *localized*. *General thinning* merupakan korosi dengan ciri-ciri area terkorosi melebih 10% dan kedalaman kurang dari 1.27 mm. *Localized thinning* merupakan korosi dengan ciri-ciri area terkorosi kurang dari 10% dan kedalaman lebih dari dari 1.27 mm. Dalam menentukan tipe *thinning,* dapat menggunakan Tabel 2.B.1.2 pada API RP 581 Part 2 Annex 2.B.

   Hasil perhitungan untuk faktor kerusakan *thinning* pada *shell side* Amine Reboiler ABC-E-0101 adalah **1.06** saat RBI *date* dan **36.78** pada saat RBI *plan date*. Dengan jenis mekanisme *thinning* yang terjadi pada *shell side* Amine Reboiler ABC-E-0101 adalah ***local thining***. Perhitungan faktor kerusakan dan jenis *thinning* pada *shell side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.1.1**.

2. **Perhitungan Stress Corrosion Cracking (SCC) – Amine Cracking**

   Amine cracking merupakan jenis SCC yang didefinisikan sebagai keretakan akibat kombinasi dari *tensile stress* dan korosi yang disebabkan adanya larutan *alkonolamine* pada suhu tertentu. Larutan *alkonolamine* biasanya terdapat pada *amine treating unit* yang digunakan untuk menghilangkan senyawa yang bersifat asam pada gas atau cairan hidrokarbon.

Terdapat 4 parameter dalam menghitung kerentanan material terhadap *amine cracking* adalah jenis amine yang digunakan, komposisi larutan amina, temperatur operasi, dan level *tensile stress* dari material.

Pada penelitian ini, larutan *alkonolamine* berupa *methyldiethanoamine* (MDEA). Dimana MDEA memiliki peluang relatif lebih kecil dibandingkan dengan jenis amine yang lain. Larutan amina pada *equipment* terdiri dari 90.5763% air dengan kandungan 0.0119% H_2S dan 0.2894% CO_2 sehingga dikategorikan sebagai *lean amine* sehingga *amine cracking* memiliki peluang yang relatif kecil. Dengan adanya perlakuan PWHT (*post weld heat treatment*) pada *equipment* menyebabkan kerentanan material terhadap *amine cracking* dapat diturunkan.

Hasil perhitungan untuk faktor kerusakan SCC-*Amine cracking* pada *shell side* Amine Reboiler ABC-E-0101 adalah **71.7739** saat RBI *date* dan **125.8925** saat RBI *plan date*. Perhitungan faktor kerusakan SCC-*Amine cracking* pada *shell side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.1.2**.

3. Perhitungan Stress Corrosion Cracking (SCC) – Sulfide Stress Cracking

Sulfide stress cracking (SSC) merupakan jenis SCC yang didefinisikan sebagai keretakan akibat kombinasi dari *tensile stress* dan korosi yang disebabkan adanya air dan hydrogen sulfide. *Hydrogen stress cracking* terjadi terjadi karena penyerapan atom hydrogen yang dihasilkan oleh proses korosi sulfida pada permukaan logam. Kerentanan material terhadap SSC dapat diturunkan dengan perlakuan PWHT (*post weld heat treatment*) pada *equipment*.

Fluida proses pada *equipment* memiliki kandungan air sebesar 90.5763% dan kandungan H_2S sebesar 0.0119%. Dengan adanya perlakuan PWHT (*post weld heat treatment*) pada *equipment* menyebabkan kerentanan material terhadap SSC dapat diturunkan.

Hasil perhitungan untuk faktor kerusakan SCC-*Sulfide stress cracking* pada *shell side* Amine Reboiler ABC-E-0101 adalah **0.000**. Perhitungan faktor kerusakan SCC-*Sulfide stress cracking* pada *shell side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.1.3**.

4. Perhitungan Stress Corrosion Cracking (SCC) – HIC/SOHIC-H_2S Cracking

HIC/SOHIC – H_2S *cracking* merupakan singkatan dari *hydrogen-induced cracking* dan *stress oriented hydrogen-induced cracking* karena pengaruh H_2S. HIC didefinisikan sebagai keretakan internal bertahap yang menghubungkan hidrogen blister yang berdekatan pada permukaan yang berbeda. Kerentanan terhadap HIC utamanya dipengaruhi oleh kadar sulfur pada logam tersebut. Semakin tinggi kadar sulfur pada material, maka semakin rentan terhadap HIC. Kerentanan terhadap HIC juga dipengaruhi oleh pH dan konsentrasi H_2S di air. Semakin jauh dari pH netral dan/atau semakin tinggi konsentrasi H_2S, maka akan semakin rentan terhadap HIC.

Pada analisa tugas akhir ini, material dari *shell side* Amine Reboiler ABC-E-0101 adalah SA-516 GR.70N yang merupakan *carbon steel* dengan kandungan sulfur sebesar 0.035% dan adanya perlakuan PWHT (*post weld heat treatment*) sehingga memiliki *environmental severity* medium. Dengan pH 7.83 dan konsentrasi H_2S sebesar 0.0119%, tingkat kerentanan terhadap HIC relatif rendah.

Hasil perhitungan untuk faktor kerusakan SCC- HIC/SOHIC – H_2S *cracking* pada *shell side* Amine Reboiler ABC-E-0101 adalah **35.8869** saat RBI *date* dan **62.9463** saat RBI *plan date*. Perhitungan faktor kerusakan SCC-HIC/SOHIC – H_2S *cracking* pada *shell side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.1.4**.

5. Perhitungan Corrosion Under Insulation – Ferritic Component

Corrosion Under Insulation (CUI) adalah korosi lokal yang terjadi karena adanya air yang terkumpul pada ruang antara insulasi dan permukaan *equipment.* Air yang terkumpul dapat berasal dari air hujan, rembesan air, kondensasi, *deluge system,* dan *steam tracing leak.* CUI akan timbul pada temperatur -12° C dan 175° C. Pada rentang suhu 77° C sampai 110° C, CUI akan terjadi dengan laju yang lebih signifikan.

Mitigasi CUI dilakukan melalui insulasi dan pengecatan yang tepat. Pemasangan dan pemeliharaan insulasi yang tepat dapat mencegah masuknya air dalam jumlah yang signifikan.

Pada analisa tugas akhir ini, tipe insulasi dari *shell side* Amine Reboiler ABC-E-0101 adalah Calcium Silicate. Driver CUI berada pada lingkungan *marine/cooling tower drift area* sehingga basis *corrosion rate* memiliki nilai 0.095 mm/y.

Hasil perhitungan untuk faktor kerusakan CUI pada *shell side* Amine Reboiler ABC-E-0101 adalah **0.3636** saat RBI *date* dan **1.1121** saat RBI *plan date*. Perhitungan faktor kerusakan CUI pada *shell side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.1.5**.

6. Perhitungan Faktor Kerusakan Total pada Shell Side ABC-E-0101

Jika terdapat lebih dari satu mekanisme faktor kerusakan, maka total Df dihitung menggunakan persamaan (4.1) apabila *thinning* diklasifikasikan sebagai *local* dan tidak terdapat *internal liner.*

$$D_{f-total} = \max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{SSC} + D_{f-gov}^{htha} + D_{f-gov}^{brit} + D_{f-gov}^{mfat} \quad (4.1)$$

Sehingga nilai total faktor kerusakaan untuk *shell side* Amine Reboiler ABC-E-0101 adalah **72.830** saat RBI *date* dan **162.673** saat RBI *plan date*.

4.3.1.3 Perhitungan Nilai Damage Factor (Df) Tube Side Amine Reboiler ABC-E-0101

Kriteria dalam menentukan faktor kerusakan atau *damage factor* yang berpengaruh pada *equipment* dapat dilihat pada **Lampiran 3** tentang d*amage factor screening questions*.

Tube side Amine Reboiler ABC-E-0101 berada dalam lingkungan fluida proses dari *shell side* Amine Reboiler ABC-E-0101. Jadi, faktor eksternal dari *tube side* disesuaikan dengan fluida proses pada *shell side*, Lean Amine.

Faktor kerusakan yang dapat mempengaruhi *tube side heat exchanger* berdasarkan kondisi operasi ABC-E-0101 tercantum pada Tabel 4.5 berikut.

Tabel 4.5 Faktor Kerusakan (Damage Factor) Tube Side Amine Reboiler

No.	Faktor Kerusakan	Kriteria *Screening*	Ya / Tidak
1	Thinning (Internal dan eksternal)	Semua *equipment* perlu dievaluasi terhadap indikator kerusakan *thinning*.	Ya
2	Stress Corrosion Cracking – Amine Cracking (External)	Jika konstruksi *equipment* dibangun dari material *carbon steel* dan fluida proses mengandung amina untuk *gas sweetening* (MEA, DEA, DIPA, MDEA, dll.) maka *equipment* harus dievaluasi untuk kerentanannya terhadap keretakan amina.	Ya
3	Stress Corrosion Cracking – Sulfide Stress Cracking (External)	Jika konstruksi *equipment* dibangun dari material *carbon steel* dan fluida proses mengandung air dan H_2S maka *equipment* harus dievaluasi untuk kerentanan terhadap keretakan sulfida.	Ya
4	Stress Corrosion Cracking – HIC/SOHIC-H_2S (External)	Jika konstruksi *equipment* dibangun dari material *carbon steel* dan fluida proses mengandung air dan H_2S maka *equipment* harus dievaluasi untuk kerentanan terhadap keretakan karena HIC/SOHIC-H_2S.	Ya

Berikut merupakan perhitungan faktor kerusakan total pada *tube side* Amine Reboiler ABC-E-0101. Perhitungan nilai faktor kerusakan pada *tube side* Amine Reboiler ABC-E-0101 secara detail dicantumkan pada **Lampiran 4.2**.

1. **Perhitungan Thinning Damage Factor**

   Semua *equipment* perlu dievaluasi terhadap indikator kerusakan *thinning* atau penipisan. Thinning disebabkan oleh berbagai macam mekanisme seperti faktor korosi dan erosi. Faktor korosi disebabkan oleh senyawa yang terkandung pada fluida proses seperti CO_2, H_2S, H_2O, CL_2, dan amina. Faktor erosi disebabkan oleh kombinasi antara kecepatan aliran fluida dan besarnya partikel dalam fluida.

   Untuk perhitungan *thinning* pada *tube side* Amine Reboiler ABC-E-0101, perlu untuk menentukan faktor korosi berdasarkan hasil *screening criteria* pada API RP 581 Part 2 Annex 2.A. Dikarenakan fluida proses berupa 100% therminol-55 laju korosi tidak dapat ditentukan dengan API RP 581 Part 2 Annex 2.A. Sehingga laju korosi untuk perhitungan *thinning* diasumsikan sebesar **0.003 mm/yr** (Deshpande, 2018).

   Berdasarkan API RP 581, terdapat 2 jenis *thinning* antara lain *general* dan *localized*. *General thinning* merupakan korosi dengan ciri-ciri area terkorosi melebih 10% dan kedalaman kurang dari 1.27 mm. *Localized thinning* merupakan korosi dengan ciri-ciri area terkorosi kurang dari 10% dan kedalaman lebih dari dari 1.27 mm. Dalam menentukan tipe *thinning,* dapat menggunakan Tabel 2.B.1.2 pada API RP 581 Part 2 Annex 2.B.

Hasil perhitungan untuk faktor kerusakan *thinning* pada *tube side* Amine Reboiler ABC-E-0101 adalah **1.61**. Dikarenakan *tube side* Amine Reboiler ABC-E-0101 belum pernah dilakukan inspeksi, maka *thining* yang terjadi diasumsikan bersifat ***local thinning***. Perhitungan faktor kerusakan dan jenis *thinning* pada *tube side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.2.1**.

2. Perhitungan Faktor Kerusakan Eksternal

Tube side Amine Reboiler ABC-E-0101 berada dalam lingkungan fluida proses dari *shell side* Amine Reboiler ABC-E-0101. Jadi, faktor eksternal dari *tube side* disesuaikan dengan fluida proses pada *shell side*, Lean Amine. Perhitungan faktor kerusakan eksternal pada *tube side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.2.2**.

- **Perhitungan Thinning Damage Factor**

Semua *equipment* perlu dievaluasi terhadap indikator kerusakan *thinning* atau penipisan. Thinning disebabkan oleh berbagai macam mekanisme seperti faktor korosi dan erosi. Faktor korosi disebabkan oleh senyawa yang terkandung pada fluida proses seperti CO_2, H_2S, H_2O, CL_2, dan amina. Faktor erosi disebabkan oleh kombinasi antara kecepatan aliran fluida dan besarnya partikel dalam fluida.

Untuk perhitungan *thinning* eksternal pada *tube side* Amine Reboiler ABC-E-0101, berdasarkan hasil *screening criteria* pada API RP 581 Part 2 Annex 2.A, faktor korosi disebabkan oleh *sour water corrosion, amine corrosion* dan CO_2 *corrosion*. *Sour water corrosion* disebabkan adanya kandungan H_2S pada fluida proses. *Amine corrosion* disebabkan karena *equipment* terpapar *gas treating amine* (MDEA) dalam proses *sweetening gas. CO_2 corrosion* disebabkan oleh adanya kandungan CO_2 dan air pada fluida proses dan material konstruksi adalah SA-179 Smls yang merupakan *carbon steel* dengan kadar Cr <13%.

Hasil perhitungan untuk faktor kerusakan eksternal *thinning* eksternal pada *tube side* Amine Reboiler ABC-E-0101 adalah **166.62** saat RBI *date* dan **296.02** saat RBI *plan date*. Dengan jenis mekanisme *thinning* eksternal yang terjadi pada *tube side* Amine Reboiler ABC-E-0101 adalah ***local thining***. Perhitungan faktor kerusakan dan jenis *thinning* ekternal pada *tube side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.2.2.1**.

- **Perhitungan Stress Corrosion Cracking (SCC) – Amine Cracking**

Amine cracking merupakan jenis SCC yang didefinisikan sebagai keretakan akibat kombinasi dari *tensile stress* dan korosi yang disebabkan adanya larutan *alkonolamine* pada suhu tertentu. Larutan *alkonolamine* biasanya terdapat pada *amine treating unit* yang digunakan untuk menghilangkan senyawa yang bersifat asam pada gas atau cairan hidrokarbon.

Terdapat 4 parameter dalam menghitung kerentanan material terhadap *amine cracking* adalah jenis amine yang digunakan, komposisi larutan amina, temperatur operasi, dan level *tensile stress* dari material.

Pada penelitian ini, larutan *alkonolamine* berupa *methyldiethanoamine* (MDEA). Dimana MDEA memiliki peluang relatif lebih kecil dibandingkan dengan jenis amine yang lain. Larutan amina pada *equipment* terdiri dari 90.5763% air dengan kandungan 0.0119% H_2S dan 0.2894% CO_2 sehingga dikategorikan sebagai *lean amine* sehingga *amine cracking* memiliki peluang yang relatif kecil. Dengan adanya perlakuan PWHT (*post weld heat treatment*) pada *equipment* menyebabkan kerentanan material terhadap *amine cracking* dapat diturunkan.

Hasil perhitungan untuk faktor kerusakan SCC-*Amine cracking* eksternal pada *tube side* Amine Reboiler ABC-E-0101 adalah **71.7739** saat RBI *date* dan **125.8925** saat RBI *plan date*. Perhitungan faktor kerusakan SCC-*Amine cracking* eksternal pada *tube side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.2.2.2**.

- **Perhitungan Stress Corrosion Cracking (SCC) – Sulfide Stress Cracking**

Sulfide stress cracking (SSC) merupakan jenis SCC yang didefinisikan sebagai keretakan akibat kombinasi dari *tensile stress* dan korosi yang disebabkan adanya air dan hydrogen sulfide. *Hydrogen stress cracking* terjadi terjadi karena penyerapan atom hydrogen yang dihasilkan oleh proses korosi sulfida pada permukaan logam. Kerentanan material terhadap SSC dapat diturunkan dengan perlakuan PWHT (*post weld heat treatment*) pada *equipment*.

Fluida proses pada *equipment* memiliki kandungan air sebesar 90.5763% dan kandungan H_2S sebesar 0.0119%. Dengan adanya perlakuan PWHT (*post weld heat treatment*) pada *equipment* menyebabkan kerentanan material terhadap SSC dapat diturunkan.

Hasil perhitungan untuk faktor kerusakan SCC-*Sulfide stress cracking* eksternal pada *tube side* Amine Reboiler ABC-E-0101 adalah **0.000** saat RBI *date* dan RBI *plan date*. Perhitungan faktor kerusakan SCC-*Sulfide stress cracking* eksternal pada *tube side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.2.2.3**.

- **Perhitungan Stress Corrosion Cracking (SCC) – HIC/SOHIC-H_2S Cracking**

HIC/SOHIC – H_2S *cracking* merupakan singkatan dari *hydrogen-induced cracking* dan *stress oriented hydrogen-induced cracking* karena pengaruh H_2S. HIC didefinisikan sebagai keretakan internal bertahap yang menghubungkan hidrogen blister yang berdekatan pada permukaan yang berbeda. Kerentanan terhadap HIC utamanya dipengaruhi oleh kadar sulfur pada logam tersebut. Semakin tinggi kadar sulfur pada material, maka semakin rentan terhadap HIC. Kerentanan terhadap HIC juga dipengaruhi oleh pH dan konsentrasi H_2S di air. Semakin jauh dari pH netral dan/atau semakin tinggi konsentrasi H_2S, maka akan semakin rentan terhadap HIC.

Pada analisa tugas akhir ini, material dari *shell side* Amine Reboiler ABC-E-0101 adalah SA-179 Smls yang merupakan *carbon steel* dengan kandungan sulfur sebesar 0.035% dan adanya perlakuan PWHT (*post weld heat treatment*) sehingga memiliki *environmental severity* medium. Dengan pH 7.83 dan konsentrasi H_2S sebesar 0.0119% sehingga tingkat kerentanan terhadap HIC relatif rendah.

Hasil perhitungan untuk faktor kerusakan SCC- HIC/SOHIC – H_2S *cracking* eksternal pada *tube side* Amine Reboiler ABC-E-0101 adalah **35.8869** pada saat RBI *date* dan **62.9463** RBI *plan date*. Perhitungan faktor kerusakan SCC- HIC/SOHIC – H_2S *cracking* eksternal pada *tube side* Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 4.2.2.4**.

3. **Perhitungan Faktor Kerusakan Total pada Tube Side**

Jika terdapat lebih dari satu mekanisme faktor kerusakan, maka total Df dihitung menggunakan persamaan (4.1) apabila *thinning* diklasifikasikan sebagai *local* dan tidak terdapat *internal liner.*

$$D_{f-total} = \max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{SSC} + D_{f-gov}^{htha} + D_{f-gov}^{brit} + D_{f-gov}^{mfat} \quad (4.1)$$

Sehingga nilai total faktor kerusakaan untuk *tube side* Amine Reboiler ABC-E-0101 adalah **166.615** saat RBI *date* dan **296.018** saat RBI *plan date.*

4.3.1.4 Perhitungan Nilai Faktor Sistem Manajemen (F_{MS})

Dalam menentukan nila faktor sistem manajemen atau management system *factor* (F_{MS}) menggunakan serangkaian pertanyaan dan survei yang mengacu pada API RP 581 Part 2, Annex 2.A. Perhitungan (F_{MS}) secara detail tercantum pada **Lampiran 4**.

Dengan total *screening score* sebesar 500 atau didapatkan nilai F_{MS} berdasarkan persamaan (2.3) sebesar **0.9333**.

4.3.1.5 Perhitungan Nilai Probability of Failure (PoF)

Dengan nilai gff sebesar 3.06E-05, F_{MS} sebesar 0.9333 dan nilai Df, maka nilai PoF dapat dihitung menggunakan persamaan (2.1). Total nilai Df dan PoF yang didapatkan pada masing-masing tipe komponen tercantum pada Tabel 4.6. Untuk perhitungan PoF secara detail tercantum pada **Lampiran 4**.

Tabel 4.6 Tabel Hasil Perhitungan Faktor Kerusakan dan PoF Amine Reboiler ABC-E-0101

Tipe Komponen	**RBI Date**		**RBI Plan Date**	
	Df total	**PoF**	**Df total**	**PoF**
Shell Side (HEXSS)	72.830	2.080E-03	162.673	4.646E-03
Tube Side (HEXTS)	166.615	4.758E-03	296.018	8.454E-03

4.3.2 Perhitungan Nilai Consequence of Failure (CoF)

Nilai *consequence of failure* (CoF) digunakan untuk mengetahui dampak atau konsekuensi dari kegagalan sebuah *equipment.* Analisa CoF dapat dihitung dengan pendekatan area dan finansial dan dibagi menjadi dua level, yaitu Level 1 dan Level 2.

Berdasarkan Tabel 4.7 yang dikutip dari API RP 581 Part 3, menunjukkan perhitungan CoF untuk komponen/*equipment* menggunakan pendekatan finansial dapat diterapkan untuk semua tipe komponen. Sedangkan perhitungan CoF menggunakan pendekatan area tidak dapat digunakan untuk tipe komponen AST Bottoms, PRD dan *heat exchanger tube bundles*.

Tabel 4.7 Perhitungan CoF Berdasarkan Tipe Komponen

Tipe Komponen	**Tipe Perhitungan Konsekuensi**	
	Berbasis Area	**Berbasis Finansial**
Air Cooler	Yes	Yes
Compressor	Yes	Yes
Heat Exchanger (Shell, Channel)	Yes	Yes
Heat Exchanger Bundle	No	Yes
Pipe	Yes	Yes
PRD	No	Yes
Pressure Vessel	Yes	Yes
Pump	Yes	Yes
Tank Shell Course	Yes	Yes
Tank Bottom	Yes	Yes

Analisa konsekuensi pada Amine Reboiler ABC-E-0101 untuk tipe komponen HEXSS menggunakan konsekuensi level 1 dan pendekatan area terdampak dalam bentuk luas area terbakar, luas area radiasi panas yang berdampak bagi manusia dan luas area terdampak racun. Sedangkan untuk tipe komponen HEXTS, analisa konsekuensi dihitung menggunakan pendekatan finansial berdasarkan *bundle criticality* yang mencakup biaya hilangnya pendapatan produksi karena *downtime,* biaya dampak terhadap lingkungan dan biaya pemeliharaan serta penggantian *tube bundles.*Perhitungan nilai konsekuensi kegagalan secara detail tercantum pada **Lampiran 5**.

4.3.2.1 Perhitungan Nilai Konsekuensi Shell Side (HEXSS) ABC-E-0101

Dalam menentukan konsekuensi area dari Shell Side (HEXSS) Amine Reboiler ABC-E-0101, terdapat 11 langkah yaitu:

Langkah 1. Menentukan jenis fluida dan propertinya termasuk *release phase.*

Fluida representatif pada *equipment* adalah senyawa dengan jumlah mol yang dominan pada fluida. Apabila senyawa yang dominan merupakan senyawa *inert* seperti CO_2 dan air, maka fluida representatif ditentukan berdasarkan dampak area terbakar atau terpapar racun selain dari senyawa tersebut. Pilihan terbaik dalam menentukan fluida representatif adalah memilih fluida dengan nilai *Normal Boiling Point* (NBP) terendah.

Fluida representatif : H_2S
NBP : -59 °C
Density : 958.71 kg/m^3
Auto-Ignition Temperature (AIT) : 260 °C
Stored phase : Liquid
Release phase : Gas

Langkah 2. Menentukan ukuran lubang (release hole size area) yang mungkin akan terjadi (*small, medium, large, dan rupture*)

Pemilihan *release hole* ditentukan berdasarkan jenis *equipment* yang dianalisa. Terdapat 4 ukuran *release hole* yaitu *small, medium, large* dan *rupture*. Tiap ukuran lubang keluaran menentukan rentang kemungkinan konsekuensi yang dihasilkan. Set ukuran lubang mengacu pada API RP 581 Part 1, Annex 3 yang ditunjukkan pada Tabel 4.8 berikut.

Tabel 4.8 Set Ukuran Lubang Keluaran

Release Hole Number.	Release Hole Size	Range of Hole Diameters (inch)	Release Hole Diameters, d_n, (inch)
1	Small	1 – ¼	$d_1 = 0.25$
2	Medium	>¼ - 2	$d_2 = 1$
3	Large	>2 – 6	$d_3 = 4$
4	Rupture	>6	$d_4 = min\ [D,16]$

Untuk *shell side* Amine Reboiler ABC-E-0101, diambil ukuran *release hole* untuk *small* sebesar 0.25 inch, *medium* sebesar 1 inch, *large* sebesar 4 inch dan *rupture* sebesar 16 inch.

Langkah 3. Menghitung laju pelepasan

Laju pelepasan atau *theoretical release rate* (W_n) dihitung untuk berdasarkan *release hole size area* (A_n) tiap ukuran menggunakan persamaan (3.36) dan didapatkan hasil:

A_1 = 3.17E-05 m^2
A_2 = 5.06E-04 m^2
A_3 = 8.10E-03 m^2
A_4 = 1.30E-01 m^2

Dari *release hole size area* (A_n), *release rate* (W_n) dihitung menggunakan persamaan (3.38) sehingga didapatkan hasil berikut:

W_1 = 0.0003 kg/s
W_2 = 0.0047 kg/s
W_3 = 0.0746 kg/s
W_4 = 1.1930 kg/s

Semakin besar laju massa berarti semakin besar konsekuensi yang dapat dihasilkan karena berhubungan dengan total massa H_2S yang dikeluarkan pada setiap waktunya.

Langkah 4. Menghitung estimasi total fluida yang dikeluarkan

Estimasi total massa fluida ($Mass_{inv}$) untuk *equipment* adalah sebesar 2000 kg. Kemudian estimasi total massa inventori yang ditambahkan dengan inventori komponen yang dapat memberikan massa tambahan. Untuk massa tambahan, API RP 581 menjelaskan bahwa ada batas massa, karena dalam waktu 3 menit akan ada intervensi dari operator untuk kebocoran.

Menggunakan persamaan (3.41), didapatkan nilai estimasi total massa fluida yang dikeluarkan untuk tiap ukuran lubang keluaran ($Mass_{avail,n}$) sebagai berikut:

$Mass_{avail,1}$ = 2000 kgs
$Mass_{avail,2}$ = 2000 kgs
$Mass_{avail,3}$ = 2000 kgs
$Mass_{avail,4}$ = 2000 kgs

Langkah 5. Menentukan tipe pelepasan *continuous* atau *instantaneous.*

Kondisi pelepasan fluida akan dinyatakan sebagai *instantaneous* apabila massa 4536 kgs keluar dalam kurun waktu kurang dari 3 menit (180 detik). Perhitungan dilakukan menggunakan persamaan (3.42) untuk tiap ukuran lubang keluaran. Didapatkan hasil sebagai berikut:

t_1 = 15573624 s (continuous)
t_2 = 973352 s (continuous)
t_3 = 60834 s (continuous)
t_4 = 3802 s (continuous)

Langkah 6. Menentukan sistem deteksi dan isolasi.

Dengan mengklasifikasikan sistem deteksi dan sistem isolasi, maka dampak dari sistem deteksi dan isolasi dapat ditentukan. Klasifikasi sistem deteksi dan isolasi berdasarkan API RP 581 Part 3, Annex 3 adalah:

Detection System Classification = **A**
Isolation System Classification = **A**

Dikarenakan kedua sistem diklasifikasikan sebagai kelas A, maka waktu maksimum kebocoran (*total leak duration*) untuk tiap ukuran lubang keluaran adalah sebagai berikut:

$Id_{max,1}$ = 20 menit
$Id_{max,2}$ = 10 menit
$Id_{max,3}$ = 5 menit
$Id_{max,4}$ = 5 menit

Total leak duration mencakup waktu untuk mendeteksi kebocoran, waktu untuk menganalisa insiden dan menentukan tindakan korektif dan waktu untuk melaksanakan tindakan korektif yang ditentukan.

Langkah 7. Menentukan laju pelepasan dan massa fluida yang terlepas untuk analisa konsekuensi.

Untuk keluaran dengan tipe *continuous*, keluaran digambarkan keluar secara stabil pada laju tertentu. Laju tersebut didapatkan dari nilai *theoretical release rate* pada langkah 3. Menggunakan persamaan (3.43) didapatkan hasil sebagai berikut:

$Rate_1$ = 0.0002 kg/s
$Rate_2$ = 0.0035 kg/s

Rate$_3$ = 0.0559 kg/s
Rate$_4$ = 0.8948 kg/s

Sebagai pertimbangan keluaran spontantaneous yang bersifat sementara, *mass rate* dihitung menggunakan persamaan (3.45) dengan hasil sebagai berikut:

Mass$_1$ = 0.2621 kgs
Mass$_2$ = 2.0971 kgs
Mass$_3$ = 16.7767 kgs
Mass$_4$ = 268 kgs

Langkah 8. Menghitung nilai *flammable* dan *explosive consequence*.

Nilai konsekuensi ledakan area bagi komponen dan personil, dihitung menggunakan release rate dan mass rate yang telah dihitung pada Langkah 7 dan persamaan (3.67) da (3.68). Konstanta a dan b pada persamaan didapatkan dari Tabel 4.9 untuk konsekuansi pada komponen dan Tabel 4.10 untuk konsekuensi pada personil dengan fluida representatif berupa H_2S.

Tabel 4.9 Konstanta *Component Damage Flammable*

Continuous Release Constant								**Instantaneous Release Constant**							
Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto Ignition Not Likely (IAINL)				Auto Ignition Likely (IAIL)			
Gas		Liq.		Gas		Liq.		Gas		Liq.		Gas		Liq.	
α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
6.6	1.00			38.1	0.89			22.6	0.63			53.72	0.61		

Hasil dari konsekuensi *flammable* pada komponen apabila terjadi kebocoran adalah:

$$CA_{cmd}^{flam} = 0.1426 \text{ m}^2$$

Tabel 4.10 Konstanta *Personnel Injury Damage Flammable*

Continuous Release Constant								**Instantaneous Release Constant**							
Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto Ignition Not Likely (IAINL)				Auto Ignition Likely (IAIL)			
Gas		Liq.		Gas		Liq.		Gas		Liq.		Gas		Liq.	
α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
10.7	1.00			73	0.94			41.4	0.63			192	0.63		

Hasil dari konsekuensi flammable pada personil apabila terjadi kebocoran adalah:

$$CA_{inj}^{flam} = 0.2318 \text{ m}^2$$

Langkah 9. Menghitung nilai *toxic consequence*.

Nilai konsekuensi fluida beracun merupakan fungsi dari *release rate* dan konsentrasi senyawa beracun pada fluida proses. Komposisi fluida proses pada *equipment* yang memberikan dampak *toxic* adalah H_2S dan Ammonia. Perhitungan nilai *toxic consequence* dihitung menggunakan persamaan (3.76) dan didapat hasil sebagai berikut:

$$CA_{inj}^{tox} = 4.5557 \text{ m}^2$$

Langkah 10. Menghitung nilai *non-flammable, non-toxic consequence.*

Terdapat 2 kategori dalam menghitung nilai konsekuensi *non-flammable, non-toxic* untuk fluida berupa liquid yaitu *steam* dan *acids and caustics.* Karena pada fluida proses tidak ditemukan senyawa yang dikategorikan sebagai *acids and caustics* maka tidak perlu untuk melakukan perhitungan untuk kategori *acids and caustics.* Namun ditemukan uap pada fluida proses.

Pada umumnya uap akan muncul saat temperatur mencapai 100°C. Namun pada perhitungan ini, digunakan pendekatan uap akan muncul saat suhu mencapai 60°C dan temperatur operasi di dalam *shell side* Amine Reboiler adalah 128.67°C.

Dengan menggunakan persamaan (3.83) maka didapatkan hasil konsekuensi *non-flammable, non-toxic* apabila terjadi kebocoran adalah sebagai berikut:

CA_{inj}^{tox} = 0.00282 m^2

Langkah 11. Menentukan nilai total luasan *final component damage* dan *personnel injury consequences*.

Final konsekuensi adalah total dari konsekuensi pada komponen (CA_{cmd}) dan konsekuensi pada personil (CA_{inj}).

Untuk konsekuensi pada komponen, hanya ada konsekuensi *flammable* oleh karena itu, nilai konsekuensi pada komponen sama dengan nilai konsekuensi *flammable* pada komponen.

CA_{cmd} = 0.14264 m^2

Nilai konsekuensi pada personil dipengaruhi oleh beberapa tipe konsekuensi yaitu, flammable, toxic, serta non-flammable dan non-toxic. Berdasarkan persamaan (3.86) diambil nilai maksimum dari ketiga konsekuensi sehingga didapatkan hasil:

CA_{inj} = 4.55574 m^2

Menggunakan persamaan (3.87) didapatkan hasil final consequence area (CA) sebesar:

CA = 4.55574 m^2

4.3.2.2 Perhitungan Nilai Konsekuensi Tube Side (HEXTS) ABC-E-0101

Dalam menentukan konsekuensi finansial dari Tube Side (HEXTS) Amine Reboiler ABC-E-0101 pada penelitian ini menggunakan asumsi dari API RP 581 Part 1 Section 8 dengan nilai US dolar pada tahun 2001. Untuk menentukan nilai konsekuensi dari kegagalan *tube bundle* yang mengakibatkan *shutdown* tanpa penjadwalan (C_f^{tube}), digunakan persamaan (3.88).

Nilai C_f^{tube} dikategorikan menjadi biaya hilangnya pendapatan produksi karena *downtime* ($Cost_{prod}$) menggunakan persamaan (3.89), biaya dampak terhadap lingkungan ($Cost_{env}$), biaya penggantian *bundles* ($Cost_{bundle}$) yang didapatkan dari persamaan (8.90), dan biaya perawatan ($Cost_{maint}$). Dari parameter yang disebutkan, maka didapatkan nilai konsekuensi sebesar:

C_f^{tube} = \$218,675.43

4.4 Penentuan Level Risiko

Nilai risiko didapatkan dengan mengkombinasikan nilai *Probability of Failure* (PoF) dan *Consequence of Failure* (CoF) sesuai persaamaan (2.5) untuk *shell side* Amine Reboiler (HEXSS) dan persamaan (2.6) untuk *tube side* Amine Reboiler (HEXTS).

4.4.1 Menghitung Nilai Risiko Amine Reboiler ABC-E-0101

Nilai risiko pada saat RBI *date* dan RBI *plan date* untuk *shell side* dan *tube side* tercantum pada Tabel 4.11 berikut.

Tabel 4.11 Perhitungan Risiko

Deskripsi	Shell Side (HEXSS)		Tube Side (HEXTS)	
PoF (RBI date)	2.080E-03		4.758E-03	
PoF (RBI plan date)	4.646E-03		8.454E-03	
CoF	4.56	m^2	218675.43	$
Risk at RBI date	9.48E-03	m^2/year	1040.49	$/year
Risk at RBI plan date	2.12E-02	m^2/year	1848.59	$/year

Perhitungan risiko Amine Reboiler ABC-E-0101 secara detail tercantum pada **Lampiran 6**.

4.4.2 Level Risiko Amine Reboiler ABC-E-0101

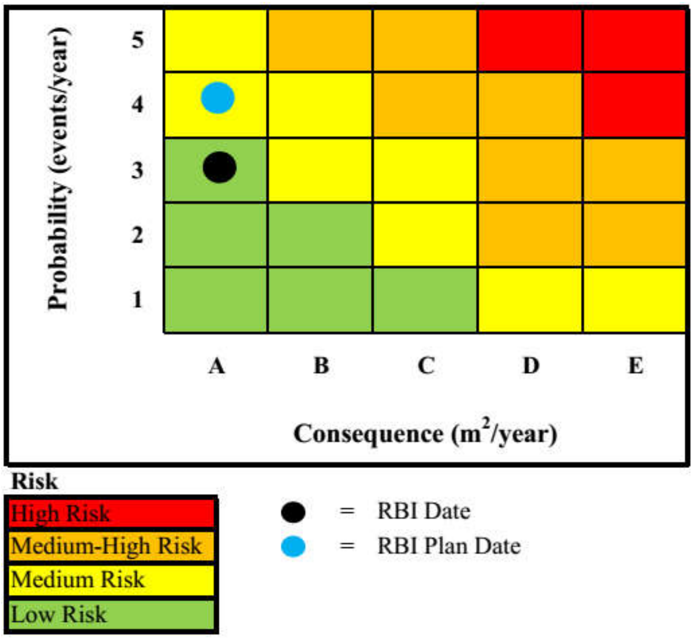
4.4.2.1 Level Risiko HEXSS ABC-E-0101

PoF dan CoF dari HEXSS dikategorikan berdasarkan Tabel 2.1 dan matriks risiko sesuai dengan Gambar 2.5, maka level risiko komponen dapat diketahui. Pada HEXSS Amine Reboiler ABC-E-0101 hasil level risiko yang didapatkan saat RBI *date* dan RBI *plan date* ditunjukkan oleh Tabel 4.12 berikut.

Tabel 4.12 Kategori Risiko HEXSS ABC-E-0101

Deskripsi	RBI date (1/1/2020)	RBI plan date (1/1/2024)
Kategori PoF	3	4
Kategori CoF	A	A
Kategori Risiko	3A	4A

Berdasarkan kategori risiko diatas maka didapatkan matriks risikonya yang ditunjukkan oleh Gambar 4.1 dengan PoF sebagai sumbu vertikal dan CoF sebagai sumbu horizontal. Didapatkan level risiko ***Low Risk*** saat RBI *date* dan ***Medium Risk*** saat RBI *plan date*.



Gambar 4.1 Matriks Risiko HEXSS ABC-E-0101

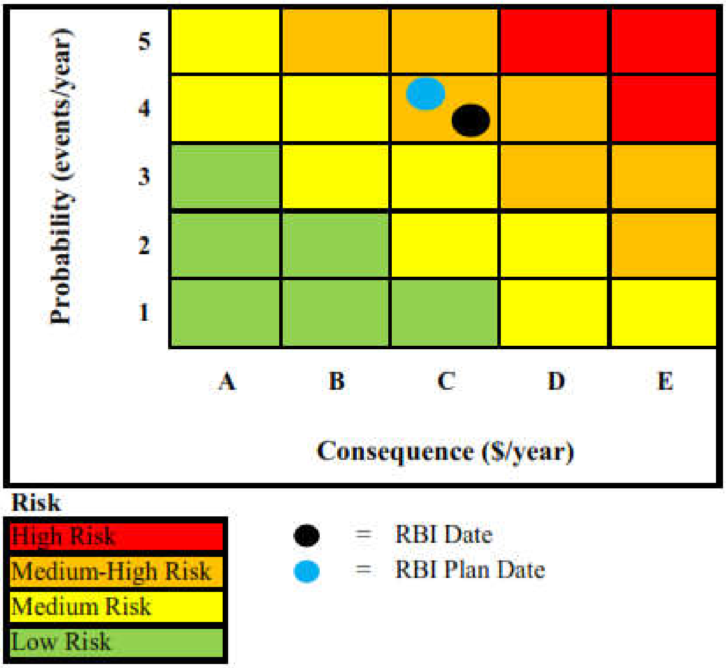
4.4.2.2 Level Risiko HEXTS ABC-E-0101

PoF dan CoF dari HEXTS dikategorikan berdasarkan Tabel 2.2 dan matriks risiko sesuai dengan Gambar 2.5, maka level risiko komponen dapat diketahui. Pada HEXTS Amine Reboiler ABC-E-0101 hasil level risiko yang didapatkan saat RBI *date* dan RBI *plan date* ditunjukkan oleh Tabel 4.13 berikut.

Tabel 4.13 Kategori Risiko HEXTS ABC-E-0101

Deskripsi	RBI date (1/1/2020)	RBI plan date (1/1/2024)
Kategori PoF	4	4
Kategori CoF	C	C
Kategori Risiko	3C	4C

Berdasarkan kategori risiko diatas maka didapatkan matriks risikonya yang ditunjukkan oleh Gambar 4.2 dengan PoF sebagai sumbu vertikal dan CoF sebagai sumbu horizontal. Didapatkan level risiko ***Medium-High Risk*** saat RBI *date* dan ***Medium-High Risk*** saat RBI *plan date*.



Gambar 4.2 Matriks Risiko HEXTS ABC-E-0101

4.5 Hasil Analisis

Untuk mengetahui apakah risiko dari suatu peralatan dapat diterima atau tidak perlu untuk menetapkan RBI target. Target didefinisikan sebagai level maksimum yang dapat diterima untuk operasi tanpa memerlukan tindakan mitigasi Pada analisis ini, digunakan target risiko sebesar 3.71 m^2/tahun untuk risiko berbasis area dan $75,000 per tahun untuk risiko berbasis finansial. Jika hasil dari perhitungan risiko berada dibawah target yang ditentukan, perusahaan dapat melanjutkan perencanaan inspeksi menggunakan metodologi perawatan yang tepat. Namun jika hasil perhitungan risiko melebihi target yang ditentukan, maka perlu dilakukan langkah mitigasi hingga nilai risiko dapat diterima.

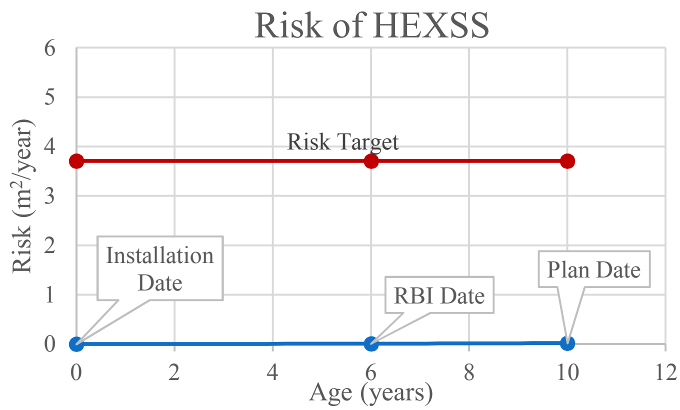
Dari perhitungan risiko HEXSS dan HEXTS ABC-E-0101, risiko berada dibawah target risiko sehingga tidak perlu diberikan rekomendasi melakukan mitigasi dan dapat melanjutkan untuk merancang metode dan penjadwalan inspeksi.

4.6 Perencanaan Metode dan Penjadwalan Inspeksi

Penjadwalan inspeksi adalah kegiatan menentukan interval waktu inspeksi yang tepat untuk komponen yang dianalisa, dalam penelitian ini adalah Amine Reboiler ABC-E-0101.

4.6.1 Waktu Pelaksanaan Inspeksi

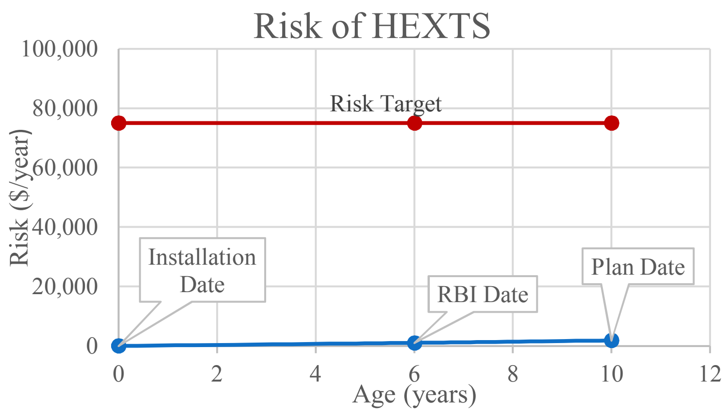
Usia pada saat *target date* HEXSS dan HEXTS dapat dihitung dengan cara interpolasi yang masing-masing ditunjukkan pada Tabel 4.14 dan Tabel 4.15. Gambar 4.3 dan Gambar 4.4 menunjukkan perpotongan kurva risiko saat RBI *date* dengan kurva *risk target* untuk mendapatkan nilai *target date*. Perhitungan interpolasi secara detail dapat dilihat pada **Lampiran 7**.



Gambar 4.3 Kurva Perbandingan Risiko Area (HEXSS ABC-E-0101)

Tabel 4.14 Perbandingan Usia pada RBI Date dan Target Date HEXSS

Data	Tanggal	Usia	Risiko (m^2/tahun)
RBI Date	1/1/2020	6	9.48E-03
Risk Target	?	2108.589	3.71
RBI Plan Date	1/1/2024	10	2.12E-02



Gambar 4.4 Kurva Perbandingan Risiko Finansial (HEXTS ABC-E-0101)

Tabel 4.15 Perbandingan Usia pada RBI Date dan Target Date HEXTS

Data	Tanggal	Usia	Risiko ($/tahun)
RBI Date	1/1/2020	6	1040.49
Risk Target	?	888.368	75000.00
RBI Plan Date	1/1/2024	10	1848.59

Karena data dan informasi yang digunakan dalam melakukan analisis RBI pada Amine Reboiler ABC-E-0101 memiliki kualitas yang belum memadai (menggunakan estimasi laju risiko API RP 581) dan data *thickness* yang digunakan adalah pada saat instalasi, maka akan berdampak pada hasil analisis. Oleh karena itu, didapatkan usia target date yang besar.

Untuk itu, penentuan jadwal inspeksi menggunakan interval berdasarkan rekomendasi API 510, yaitu 10 tahun (inspeksi internal) dan 5 tahun (inspeksi eksternal) sejak inspeksi terakhir dilaksanakan, dimana pada studi kasus ini inspeksi terakhir adalah pada saat instalasi yaitu 1 Juni 2014. Berdasarkan asumsi tersebut, maka tanggal dimana inspeksi harus dilaksanakan adalah **1 Januari 2024**.

4.6.2 Perencanaan dan Metode Inspeksi ABC-E-0101

Perencanaan inspeksi yang direkomendasikan tercantum pada Tabel 4.16 berikut.

Tabel 4.16 Rekomendasi Perencanaan Inspeksi Amine Reboiler ABC-E-0101

Damage Factor	Effecti-veness	Description		Due date	
				HEXSS	HEXTS
Local Thinning	C	Untuk area permukaan total:		1/1/2024	1/1/2024
		1	>50% pemeriksaan visual		
		DAN			
		2	100% follow up di area local thinning		
SCC-Amine Cracking	C	Untuk las / area las yang dipilih:		1/1/2024	1/1/2024
		1	>35% WMFT/ACFM		
		DAN			
		2	100% UT follow-up dari semua indikasi yang relevan		
SCC-Sulfide Stress Cracking	C	Untuk las / area las yang dipilih:		1/1/2024	1/1/2024
		1	>35% WMFT/ACFM		
		DAN			
		2	100% UT follow-up dari semua indikasi yang relevan		
SCC-HIC/SOHIC-H_2S	C	Untuk total area permukaan:		1/1/2024	1/1/2024
		1	>35% A atau C scan dengan straight beam		
		2	Diikuti dengan TOFD / Shear wave		
		3	100% Visual		
		ATAU			
		4	>50% WFMT/ACFM		
		5	UT Follow-up		
		6	100% Visual dari total area permukaan		
Corrosion Under Insulation (CUI)	C	Untuk total area permukaan:		1/1/2024	-
		1	100% Inspeksi visual eksternal sebelum insulasi dilepas		
		DAN			
		2	Melepaskan >25% insulasi dari total luas permukaan termasuk area yang rusak atau berpotensi rusak		
		DAN			
		3	Follow-up area yang terkorosi dengan inspeksi visual 100% pada permukaan yang terekspos menggunakan UT, RT atau pit gauge		

Perencanaan inspeksi pada metode ini mencakup pengukuran *wall thickness* pada beberapa titik yang direkomendasikan oleh API RP 572 berdasarkan tipe *heat exchanger* yaitu tipe BKU. Titik-titik yang direkomendasikan adalah *shell, head, tubing* dan *nozzle*.

Metode inspeksi yang direkomendasikan untuk masing-masing faktor kerusakan (*damage factor*) pada Amine Reboiler ABC-E-0101 secara detail dan poin-poin inspeksi yang direkomendasikan karena berpeluang terjadinya korosi dapat dilihat pada **Lampiran 7**.

BAB 5
KESIMPULAN DAN SARAN

5.1 Kesimpulan

Kesimpulan yang dapat diambil dari hasil analisis RBI pada Amine Reboiler Heat Exchanger ABC-E-0101 adalah:

1. Berdasarkan API RP 581, nilai *Probability of Failure* (PoF) dan *Consequence of Failure* (CoF) untuk *equipment heat exchanger* dikategorikan menjadi dua yaitu HEXSS (*shell side*) dan HEXTS (*tube side*). Berikut adalah nilai PoF dan CoF dari ABC-E-0101:

Equipment	Tipe Komponen	PoF		CoF
		RBI Date (1/1/2020)	RBI Plan Date (1/1/2024)	
ABC-E-0101	HEXSS	2.080E-03	4.646E-03	4.56 m^2
	HEXTS	4.758E-03	8.454E-03	$218,675.43

2. Nilai risiko yang didapatkan dari hasil kombinasi PoF dan CoF masing-masing tipe komponen Amine Reboiler ABC-E-0101 dimasukkan ke dalam matriks risiko. Sehingga level risiko masing-masing komponen berada pada:

Deskripsi	Shell Side (HEXSS)		Kategori	Tube Side (HEXTS)		Kategori
PoF at RBI date	2.080E-03		3	4.758E-03		4
PoF at RBI plan date	4.646E-03		4	8.454E-03		4
CoF	4.56	m^2	A	218675.43	$	C
Risk at RBI date	9.48E-03	m^2/year	3A	1040.49	$/year	4C
Risk at RBI plan date	2.12E-02	m^2/year	4A	1848.59	$/year	4C

Warna hijau menunjukkan nilai risiko berada pada level ***low***, warna kuning menunjukkan bahwa risiko berada pada level ***medium***, dan warna oranye menunjukkan nilai risiko berada pada level ***medium-high***.

Dengan target risiko dengan konsekuensi area adalah 3.71 m^2 dan target risiko dengan konsekuensi finansial adalah $75,000, nilai risiko HEXSS dan HEXTS menunjukkan hasil risiko berada di bawah target, sehingga nilai risiko dapat diterima.

3. Berdasarkan analisis RBI pada Amine Reboiler ABC-E-0101, jadwal inspeksi dan metode inspeksi yang direkomendasikan adalah:
   a. Jadwal Inspeksi

      Berdasarkan hasil perhitungan *inspection date* menggunakan analisis RBI, didapatkan hasil yang besar dan melebihi rekomendasi maksimum interval inspeksi dari *code.* Untuk itu, jadwal inspeksi menggunakan rekomendasi maksimum interval dari API RP 510 yaitu 5 tahun (inspeksi eksternal) dan 10 tahun (inspeksi internal) sejak inspeksi terakhir dilaksanakan. Oleh karena itu, tanggal dimana inspeksi untuk *equipment* Amine Reboiler ABC-E-0101 harus dilaksanakan adalah **1 Januari 2024**

b. Metode Inspeksi

Metode inspeksi yang dirancang disesuaikan dengan *damage factor equipment* dengan *inspection effectiveness* C. Untuk Amine Reboiler ABC-E-0101, direkomendasikan untuk melaksanakan metode inspeksi:

- *Visual Testing (VT),*
- *Ultrasonic Testing (UT)* atau *Radiographic Testing (RT),*
- *Magnetic Particle Testing* atau *Eddy Current Testing.*

Apabila terdapat *crack* yang terdeteksi pada Amine Reboiler, dapat melakukan metode inspeksi *Accoustic Emission Testing* untuk memonitoring pertumbuhan *crack*.

Perencanaan inspeksi yang dirancang mencakup pengukuran *wall thickness* pada poin-poin yang memiliki peluang korosi. Pada analisis Amine Reboiler beberapa titik yang direkomendasikan terletak pada *shell, head, nozzle* dan *tubing*.

5.2 Saran

1. Analisis RBI yang dilakukan pada Amine Reboiler menggunakan data informasi pada saat instalasi dan laju risiko menggunakan pendekatan dari API RP 581 sehingga berdampak pada hasil analisis *inspection date.*
2. Saat inspeksi dilaksanakan, sebaiknya dilakukan pada titik-titik yang sesuai dengan API RP 572 dan konsisten setiap inspeksi dilaksanakan sehingga data *wall thickness* yang didapatkan akan lebih akurat.

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ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

ATTACHMENT 01

General Specification

Amine Reboiler

<table>
<tr><td rowspan="4">Rev</td><td rowspan="4">Tanggal</td><td rowspan="4">Deskripsi</td><td rowspan="2">Disiapkan</td><td colspan="2">Disetujui</td></tr>
<tr><td colspan="2">Dosen Pembimbing</td></tr>
<tr><td>Khoirunnisa M.S.</td><td rowspan="2">Ir. Dwi Priyanta, M.SE</td><td rowspan="2">Nurhadi Siswantoro, S.T., M.T.</td></tr>
<tr><td>0421164000021</td></tr>
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<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

GENERAL SPECIFICATION

<table>
<tr><th colspan="4">GENERAL DATA</th></tr>
<tr><td colspan="2">Tag Number</td><td colspan="2">ABC-E-0101</td></tr>
<tr><td colspan="2">Process Unit</td><td colspan="2">Amine Reboiler</td></tr>
<tr><td colspan="2">Manufactured by</td><td colspan="2">Samsung Engineering Co., Ltd.</td></tr>
<tr><td colspan="2">TEMA Type *)</td><td colspan="2">BKU</td></tr>
<tr><td colspan="2">TEMA Class *)</td><td colspan="2">R</td></tr>
<tr><td colspan="2">Code</td><td colspan="2">ASME Section VIII Division 1 Edition 2010</td></tr>
<tr><td colspan="2">Exchanger Type</td><td colspan="2">Reboiler</td></tr>
<tr><td colspan="2">Geometry Type</td><td colspan="2">Elliptical Head</td></tr>
<tr><td colspan="2">Dimension</td><td colspan="2">508 mm (ID) / 914.4 mm (ID) X 5486.4 mm (L)</td></tr>
<tr><td colspan="2">Insulation</td><td colspan="2">Yes</td></tr>
<tr><td colspan="2">Postweld Heat Treatment</td><td colspan="2">Yes</td></tr>
<tr><td colspan="2">Install Date</td><td colspan="2">June 1, 2014</td></tr>
<tr><td colspan="2">Tube Joint Design</td><td colspan="2">Plain Type</td></tr>
<tr><td rowspan="2">Quantitiy</td><td>Shell</td><td colspan="2">1</td></tr>
<tr><td>Tube</td><td colspan="2">224</td></tr>
<tr><td rowspan="2">Material</td><td>Shell</td><td colspan="2">SA-516 Gr.70N</td></tr>
<tr><td>Tube</td><td colspan="2">SA-179 Smls</td></tr>
<tr><td rowspan="4">Diameter</td><td rowspan="2">Shell (ID)</td><td>36.00</td><td>inch</td></tr>
<tr><td>914.40</td><td>mm</td></tr>
<tr><td rowspan="2">Tube (OD)</td><td>0.75</td><td>inch</td></tr>
<tr><td>19.05</td><td>mm</td></tr>
<tr><td rowspan="4">Thickness</td><td rowspan="2">Shell</td><td>0.472</td><td>inch</td></tr>
<tr><td>12.00</td><td>mm</td></tr>
<tr><td rowspan="2">Tube</td><td>0.083</td><td>inch</td></tr>
<tr><td>2.11</td><td>mm</td></tr>
<tr><td rowspan="2">Fluid Category</td><td>Shell</td><td colspan="2">Lean Amine</td></tr>
<tr><td>Tube</td><td colspan="2">Hot Oil (Therminol 55)</td></tr>
<tr><td rowspan="2">Fluid Phase</td><td>Shell</td><td colspan="2">Liquid</td></tr>
<tr><td>Tube</td><td colspan="2">Liquid</td></tr>
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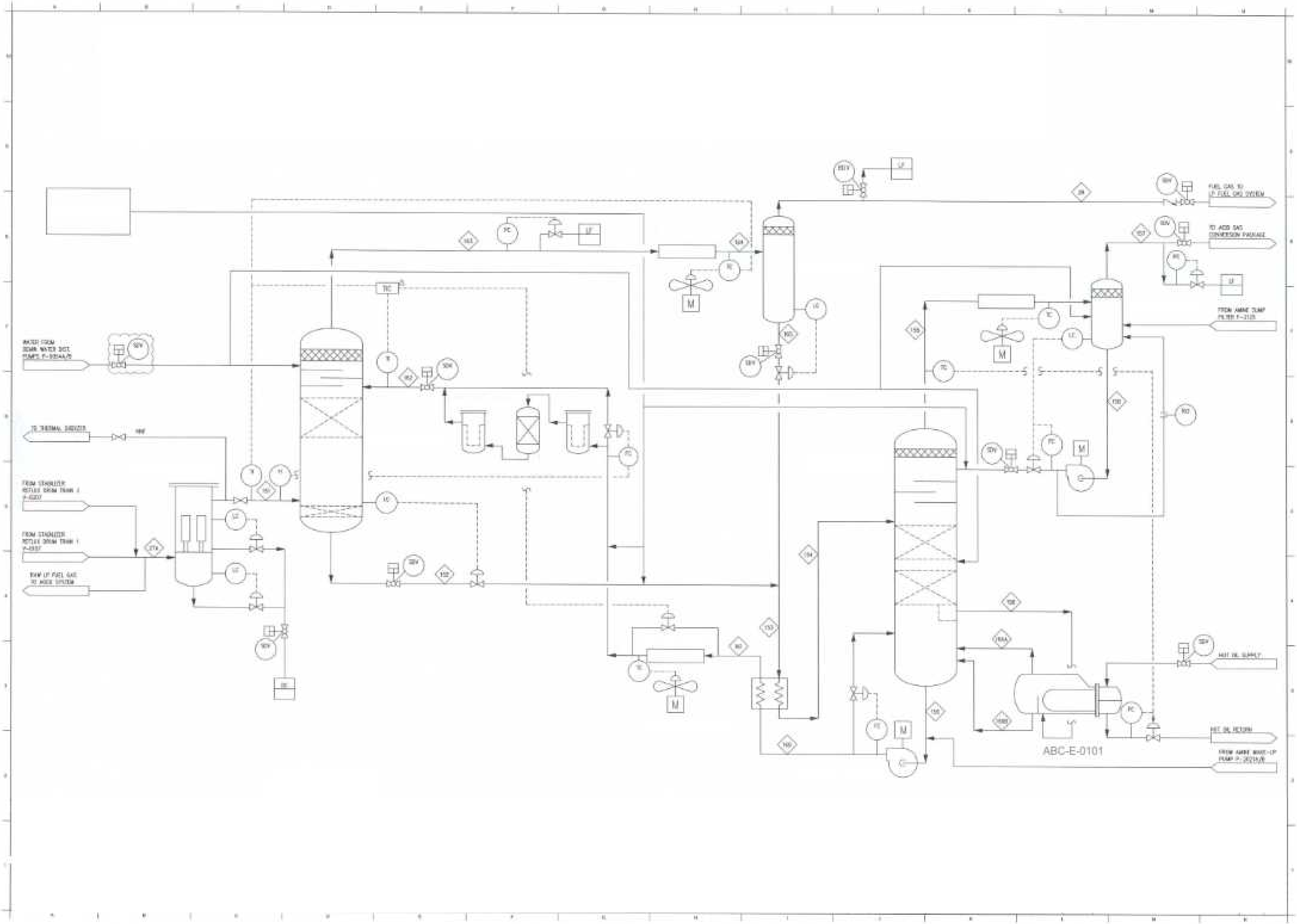
<tr><td>586.08</td><td>Kpa</td></tr>
<tr><td rowspan="2">Tube</td><td>210</td><td>psig</td></tr>
<tr><td>1447.95</td><td>Kpa</td></tr>
<tr><td rowspan="4">Operating Pressure</td><td rowspan="2">Shell</td><td>20.7</td><td>psig</td></tr>
<tr><td>142.73</td><td>Kpa</td></tr>
<tr><td rowspan="2">Tube</td><td>65</td><td>psig</td></tr>
<tr><td>448.18</td><td>Kpa</td></tr>
<tr><td rowspan="4">Design Temperature</td><td rowspan="2">Shell</td><td>300</td><td>F</td></tr>
<tr><td>148.89</td><td>C</td></tr>
<tr><td rowspan="2">Tube</td><td>450</td><td>F</td></tr>
<tr><td>232.22</td><td>C</td></tr>
</table>

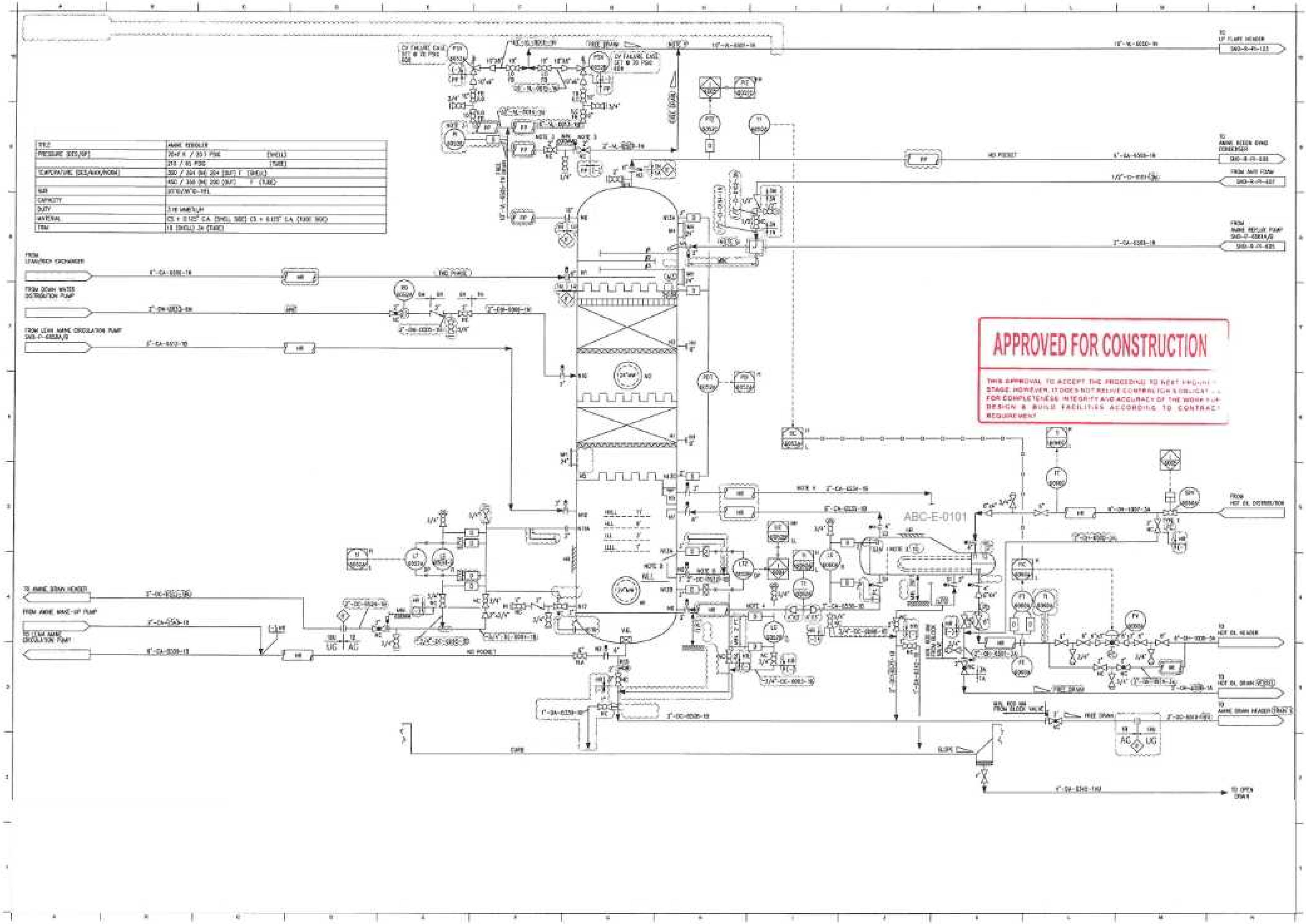
GENERAL DATA			
Operating Temperature	Shell	264	F
		128.67	C
	Tube	350	F
		176.67	C
Minimum Wall Thickness per Code	Shell	6.98	mm
	Tube	0.28	mm
Corrosion Allowance	Shell	5.02	mm
	Tube	1.83	mm
Allowable Stress (S)	Shell	138000	Kpa
	Tube	132000	Kpa

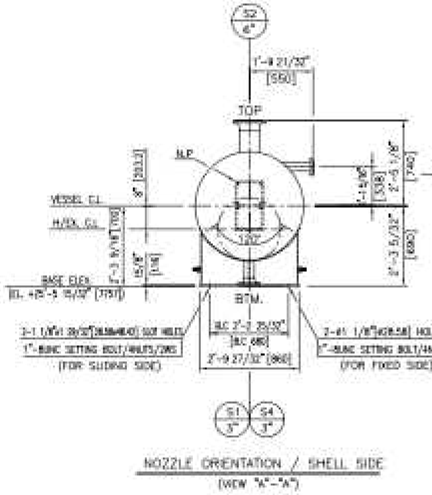
*) TEMA: Tubular Exchanger Manufacturers Association
BKU: kettle type reboiler with a removable U-tube bundle is a 'BKU' type.
TEMA CLASS R: for Refinery Service

TABLE OF CONVERSION				
1	$inch^2$	=	0.000645	m^2
1	m2	=	6.29	BBLS
1	psi	=	6.895	Kpa
1	lb/ft^3	=	16.018	kg/m^3



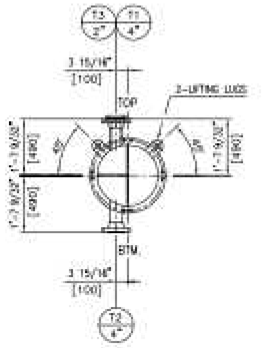
FUEL GAS TO
LP FUEL GAS SYSTEM
TO ACID GAS
CONVERSION PACKAGE
TO THERMAL OXIDIZER
HOT OIL SUPPLY
HOT OIL RETURN
ABC-E-0101


APPROVED FOR CONSTRUCTION
ABC-E-0101
TITLE
AMINE REBOILER
PRESSURE (DES/OP)
TEMPERATURE (DES/MAX/NORM)
SIZE
CAPACITY
DUTY
MATERIAL
TRIM
FROM LEAN/RICH EXCHANGER
FROM DEMIN WATER DISTRIBUTION PUMP
FROM LEAN AMINE CIRCULATION PUMP
TO AMINE DRAIN HEADER
FROM AMINE MAKE-UP PUMP
TO LEAN AMINE CIRCULATION PUMP
TO LP FLARE HEADER
FROM AMINE REFLUX PUMP
FROM HOT OIL DISTRIBUTION
TO HOT OIL HEADER
TO HOT OIL DRAIN
TO AMINE DRAIN HEADER
TO OPEN DRAIN
NO POCKET
FREE DRAIN
SLOPE



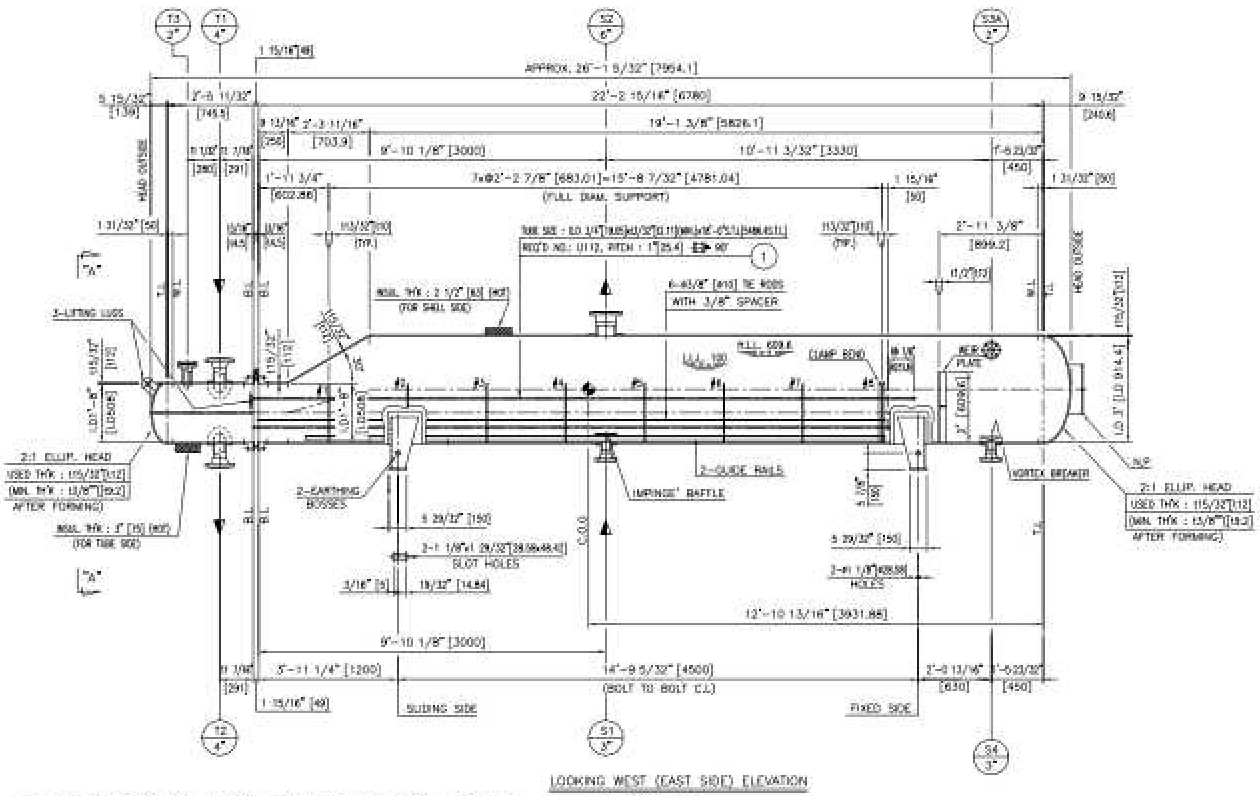
NOZZLE ORIENTATION / SHELL SIDE

(VIEW "A"-"A")



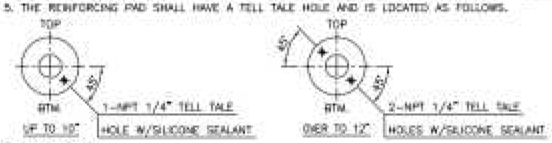
NOZZLE ORIENTATION / TUBE SIDE

(VIEW "A"-"A")



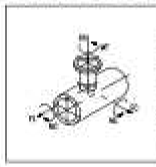
LOOKING WEST (EAST SIDE) ELEVATION

5. THE REINFORCING PAD SHALL HAVE A TELL TALE HOLE AND IS LOCATED AS FOLLOWS.



6. SPARE PARTS
 A) FOR COMMISIONING AND CONSTRUCTION
 .GASKET : 200%
 .BOLT AND NUTS : 10% (MIN. 4 SETS PER SIZE)
 B) FOR TWO YEARS OPERATION
 .GASKET : 200%
 .BOLT AND NUTS : 10% (MIN. 3 SETS PER SIZE)
7. TUBE TO TUBESHEET JOINT : HEAVY EXPANDING WITH TWO GROOVES
8. FOLLOWING DOCUMENTS ARE APPLIED TO FABRICATION, INSPECTION AND PAINTING
 1) WPS & PQR
 2) INSPECTION AND TEST PROCEDURE
 3) PAINTING PROCEDURE
9. INSULATION MATERIAL
 * HOT : CALCIUM SILICATE

10. GASKET MATERIAL
 1) GIRTH FLANGE : SPIRAL WOUND GASKET (13/16" [4.5]) 2) NOZZLE FLANGE : SPIRAL WOUND GASKET (13/16" [4.5])
 - HOOP : 316 S.S - HOOP : 316 S.S
 - FILLER : FLEXIBLE GRAPHITE - FILLER : FLEXIBLE GRAPHITE
 - INNER RING : 316 S.S - INNER RING : 316 S.S
 - OUTER RING : 316 S.S
 3) PASS PARTITION PART
 - FILLER : FLEXIBLE GRAPHITE
 - JACKET : 316 SS
11. CARBON STEEL TUBES IN AMINE SERVICE SHALL BE STRESS RELIEVED OVER THEIR BEND AREA PLUS 300 MM PROTRUDING, REGARDLESS OF OPERATING TEMPERATURE.
12. NOZZLE LOADS
13. S.R FOR HEAD SHALL BE COVERED BY PWHT.



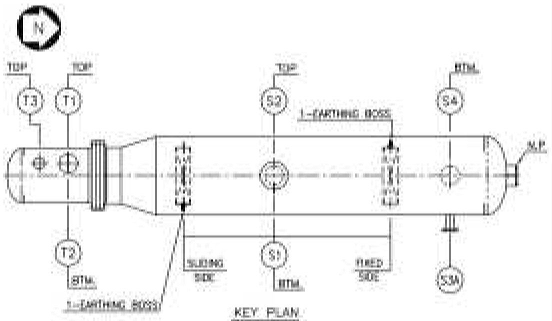
NOZZLE NO.	NOZZLE SIZE	FLANGE RATING	MOMENTS (kg.-m) ML	MC	MB	MT	FORCE (kg) FL	FC	FR	FA
S1,S4	3"	150#	87.75	87.75	–	101.25	450	337.5	–	-450
S2	6"	150#	351	351	–	405	900	675	–	-900
S3A	2"	150#	39	39	–	45	300	225	–	-300
T1,T2	4"	300#	208	208	–	240	800	600	–	-800

☐ APPROVED ☐ WITH COMMENTS
☐ REVIEWED ☐ RESUBMIT

This approval or review does not relieve the vendor/subcontractor of his responsibilities to meet all requirements of the purchase order

	ORIGINAL	CHECKED	APPD(PR)
SIGN			
DATE			
SAMSUNG ENGINEERING CO., LTD.			

SHELL SIDE/TUBE SIDE : AMINE SERVICE



KEY PLAN

PART NAME TO BE PAINTED	SURFACE PREPARATION SHELL	SURFACE PREPARATION TUBE	PRIMER COAT DFT (MILS) SHELL	PRIMER COAT TUBE	INTERMEDIATE COAT DFT (MILS) SHELL	INTERMEDIATE COAT TUBE	FINISH COAT DFT (MILS) SHELL	FINISH COAT TUBE	TOTAL DFT (MILS) SHELL	TOTAL DFT TUBE	FINISH COLOR SHELL	FINISH COLOR TUBE	MARKER SHELL	MARKER TUBE
EXTERNAL SURFACE OF CARBON STEEL SUCH AS SHELL, HEAD, SHELL FLANGE, CHANNEL FLANGE, REINFORCING PAD, ETC.	SSPC-SP10	SSPC-SP10	INTERZINC 12 (3.0)	INTERZINC 12 (3.0)	–	–	–	–	3.0	3.0	GREEN GRAY	GREEN GRAY		
EXTERNAL SURFACE OF PROTRUDING PORTIONS WHICH NOT TO BE COVERED BY INSULATION AND FIRE PROOFING SUCH NOZZLE, FLANGE, MANHOLE, CLIP, LIFTING LUG AND OTHERPROTRUSION.	SSPC-SP10	SSPC-SP10	INTERZINC 12 (3.0)	INTERZINC 12 (3.0)	–	–	INTERTHERM 50 (2.0)	INTERTHERM 50 (2.0)	5.0	5.0	SILVER (STD. MANUF.)	SILVER (STD. MANUF.)		
SUPPORT SADDLE, BASE PLATE INCLUDING BOTTOM SIDE OF BASE PLATE.	SSPC-SP10	SSPC-SP10	INTERZINC 12 (3.0)	–	INTERGARD 475 HS (5.0)	–	INTERTHANE 990 (2.0)	–	10.0	–	SILVER GREY RAL 7001	–		

CUSTOMER REF. DWG. NO.	DHI REF. DWG. NO.	TITLE	REV. No.	DATE	DESCRIPTION	DRAWN	CHK'D	VER'D	APP'D
			4	FEB. 19, '14	FOR FINAL	HABIB	MASKUR	APRIADI	J.H. KIM
SNO-M-450011B181-FD-025	D13020W-03-009	DETAIL OF TEST RING	3	DEC. 20, '13	FOR FINAL	HABIB	MASKUR	APRIADI	J.H. KIM
SNO-M-450011B181-FD-042	D13020W-06-007	DETAIL OF INSULATION	2	NOV. 04, '13	FOR FINAL	HABIB	MASKUR	APRIADI	J.H. KIM
SNO-M-450011B181-FD-045	D13020W-06-006	DETAIL OF NAME PLATE	1	OCT. 12, '13	FOR FINAL	HABIB	MASKUR	APRIADI	J.H. KIM
SNO-M-450011B181-FD-044	D13020W-06-005	DETAIL OF SADDLE	C	SEP. 16, '13	FOR FINAL	HABIB	MASKUR	APRIADI	J.H. KIM
SNO-M-450011B181-FD-043	D13020W-06-004	DETAIL OF NOZZLE	B2	JUL. 04, '13	RE-ISSUED FOR APPROVAL	PT.MK	MASKUR	APRIADI	J.H. KIM
SNO-M-450011B181-FD-042	D13020W-06-003	DETAIL OF TUBE BUNDLE	B1	MAY. 08, '13	RE-ISSUED FOR APPROVAL	PT.MK	MASKUR	APRIADI	J.H. KIM
SNO-M-450011B181-FD-041	D13020W-06-002	DETAIL OF BODY	B	MAR. 26, '13	ISSUED FOR APPROVAL	PT.MK	MASKUR	APRIADI	J.H. KIM

DESIGN DATA

CODE	ASME SEC. VIII DIV.1 2010 ED. 4 2011 ADD. & TEMA 9th ED. & API 660 8th ED. [ISO 16812]		TYPE		H-BKU
CODE STAMP	NO		SIZE		[illegible]
TEMA CLASS	"R"		WEIGHT lb (kg)	ERECTION	9480 [4300]
	SHELL SIDE	TUBE SIDE		EMPTY	9921 [4500]
PRESSURE PSIG (bar.g) DESIGN (INT./EXT.)	70 (4.83) / F.V	210 (14.48) / –		OPERAT.	18739 (8500)
OPERAT. (IN/OUT.)	20.7 (1.427) / –	65 (4.482) / –		FULL WATER	19401 (8800)
TEMP. °F (°C) DESIGN (MAX./MIN.)	300(148.89)/57.02(13.9)	450(232.22)/57.02(13.9)		BUNDLE	3527 (1600)
OPERAT. (IN/OUT.)	263.6(128.67)/264.2(129)	350(176.67)/290(143.33)	SURFACE AREA ft² (m²)		812.1 (75.45)
TEST PRESSURE PSIG (bar.g) HYDRO.	296 (20.42)	378 (26.03)	WIND CODE		ASCE-7-10
PNEUM.	–	–	SEISMIC CODE		UBC-97, ZONE 4
CORROSION ALLOWANCE INCH [MM]	0.125" [3]	0.125" [3]	SPECIAL SERVICE (S/T)		AMINE/AMINE
RADIOGRAPHY (SHELL/HEAD)	FULL /FULL	FULL / FULL	REGULATION		MIGAS
JOINT EFFICIENCY (SHELL/HEAD)	1 / 1	1 / 1	PAINTING SPEC.		
POST WELD HEAT TREATMENT	YES	YES			
S.R. HEAD COVER AFTER COLD FORMING	YES (SEE NOTE 13)	YES (SEE NOTE 13)			
FLUID NAME	LEAN AMINE	HOT OIL (THERMINOL 55)			
M.A.W.P. PSIG (bar.g)	228 (15.71)	248 (17.13)			
M.A.W.P. LIMITED BY	ASME B16.5 FLANGE 150#	CHANNEL FLANGE	GASKET CONTACT SURFACE	GIRTH FLANGE & TUBESHEET	125 – 250 AARH (SMOOTH FINISH)
M.D.M.T. °F (°C)	57.02 (13.9)	57.02 (13.9)			
NO. OF PASS.	1 (ONE)	4 (FOUR)		STD NOZZLE FLANGE	125 – 250 AARH (SMOOTH FINISH)
INSULATION INCH [MM]	2 1/2" [63] (HOT)	3" [75] (HOT)			

NOZZLE LIST

NOZZLE MARK	REQ'D NO.	NOM. SIZE	SCH. NO.	FLANGE RATING	SERVICE	REMARKS	TO C.L PROJECTION
S1	1	3"	160	ASME 150# W.N R.F	SHELL INLET		2'-3 5/32" [690]
S2	1	6"	120	ASME 150# W.N R.F	SHELL OUTLET		2'-5 1/8" [740]
S3A	2	2"	–	ASME 150# L.W.N R.F	LEVEL GAUGE		SEE DWG.
S4	1	3"	160	ASME 150# W.N R.F	LIQUID OUTLET	W/VORTEX BREAKER	2'-3 5/32" [690]
T1	1	4"	160	ASME 300# W.N R.F	TUBE INLET		1'-7 9/32" [490]
T2	1	4"	160	ASME 300# W.N R.F	TUBE OUTLET		1'-7 9/32" [490]
T3	1	2"	–	ASME 300# L.W.N R.F	VENT	W/BLIND	1'-7 9/32" [490]

MATERIAL SPECIFICATION

SHELL SIDE			TUBE SIDE			TUBE BUNDLE	
SHELL		SA516-70N	CHANNEL/HEAD		SA516-70N	TUBES	SA179 SMLS
REINF. PAD		SA516-70N	REINF. PAD		SA516-70N	TUBESHEET	SA266-2N
GIRTH FLANGE		SA266-2N	GIRTH FLANGE		SA266-2N	BAFFLE	SA285-C
NOZZLE FLANGE		SA105	NOZZLE FLANGE		SA105	TIE RODS/SPACER	SA36/SA53-B(E)
NOZZLE NECK	PLATE	–	NOZZLE NECK	PLATE	–		
	PIPE	SA106-B		PIPE	SA106-B		
SADDLE		SA283-C	STUD BOLT/NUT		SA193-B7/SA194-2H (H.D.G)		
SADDLE PAD		SA516-70N					
EARTHING BOSS		316 S.S					
EXTERNAL ATTACHMENTS		SA516-70N					
STUD BOLT/NUT		SA193-B7/SA194-2H(H.D.G)					
SETTING BOLT/4NUTS/2WS			SA325/SA194/ASTM F436 (H.D.G)				
GASKET (FOR GIRTH FLANGE & TUBESHEET)			SEE NOTE 10				
GASKET (FOR STD'D FLANGE)			SEE NOTE 10				

GENERAL NOTES
1. DIMENSIONS IN PARENTHESIS [ ] DENOTES MILLIMETER UNIT.
2. ALL BOLT HOLES SHALL BE STRADDLE WITH NORTH & SOUTH CENTER LINE OR NATURAL HORIZ. & VERT. CENTER LINE OF EQUIPMENT UNLESS OTHERWISE NOTED.
3. BASE LINE (B.L.) INDICATES THE GASKET CONTACT SURFACE OF GIRTH FLANGE.
4. ALL PADS FOR NOZZLE OR ATTACHMENTS SHALL BE PROVIDE WITH NPT 1/4" TELL TALE HOLE AND SHALL BE TESTED WITH COMPRESSED AIR AT MIN. 50 PSI.G PRIOR TO FINAL HYDROSTATIC TEST.

(1) SET TO BE MANUFACTURED

	ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

ATTACHMENT 02

Fluid Chemical Composition and Properties

Amine Reboiler

Rev	Tanggal	Deskripsi	Disiapkan	Disetujui	
				Dosen Pembimbing	
			Khoirunnisa M.S. 0421164000021	Ir. Dwi Priyanta, M.SE	Nurhadi Siswantoro, S.T., M.T.

FLUID CHEMICAL COMPOSITION PROPERTIES

Table 2.1 Fluid Composition

Stream Number	Stream Name	Composition	Symbol	Amount	Unit
158	Liquid to Amine Regenerator Reboiler	Hydrogen Sulfide	H_2S	0.0119	% mole
		Carbondioxide	CO_2	0.2894	% mole
		Water	H_2O	90.5763	% mole
		Methyl diethanolamine	aMDEA	9.1224	% mole
117A	Hot Oil to LP Fuel Gas Treatment Reboiler 1	Therminol 55	-	100.0000	% mole

Table 2.2 Fluid Properties

Stream Number	Stream Name	Properties	Amount	Unit
158	Liquid to Amine Regenerator Reboiler	Vapour Fraction	0.000	<none>
		Pressure	21	psig
		Temperature	264	F
		Mass Flow	40797	lb/hr
		Molecular Weight	27.02	<none>
		Mass Density	59.85	lb/ft3
		Mass Heat Capacity	1.01	Btu/lb-F
		Heat flow	8.6	MMBtu/hr
		Liquid Vol Flow @STD	2914	barrel/day
		Actual Volume Flow	40797	barrel/day
		Thermal Conductivity	0.276	Btu/hr-ft-F
		Viscosity	0.515	cP
		Cp/Cv (Gamma)	-	<none>
		Surface Tension	37.00	dyne/cm
117A	Hot Oil to LP Fuel Gas Treatment Reboiler 1	Vapour Fraction	0.000	<none>
		Pressure	65	psig
		Temperature	350	F
		Mass Flow	100216	lb/hr
		Molecular Weight	320	<none>
		Mass Density	47.75	lb/ft3
		Mass Heat Capacity	0.59	Btu/lb-F
		Heat flow	17.8	MMBtu/hr
		Liquid Vol Flow @STD	7846	barrel/day
		Actual Volume Flow	100216	barrel/day
		Thermal Conductivity	0.064	Btu/hr-ft-F
		Viscosity	0.949	cP
		Cp/Cv (Gamma)	-	<none>
		Surface Tension	-	dyne/cm

Calculation Stream Flow Velocity

Table 2.3 Stream Debit Calculation

Stream Number	Mass Flow (lb/hr)	Mass Density (lb/ft3)	Mass Density (kg/m3)	Debit (ft3/hr)	Debit (m3/s)
158	48660	59.85	958.707	813.0326	0.00639
117A	83914	47.75	764.883	1757.361	0.01382

Table 2.4 Stream Velocity Calculation

Stream Number	Equipment Type	Diameter (mm)	Area (m2)	Velocity (m/s)
158	HEXSS	914.40	0.6563600	0.0097
117A	HEXTS	19.05	0.0002849	48.5177

TABLE OF CONVERSION				
1	$inch^2$	=	0.000645	m^2
1	inch	=	25.4	mm
1	psi	=	6.895	Kpa
1	lb/ft^3	=	16.0185	kg/m^3

STREAM NUMBER		101	102	103	104	105	106	120	121	122	151	152	153	154	155	156	157	158	159	160	161	162	163
STREAM NAME		Fuel Gas from Sales Gas Header	HP Fuel Gas Scrubber Inlet	HP FG to GTG (Note 3)	HP FG to LP system	LP Fuel Gas Scrubber Inlet	LP Fuel Gas Header	Stabilizer OVHD Condenser Outlet to Reflux	Stabilizer Reflux Pump Suction	Stabilizer Reflux Pump Discharge	Inlet Amine Contactor	Rich Outlet Amine Contactor	Rich Amine Inlet Lean/Rich Exchanger	Rich Amine Inlet amine Regenerator	Regenerator O/H Vapor	Amine Reflux Drum Bottom Liquid	Offgas to AGCU	Liquid to Amine Regenerator Reboiler	Amine Regenerator Bottom Liquid	Lean Amine Inlet Lean/Rich Exchanger	Lean Amine Outlet Lean/Rich Exchanger	Lean Amine Inlet Amine Contactor	O/H Vapor Amine Contactor
Composition MOLE %																							
H_2S		0.0001	0.0001	0.0001	0.0001	0.0009	0.0009	0.1176	0.0522	0.0522	0.1335	0.0568	0.0568	0.0568	1.5522	0.0000	5.5240	0.0119	0.0092	0.0092	0.0092	0.0092	0.0020
CO_2		0.0040	0.0040	0.0040	0.0040	0.0108	0.0108	0.6245	0.1795	0.1795	2.6114	0.5796	0.5796	0.5796	23.9671	0.0612	85.2965	0.2894	0.2459	0.2459	0.2459	0.2459	0.0136
Nitrogen		0.8895	0.8895	0.8895	0.8895	0.6073	0.6074	0.0154	0.0007	0.0007	0.2361	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2352
Methane		90.7875	90.7875	90.7875	90.7875	78.0124	78.0213	11.0550	1.3360	1.3360	60.5001	0.0147	0.0147	0.0147	0.4751	0.0000	1.7059	0.0000	0.0000	0.0000	0.0000	0.0000	61.2417
Ethane		4.2917	4.2917	4.2917	4.2917	7.0454	7.0464	7.4840	3.0325	3.0325	10.4858	0.0035	0.0035	0.0035	0.1141	0.0000	0.4062	0.0000	0.0000	0.0000	0.0000	0.0000	10.6114
Propane		2.0752	2.0752	2.0752	2.0752	6.2751	6.2760	18.8770	15.0859	15.0859	11.3848	0.0042	0.0042	0.0042	0.1370	0.0000	0.4874	0.0000	0.0000	0.0000	0.0000	0.0000	11.7230
i-Butane		0.4806	0.4806	0.4806	0.4806	1.9876	1.9970	11.1349	12.5129	12.5129	3.9190	0.0014	0.0014	0.0014	0.0457	0.0000	0.1625	0.0000	0.0000	0.0000	0.0000	0.0000	3.9658
n-Butane		0.6674	0.6674	0.6674	0.6674	3.0288	3.0202	21.2518	25.6406	25.6406	6.0708	0.0021	0.0021	0.0021	0.0685	0.0000	0.2437	0.0000	0.0000	0.0000	0.0000	0.0000	6.2926
i-Pentane		0.3128	0.3128	0.3128	0.3128	0.1770	0.1770	13.7730	19.6983	19.6983	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane		0.2343	0.2343	0.2343	0.2343	1.7584	1.7587	10.5455	15.3965	15.3966	3.6926	0.0014	0.0014	0.0014	0.0457	0.0000	0.1625	0.0000	0.0000	0.0000	0.0000	0.0000	3.7964
n-Hexane		0.1719	0.1719	0.1719	0.1719	0.3645	0.3046	3.7816	5.9796	5.9796	0.4700	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4764
n-Heptane		0.0137	0.0137	0.0137	0.0137	0.0214	0.0214	0.1114	0.2145	0.2145	0.0310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0414
n-Octane		0.0233	0.0233	0.0233	0.0233	0.0413	0.0413	0.1169	0.1502	0.1502	0.0630	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0647
n-Nonane		0.0038	0.0038	0.0038	0.0038	0.0090	0.0090	0.0118	0.0155	0.0155	0.0155	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0157
n-Decane		0.0006	0.0006	0.0006	0.0006	0.0029	0.0029	0.0013	0.0021	0.0021	0.0050	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0059
C11+		0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O		0.0097	0.0097	0.0097	0.0097	0.6581	0.6543	0.2864	0.0702	0.0702	0.6509	89.8766	89.8766	89.8766	73.3294	99.9298	5.1178	90.5763	90.6182	90.6182	90.6182	90.6182	1.6545
TEGlycol		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CS2		0.0002	0.0001	0.0001	0.0001	0.0009	0.0009	0.0050	0.0067	0.0067	0.0019	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020
t-B-Mercaptan		0.0001	0.0001	0.0001	0.0001	0.0000	0.0000	0.0020	0.0031	0.0031	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Benzene		0.0076	0.0076	0.0076	0.0076	0.0162	0.0162	0.2358	0.3728	0.3728	0.0810	0.0014	0.0014	0.0014	0.0457	0.0000	0.1625	0.0000	0.0000	0.0000	0.0000	0.0000	0.0274
Toluene		0.0260	0.0260	0.0260	0.0260	0.0540	0.0540	0.3688	0.6031	0.6031	0.1064	0.0063	0.0063	0.0063	0.2654	0.0000	0.7311	0.0000	0.0000	0.0000	0.0000	0.0000	0.0902
p-Xylene		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
aMDEA		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	9.0520	9.0520	9.0520	0.0000	0.0000	0.0000	9.1224	9.1267	9.1267	9.1267	9.1267	0.0000
OVERALL																							
Vapour Fraction	<none>	1.000	1.000	1.000	1.000	1.000	1.000	0.421	0.000	0.000	1.000	0.000	0.000	0.025	1.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	1.000
Pressure	psig	842	302	292	292	102	102	120	120	148	115	115	130	20	20	19	19	21	21	205	195	120	114
Temperature	F	100	73	100	100	91	91	120	120	120	108	132	132	246	246	120	120	264	264	264	150	140	140
Mass Flow	lb/hr	20200	20200	8057	12143	26281	26278	10865	7536	7536	14571	39573	39573	40284	1648	568	519	40797	39055	39055	39055	39055	14156
Molecular Weight	<none>	18.31	18.31	18.31	18.31	22.42	22.42	53.24	61.60	61.60	28.20	27.73	27.73	28.25	24.79	18.02	42.13	27.82	27.73	27.73	27.60	27.60	27.75
Mass Density	lb/ft3	3.00	1.09	0.98	0.98	0.46	0.46	3.02	34.78	34.77	0.62	64.34	64.34	5.14	0.11	61.68	0.22	59.85	59.86	59.86	63.21	63.60	0.58
Mass Heat Capacity	Btu/lb-F	0.62	0.54	0.55	0.55	0.50	0.50	0.56	0.60	0.60	0.46	0.90	0.90	0.97	0.32	1.00	0.22	1.01	1.01	1.01	0.92	0.91	0.50
Heat Flow	MMBtu/hr	-36.6	-36.6	-14.4	-21.8	-41.5	-41.5	-11.8	-7.9	-7.9	0.5	3.0	3.0	7.3	0.7	0.1	0.0	8.6	8.2	8.2	3.9	2.2	0.7
Vapour																							
Std Gas Flow	MMSCFD	10.03	10.03	4.00	6.03	10.65	10.65	0.74	-	-	4.71	-	-	0.03	0.40	-	0.11	-	-	-	-	-	4.65
Actual Gas Flow	ACFM	112	309	136	206	958	958	56	-	-	392	-	-	120	250	-	39	-	-	-	-	-	407
Mass Flow	lb/hr	20200	20200	8057	12143	26279	26278	3329	-	-	14571	-	-	762	1648	-	519	-	-	-	-	-	14156
Molecular Weight	<none>	18.31	18.31	18.31	18.31	22.42	22.42	40.73	-	-	28.20	-	-	23.38	24.79	-	42.13	-	-	-	-	-	27.75
Mass Density	lb/ft3	3.00	1.09	0.98	0.98	0.46	0.46	0.99	-	-	0.62	-	-	0.11	0.21	-	0.22	-	-	-	-	-	0.58
Mass Heat Capacity	Btu/lb-F	0.621	0.540	0.547	0.547	0.498	0.498	0.475	-	-	0.464	-	-	0.317	0.317	-	0.223	-	-	-	-	-	0.495
Thermal Conductivity	Btu/hr-ft-F	0.023	0.019	0.021	0.021	0.018	0.018	0.014	-	-	0.013	-	-	0.014	0.015	-	0.011	-	-	-	-	-	0.014
Viscosity	cP	0.015	0.012	0.012	0.012	0.011	0.011	0.010	-	-	0.010	-	-	0.016	0.015	-	0.015	-	-	-	-	-	0.010
Compressibility	<none>	0.870	0.937	0.950	0.950	0.969	0.969	0.894	-	-	0.954	-	-	0.987	0.987	-	0.989	-	-	-	-	-	0.957
Cp/Cv (Gamma)	<none>	1.483	1.357	1.334	1.334	1.254	1.254	1.182	-	-	1.219	-	-	1.300	1.300	-	1.283	-	-	-	-	-	1.230
HC Liquid																							
Liquid Vol Flow @Std Cond	barrel/day	-	-	-	-	-	-	864	864	864	-	-	-	-	-	-	-	-	-	-	-	-	-
Actual Volume Flow	barrel/day	-	-	-	-	-	-	926	926	926	-	2630	2630	2762	-	39	-	2914	2789	2789	2641	2622	-
Mass Flow	lb/hr	-	-	-	-	-	-	7536	7536	7536	-	39573	39573	39491	-	568	-	40797	39055	39055	39055	39055	-
Molecular Weight	<none>	-	-	-	-	-	-	61.60	61.60	61.60	-	27.73	27.73	27.74	-	18.02	-	27.82	27.73	27.73	27.60	27.60	-
Mass Density	lb/ft3	-	-	-	-	-	-	34.78	34.78	34.77	-	64.34	64.34	81.13	-	61.68	-	59.85	59.86	59.86	63.21	63.60	-
Mass Heat Capacity	Btu/lb-F	-	-	-	-	-	-	0.60	0.60	0.60	-	0.90	0.90	0.99	-	1.00	-	1.01	1.01	1.01	0.92	0.91	-
Thermal Conductivity	Btu/hr-ft-F	-	-	-	-	-	-	0.051	0.051	0.051	-	0.230	0.230	0.270	-	0.371	-	0.270	0.280	0.280	0.240	0.230	-
Viscosity	cP	-	-	-	-	-	-	0.143	0.143	0.143	-	2.170	2.170	0.629	-	0.552	-	0.515	0.511	0.511	1.660	2.185	-
Cp/Cv (Gamma)	<none>	-	-	-	-	-	-	1.06	1.06	1.43	-	-	-	-	-	-	-	-	-	-	-	-	-
Surface Tension	dyne/cm	-	-	-	-	-	-	9.45	9.45	9.44	-	47.60	47.60	38.34	-	68.13	-	37.30	36.99	36.99	46.24	47.73	-
Aqueous																							
Liquid Vol Flow @Std Cond	barrel/day	-	-	-	-	0	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Actual Volume Flow	barrel/day	-	-	-	-	0	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Flow	lb/hr	-	-	-	-	3	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Molecular Weight	<none>	-	-	-	-	18.02	-	87.25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Density	lb/ft3	-	-	-	-	62.34	-	68.43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Heat Capacity	Btu/lb-F	-	-	-	-	1.00	-	0.62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Conductivity	Btu/hr-ft-F	-	-	-	-	0.359	-	0.129	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Viscosity	cP	-	-	-	-	0.754	-	9.280	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cp/Cv (Gamma)	<none>	-	-	-	-	1.36	-	1.06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surface Tension	dyne/cm	-	-	-	-	70.77	-	44.69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

STREAM NUMBER		112	112A	113	113A	114	114A	115A	115B	116A	116B	117A	117B	118	118A	119A	119B
STREAM NAME		Hot Oil Circulation Pump Suction	Hot Oil Circulation Pump Suction	Hot Oil Circulation Pump Discharge	Hot Oil Heater Train 1 By pass Line	Hot Oil from Hot Oil Heater Train 1	Hot Oil Heater Outlet Balance Line	Hot Oil to Stabilizer Reboiler 1	Hot Oil from Stabilizer Reboiler 1	Hot Oil to Amine Regeneration Reboiler 1	Hot Oil from Amine Regeneration Reboiler 1	Hot Oil to LP Fuel Gas Treatment Reboiler 1	Hot Oil from LP Fuel Gas Treatment Reboiler 1	Hot Oil Return	Hot Oil Return Train 1	Hot Oil to TEG Regeneration Reboiler 1	Hot Oil from TEG Regeneration Reboiler 1
Composition MOLE %																	
H2S		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO2		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Nitrogen		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Methane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Ethane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Propane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
i-Butane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
i-Pentane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Hexane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Heptane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Octane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Nonane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Decane		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C11+		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2O		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CS2		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
t-B-Mercapta		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Benzene		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Toluene		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
p-Xylene		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Therminol 55		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
OVERALL																	
Vapour Fraction	<none>	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Pressure	psig	95	95	175	175	85	85	65	55	65	55	65	55	40	40	65	55
Temperature	F	301	301	301	301	450	450	450	400	350	290	350	300	301	301	450	410
Mass Flow	lb/hr	4549905	2274953	2068139	1292545	775595	587345	97255	97255	1789673	1789673	100216	100216	4036062	2068139	80955	80955
Molecular Weight	<none>	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
Mass Density	lb/ft3	49.00	49.00	49.00	49.00	45.25	45.25	45.25	46.50	47.75	49.20	47.75	49.00	49.00	49.00	45.25	46.25
Mass Heat Capacity	Btu/lb-F	0.57	0.57	0.57	0.57	0.64	0.64	0.64	0.61	0.56	0.56	0.59	0.57	0.57	0.57	0.64	0.62
Heat Flow	MMBtu/hr	674.8	337.4	306.7	191.7	184.9	142.6	23.2	20.1	317.0	255.4	17.8	14.5	598.5	306.7	19.3	17.5
Vapour																	
Std Gas Flow	MMSCFD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Actual Gas Flow	ACFM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Flow	lb/hr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Molecular Weight	<none>	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Density	lb/ft3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Heat Capacity	Btu/lb-F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Conductivity	Btu/hr-ft-F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Viscosity	cP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Compressibility	<none>	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cp/Cv (Gamma)	<none>	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HC Liquid																	
Liquid Vol Flow @Std Cond	barrel/day	356208	178104	161913	101192	60721	46786	7614	7614	140112	140112	7846	7846	315979	161913	6341	6341
Actual Volume Flow	barrel/day	398817	199409	180417	112757	73267	56429	9187	8940	160212	155490	8971	8743	352031	180417	7053	7466
Mass Flow	lb/hr	4549905	2274953	2068139	1292545	775595	587345	97255	97255	1789673	1789673	100216	100216	4036062	2068139	80955	80955
Molecular Weight	<none>	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
Mass Density	lb/ft3	49.00	49.00	49.00	49.00	45.25	45.25	45.25	46.50	47.75	49.20	47.75	49.00	49.00	49.00	45.25	46.25
Mass Heat Capacity	Btu/lb-F	0.57	0.57	0.57	0.57	0.64	0.64	0.64	0.61	0.59	0.56	0.59	0.57	0.57	0.57	0.64	0.62
Thermal Conductivity	Btu/hr-ft-F	0.066	0.066	0.066	0.066	0.060	0.060	0.060	0.062	0.064	0.066	0.064	0.066	0.066	0.066	0.060	0.061
Viscosity	cP	1.311	1.311	1.311	1.311	0.564	0.564	0.564	0.738	0.949	1.418	0.949	1.311	1.311	1.311	0.564	0.684
Cp/Cv (Gamma)	<none>	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surface Tension	dyne/cm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aqueous																	
Liquid Vol Flow @Std Cond	barrel/day	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Actual Volume Flow	barrel/day	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Flow	lb/hr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Molecular Weight	<none>	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Density	lb/ft3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mass Heat Capacity	Btu/lb-F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Conductivity	Btu/hr-ft-F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Viscosity	cP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cp/Cv (Gamma)	<none>	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surface Tension	dyne/cm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

ATTACHMENT 03

Damage Factor Screening Questions

Amine Reboiler

Rev	Tanggal	Deskripsi	Disiapkan	Disetujui	
				Dosen Pembimbing	
			Khoirunnisa M.S.	Ir. Dwi Priyanta, M.SE	Nurhadi Siswantoro, S.T., M.T.
			0421164000021		

Based on API RP 581: Risk Based-Inspection

Damage Factor(s) screening untuk menentuk faktor-faktor kerusakan apa yang berpengaruh pada Amine Reboiler ABC-E-0101. Screening dilakukan untuk menentukan prioritas inspeksi dan mengoptimalkan inspeksi. DF menggambarkan tingkat kerusakan relatif tentang equipment berdasarkan asumsi yang dinyatakan di setiap bagian dokumen yang berlaku. Berikut merupakan kriteria screening untuk damage factor yang terjadi pada Shell Side dan Tube Side Amine Reboiler ABC-E-0101 berdasarkan API RP 581 Part 2.

Table 3.1 Damage Factor Screening Questions for ABC-E-0101 (Shell Side)

No.	Damage Factor	Screening Criteria		Yes/No
1	Thining	All component should be checked for thining		Yes
2	Component Lining	If the component has organic or inorganic lining, then the component should be evaluated for lining damage		No
3	SCC Damage Factor-Caustic Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains caustic in any concentration, then the component should be evaluated for susceptibility to caustic cracking.		No
4	SCC Damage Factor-Amine Cracking	If the component's material of construction is carbon or low alloy steel and process environment contains acid gas treating amines (MEA, DEA, DIPA, MDEA, etc.) in any concentration, then the component should be evaluated for susceptibility to amine cracking.		Yes
5	SCC Damage Factor-Sulfide Stress Cracking	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to Sulfide Ctress Cracking (SCC).		Yes
6	SCC Damage Factor HIC/SOHIC-H_2S	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to HIC/SOHIC-H_2 S cracking.		Yes
7	SCC Damage Factor-Alkaline Carbonate Stress Corrosion Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains alkaline water at pH>7.5 in any concentration, the the component should be evaluated to ACSCC.	Y	No
		Another trigger would be changes in FCCU feed sulfurr and nitrogen contents particularly when feed changes have reduced sulfur (low sulfur feeds or hydroprocessed feeds) or increased nitrogen.	N	
8	SCC Damage Factor-Polythionic Acid Stress Corrosion Cracking	If the component's material of construction is an austenitic stainless steel or nickel based alloys and the components is exposed to sulfur bearing compunds, then the component should be evaluated for susceptibility to PASCC		No

Table 3.1 Damage Factor Screening Questions for ABC-E-0101 (Shell Side)

No.	Damage Factor	Screening Criteria	Yes/No
9	SCC Damage Factor-Chloride Stress Corrosion Cracking	If **ALL** of the following are true, then the component should evaluated for suscepibility to CLSCC cracking:	No
		a. The component's material of construction is an austenitic stainless steel. — N	
		b. The component is exposed or potentially exposed to chlorides and water also considering upsets and hydrotest water remaining in component, and cooling tower drift (consider both under insulation and process conditions). — N	
		c. The operating temperature is above 38° (100°F) — Y	
10	SCC Damage Factor-Hydrogen Stress Cracking-HF	If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HSC-HF.	No
11	SCC Damage Factor HIC/SOHIC-HF	If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HIC/SOHIC-HF.	No
12	External Corrosion Damage Factor	If the component is **un-insulated** and subject to any of the following , then the component should be evaluated for external damage from corrosion.	No
13	Corrosion Under Insulation Damage Factor-Ferritic Commponent	If the component is **insulated** and subject to any of the following , then the component should be evaluated for external damage from corrosion.	Yes
		a. Areas exposed to mist overspray from cooling towers. — N	
		b. Areas exposed to steam vents. — N	
		c. Areas exposed to deluge systems. — N	
		d. Areas subject to process spills, ingress of moisture, or acid vapors. — Y	
		e. Insulation jacketing seams located on top of horizontal vessels or improperly lapped or sealed insulation systems, — N	
		f. Carbon steel systems, including those insulated for personnel protection, operating between -12°C and 175°C (10°F and 350°F). CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture. — Y	

Table 3.1 Damage Factor Screening Questions for ABC-E-0101 (Shell Side)

No.	Damage Factor	Screening Criteria			Yes/No
		g.	Carbon steel systems that normally operate in services above 175°C (350°F) but are in intermittent service or are subjected to frequent outages.	N	
		h.	Dead legs and attachments that protrude from the insulation and operate at a different temperature than the operating temperature of the active line, i.e., insulation support rings, piping/platform attachments.	N	
		i.	Systems in which vibration has a tendency to inflict damage to insulation jacketing providing paths for water ingress.	N	
		j.	Steam traced systems experiencing tracing leaks, especially at tubing fittings beneath the insulation.	N	
		k.	Systems with deteriorated coating and/or wrappings.	N	
		l.	Cold service equipment consistently operating below the atmospheric dew point.	N	
		m.	Inspection ports or plugs which are removed to permit thickness measurements on insulated systems represent a major contributor to possible leaks in insulated systems. Special attention should be paid to these locations. Promptly replacing and resealing of these plugs is imperative.	N	
14	External Chloride Stress Corrosion Cracking Damage Factor-Austenitic Component	If **ALL** of the following are true, then the component should evaluated for suscepibility to CLSCC:			No
		a.	The component's material of construction is an austenitic stainless steel.	N	
		b.	The component external surface is exposed to chloride containing fluids, mists, or solids.	N	
		c.	The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.	Y	
15	External Chloride Stress Corrosion Cracking Under Insulation Damage Factor-Austenitic Component	If **ALL** of the following are true, then the component should be evaluated for susceptibiity to CUI CLSCC:			No
		a.	The component's material of construction is an austenitic stainless steel.	N	
		b.	The component is insulated	Y	

Table 3.1 Damage Factor Screening Questions for ABC-E-0101 (Shell Side)

No.	Damage Factor	Screening Criteria			Yes/No
		c.	The component external surface is exposed to chloride containing fluids, mists, or solids.	N	
		d.	The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.	Y	
16	High Temperature Hydrogen Attack Damage Factor	If **ALL** of the following are true, then the component should be evaluated for susceptibiity to HTHA:			No
		a.	The material is carbon steel, C-½ Mo, or a Cr-Mo low alloy steel (such as ½ Cr-½ Mo, 1 Cr-½ Mo, 1¼ Cr-½ Mo, 2¼ Cr-1 Mo, 3 Cr-1 Mo, 5 Cr-½ Mo, 7 Cr-1 Mo, and 9 Cr-1 Mo)	Y	
		b.	The operating temperature is greater than 177°C (350°F)	N	
		c.	The operating hydrogen partial pressure is greater than 0.345 MPa (50 psia)	N	
17	Brittle Fracture Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to brittle:			No
		a.	The material is carbon steel or low alloy steel (see Table 20.1).	Y	
		b.	If Minimum Design Metal Temperature (MDMT), TMDMT , or Minimum Allowable Temperature (MAT), TMAT , is unknown, or the component is known to operate at or below the MDMT or MAT under normal or upset conditions.	N	
18	Low Alloy Steel Embrittlement Damage Factor	If **ALL** of the following are true, then the component should be evaluated for susceptibility to low alloy steel embrittlement.			No
		a.	The material is 1Cr-0.5Mo, 1.25Cr -0.5Mo, 2.25Cr -1Mo or 3Cr-1 Mo low alloy steel.	N	
		b.	The operating temperature is between 343 and 577°C (650 and 1,070°F).	N	
19	885°F Embrittlement Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to 885°F embrittlement:			No
		a.	The material is a high chromium (>12% Cr) ferritic steel	N	
		b.	The operating temperature is between 371°C and 566°C (700°F and 1,050 °F)	N	
20	Sigma Phase Embrittlement Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to Sigma Phase Embrittlement:			No
		a.	The material an austenitic stainless steel	N	
		b.	The operating temperature between 593°C and 927°C (1,100 and 1,700 °F)	N	

Table 3.1 Damage Factor Screening Questions for ABC-E-0101 (Shell Side)

No.	Damage Factor	Screening Criteria			Yes/No
21	Piping Mechanical Fatigue Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to mechanical fatigue:			No
		a.	The component is pipe	N	
		b.	There have been past fatigue failures in this piping system or there is visible/audible shaking in this piping system or there is a source of cyclic vibration within approximately 15.24 meters (50 feet) and connected to the piping (directly or indirectly via structure). Shaking and source of shaking can be continuous or intermittent. Transient conditions often cause intermittent vibration.	N	

Table 3.2 Damage Factor Screening Questions for ABC-E-0101 (Tube Side)

No.	Damage Factor	Screening Criteria		Yes/No
1	Thining (Internal & External)	All component should be checked for thining		Yes
2	Component Lining	If the component has organic or inorganic lining, then the component should be evaluated for lining damage		No
3	SCC Damage Factor-Caustic Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains caustic in any concentration, then the component should be evaluated for susceptibility to caustic cracking.		No
4	SCC Damage Factor-Amine Cracking (External Side)	If the component's material of construction is carbon or low alloy steel and process environment contains acid gas treating amines (MEA, DEA, DIPA, MDEA, etc.) in any concentration, then the component should be evaluated for susceptibility to amine cracking.		Yes
5	SCC Damage Factor-Sulfide Stress Cracking (External Side)	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to Sulfide Ctress Cracking (SCC).		Yes
6	SCC Damage Factor HIC/SOHIC-H_2S (External Side)	If the component's material of construction contains is carbon or low alloy steel and the process environment contains water and H_2S in any concentration, then the component should be evaluated to HIC/SOHIC-H_2 S cracking.		Yes
7	SCC Damage Factor-Alkaline Carbonate Stress Corrosion Cracking	If the component's material of construction is carbon or low alloy steel and the process environment contains alkaline water at pH>7.5 in any concentration, the the component should be evaluated to ACSCC.	N	No

Table 3.2 Damage Factor Screening Questions for ABC-E-0101 (Tube Side)

No.	Damage Factor	Screening Criteria			Yes/No
		Another trigger would be changes in FCCU feed sulfurr and nitrogen contents particularly when feed changes have reduced sulfur (low sulfur feeds or hydroprocessed feeds) or increased nitrogen.		N	
8	SCC Damage Factor-Polythionic Acid Stress Corrosion Cracking	If the component's material of construction is an austenitic stainless steel or nickel based alloys and the components is wxposed to sulfur bearing compunds, then the component should be evaluated for susceptibility to PASCC			No
9	SCC Damage Factor-Chloride Stress Corrosion Cracking	If **ALL** of the following are true, then the component should evaluated for suscepibility to CLSCC cracking:			No
		a.	The component's material of construction is an austenitic stainless steel.	N	
		b.	The component is exposed or potentially exposed to chlorides and water also considering upsets and hydrotest water remaining in component, and cooling tower drift (consider both under insulation and process conditions).	N	
		c.	The operating temperature is above 38°C(100°F)	Y	
10	SCC Damage Factor-Hydrogen Stress Cracking-HF	If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HSC-HF.			No
11	SCC Damage Factor HIC/SOHIC-HF	If the component's material of construction is ccarbon or low alloy steel and the component is exposed too hydrofluoric acid in any concentration, then the component should be evaluated for susceptibility to HIC/SOHIC-HF.			No
12	External Corrosion Damage Factor	If the component is **un-insulated** and subject to any of the following , then the component should be evaluated for external damage from corrosion.			No
13	Corrosion Under Insulation Damage Factor-Ferritic Commponent	If the component is **insulated** and subject to any of the following , then the component should be evaluated for external damage from corrosion.			No
		a.	Areas exposed to mist overspray from cooling towers.	N	
		b.	Areas exposed to steam vents.	N	
		c.	Areas exposed to deluge systems.	N	
		d.	Areas subject to process spills, ingress of moisture, or acid vapors.	N	

Table 3.2 Damage Factor Screening Questions for ABC-E-0101 (Tube Side)

No.	Damage Factor	Screening Criteria			Yes/No
		e.	Insulation jacketing seams located on top of horizontal vessels or improperly lapped or sealed insulation systems,	N	
		f.	Carbon steel systems, including those insulated for personnel protection, operating between -12°C and 175°C (10°F and 350°F). CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture	Y	
		g.	Carbon steel systems that normally operate in services above 175°C (350°F) but are in intermittent service or are subjected to frequent outages.	N	
		h.	Dead legs and attachments that protrude from the insulation and operate at a different temperature than the operating temperature of the active line, i.e., insulation support rings, piping/platform attachments.	N	
		i.	Systems in which vibration has a tendency to inflict damage to insulation jacketing providing paths for water ingress.	N	
		j.	Steam traced systems experiencing tracing leaks, especially at tubing fittings beneath the insulation.	N	
		k.	Systems with deteriorated coating and/or wrappings.	N	
		l.	Cold service equipment consistently operating below the atmospheric dew point.	N	
		m.	Inspection ports or plugs which are removed to permit thickness measurements on insulated systems represent a major contributor to possible leaks in insulated systems. Special attention should be paid to these locations. Promptly replacing and resealing of these plugs is imperative.	N	
14	External Chloride Stress Corrosion Cracking Damage Factor-Austenitic Component	If **ALL** of the following are true, then the component should evaluated for suscepibility to CLSCC:			No
		a.	The component's material of construction is an austenitic stainless steel.	N	

Table 3.2 Damage Factor Screening Questions for ABC-E-0101 (Tube Side)

No.	Damage Factor	Screening Criteria			Yes/No
		b.	The component external surface is exposed to chloride containing fluids, mists, or solids.	N	
		c.	The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.	N	
15	External Chloride Stress Corrosion Cracking Under Insulation Damage Factor-Austenitic Component	If **ALL** of the following are true, then the component should be evaluated for susceptibiity to CUI CLSCC:			No
		a.	The component's material of construction is an austenitic stainless steel.	N	
		b.	The component is insulated	N	
		c.	The component external surface is exposed to chloride containing fluids, mists, or solids.	N	
		d.	The operating temperature is between 50°C and 150°C (120°F and 300°F) , or the system heats or cools into this range intermittently.	N	
16	High Temperature Hydrogen Attack Damage Factor	If **ALL** of the following are true, then the component should be evaluated for susceptibiity to HTHA:			No
		a.	The material is carbon steel, C-½ Mo, or a Cr-Mo low alloy steel (such as ½ Cr-½ Mo, 1 Cr-½ Mo, 1¼ Cr-½ Mo, 2¼ Cr-1 Mo, 3 Cr-1 Mo, 5 Cr-½ Mo, 7 Cr-1 Mo, and 9 Cr-1 Mo)	Y	
		b.	The operating temperature is greater than 177°C (350°F)	N	
		c.	The operating hydrogen partial pressure is greater than 0.345 MPa (50 psia)	Y	
17	Brittle Fracture Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to brittle:			No
		a.	The material is carbon steel or low alloy steel (see Table 20.1).	Y	
		b.	If Minimum Design Metal Temperature (MDMT), TMDMT , or Minimum Allowable Temperature (MAT), TMAT , is unknown, or the component is known to operate at or below the MDMT or MAT under normal or upset conditions.	N	
18	Low Alloy Steel Embrittlement Damage Factor	If **ALL** of the following are true, then the component should be evaluated for susceptibility to low alloy steel embrittlement.			No
		a.	The material is 1Cr-0.5Mo, 1.25Cr -0.5Mo, 2.25Cr -1Mo or 3Cr-1 Mo low alloy steel.	N	
		b.	The operating temperature is between 343 and 577°C (650 and 1,070°F).	N	

Table 3.2 Damage Factor Screening Questions for ABC-E-0101 (Tube Side)

No.	Damage Factor	Screening Criteria			Yes/No
19	885°F Embrittlement Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to 885°F embrittlement:			No
		a.	The material is a high chromium (>12% Cr) ferritic steel	N	
		b.	The operating temperature is between 371°C and 566°C (700°F and 1,050 °F)	N	
20	Sigma Phase Embrittlement Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to Sigma Phase Embrittlement:			No
		a.	The material an austenitic stainless steel	N	
		b.	The operating temperature between 593°C and 927°C (1,100 and 1,700 °F)	N	
21	Piping Mechanical Fatigue Damage Factor	If **BOTH** of the following are true, then the component should be evaluated for susceptibility to mechanical fatigue:			No
		a.	The component is pipe	N	
		b.	There have been past fatigue failures in this piping system or there is visible/audible shaking in this piping system or there is a source of cyclic vibration within approximately 15.24 meters (50 feet) and connected to the piping (directly or indirectly via structure). Shaking and source of shaking can be continuous or intermittent. Transient conditions often cause intermittent vibration.	N	

ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

ATTACHMENT 04

Probability of Failure

Amine Reboiler

Rev	Tanggal	Deskripsi	Disiapkan	Disetujui	
				Dosen Pembimbing	
			Khoirunnisa M.S. 0421164000021	Ir. Dwi Priyanta, M.SE	Nurhadi Siswantoro, S.T., M.T.

ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

Probability of Failure

Calculation of Shell Side Damage Factor

Attachment 4-1

Probability of Failure

Thinning Damage Factor Calculation

Attachment 4-1-1

Table 4.1.1 - Step to Calculate Thinning Damage Factor

Step - 1	Determine the furnished thickness, t , and age, for the component from the installation
Step - 2	Determining the corrosion rate for base material, $C_{r,bm}$ based on the material construction and environment, and cladding/weld overlay corrosion rate, $C_{r,cm}$.
Step - 3	Determine the time in service, age_{tk}, since the last known inspection, t_{rdi}.
Step - 4	For cladding/weld overlay pressure vessel components, calculate the age from the date starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using equation below: $$age_{rc} = \max\left[\left(\frac{t_{rdi} - t_{bm}}{C_{r,cm}}\right), 0.0\right]$$
Step - 5	Determine the t_{min}
Step - 6	Determine the A_{rt} Parameter
Step - 7	Calculate the Flow Stress, Fs^{thin} , using E from STEP 5 and equation below. $$FS^{Thin} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1$$
Step - 8	Calculate the strength ratio parameter, SR_p^{thin}, using the appropriate equation. $$SR_P^{Thin} = \frac{S \cdot E}{FS^{Thin}} \cdot \frac{Max\ (t_{min}, t_c)}{t_{rdi}}$$
Step - 9	Determine the number of inspections for each of the correspondesing inspection effectiveness, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, using Section 4.5.6 of the API RP 581 Part 2 for past inspections performed during in-service time.
Step - 10	Calculate the inspection effectiveness factors, $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$, using eq.12, eq.13, eq.14 below, prior probabilities, $Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}$, from Table 4.1.9. The Conditional Probabilities (for each inspection effectiveness level), $Co_{p1}^{Thin}, Co_{p2}^{Thin}, Co_{p3}^{Thin}$, from Table 4.1.10, and the number of inspection, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, in each effectiveness level from STEP 9.
Step - 11	Calculate the Posteroir Probability, $Po_{p1}^{Thin}, Po_{p2}^{Thin}, Po_{p3}^{Thin}$, Equation below with $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$ in Step 10. $$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$$

Table 4.1.1 - Step to Calculate Thinning Damage Factor

	$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$ $Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$
Step - 12	Calculate the parameters, $\beta_1^{Thin}, \beta_2^{Thin}, \beta_3^{Thin}$ using equation below and also assigning $COV_{\Delta t}, COV_{sf} = 0.20, COV_P = 0.05$ $ß_1^{Thin} = \frac{1-D_{S1}\,.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$ $ß_2^{Thin} = \frac{1-D_{S2}\,.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$ $ß_3^{Thin} = \frac{1-D_{S3}\,.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$
Step - 13	For tank bottom components, determine the base damage factor for thinning using Table 4.8 and calculated Art parameter from STEP 6.
Step - 14	For all components (excluding tank bottoms covered in STEP 13), calculate the base damage factor, D_{fb}^{Thin}. D_{fb}^{Thin} = [$\frac{\left(Po_{P1}^{Thin}\Phi\left(-\beta_1^{Thin}\right)\right)+\left(Po_{P2}^{Thin}\Phi\left(-\beta_2^{Thin}\right)\right)+\left(Po_{P3}^{Thin}\Phi\left(-\beta_3^{Thin}\right)\right)}{1.56E-0.4}$
Step - 15	Determine the DF for thinning, D_f^{Thin} , using equation equation below. D_f^{Thin} = Max[($\frac{(D_{fb}^{Thin}.F_{IP}.F_{DL}.F_{WD}.F_{AM}.F_{SM})}{F_{OM}}$),0.1]

CALCULATION OF THINNING DAMAGE FACTOR

1. Required Data

Basic data yang dibutuhkan pada analisis ini tercantum pada API RP 581 Part 2 Table 4.1. Sedangkan component dan geometry type berdasarkan jenis equipment ditunjukkan oleh Table 4.2, Geometry data yang dibutuhkan dalam analsis berdasarkan geometry type tercantum pada Table 4.3. Dalam menentukan data yang diperlukan untuk analisis Thinning Damage Factor, dapat menggunakan Table 4.4.

Table 4.1.2 – Basic Component Data Required for Analysis (Refer to Table 4.1 API RP 581 Part 2)

<table>
<tr><th colspan="2">Basic Data</th><th>Value</th><th>Unit</th><th>Comments</th></tr>
<tr><td colspan="2">Start Date</td><td colspan="2">6/1/2014</td><td>The date the component was placed in service.</td></tr>
<tr><td rowspan="2">Thickness</td><td>SS</td><td>12.00</td><td rowspan="2">mm</td><td rowspan="2">Thickness used for DF is either the furnished thickness or the measured thickness</td></tr>
<tr><td>TS</td><td>2.11</td></tr>
<tr><td rowspan="2">Corrosion Allowance</td><td>SS</td><td>5.02</td><td rowspan="2">mm</td><td rowspan="2">The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current service.</td></tr>
<tr><td>TS</td><td>1.83</td></tr>
<tr><td rowspan="2">Design Temperature</td><td>SS</td><td>148.89</td><td rowspan="2">^{o}C</td><td rowspan="2">The design temperature, shell side and tube side for heat exchanger.</td></tr>
<tr><td>TS</td><td>232.22</td></tr>
<tr><td rowspan="2">Design Pressure</td><td>SS</td><td>586.08</td><td rowspan="2">Kpa</td><td rowspan="2">The design pressure, shell side and tube side for heat exchanger.</td></tr>
<tr><td>TS</td><td>1447.95</td></tr>
<tr><td rowspan="2">Operating Tempearture</td><td>SS</td><td>128.67</td><td rowspan="2">^{o}C</td><td rowspan="2">The highest expected operating temperature expected during operation including normal and unusual operating conditions, shell side and tube side for heat exchanger.</td></tr>
<tr><td>TS</td><td>176.67</td></tr>
<tr><td rowspan="2">Operating Pressure</td><td>SS</td><td>142.73</td><td rowspan="2">Kpa</td><td rowspan="2">The highest expected operating pressure expected during operation including normal and unusual operating conditions, shell side and tube side for heat exchanger.</td></tr>
<tr><td>TS</td><td>448.18</td></tr>
<tr><td colspan="2">Design Code</td><td colspan="2">ASME Section VIII Division I Edition 2010</td><td>The designing of the component containing the component.</td></tr>
<tr><td colspan="2">Equipment Type</td><td colspan="2">Heat Exchanger</td><td>The type of equipment.</td></tr>
<tr><td colspan="2" rowspan="2">Component Type</td><td colspan="2">HEXSS</td><td rowspan="2">The type of component.</td></tr>
<tr><td colspan="2">HEXTS</td></tr>
<tr><td colspan="2">Geometry Data</td><td colspan="2">ELL (Elliptical Head)</td><td>Component geometry data depending on the type of component.</td></tr>
</table>

Table 4.1.2 – Basic Component Data Required for Analysis (Refer to Table 4.1 API RP 581 Part 2)

Basic Data		Value	Unit	Comments
Material Specification	SS	SA-516 Gr.70N		The specification of the material of construction, the ASME SA or SB specification for pressure vessel components or for ASTM specification for piping and tankage components. Data entry is based on the material specification, grade, year, UNS Number, class /condition /temper /size /thickness; this data is readdily available in the ASME Code.
	TS	SA 179 Smls		
Yield Strength	SS	260000	Kpa	The design yield strength of the material based on material specification.
	TS	180000		
Tensile Strength	SS	485000	Kpa	The design tensile strength of the material based on material specification.
	TS	325000		
Weld Joint Efficiency	SS	1.00		Weld joint efficiency per the Code of construction.
	TS	1.00		
Heat Tracing		Yes		Is the component heat traced?

2. Shell Side Thinning Calculation

STEP 1

Determining the furnished thickness, t, and age for the component from the installation date.

t = 0.472 inch

= 12.00 mm

age = 6 years

(it is assumed from the default date for the first installement in a plant on June 1st 2014 (06/01/2014) until this date on January 1st 2020)

STEP 2

Determining the corrosion rate for base material, $C_{r,bm}$ based on the material construction and environment, and cladding/weld overlay corrosion rate, $C_{r,cm}$

Based on the explanation from Section 4.5.2 that the corrosion rate is **CALCULATED** using the approach of Annex 2B. Then, first of all, the corrosion screening question must be done as Table 4.1.3 (Refer to Table 2.B.1.1 API RP 581 Part 2)

Table 4.1.3-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion	Screening Question		Yes/No	Action
1.	Hydrochloric Acid (HCl) Corrosion	1.	Does the process contain HCl?	N	No
		2.	Is free water present in the process stream (including initial condensing condition)?	Y	
		3.	Is the pH < 7.0?	N	
			Actual relatively pH is 7.83		
2.	High Temperature Sulfidic/Naphtenic Acid Corrosion	1.	Does the process contain oil with sulfur compounds?	N	No
		2.	Is the operating temperature > 204°C (400°F)?	N	
			The operating temperature is 128.67°C.		
3.	Sulfuric Acid Corrosion	1.	Does the process contain H_2SO_4	N	No
4.	High Temperature H_2S/H_2 Corrosion	1.	Does the process contain H_2S and Hydrogen?	Y	No
		2.	Is the operating temperature >204°C (400°F)?	N	
			The operating temperature is 128.67°C.		
5.	Hydrifluoric Corrosion	1.	Does the process contain HF	N	No
6.	Sour Water Corrosion	1.	Is free water with H_2S present?	Y	Yes
7.	Amine Corrosion	1.	Is equipment exposed to acid gas treaating amines (MEA, DEA, DIPA, or MDEA)?	Y	Yes
8.	High Temperature Oxidation Corrosion	1.	Is the temperature ≥482°C (900°F)?	N	No
			The operating temperature is 128.67°C.		
		2.	Is the oxygen present?	N	
9.	Acid Sour Water Corrosion	1.	Is free water with H_2S present and pH < 7.0?	N	No
			Actual relatively pH is 7.83		
		2.	Does the proocess contain < 50 ppm chlorides?	N	
10.	Cooling Water	1.	Is equipment in cooling water service?	N	No

Table 4.1.3-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion	Screening Question		Yes/No	Action
11.	Soil Side Corrosion	1.	Is equipment in contact with soil (buried or partially buried)?	N	No
		2.	Is the material of construction carbon steel?	Y	
12.	CO_2 Corrosion	1.	Is the free water with CO_2 present (including consideration for dew point condensation)?	Y	Yes
		2.	Is the material of construction carbon steel or < 13% Cr?	Y	
13.	AST Bottom	1.	Is the equipment item an AST tank bottom?	N	No

T	=	128.67	C
	=	300	F
P	=	142.73	Kpa
H_2S Concentration	=	0.0119	% mole
CO_2 Concentration	=	0.2894	% mole
H_2O Concentration	=	90.5763	% mole
aMDEA Concentration	=	9.1224	% mole
Material	=	Carbon Steel (SA 516 Gr. 70N)	

Basically, there are 3 types of Corrosion Rate (Cr) calculation which are based on the RLA data from the last inspection, based on the calculation referred to the API 581 Annex 2B, and the last is based on worst case scenario.

If multiple thinning mechanisms are possible, the **maximum corrosion rate should be used.**

A. Corrosion Rate (Cr) based on the Annex 2B Alkaline Sour Water Corrosion

The steps required to determine the corrosion rate are shown in Figure 2.B.7.1. API RP 581 Annex 2B. The corrosion rate may be determined using the basic data in Table 4.1.4 (Refer to Table 2.B.7.1) in conjunction with the baseline corrosion rates and equations in Table 2.B.7.2 to correct for H_2S partial pressure.

Table 4.1.4 – Alkaline Sour Water Corrosion – Basic Data Required for Analysis (Refer to Table 2.B.7.1 API RP 581 Annex 2B)

Basic Data	Value	Comments
NH_4HS concentration (wt%)	0.0357	Determine the NH_4HS concentration of the condensed water. It is suggested to determine this value with ionic process models. However, approximate values may be calculated from analyses of H_2S and NH_3 as follows
		If wt% H_2S < 2 x (wt% NH_3), wt% NH_4HS =1.5 x (wt% H_2S)

Table 4.1.4 – Alkaline Sour Water Corrosion – Basic Data Required for Analysis (Refer to Table 2.B.7.1 API RP 581 Annex 2B)		
Basic Data	**Value**	**Comments**
		If wt% H_2S > 2 x (wt% NH_3), wt% NH_4HS =3.0 x (wt% H_2S)
Stream Velocity (m/s)	0.0097	The vapor phase velocity should be used in a two-phase system. The liquid phase velocity should be used in a liquid full system.
H_2S partial pressure, psia (kPa)	1.6984	Determine the partial pressure of H_2S by multiplying the mole% of H_2S in the gas phase by the total system pressure.

Determining NH4HS Concentration

to determine NH_4HS concentration, we must first determine if wt% H_2S

wt% H_2S = 0.0119

wt% NH_3 = 0

Since the value of H_2S is higher than NH_3, the wt% of NH_4HS can be determined by the formula of: wt% NH_4HS = 3.0 x (wt% H_2S)

NH_4HS= 3.0 x (wt% H_2S)

NH_4HS Concentration = 0.0357 wt%

Stream Velocity = 0.0316 m/s

H_2S partial pressure = 1.6984 KPa

Baseline CR based on Table 2.B.7.2M for Carbon Steel

Baseline CR = 0.08 mm/y

$$\text{Adjusted } CR = \max\left[\left\{\left(\frac{Baseline\ CR}{173}\right).(pH2S\ - 345) + Baseline\ CR\right\},0\right] \quad \text{.......(equation 1)}$$

Adjusted CR = 0.0000 mm/y

B. Corrosion Rate (Cr) based on the Annex 2B Amine Corrosion

The steps required to determine the corrosion rate are shown in Figure 2.B.8.1 in API RP 581 Annex 2B. The corrosion rate may be determined using the basic data in Table 4.1.5 (Refer to Table 2.B.8.1 in conjunction with Tables 2.B.8.3 for 50% MDEA in carbon steel material API RP 581 Annex 2B)

Table 4.1.5 – Amine Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Material of Construction	CS	Determine the material of construction of equipment/piping.
Amine Concentration (wt%)	9.1224	Determine the amine concentration in the equipment or piping. Due to vaporization of water, a local increase in amine concentration may need to be considered in evaluating the corrosion of some reboilers and declaimers.

Table 4.1.5 – Amine Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Maximum Process Temp. (°C)	128.67	Determine the maximum process temperature. In reboilers and reclaimers, tube metal temperatures may be higher than the bulk process temperature.
Acid Gas Loading (mole acid gas/mole active amine)	0.091	Determine the acid gas loading in the amine. If analytical results are not available, it should be estimated by a knowledgeable process engineer.
Velocity (m/s)	0.0097	Determine the maximum velocity of the amine
Heat Stable Amine Salt (HSAS) Concentration: MDEA (<500, 500-4000, >4000, wppm)	<500	In MDEA "HSAS" refers to organic acid contaminants, mainly formate, oxalate, and acetate

Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MDEA (≤ 50 wt%) (mm/y) based on Table 4.1.6 (Refer to Table 2.B.3.M API RP 581 Annex 2B)

Table 4.1.6 - Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MDEA (≤50 wt%) (mm/y)

Acid Gas Loading (mol/mol)	**HSAS (wt%)**	**Temperature (°C)**											
		88		93		104		116		127		132	
		Velocity (m/s)											
		≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1
<0.1	0.5	0	0.1	0	0.1	0.1	0.3	0.1	0.4	0.3	0.64	0.4	1.02
	2.25	0.1	0.2	0.1	0.2	0.2	0.5	0.4	1	0.5	1.14	0.8	2.30
	4.0	0.1	0.3	0.1	0.4	0.4	1	0.8	1.5	1	2.29	1.5	3.05

Amine CR = 0.250 mm/y

C. Corrosion Rate (Cr) based on the Annex 2B CO2 Corrosion

The steps required to determine the corrosion rate are shown in Figure 2.B.13.1. The corrosion rate may be determined using the basic data in Table 4.1.7 (Refer to Table 2.B.13.1 API RP 581 Annex 2B) in conjunction with Equation below.

Table 4.1.7 – CO2 Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Temperature (°C)	128.67	The corrosion phenomenon is highly temperature dependent. The maximum temperature of the process is required. Temperatures above 140°C (284°F) are not considered.

Table 4.1.7 – CO2 Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Pressure (Kpa)	142.73	Total pressure of the system. The total pressure of the gas is a big contributor in the corrosion rate up to about 250 psig.
CO2 concentration (mole %)	0.2894	Determine the CO2 partial pressure (pCO2) = (mol fraction of CO2 × total pressure), a maximum 4 MPa (580 psi) partial CO2 pressure is considered.
Material of Construction	SA-516 Gr.70N	Determine the material of construction of equipment or piping. Stainless steels and copper alloys are assumed to be resistant to CO2 corrosion
pH	4.36	If known explicitly, the pH of the stream should be used; otherwise Equations(2.B.27), (2.B.28), and (2.B.29), can be used to estimate the pH based on the CO2 partial pressure, whether the water in the stream is Fe++ saturated or water with salinity slightly larger than seawater
Stream properties: bulk density, ρm, viscosity, mm, gas to liquid ratios (cP)	0.515	Guidance with respect to typical values properties expected in natural gas-oil mixtures (i.e. reservoir fluids) is provided. Estimation of densities can be made on the basis of the oil density (°API), gas oil ratio (GOR) and pressure, P and temperature, T. For other streams, a process engineer should assess these parameters.

$$\mathrm{CR} = CR_B \,.\, \min[F_{glycol}, F_{inhib}]$$ ....(equation 2)

<u>Base Corrosion Rate</u>

$$CR_B = \mathrm{f(T,pH)} \,.\, \mathrm{f}_{CO2}^{\ 0.62} \,.\, \left(\frac{S}{19}\right)^{0.146+0.0324\, fco2}$$

Where:

CR_B = Base corrosion rate (mm/y)

f(T,pH) = Temperature-pH function tabulated in Table 2.B.13.2

f_{CO2} = CO_2 fugacity

S = Shear stress yo calculate the flow velocity (Pa)

a. Determine the calculated pH

For RBI purposes, the pH termin temperature-pH function tabulated in Table 2.B.13.2 may be calculated using the following equation approximation for SATURATED WATER, because it is asssumed that in temperature of 100°C is placed on the transition condition and there will be some mixture between liquid phase and gas phase (saturated water and saturated steam).

$pH = 2.5907 + 0.8668.log_{10}[T] - 0.49log_{10}[p_{CO2}]$ …….(equation 3)

T = 128.67 C

263.60 F

p_{CO2} = Partial pressure of carbon dioxide

= (mol fraction of CO2 × total pressure) …….(equation 4)

p_{CO2} = 41.31 Kpa

= 5.991 psi

$pH = 2.5907 + 0.8668.log_{10}[T] - 0.49log_{10}[p_{CO2}]$

= 4.36

b. Determine the CO_2 fugacity

$log_{10}\,[f_{CO2}] = log_{10}[p_{CO2}] + \min[250, p_{CO2}].(0.0031\text{-}\frac{1.4}{T+273})$

$log_{10}\,[f_{CO2}] = log_{10}[5.410] + \min[250{,}5.410].(0.0031\text{-}\frac{1.4}{128.89+273})$

= 0.775

c. Determine the flow velocity

To determine the flow velocity, the API 581 reffers to the NORSOK M-506. and both of the Recommended Practice use the fluid flow shear stress, S, to model the effect of flow velocity n the base corrosion rate.

$S = \frac{f.\rho m.um^2}{2}$ ...……....……....……......…...…….(equation 5)

In the calculation for the corrosion rate, the shear stress need not exceed 150 Pa.

Where;

f = Friction factor

ρ_m = Mixture mass density kg/m³

= 958.707 kg/m³

u_m = Mixture flow velocity m/s

= 0.00974 m/s

$f = 0.001375\,[\,1\text{+}\,(20000(\frac{e}{D}) + (\frac{10^6}{Re})^{0.33}]$ ......…...…….(equation 6)

$\frac{\varepsilon}{D}$ = Relative roughness of the material

0.1

Based on the Table 4.1.8 (Refer to https://www.nuclear-power.net/nuclear-engineering/fluid-dynamics/major-head-loss-friction-loss/relative-roughness-of-pipe/) that for the Carbon Steel (SA-516 Gr.70N) material of construction which is assumed as new is approximately ranging from 0.05-0.15

Table 4.1.8 Material Absolute Rougness (Refer to

Material	Absolute Roughness (mm)
Copper, Lead, Brass, Aluminium (new)	0.001 -0.002
PVC and Plastic Pipes	0.0015 - 0.007
Flexible Rubber Tubing - Smooth	0.006 - 0.07
Stainless Steel	0.0015
Steel Commercial Pipe	0.045 - 0.09
Weld Steel	0.0045
Carbon Steel (New)	0.02 - 0.05
Carbon Steel (Slightly Corroded)	0.05 - 0.15
Carbon Steel (Moderately Corroded)	0.15 - 1

$$Re = \frac{D.\rho m.um}{\mu m}$$ ……………………………........…....…….(equation 7)

Re	=	Reynolds number	
D	=	Diameter	mm
	=	914.40	mm
	=	0.9144	m
µm	=	Viscosity of the mixture	cp
	=	0.515	Cp
	=	0.000515	Pa.s
Re	=	16583.62902	

f = 0.001375 [1+ (20000($\frac{e}{D}$) + ($\frac{10^6}{Re}$)$^{0.33}$]

f = 0.00863

$$S = \frac{f.\rho m.um^2}{\mu m}$$

S = 1.5246385 Pa

Those calculated pH, CO_2 fugacity, and also flow velocity have been known. So, the value of Base Corrosion Rate (Cr_{base}) can be determined.

$$CR_B = f(T,pH) \cdot f_{CO2}^{\;0.62} \cdot (\frac{S}{19})^{0.146+0.0324\,fco2}$$

f(T,pH)	=	Temperature-pH function tabulated in Table 2.B.13.2	
	=	3.98	
Cr_{base}	=	3.20516	mpy
	=	0.08141	mm/y

Because there is no any mixture for glycol and the other inhibitors inside the Production Separator, then, Cr is equal to Cr_{base}.

Where;

CO_2 CR = $CR_B . \min[F_{glycol}, F_{inhib}]$

= Cr_{base}

= 0.08141 mm/y

Based on API RP 581 Annex 2B, if multiple thinning mechanisms are possible, the **maximum corrosion rate should be used.**

CR = 0.250 mm/y

STEP 3

Determine the time in service, age_{tk}, since the last known inspection, t_{rdi}.
Because the inspection never been held. Then, the thickness used in this calculation is based on manufactured-thickness from datasheet.

t_{rdi} = 12.00 mm

age at the RBI Date

age_{tk} = RBI Date - Last Inspection Date
(Last inspection date using the installment date)

age_{tk} = 1/1/2020 - 6/1/2014
= 6 year

age at the RBI Plan Date

age_{tk} = RBI Plan Date - Last Inspection Date
(Last inspection date using the installment date)

age_{tk} = 1/1/2024 - 6/1/2014
= 10 year

STEP 4

For cladding/weld overlay pressure vessel components, calculate the age from the date starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using equation below:

$$age_{rc} = \max\left[\left(\frac{t_{rdi} - tbm}{C_{r\,cm}}\right), 0.0\right] \quad \text{……………………..…..…..…….(equation 8)}$$

This equipment does not have cladding, so this step are skipped

STEP 5

Determine the t_{min}

Actually there are 4 methods used to determine the minimum thickness of the equipment (t_{min}). Based on the condition, the method used by the author is the first method which is for cylindrical, spherical, or head components, determine the allowable Stress, S, weld joint efficiency, E, and the minimum thickness, t_{min}.

t_{min} = 6.98 mm
S = 138000 Kpa
E = 1.00

STEP 6

Determine the A_{rt} Parameter

For component without clading/weld overlay then use the equation below.

at RBI Date

$$A_{rt} = \frac{Cr_{b,m}.age_{tk}}{t_{rdi}} \quad \text{……………………........…....…….(equation 9)}$$

= 0.1250

at RBI Plan Date

$$A_{rt} = \frac{Cr_{b,m}.age_{tk}}{t_{rdi}}$$

= 0.2083

STEP 7

Calculate the Flow Stress, FS^{Thin}, using E from STEP 5 and equation below.

$$FS^{Thin} = \frac{(YS+TS)}{2}. E.1,1 \quad \text{…...……………………........…....…….(equation 10)}$$

Where;

YS = 260000 KPa

TS = 485000 KPa

E = 1.00

$$FS^{Thin} = \frac{(YS+TS)}{2}. E.1,1$$

= 409750

STEP 8

Calculate the strength ratio parameter, SR_P^{Thin}, using the appropriate equation.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}}.\frac{Max\,(t_{min},t_c)}{t_{rdi}} \quad \text{…...……………………........…….(equation 11)}$$

Where;

t_c = is the minimum structural thickness of the component base material (t_{min})

= 6.98 mm

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}}.\frac{Max\,(t_{min},t_c)}{t_{rdi}}$$

= 0.1959

STEP 9

Determine the number of inspections for each of the correspondesing inspection effectiveness, N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}, using Section 4.5.6 of the API RP 581 Part 2 for past inspections performed during in-service time.

N_A^{Thin} = 0
N_B^{Thin} = 0
N_C^{Thin} = 0
N_D^{Thin} = 0

STEP 10

Calculate the inspection effectiveness factors, $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$, using eq.12, eq.13, eq.14, prior probabilities, $Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}$, from Table 4.1.9. The Conditional Probabilities , $Co_{p1}^{Thin}, Co_{p2}^{Thin}, Co_{p3}^{Thin}$, from Table 4.1.10, and the number of inspection, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, in each effectiveness level from STEP 9.

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}} \quad \text{..(eq. 12)}$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_A^{Thin}} \quad \text{..(eq. 13)}$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_A^{Thin}} \quad \text{..(eq. 14)}$$

Table 4.1.9 - Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Conf. Data	High Conf. Data
Pr_{P1}^{Thin}	0.5	0.7	0.8
Pr_{P2}^{Thin}	0.3	0.2	0.15
Pr_{P3}^{Thin}	0.2	0.1	0.05

Table 4.1.10 - Conditional Probability for Inspection Effectiveness

Conditional P. of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B-Usually Effective	A-Highly Effective
Co_{P1}^{Thin}	0.33	0.4	0.5	0.7	0.9
Co_{P2}^{Thin}	0.33	0.33	0.3	0.2	0.09
Co_{P3}^{Thin}	0.33	0.27	0.2	0.1	0.01

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$
$$= 0.50$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_A^{Thin}}$$
$$= 0.30$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_A^{Thin}}$$
$$= 0.20$$

STEP 11

Calculate the Posteroir Probability, Po_{p1}^{Thin}, Po_{p2}^{Thin} and Po_{p3}^{Thin}, using equation 15, equation 16, equation 17 below

$$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad \text{……………………………..(equation 15)}$$
$$= 0.50$$

$$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$$ ……..…………………….......(equation 16)

$= 0.30$

$$Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}}$$ ……..…………………….......(equation 17)

$= 0.20$

STEP 12

Calculate the parameters, $ß_1$, $ß_2$, and $ß_3$ using equation 18, 19 and 20 below and also assigning $COV_{\Delta t} = 0.20$, $COV_{sf} = 0.20$, and $COV_P = 0.05$.

$$ß_1^{Thin} = \frac{1 - D_{S1}.A_{rt} - SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2 + (1 - D_{S1}.A_{rt})^2.COV_{sf}{}^2 + (SR_P^{Thin})^2.(COV_P)^2}}$$ ....(equation 18)

$$ß_2^{Thin} = \frac{1 - D_{S2}.A_{rt} - SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2 + (1 - D_{S2}.A_{rt})^2.COV_{sf}{}^2 + (SR_P^{Thin})^2.(COV_P)^2}}$$ ....(equation 19)

$$ß_3^{Thin} = \frac{1 - D_{S3}.A_{rt} - SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2 + (1 - D_{S3}.A_{rt})^2.COV_{sf}{}^2 + (SR_P^{Thin})^2.(COV_P)^2}}$$ ....(equation 20)

Where;

$COV_{\Delta t}$ = The thinning coefficient of variance ranging from $0.1 \le COV_{\Delta t} \le 0.2$

= 0.2

COV_{sf} = The flow stress coefficient of variance

= 0.2

COV_P = Pressure coeffficient of variance

= 0.05

D_{s1} = Damage State 1

= 1

D_{s2} = Damage State 2

= 2

D_{s3} = Damage State 3

= 4

at RBI Date

$$ß_1^{Thin} = \frac{1 - D_{S1}.A_{rt} - SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2 + (1 - D_{S1}.A_{rt})^2.COV_{sf}{}^2 + (SR_P^{Thin})^2.(COV_P)^2}}$$

$= 3.8357$

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{{D_{S2}}^2.{A_{rt}}^2.{COV_{\Delta t}}^2+(1-D_{S2}.A_{rt})^2.{COV_{sf}}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 3.4977

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{{D_{S3}}^2.{A_{rt}}^2.{COV_{\Delta t}}^2+(1-D_{S3}.A_{rt})^2.{COV_{sf}}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 2.1452

at RBI Plan Date

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{{D_{S1}}^2.{A_{rt}}^2.{COV_{\Delta t}}^2+(1-D_{S1}.A_{rt})^2.{COV_{sf}}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 3.6324

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{{D_{S2}}^2.{A_{rt}}^2.{COV_{\Delta t}}^2+(1-D_{S2}.A_{rt})^2.{COV_{sf}}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 2.6960

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{{D_{S3}}^2.{A_{rt}}^2.{COV_{\Delta t}}^2+(1-D_{S3}.A_{rt})^2.{COV_{sf}}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= -0.1717

STEP 13

For tank bottom components, determine the base damage factor for thining using Table 4.8 in API RP 581 Part 2 and based on Art parameter from STEP 6.

STEP 14

For all components (excluding tank bottoms covered in STEP 13), calculate the base damage factor, D_{fB}^{Thin} using equation 21.

at RBI Date

$$D_{fB}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4} \quad \text{....(equation 21)}$$

= 21.1255486

at RBI Plan Date

$$D_{fB}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4}$$

= 735.6162294

STEP 15

Determine the DF for thinning, D_f^{Thin} using equation equation 22.

$$D_f^{Thin} = \text{Max}[(\frac{(D_{fb}^{Thin} . F_{IP} . F_{DL} . F_{WD} . F_{AM} . F_{SM})}{F_{OM}}), 0.1] \quad \text{………………....(equation 22)}$$

Where;

F_{IP} = DF adjustent for injection points (for piping circuit)
= 0

F_{DL} = DF adjustment for dead legs (for piping only used to intermittent service)
= 0

F_{WD} = DF adjustment for welding construction (for only AST Bottom)
= 0

F_{AM} = DF adjustment for AST maintenance per API STD 653 (for only AST)
= 0

F_{SM} = DF adjustment for settlement (for only AST Bottom)
= 0

F_{OM} = DF adjustment for online monitoring based on Table 4.8

Sour Water Corrosion for Low Velocity (≤ 20 ft/s)	=	20
Amine Corrosion for Low Velocity (≤ 20 ft/s)	=	20
Other Corrosion Mechanism	=	1

If more than one monitoring method is used, only the **highest** monitoring factor should be used

F_{OM} = 20

at RBI Date

$$D_f^{Thin} = \text{Max}[(\frac{(D_{fb}^{Thin} .}{F_{OM}}), 0.1]$$

= 1.06

at RBI Plan Date

$$D_f^{Thin} = \text{Max}[(\frac{(D_{fb}^{Thin} .}{F_{OM}}), 0.1]$$

= 36.78

DETERMINE THE TYPE OF THINNING

The type of thinning (wheter it is local or general) can be determined from Table 4.1.11 (Refer to 2.B.1.2 from API RP 581 3rd Edition Part 2 - Annex 2.B), as follow:

Table 4.1.11 Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
Hydrochloric Acid (HCl) Corrosion	-	Local
High Temperature Sulfidic/Naphthenic Acid Corrosion	TAN ≤ 0.5	General
	TAN > 0,5	Local
High Temperature H_2S/H_2 Corrosion	-	General
Sulfuric Acid (H_2SO_4) Corrosion	Low Velocity ≤0.61 m/s (2ft/s) for CS, ≤1.22 m/s (2ft/s) for SS, and ≤1.83m/s(6ft/s) for higher alloys	General
	High Velocity ≥0.61 m/s (2ft/s) for CS, ≥1.22 m/s (2ft/s) for SS, and ≥1.83m/s(6ft/s) for higher alloys	Local
Hydrofluoric Acid (HF) Corrosion	-	Local
Sour Water Corrosion	Low Velocity: ≤6.1m/s(20ft/s)	General
	High Velocity: >6.1m/s(20ft/s)	Local
Amine Corrosion	Low Velocity <1.5 m/s (5ft/s) rich amine <6.1 m/s (20ft/s) lean amine	General
	High Velocity >1.5 m/s (5ft/s) rich amine >6.1 m/s (20ft/s) lean amine	Local
High Temperature Oxidation	-	General
Acid Sour Water Corrosion	<1.83 m/s (6 ft/s)	General
	≥1.83 m/s (6 ft/s)	Local
Cooling Water Corrosion	≤0.91 m/s (3 ft/s)	Local
	0.91-2.74 m/s (3-9 ft/s)	General
	>2.74 m/s (9 ft/s)	Local
Soil Side Corrosion	-	Local
CO_2 Corrosion	-	Local
AST Bottom	Product Side	Local
	Soil Side	Local

If both general and localized thinning mechanisms are possible, then the type of thinning should be designated as **localized**. The type of thinning designated will be used to determine the effectiveness of inspection performed.

Type of Thinning DF : **Localized**

Probability of Failure

SCC - Amine Cracking Damage Factor Calculation

Attachment 4-1-2

Table 4.1.12 Step to Calculate SCC-Amine Cracking Damage Factor

Step-1	Determine the susceptibility for cracking using Figure 4.1. Note that a HIGH susceptibility should be used if cracking is confirmed to be present.
Step-2	Based on the susceptibility in STEP 3, determine the severity index, S_{VI} from Table 4.1.14.
Step-3	Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation
Step-4	Determine the number of inspections, and the corresponding inspection effectiveness category using Section 7.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.
Step-5	Determine the base DF for amine cracking, D_{fB}^{Amine} , using Table Table 4.1.15 based on the number of, and the highest inspection effectiveness determined in STEP 4, and the severity index, S_{VI}, from STEP 2.
Step-6	Calculate the escalation in the DF based on the time in-service since the last inspection using the age from STEP 3 and Equation 23. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. $D_f^{amine} = D_{fB}^{Amine} \cdot (Max\ [age, 1.0])^{1.1}$

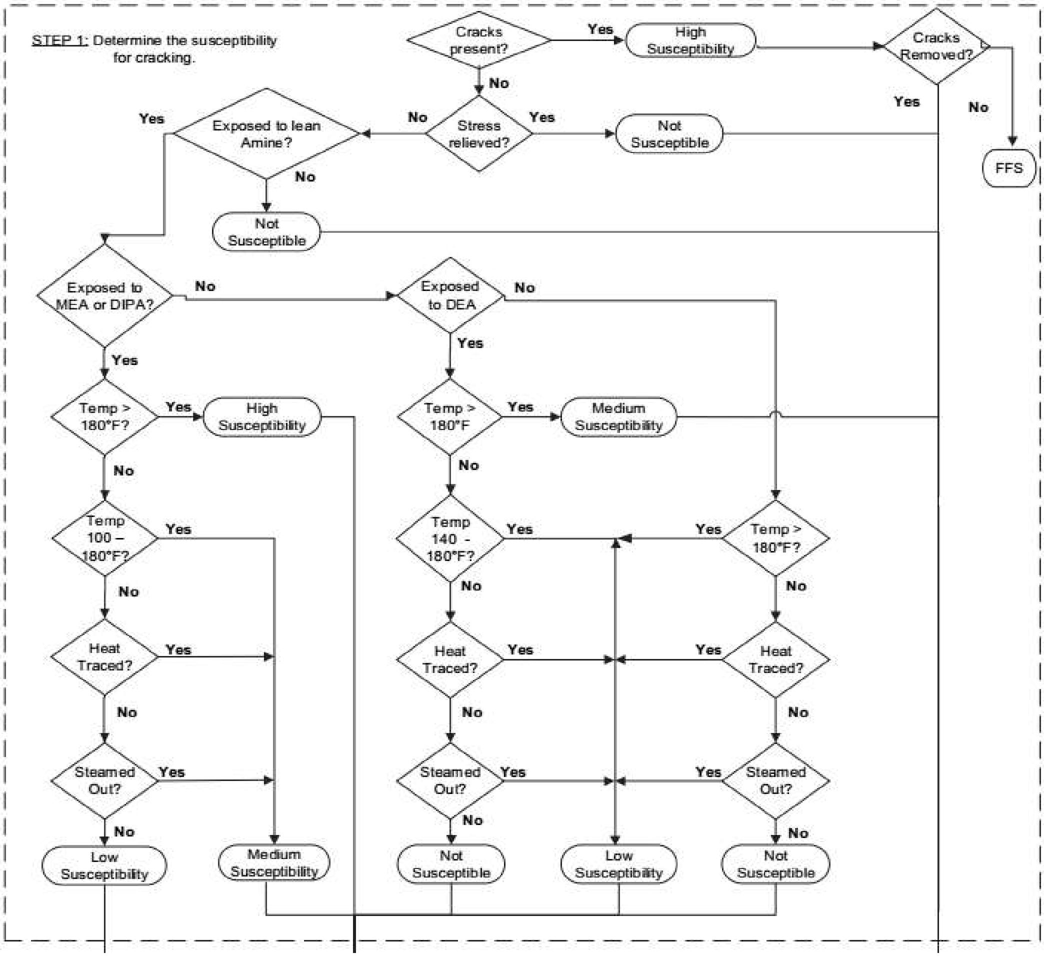


Figure 4.1 Determination of the Amine Cracking DF

CALCULATION OF SCC-AMINE CRACKING DAMAGE FACTOR

1. Required Data

The basic component data required for analysis is given in Table 4.1 and the specific data required for determination of the amine cracking DF is provided in Table 4.1.13 (Refer to Table 7.1 API RP 581 Part 2).

Table 4.1.13 – Data Required for Determination of the Damage Factor – Amine Cracking

Basic Data	Value	Unit	Comments
Susceptibility	Low		The susceptibility is determined by expert advice or using the procedures in this section.
Amine Solution Composition	Lean Amine		Determine what amine solution composition is being handled in this component. Fresh amine has not been exposed to H_2S or CO_2. Lean amine contains low levels of H_2S or CO_2. Rich amine contains high levels of H_2S or CO_2. For components exposed to both lean and rich amine solutions (i.e., amine contactors and regenerators), indicate lean.
Maximum Process Temperature	128.67	°C	Determine the maximum process temperature in this component.
Steam out	Yes		Determine whether the component has been steamed out prior to water flushing to remove residual amine.
Age	6	years	Use inspection history to determine the time since the last SCC inspection.
Inspection Effectiveness Category	E-None or Ineffective		The effectiveness category that has been performed on the component.
Number of Inspections	0	times	The number of inspections in each effectiveness category that have been performed.

2. SCC-Amine Cracking Calculation

STEP 1

Determine the susceptibility for cracking using Figure 4.1 (Refer to Figure 7.1. API RP 581 Part 2 Note that a HIGH susceptibility should be used if cracking is confirmed to be present.

Suscpetibility : Low

STEP 2

Based on the susceptibility in STEP 3, determine the severity index, S_{VI} from Table 4.1.14 (Refer to Table 7.2 API RP 581 Part 2)

Suscpetibility from STEP 1 : Low

Severity Index - S_{VI} : 10

Table 4.1.14 – Determination of Severity Index - Amine Cracking

Susceptibility	Severity Index - S_{VI}
High	1000
Medium	100
Low	10
None	0

STEP 3

Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.

Determine the time in service, age, since the last inspection.

age at the RBI Date

age_{RI} = RBI Date - Last Inspection Date

(Last inspection date using the installment date)

age_{RI} = 1/1/2020 - 6/1/2014

= 6 year

age at the RBI Plan Date

age_{RI} = RBI Plan Date - Last Inspection Date

(Last inspection date using the installment date)

age_{RI} = 1/1/2024 - 6/1/2014

= 10 year

STEP 4

Determine the number of inspections, and the corresponding inspection effectiveness category using Section 7.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

Damage Mechanism : SCC

Inspection Performed : 0

Inspection Category : E

Inspection Effectiveness : Ineffective / No Inspection

STEP 5

Determine the base DF for amine cracking, D_{fB}^{Amine} , using Table 4.1.15 (Refer to Table 6.3 API RP 581 Part 2) based on the number of, and the highest inspection effectiveness determined in STEP 4, and the severity index, S_{VI} , from STEP 2.

Inspection Effectiveness : Ineffective / No Inspection

Inspection Performed : 0

Inspection Category : E

S_{VI} according to susceptibility to SCC : 10

Table 4.1.15 - SCC Damage Factors - All SCC Mechanisms

S_{VI}	E	1 Inspection				2 Inspections				3 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	8	3	1	1	6	2	1	1	4	1	1	1
50	50	40	17	5	3	30	10	2	1	20	5	1	1
100	100	80	33	10	5	60	20	4	1	40	10	2	1
500	500	400	170	50	25	300	100	20	5	200	50	8	1
1000	1000	800	330	100	50	600	200	40	10	400	100	16	2
5000	5000	4000	1670	500	250	3000	1000	250	50	2000	500	80	10

S_{VI}	E	4 Inspections				5 Inspections				6 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	2	1	1	1	1	1	1	1	1	1	1	1
50	50	10	2	1	1	5	1	1	1	1	1	1	1
100	100	20	5	1	1	10	2	1	1	5	1	1	1
500	500	100	25	2	1	50	10	1	1	25	5	1	1
1000	1000	200	50	5	1	100	25	2	1	50	10	1	1
5000	5000	1000	250	25	2	500	125	5	1	250	50	2	1

(Both halves headed "Inspection Effectiveness".)

Base Damage factor

$D_{fB}^{amine} = \quad 10$

STEP 6

Calculate the escalation in the DF based on the time in-service since the last inspection using the age from STEP 3 and equation 23. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

Damage Factor at RBI Date

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[age, 1.0])^{1.1} \qquad \text{………………....(equation 23)}$$

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[6,1.0])^{1.1}$$

$$D_f^{amine} = \quad 71.7739$$

Damage Factor at RBI Plan Date

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[age, 1.0])^{1.1}$$

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[10,1.0])^{1.1}$$

$$D_f^{amine} = \quad 125.8925$$

Probability of Failure

SCC-Sulfide Stress Cracking Damage Factor Calculation

Attachment 4-1-3

Table 4.1.16 Step to Calculate SCC-Sulfide Stress Cracking Damage Factor

Step-1	Determine the environmental severity (potential level of hydrogen flux) for cracking based on the H_2S content of the water and its pH using Table 4.1.18.
Step-2	Determine the susceptibility for cracking using Figure 8.1 and Table 4.1.19 based on the environmental severity from STEP 1, the maximum Brinnell hardness of weldments, and knowledge of whether the component was subject to PWHT. Note that a HIGH susceptibility should be used if cracking is confirmed to be present.
Step-3	Based on the susceptibility in STEP 3, determine the severity index, S_{VI}, from Table 4.1.20.
Step-4	Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation
Step-5	Determine the number of inspections, and the corresponding inspection effectiveness category using Section 8.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.
Step-6	Determine the base DF for sulfide stress cracking, D_{fB}^{SSC} , using Table 4.1.21 based on the number of, and the highest inspection effectiveness determined in STEP 5, and the severity index, S_{VI}, from STEP 3.
Step-7	Calculate the escalation in the DF based on the time in-service since the last inspection using the age from STEP 4 and Equation 24. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. $$D_f^{SCC} = D_{fB}^{SCC} \cdot (Max\ [age, 1.0])^{1.1}$$

CALCULATION OF SULFIDE STRESS CRACKING DAMAGE FACTOR

1. Required Data

The basic component data required for analysis is given in Table 4.1 and the specific data required for determination of the sulfide stress cracking DF is provided in Table 4.1.17 (Refer to Table 8.1 API RP 581 Part 2)

Table 4.1.17 – Data Required for Determination of the Damage Factor – SSC

Basic Data	Value	Unit	Comments
Susceptibility	None		The susceptibility is determined by expert advice or using the proceduresin this section.
Presence of Water	Yes		Determine whether free water is present in the component. Consider not only normal operating conditions, but also startup, shutdown, process upsets, etc.
H2S Content of Water	119	ppm	Determine the H_2S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore
pH of Water	7.83		Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Presence of Cyanides	No		Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also startup and shutdown conditions.
Max Brinnell Hardness	<200	HB	Determine the maximum Brinnell hardness actually measured at the weldments of the steel components. Report readings actually taken as Brinnell, not converted from finer techniques (e.g., Vickers, Knoop, etc.) If actual readings are not available, use the maximum allowable hardness permitted by the fabrication specification.
Age	6	years	Use inspection history to determine the time since the last SCC inspection.
Inspection Effectiveness Category	E-None or Ineffective		The effectiveness category that has been performed on the component.
Number of Inspections	0	times	The number of inspections in each effectiveness category that have been performed.

2. SCC-Sulfide Stress Cracking Calculation

STEP 1

Determine the environemental severity (potential level of hydrogen flux) for cracking based on the H_2S Content of water and its pH using Table 4.1.18 (Refer to Table 8.2 API RP 581 Part 2)

pH : 7.83

Content of water : 119.00 ppm

Table 4.1.18 - Environmental Severity - SSC

pH of Water	Environmental Severity as Function of H_2S Content of Water			
	<50 ppm	50 to 1000 ppm	1000 to 10000 ppm	>10000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate	High
>9.0	Low	Moderate	High	High

Environmental Severity of H_2S : Moderate

STEP 2

Determine the susceptibility for cracking using figure 8.1 API RP 581 Part 2 and Table 4.1.19 (Refer to Table 8.3 API RP 581 Part 2) based on the environmental severity from STEP 1, the maximum brinnel hardness of weldments, and knowledge of whether the component was subject to PWHT.

Table 4.1.19 - Susceptibility to SSC - SSC

Environmental Severity	Susceptibility to SSC as a Function of Heat Treatment					
	As-Welded Max Brinnell Hardness			PWHT Max Brinnell Hardness		
	< 200	200-237	> 237	< 200	200-237	> 237
High	Low	Medium	High	Not	Low	Medium
Moderate	Low	Medium	High	Not	Not	Low
Low	Low	Low	Medium	Not	Not	Not

Maximum allowable hardness for material ASME SA-516 Gr.70 is under 200HB (Refer to https://gangsteel.net/News/A516GR70.html)

Maximum Brinell Hardness : <200 hB

PWTH : Yes

Susceptibility to SSC : None

STEP 3

Based on the susceptibility in STEP 3, determine the severity index, S_{VI}, from Table 4.1.20 (Refer to Table 8.4 API RP 581 Part 2).

S_{VI} according to susceptibility to SSC : 0

Table 4.1.20 - Determination of Severity Index - SSC

Susceptibility	Severity Index - S_{VI}
High	100
Medium	10
Low	1
None	0

STEP 4

Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation

age at the RBI Date

age_{RBI} = RBI Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2020 - 6/1/2014

= 6 years

age at the RBI Plan Date

age_{RBI} = RBI Plan Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2024 - 6/1/2014

= 10 years

STEP 5

Determine the number of inspections, and the corresponding inspection using Section 8.6.2 for past inspections performed during the in-service time. Combine the inspections toeffectiveness category the highest effectiveness performed using Section 3.4.3.

Damage Mechanism : SCC

Inspection Performed : 0

Inspection Category : E

Inspection Effectiveness : Ineffective / No Inspection

STEP 6

Determine the base DF for sulfide stress cracking, D_{fB}^{SCC} , using Table 4.1.21 (Refer to Table 6.3 API RP 581 Part 2) based on the number of, and the highest inspection effectiveness determined in STEP 5, and the severity index, S_{VI}, from STEP 3.

Inspection Effectiveness : Ineffective / No Inspection

Inspection Performed : 0

Inspection Category : E

S_{VI} according to susceptibility to SCC : 0

Table 4.1.21 - SCC Damage Factors - All SCC Mechanisms

S_{VI}	E	Inspection Effectiveness											
		1 Inspection				2 Inspections				3 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	8	3	1	1	6	2	1	1	4	1	1	1
50	50	40	17	5	3	30	10	2	1	20	5	1	1
100	100	80	33	10	5	60	20	4	1	40	10	2	1
500	500	400	170	50	25	300	100	20	5	200	50	8	1
1000	1000	800	330	100	50	600	200	40	10	400	100	16	2
5000	5000	4000	1670	500	250	3000	1000	250	50	2000	500	80	10

S_{VI}	E	Inspection Effectiveness											
		4 Inspections				5 Inspections				6 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	2	1	1	1	1	1	1	1	1	1	1	1
50	50	10	2	1	1	5	1	1	1	1	1	1	1
100	100	20	5	1	1	10	2	1	1	5	1	1	1
500	500	100	25	2	1	50	10	1	1	25	5	1	1
1000	1000	200	50	5	1	100	25	2	1	50	10	1	1
5000	5000	1000	250	25	2	500	125	5	1	250	50	2	1

Base Damage factor

$D_{fB}^{SCC}=$ 0

STEP 7

Calculate the escalation in the DF based on the time in-service since the last inspection using the age from STEP 4 and equation 24. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

Damage factor at RBI Date

$D_{f}^{SSC}= D_{fB}^{SCC}.(Max[age,1.0])^{1.1}$ ……………….....……….....(equation 24)

$D_{f}^{SCC}= 0.(Max[6,1.0])^{1.1}$

$D_{f}^{SCC}=$ 0.0000

Damage factor at RBI Plan Date

$D_f^{SSC} = D_{fB}^{SCC} .(Max[age, 1.0])^{1.1}$

$D_f^{SCC} = 0.(Max[10,1.0])^{1.1}$

$D_f^{SCC} =$ 0.0000

Probability of Failure

SCC-HIC/SOHIC-H_2S Damage Factor Calculation

Attachment 4-1-4

Table 4.1.22 Step to Calculate SCC-HIC/SOHIC-H2S Damage Factor

Step-1	Determine the environmental severity (potential level of hydrogen flux) for cracking based on the H2S content of the water and its pH using Table 4.1.24. Note that a HIGH environmental severity should be used if cracking is confirmed to be present.
Step-2	Determine the susceptibility for cracking using Figure 9.1 and Table 4.1.25 based on the environmental severity from STEP 1, the sulfur content of the carbon steel, product form and knowledge of whether the component was subject to PWHT
Step-3	Based on the susceptibility in STEP 2, determine the severity index, S_{VI}, from Table 4.1.26.
Step-4	Determine the time in-service, age , since the last Level A, B or C inspection was performed performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.
Step-5	Determine the number of inspections, and the corresponding inspection effectiveness category using Section 9.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.
Step-6	Determine the base DF for HIC/SOHIC-H_2S, $D_{fB}^{HIC/SOHIC-H_2S}$ using Table 4.1.27 based on the number of, and the highest inspection effectiveness determined in STEP 5, and the severity index S_{VI} from STEP 3.
Step-7	Determine the on-line adjustment factor, F_{OM}, from Table 4.1.28 .
Step-8	Calculate the final DF accounting for escalation based on the time in-service since the last inspection using the age from STEP 4 and Equation 25. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. The equation also applies the adjustment factor for online monitoring. $$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} \cdot (Max[age, 1.0])^{1.1}}{Fom}$$

CALCULATION OF SCC-HIC/SOHIC-H_2S CRACKING DAMAGE FACTOR

1. Required Data

The basic component data required for analysis is given in Table 4.1 and the specific data required for determination of the HIC/SOHIC-H2S cracking DF is provided in Table 4.1.23 (Refer to Table 9.1 API RP 581 Part 2).

Table 4.1.23 – Data Required for Determination of the Damage Factor – HIC/SOHIC-H_2S Cracking

Basic Data	Value	Unit	Comments
Susceptibility	Medium		The susceptibility is determined by expert advice or using the proceduresin this section.
Presence of Water	Yes		Determine whether free water is present in the component. Consider not only normal operating conditions, but also startup, shutdown, process upsets, etc.
H2S Content of Water	119	ppm	Determine the H2S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore
pH of Water	7.83		Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Presence of Cyanides	No		Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also startup and shutdown conditions.
Sulfur Content of Plate Steel	0.035	%	Determine the sulfur content of the steel used to fabricate the component. This information should be available on MTR's in equipment files. If not available, it can be estimated from the ASTM or ASME specification of the steel listed on the U-1 form in consultation with materials engineer.
Steel Product Form (Plate or Pipe)	Plate		Determine what product form of steel was used to fabricate the component. Most components are fabricated from rolled and welded steel plates (e.g. A285, A515, A516,, etc.), but some small-diameter components is fabricated from steel pipe and piping components. Most small-diameter piping is fabricated from steel pipe (e.g. A106, A53, API 5L, etc.) and piping components (e.g. A105, A234, etc.), but most large diameter piping (above approximately NPS 16 diameter) is fabricated from rolled and welded plate steel.

Table 4.1.23 – Data Required for Determination of the Damage Factor – HIC/SOHIC-H_2S Cracking

Basic Data	Value	Unit	Comments
Age	6	years	Use inspection history to determine the time since the last SCC inspection.
Inspection Effectiveness Category	E-None or Ineffective		The effectiveness category that has been performed on the component.
On-Line Monitoring	Key Process Variables		The type of proactive corrosion monitoring methods or tools employed such as hydrogen probes and/or process variable monitoring.
Number of Inspections	0	times	The number of inspections in each effectiveness category that have been performed.

2. SCC- HIC/SOHIC-H_2S Cracking Calculation

STEP 1

Determine the environmental severity (potential level of hydrogen flux) for cracking based on the H_2S content of the water and its pH using Table 4.1.24 (Refer to Table 9.2 API RP 581 Part 2)

pH : 7.83
H2S Content of water : 119 ppm

Table 4.1.24 - Environmental Severity - HIC/SOHIC-H_2S Content of Water

pH of Water	Environmental Severity as Function of H_2S Content of Water			
	<50 ppm	50 to 1000 ppm	1000 to 10000 ppm	>10000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate	High
>9.0	Low	Moderate	High	High

Enviromental Severity : Moderate

STEP 2

Determine the susceptibility for cracking using Figure 9.1 API RP 581 Part 2 and Table 4.1.25 (Refer to Table 9.3 API RP 581 Part 2) based on the environmental severity from STEP 1, the maximum brinnel hardness of weldments, and knowledge of whether the component was subject to PWHT.

Steel sulphur content for material ASME SA-516 Gr.70 is not exceed 0.035%
(Refer to https://www.alro.com/divsteel/metals_gridpt.aspx?gp=0045)
Steel sulfur content: : 0.035%
Environmental severity: : Moderate
Post Weld Heat Treatment (PWHT) : Yes
Susceptibility for Cracking: : Medium

Table 4.1.25 - Susceptibility to Cracking - HIC/SOHIC-H_2S

Environmental Severity	Susceptibility to Cracking as a Function of Steel Sulfur Content					
	High Sulfur Steel > 0.01% S		Low Sulfur Steel ≤ 0.01% S		Product Form - Seamless/Extruded Pipe	
	As-Welded	PWHT	As-Welded	PWHT	As-Welded	PWHT
High	High	High	High	Medium	Medium	Low
Moderate	High	Medium	Medium	Low	Low	Low
Low	Medium	Low	Low	Low	Low	Low

STEP 3

Based on the susceptibility in STEP 2, determine the severity index, S_{VI}, from Table 4.1.26 (Refer to Table 9.4 API RP 581 Part 2).

Table 4.1.26 - Determination of Severity Index - HIC/SOHIC-H_2S

Susceptibility	Severity Index - S_{VI}
High	100
Medium	10
Low	1
None	0

Suscpetibility from STEP 2 : Medium

S_{VI} according to susceptibility : 10

STEP 4

Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation

age at the RBI Date

age_{RBI} = RBI Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2020 - 6/1/2014

= 6 year

age at the RBI Plan Date

age_{RBI} = RBI Plan Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2024 - 6/1/2014

= 10 year

STEP 5

Determine the number of inspections, and the corresponding inspection using Section 9.6.2 for past inspections performed during the in-service time. Combine the inspections toeffectiveness category the highest effectiveness performed using Section 3.4.3.

Damage Mechanism	:	SCC
Inspection Performed	:	0
Inspection Category	:	E
Inspection Effectiveness	:	Ineffective / No Inspection

STEP 6

Determine the base DF for sulfide stress cracking $D_{fB}^{HIC/SOHIC-H_2S}$ using Table 4.1.27 (Refer to Table 6.3 API RP 581 Part 2) based on the number of, and the highest inspection effectiveness determined in STEP 5, and the severity index S_{VI} from STEP 3.

Inspection Effectiveness	:	Ineffective / No Inspection
Inspection Performed	:	0
Inspection Category	:	E
S_{VI} according to susceptibility to SCC	:	10

Table 4.1.27 - SCC Damage Factors - All SCC Mechanisms

S_{VI}	Inspection Effectiveness												
	E	1 Inspection				2 Inspections				3 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	8	3	1	1	6	2	1	1	4	1	1	1
50	50	40	17	5	3	30	10	2	1	20	5	1	1
100	100	80	33	10	5	60	20	4	1	40	10	2	1
500	500	400	170	50	25	300	100	20	5	200	50	8	1
1000	1000	800	330	100	50	600	200	40	10	400	100	16	2
5000	5000	4000	1670	500	250	3000	1000	250	50	2000	500	80	10

S_{VI}	Inspection Effectiveness												
	E	4 Inspections				5 Inspections				6 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	2	1	1	1	1	1	1	1	1	1	1	1
50	50	10	2	1	1	5	1	1	1	1	1	1	1
100	100	20	5	1	1	10	2	1	1	5	1	1	1
500	500	100	25	2	1	50	10	1	1	25	5	1	1
1000	1000	200	50	5	1	100	25	2	1	50	10	1	1
5000	5000	1000	250	25	2	500	125	5	1	250	50	2	1

Base Damage factor

$D_f^{HIC/SOHIC-H_2S}$ = 10

STEP 7

Determine the on-line adjustment factor, F_{OM} , from Table 4.1.28 (Refer to Table 9.5 API RP 581 Part 2)

Table 4.1.28 - On-Line Monitoring Adjustment Factors for HIC/SOHIC-H_2S

On-Line Monitoring Method	Adjustment Factors as a Function of On-Line Monitoring - F_{OM}
Key Process Variables	2
Hydrogen Probes	2
Key Process Variables and Hydrogen Probes	4

On-Line Monitoring Method : Key Process Variables

Adjustment Factor (F_{OM}) : 2

STEP 8

Calculate the final DF accounting for escalation based on the time in-service since the last inspection using the age from STEP 4 and equation 25. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. The equation also applies the adjustment factor for online monitoring

Damage Factor at RBI Date

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} .(Max[age,1.0])^{1.1}}{Fom} \quad \text{...(equation 25)}$$

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} .(Max[6,1.0])^{1.1}}{Fom}$$

$$D_f^{HIC/SOHIC-H_2S} = 35.8869$$

Damage Factor at RBI Plan Date

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} .(Max[age,1.0])^{1.1}}{Fom}$$

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} .(Max[10,1.0])^{1.1}}{Fom}$$

$$D_f^{HIC/SOHIC-H_2S} = 62.9463$$

Probability of Failure

Corrosion Under Insulation Damage Factor – Ferritic Component Damage Factor Calculation

Attachment 4-1-5

Table 4.1.29 Step to Calculate Corrosion Under Insulation Damage Factor – Ferritic Component Damage Factor

Step-1	Determine the furnished thickness, t , and age, for the component from the installation date.
Step-2	Determine the base corrosion rate,C_{rB}, based on the driver and operating temperature using Table 4.1.31.
Step-3	Compute the final corrosion rate using equation 26 below. $C_r = C_{rB} \cdot F_{INS} \cdot F_{CM} \cdot F_{IC} \cdot \max[F_{EQ}, F_{IF}]$
Step-4	Determine the time in-service, age_{tk}, since the last known thickness, t_{rde} (see Section 4.5.5). The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion (see Section 4.5.5). If no measured thickness is available, set t_{rde} = t and age_{tk} = age
Step-5	Determine the in-service time, age_{coat} , since the coating has been installed using Equation below.
	$age_{coat} = Calculation\ Date\ - Coating\ Installation\ Date$
Step-6	Determine the coating adjustment,$Coat_{adj}$, using Equations from API RP 581 Part 2 Section 16
Step-7	Determine the in-service time, age , over which CUI may have occurred using Equation below. $age = age_{tk} - Coat_{adj}$
Step-8	Determine the allowable stress, S , weld joint efficiency, E , and minimum required thickness, tmin , per the original construction code or API 579-1/ASME FFS-1 [10]. In cases where components are constructed of uncommon shapes or where the component's minimum structural thickness, tc , may govern, the user may use the tc in lieu of tmin where pressure does not govern the minimum required thickness criteria.
Step-9	Determine the A_{rt} parameter using Equation below based on the age and t_{rde} from STEP 4, Cr from STEP 3.
	$A_{rt} = \frac{C_r \cdot age}{t_{rde}}$
Step-10	Calculate the Flow Stress, FS^{CUIF} ,using E from STEP 8 and Equation below
	$FS^{CUIF} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1$
Step-11	Calculate strength ratio parameter, SR_P^{Thin} , using one of Equation below $SR_P^{CUIF} = \frac{S \cdot E}{FS^{CUIF}} \cdot \frac{Min\ (t_{min}, t_c)}{t_{rde}}$

Table 4.1.29 Step to Calculate Corrosion Under Insulation Damage Factor – Ferritic Component Damage Factor

Step-11	$SR_P^{CUIF} = \frac{P \cdot D}{\alpha \cdot FS^{CUIF} \cdot t_{rde}}$
Step-12	Determine the number of inspections, $N_A^{CUIF}, N_B^{CUIF}, N_C^{CUIF}, N_D^{CUIF}$, and the corresponding inspection effectiveness category using Section 16.6.2 for all past inspections.
Step-13	Determine the inspection effectiveness factors, $I_1^{CUIF}, I_2^{CUIF}, I_3^{CUIF}$, using Equation below, Prior Probabilities, $Pr_{p1}^{CUIF}, Pr_{p2}^{CUIF}, Pr_{p3}^{CUIF}$, from Table 4.1.33, Conditional Probabilities, $Co_{p1}^{CUIF}, Co_{p2}^{CUIF}, Co_{p3}^{CUIF}$, from Table 4.1.34, and the number of inspections, $N_A^{CUIF}, N_B^{CUIF}, N_C^{CUIF}, N_D^{CUIF}$, in each effectiveness level obtained from STEP 12. $I_1^{CUIF} = Pr_{p1}^{CUIF} \left(Co_{p1}^{CUIF}\right)^{N_A^{CUIF}} \left(Co_{p1}^{CUIF}\right)^{N_B^{CUIF}} \left(Co_{p1}^{CUIF}\right)^{N_C^{CUIF}} \left(Co_{p1}^{CUIF}\right)^{N_D^{CUIF}}$ $I_2^{CUIF} = Pr_{p2}^{CUIF} \left(Co_{p2}^{CUIF}\right)^{N_A^{CUIF}} \left(Co_{p2}^{CUIF}\right)^{N_B^{CUIF}} \left(Co_{p2}^{CUIF}\right)^{N_C^{CUIF}} \left(Co_{p2}^{CUIF}\right)^{N_D^{CUIF}}$ $I_3^{CUIF} = Pr_{p3}^{CUIF} \left(Co_{p3}^{CUIF}\right)^{N_A^{CUIF}} \left(Co_{p3}^{CUIF}\right)^{N_B^{CUIF}} \left(Co_{p3}^{CUIF}\right)^{N_C^{CUIF}} \left(Co_{p3}^{CUIF}\right)^{N_D^{CUIF}}$
Step-14	Calculate the Posterior Probabilities, $Po_{p1}^{CUIF}, Po_{p2}^{CUIF}, Po_{p3}^{CUIF}$ using Equation below with $I_1^{CUIF}, I_2^{CUIF}, I_3^{CUIF}$ in Step 13. $Po_{p1}^{CUIF} = \frac{I_1^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}}$ $Po_{p2}^{CUIF} = \frac{I_2^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}}$ $Po_{p3}^{CUIF} = \frac{I_3^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}}$
Step-15	Calculate the parameters, $\beta_1^{CUIF}, \beta_2^{CUIF}, \beta_3^{CUIF}$, using Equation below and assigning $COV_{\Delta t} = 0.20, COV_{Sf} = 0.20, COV_P = 0.05$ $\beta_1^{CUIF} = \frac{1 - D_{S_1} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_1}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_1} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$ $\beta_2^{CUIF} = \frac{1 - D_{S_2} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_2}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_2} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$ $\beta_3^{CUIF} = \frac{1 - D_{S_3} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_3}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_3} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$

Table 4.1.29 Step to Calculate Corrosion Under Insulation Damage Factor – Ferritic Component Damage Factor

	Where $D_{S_1} = 1, D_{S_2} = 2, D_{S_3} = 4$ These are the corrosion rate factors for damage states 1, 2 and 3 as as discussed in 4.5.3 [35]. Note that the DF calculation is very sensitive to the value used for the coefficient of variance for thickness, $COV_{\Delta t}$. The $COV_{\Delta t}$is in the range 0.10≤ $COV_{\Delta t}$≤0.20 , with a recommended conservative value of $COV_{\Delta t} = 0.20$
Step-16	Calculate D_f^{CUIF} , using one of Equation below $D_f^{CUIF} = \left[\frac{\left(Po_{p1}^{CUIF}\phi\left(-\beta_1^{CUIF}\right)\right) + \left(Po_{p2}^{CUIF}\phi\left(-\beta_2^{CUIF}\right)\right) + \left(Po_{p3}^{CUIF}\phi\left(-\beta_3^{CUIF}\right)\right)}{1.56E-0.4}\right]$

CALCULATION OF CORROSION UNDER INSULATION (CUI) DAMAGE FACTOR - FERRITIC COMPONENT

1. Required Data

The basic component data required for analysis is given in Table 4.1 and the specific data required for determination of the DF for CUI is provided in Table 4.1.30 (Refer to Table 16.1 API RP 581 Part 2)

Table 4.1.30 – Data Required for Determination of the DF – CUI

Basic Data	Value	Unit	Comments
Ins.Type	Calcium Silicate		Type of insulation per Table 16.3.
Driver	Marine/Cooling Tower Drift Area		The drivers for external CUI corrosion. This can be the condition of the insulation and weather resistant jacketing, the weather at a location (e.g. Marine), the potential for cooling tower drift, the use of sprinkler systems, or other contributors.
Corrosion Rate (mm/yr:mpy)	2	mpy	Corrosion rate for external CUI corrosion. Based on Temperature, and Driver (see below), or user input.
Coating Installation Date	6/1/2014		The date the coating was installed
Coating Quality	Medium		Relates to the type of coating applied under the insulation, for example: None – No coating or primer only. Medium – Single coat epoxy. High – Multi coat epoxy or filled epoxy.
Equipment Design /Fabrication Penalty	Yes		If the equipment has a design or fabrication detail which allows water to pool and increase metal loss rates, such as piping supported directly on beams, vessel external stiffener rings or insulation supports or other such configuration that does not allow water egress and/or does not allow for proper coating maintenance, external metal loss can be more severe.
Complexity	Below Average		The number of protrusions such as branch connections, nozzles, pipe supports, poorly designed insulation support rings, etc. and any design feature that would promote the retention and/or collection of moisture. The complexity is defined as follows: Below Average – Penetrations in the insulation system do not exist

Table 4.1.30 – Data Required for Determination of the DF – CUI

Basic Data	Value	Unit	Comments
			Average – Some penetrations in the insulation systems, or the insulation system is slightly complex do to some appurtenances or multiple branches in a piping system. Above Average – Many penetrations in the insulation systems, or the insulation system is very complex do to many appurtenances or multiple branches in a piping system.
Insulation Condition?	Average		Determine the insulation condition based on external visual inspection of jacketing condition. Above Average insulation will show no signs of damage (i.e. punctured, torn or missing water proofing, and missing caulking) or standing water (i.e. brown, green, or black stains). Take careful note of areas where water can enter into the insulation system, such as inspection ports and areas where the insulation is penetrated (i.e. nozzles, ring supports and clips). Horizontal areas also accumulate water. Average insulation condition will have good jacketing with some areas of failed weatherproofing or small damaged areas. Note that the corrosion rates for CUI represent average/typical insulation systems found in most plants. This should be considered when determining if any adjustment or penalty multipliers apply
Pipe Support Penalty	Yes		If piping is supported directly on beams or other such configuration that does not allow for proper coating maintenance, CUI can be more severe.
Interface Penalty	Yes		If the piping has an interface where it enters either soil or water, this area is subject to increased corrosion.
Effectiveness Category	E-None or Ineffective		The effectiveness category that has been performed on the component.
Number of Inspections	0	times	The number of inspections in each effectiveness category that have been performed.
Thickness Reading	0.472	inch	The thickness used for the DF calculation is either the furnished thickness or the measured thickness (see Section 4.5.5).

Table 4.1.30 – Data Required for Determination of the DF – CUI

Basic Data	Value	Unit	Comments
Thickness Reading Date	6/1/2014		The date at which the thickness measurement used in the calculation was obtained. If no acceptable inspection has been conducted, the installation date should be used.

2. Corrosion Under Insulation (CUI) - Ferritic Component Calculation

STEP 1

Determine the furnished thickness, t , and age, for the component from the installation date.

t = 0.472 inch

= 12.00 mm

age at RBI Date

age = RBI Date - Installment Date

= 1/1/2020 - 6/1/2014

= 6 years

age at RBI Plan Date

age = RBI Plan Date - Installment Date

= 1/1/2024 - 6/1/2014

= 10 years

STEP 2

Determine the base corrosion rate, C_{rB}, based on the driver and operating temperature using Table 4.1.31 (Refer to Table 16.2 API RP 581 Part 2).

Driver = Severe

Operating Temperature = 263.60 °F

= 128.67 °C

Table 4.1.31 - Corrosion Rates for Calculation of the DF -CUI

Operating Temperature (°F)	Corrosion Rate as a Function of Driver (1) (mpy)			
	Marine/Cooling Tower Drift Area	Temperate	Arid/Dry	Severe
10	0	0	0	0
18	1	0	0	3
43	5	3	1	10
90	5	3	1	10
160	10	5	2	20
225	5	1	1	10
275	2	1	0	10
325	1	0	0	5
350	0	0	0	0

C_{rB} = 2 mpy

= 0.0508 mm/y

STEP 3

Compute the final corrosion rate using equation 26 below.

$$C_r = C_{rB} \cdot F_{INS} \cdot F_{CM} \cdot F_{IC} \cdot \max[F_{EQ}, F_{IF}]$$ …………………......(equation 26)

1) Adjustment for insulation type; F_{INS} , based on Table 4.1.32 (Refer to Table 16.3 API RP 581 Part 2)

   Insulation Type = Calcium Silicate

   F_{INS} = 1.25

Table 4.1.32 - Corrosion Rate Adjustment Factor for Insulation Type

Insulation Type	Adjustment Factor, F_{INS}
Unknown/Unspecified	1.25
Foamglass	0.75
Pearlite	1.0
Fiberglass	1.25
Mineral Wool	1.25
Calcium Silicate	1.25
Asbestos	1.25

2) Adjustment for Complexity, F_{CM}

   Complexity = Below Average

   F_{CM} = 0.75

3) Adjustment for Insulation Condition, F_{IC}

   Insulation Condition = Average

   F_{IC} = 1.0

4) Adjustment for Equipment Design or Fabrication, F_{EQ}

   Pipe Support Penalty = Yes

   F_{EQ} = 2

5) Adjustment for Interface, F_{IF}

   Interface Penalty = Yes

   F_{EQ} = 2

$$C_r = C_{rB} \cdot F_{INS} \cdot F_{CM} \cdot F_{IC} \cdot \max[F_{EQ}, F_{IF}]$$

$$C_r = 10 \cdot 1.25 \cdot 0.75 \cdot 1.25 \cdot \max[2,2]$$

$C_r =$ 3.75 mpy

0.09525 mm/y

STEP 4

Determine the time in-service, age_{tk} , since the last known thickness, t_{rde} (see Section 4.5.5). The t_{rde} is the starting thickness with respect to wall loss associated with external corrosion (see Section 4.5.5). If no measured thickness is available, set $t_{rde} = t$ and $age_{tk} = age$

t_{rde} = t
= 0.472 inch
= 12.00 mm

age at the RBI Date

age_{tk} = age at RBI Date
age_{tk} = 6 years

age at the RBI Plan Date

age_{tk} = age at RBI Plan Date
10 years

STEP 5

Determine the in-service time, age_{coat} , since the coating has been installed using equation 27 below.

at the RBI Date

age_{coat} = Calculation Date - Coating Installation Date ……....(equation 27)
= 1/1/2020 - 6/1/2014
= 6 years

at the RBI Plan Date

age_{coat} = Calculation Date - Coating Installation Date
= 1/1/2024 - 6/1/2014
= 10 years

STEP 6

Determine the coating adjustment, $Coat_{adj}$, using Equations from API RP 581 Part 2 Section 16

If $age_{tk} \geq age_{coat}$

$Coat_{adj} = 0$ if no of poor coating quality ..(equation 28)
$Coat_{adj} = \min[5, Age_{coat}]$ if medium coating quality ..(equation 29)
$Coat_{adj} = \min[15, Age_{coat}]$ if high coating quality ..(equation 30)

If $age_{tk} < age_{coat}$

$Coat_{adj} = 0$ poor quality ...(eq. 31)
$Coat_{adj} = \min[5, Age_{coat}] - \min[5, age_{coat} - age_{tk}]$ med. quality ...(eq. 32)
$Coat_{adj} = \min[15, Age_{coat}] - \min[15, age_{coat} - age_{tk}]$ high quality ...(eq. 33)

Assumed that the coating quality is in poor quality and has $age_{tk} = age_{coat}$

at the RBI Date

$Coat_{adj} = 0$

at the RBI Plan Date

$Coat_{adj} = 0$

STEP 7

Determine the in-service time, age , over which CUI may have occurred using Equation 34 below.

at RBI Date

$$age = age_{tk} - Coat_{adj} \quad \text{.......................................(equation 34)}$$

= 6 years

at RBI Plan Date

$$age = age_{tk} - Coat_{adj}$$

= 10 years

STEP 8

Determine the allowable stress, S , weld joint efficiency, E , and minimum required thickness, tmin , per the original construction code or API 579-1/ASME FFS-1 [10]. In cases where components are constructed of uncommon shapes or where the component's minimum structural thickness, tc , may govern, the user may use the tc in lieu of tmin where pressure does not govern the minimum required thickness criteria.

t_{min} = 6.98 mm

S = 138000 Kpa

E = 1.00

STEP 9

Determine the A_{rt} parameter using Equation 35 below based on the age and t_{rde} from STEP 4, Cr from STEP 3.

$$A_{rt} = \frac{C_r . age}{t_{rde}} \quad \text{...(equation 35)}$$

at RBI Date

A_{rt} = 0.04762

at RBI Plan Date

A_{rt} = 0.07937

STEP 10

Calculate the Flow Stress, FS^{CUIF} ,using E from STEP 8 and Equation 36 below

$$FS^{CUIF} = \frac{(YS + TS)}{2} \cdot E \cdot 1.1 \quad \text{.......................................(equation 36)}$$

Where,

YS = Yield Strength

= 485000 Kpa

TS = Tensile Strength

= 260000 Kpa

E = Weld Joint Efficiency

= 1.0

FS^{CUIF} = 409750

STEP 11

Calculate strength ratio parameter, SR_P^{Thin} , using one of Equation 37

$$SR_P^{CUIF} = \frac{S \cdot E}{FS^{CUIF}} \cdot \frac{Min\,(t_{min}, t_c)}{t_{rde}} \quad \text{.....................................(equation 37)}$$

Where,

t_{min} = 6.98 mm

t_c = t_{min} = 6.98 mm

t_{rde} = 12.00 mm

S = 138000 Kpa

SR_P^{CUIF} = 0.1959

STEP 12

Determine the number of inspections, $N_A^{CUIF}, N_B^{CUIF}, N_C^{CUIF}, N_D^{CUIF}$, and the corresponding inspection effectiveness category using Section 16.6.2 for all past inspections.

N_A^{CUIF} = 0

N_B^{CUIF} = 0

N_C^{CUIF} = 0

N_D^{CUIF} = 0

STEP 13

Determine the inspection effectiveness factors, $I_1^{CUIF}, I_2^{CUIF}, I_3^{CUIF}$, using eq. 38, 39, 40 below, Prior Probabilities, $Pr_{p1}^{CUIF}, Pr_{p2}^{CUIF}, Pr_{p3}^{CUIF}$, from Table 4.1.33 (Refer to Table 4.5 API RP 581 Part 2), Conditional Probabilities, $Co_{p1}^{CUIF}, Co_{p2}^{CUIF}, Co_{p3}^{CUIF}$, from Table 4.1.34 (Refer to Table 4.6 API RP 581 Part 2), and the number of inspections, $N_A^{CUIF}, N_B^{CUIF}, N_C^{CUIF}, N_D^{CUIF}$, in each effectiveness level obtained from STEP 12.

$$I_1^{CUIF} = Pr_{p1}^{CUIF}\left(Co_{p1}^{CUIF}\right)^{N_A^{CUIF}}\left(Co_{p1}^{CUIF}\right)^{N_B^{CUIF}}\left(Co_{p1}^{CUIF}\right)^{N_C^{CUIF}}\left(Co_{p1}^{CUIF}\right)^{N_D^{CUIF}} \quad \text{..(eq. 38)}$$

$$I_2^{CUIF} = Pr_{p2}^{CUIF}\left(Co_{p2}^{CUIF}\right)^{N_A^{CUIF}}\left(Co_{p2}^{CUIF}\right)^{N_B^{CUIF}}\left(Co_{p2}^{CUIF}\right)^{N_C^{CUIF}}\left(Co_{p2}^{CUIF}\right)^{N_D^{CUIF}} \quad \text{..(eq. 39)}$$

$$I_3^{CUIF} = Pr_{p3}^{CUIF}\left(Co_{p3}^{CUIF}\right)^{N_A^{CUIF}}\left(Co_{p3}^{CUIF}\right)^{N_B^{CUIF}}\left(Co_{p3}^{CUIF}\right)^{N_C^{CUIF}}\left(Co_{p3}^{CUIF}\right)^{N_D^{CUIF}} \quad \text{..(eq. 40)}$$

Table 4.1.33 - Prior Probability

Damage State	Low Confidence Data	Medium Conf. Data	High Conf. Data
Pr_{P1}^{CUIF}	0.5	0.7	0.8
Pr_{P2}^{CUIF}	0.3	0.2	0.15
Pr_{P3}^{CUIF}	0.2	0.1	0.05

Table 4.1.34 - Conditional Probability for Inspection Effectiveness

Conditional P. of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B-Usually Effective	A-Highly Effective
Co_{P1}^{CUIF}	0.33	0.4	0.5	0.7	0.9
Co_{P2}^{CUIF}	0.33	0.33	0.3	0.2	0.09
Co_{P3}^{CUIF}	0.33	0.27	0.2	0.1	0.01

$$I_1^{CUIF} = Pr_{p1}^{CUIF}\left(Co_{p1}^{CUIF}\right)^{N_A^{CUIF}}\left(Co_{p1}^{CUIF}\right)^{N_B^{CUIF}}\left(Co_{p1}^{CUIF}\right)^{N_C^{CUIF}}\left(Co_{p1}^{CUIF}\right)^{N_D^{CUIF}}$$

$$= \quad 0.50$$

$$I_2^{CUIF} = Pr_{p2}^{CUIF}\left(Co_{p2}^{CUIF}\right)^{N_A^{CUIF}}\left(Co_{p2}^{CUIF}\right)^{N_B^{CUIF}}\left(Co_{p2}^{CUIF}\right)^{N_C^{CUIF}}\left(Co_{p2}^{CUIF}\right)^{N_D^{CUIF}}$$

$$= \quad 0.30$$

$$I_3^{CUIF} = Pr_{p3}^{CUIF}\left(Co_{p3}^{CUIF}\right)^{N_A^{CUIF}}\left(Co_{p3}^{CUIF}\right)^{N_B^{CUIF}}\left(Co_{p3}^{CUIF}\right)^{N_C^{CUIF}}\left(Co_{p3}^{CUIF}\right)^{N_D^{CUIF}}$$

$$= \quad 0.20$$

STEP 14

Calculate the Posterior Probabilities, $Po_{p1}^{CUIF}, Po_{p2}^{CUIF}, Po_{p3}^{CUIF}$ using equation 41, 42 and 43 below with $I_1^{CUIF}, I_2^{CUIF}, I_3^{CUIF}$ in STEP 13

$$Po_{p1}^{CUIF} = \frac{I_1^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}} \qquad \text{(equation 41)}$$

$$Po_{p1}^{CUIF} = 0.5$$

$$Po_{p2}^{CUIF} = \frac{I_2^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}} \qquad \text{(equation 42)}$$

$$Po_{p2}^{CUIF} = 0.3$$

$$Po_{p3}^{CUIF} = \frac{I_3^{CUIF}}{I_1^{CUIF} + I_2^{CUIF} + I_3^{CUIF}} \qquad \text{(equation 43)}$$

$$Po_{p3}^{CUIF} = 0.2$$

STEP 15

Calculate the parameters, β_1, β_2, and β_3 using equation 44, 45 and 46 below and also assigning $COV_{\Delta t} = 0.20$, $COV_{sf} = 0.20$, and $COV_P = 0.05$.

$$\beta_1^{CUIF} = \frac{1 - D_{S_1} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_1}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_1} \cdot A_{rt}\right)^2 \cdot {COV_{sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}} \qquad \text{(eq. 44)}$$

$$\beta_2^{CUIF} = \frac{1 - D_{S_2} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_2}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_2} \cdot A_{rt}\right)^2 \cdot {COV_{sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}} \qquad \text{(eq. 45)}$$

$$\beta_3^{CUIF} = \frac{1 - D_{S_3} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_3}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_3} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}} \quad \text{..(eq. 46)}$$

Where;

$COV_{\Delta t}$	=	The thinning coefficient of variance ranging from $0.1 \leq COV_{\Delta t} \leq 0.2$
	=	0.2
COV_{sf}	=	The flow stress coefficient of variance
	=	0.2
COV_P	=	Pressure coeffficient of variance
	=	0.05
D_{s1}	=	Damage State 1
	=	1
D_{s2}	=	Damage State 2
	=	2
D_{s3}	=	Damage State 3
	=	4

at RBI Date

$$\beta_1^{CUIF} = \frac{1 - D_{S_1} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_1}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_1} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$$

= 3.9613

$$\beta_2^{CUIF} = \frac{1 - D_{S_2} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_2}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_2} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$$

= 3.8902

$$\beta_3^{CUIF} = \frac{1 - D_{S_3} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_3}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_3} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$$

= 3.6828

at RBI Plan Date

$$\beta_1^{CUIF} = \frac{1 - D_{S_1} \cdot A_{rt} - SR_P^{CUIF}}{\sqrt{{D_{S_1}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_1} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$$

= 3.9160

$$\beta_2^{CUIF} = \frac{1 - D_{S_2} \cdot A_{rt} \cdot SR_P^{CUIF}}{\sqrt{{D_{S_2}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_2} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$$

= 3.7630

$$\beta_3^{CUIF} = \frac{1 - D_{S_3} \cdot A_{rt} \cdot SR_P^{CUIF}}{\sqrt{{D_{S_3}}^2 \cdot {A_{rt}}^2 \cdot {COV_{\Delta t}}^2 + \left(1 - D_{S_3} \cdot A_{rt}\right)^2 \cdot {COV_{Sf}}^2 + (SR_P^{CUIF})^2 \cdot {COV_P}^2}}$$

= 3.2254

STEP 16

Calculate D_f^{CUIF} , using one of equation 47 below

$$D_f^{CUIF} = \left[\frac{\left(Po_{p1}^{CUIF}\phi\left(-\beta_1^{CUIF}\right)\right) + \left(Po_{p2}^{CUIF}\phi\left(-\beta_2^{CUIF}\right)\right) + \left(Po_{p3}^{CUIF}\phi\left(-\beta_3^{CUIF}\right)\right)}{1.56E - 0.4}\right] \quad \text{..(eq. 47)}$$

<u>at RBI Date</u>

D_f^{CUIF} = 0.3636

<u>at RBI Plan Date</u>

D_f^{CUIF} = 1.1121

Probability of Failure

Calculation of Tube Side Damage Factor

Attachment 4-2

Probability of Failure

Thinning Damage Factor Calculation

Attachment 4-2-1

CALCULATION OF THINNING DAMAGE FACTOR

1. Required Data

Basic data yang dibutuhkan pada analisis ini tercantum pada API RP 581 Part 2 Table 4.1. Sedangkan component dan geometry type berdasarkan jenis equipment ditunjukkan oleh Table 4.2, Geometry data yang dibutuhkan dalam analsis berdasarkan geometry type tercantum pada Table 4.3. Dalam menentukan data yang diperlukan untuk analisis Thinning Damage Factor, dapat menggunakan Table 4.4.

Table 4.2.1 – Basic Component Data Required for Analysis (Refer to Table 4.1 API RP 581 Part 2)

Basic Data		Value	Unit	Comments
Start Date		6/1/2014		The date the component was placed in service.
Thickness	SS	12.00	mm	Thickness used for DF is either the furnished thickness or the measured thickness
	TS	2.11		
Corrosion Allowance	SS	5.02	mm	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current service.
	TS	1.83		
Design Temperature	SS	148.89	^{o}C	The design temperature, shell side and tube side for heat exchanger.
	TS	232.22		
Design Pressure	SS	586.08	Kpa	The design pressure, shell side and tube side for heat exchanger.
	TS	1447.95		
Operating Tempearture	SS	128.67	^{o}C	The highest expected operating temperature expected during operation including normal and unusual operating conditions, shell side and tube side for heat exchanger.
	TS	176.67		
Operating Pressure	SS	142.73	Kpa	The highest expected operating pressure expected during operation including normal and unusual operating conditions, shell side and tube side for heat exchanger.
	TS	448.18		
Design Code		ASME Section VIII Division I Edition 2010		The designing of the component containing the component.
Equipment Type		Heat Exchanger		The type of equipment.
Component Type		HEXSS		The type of component.
		HEXTS		
Geometry Data		ELL (Elliptical Head)		Component geometry data depending on the type of component.

Table 4.2.1 – Basic Component Data Required for Analysis (Refer to Table 4.1 API RP 581 Part 2)

Basic Data		Value	Unit	Comments
Material Specification	SS	SA-516 Gr.70N		The specification of the material of construction, the ASME SA or SB specification for pressure vessel components or for ASTM specification for piping and tankage components. Data entry is based on the material specification, grade, year, UNS Number, class /condition /temper /size /thickness; this data is readdily available in the ASME Code.
	TS	SA 179 Smls		
Yield Strength	SS	260000	Kpa	The design yield strength of the material based on material specification.
	TS	180000		
Tensile Strength	SS	485000	Kpa	The design tensile strength of the material based on material specification.
	TS	325000		
Weld Joint Efficiency	SS	1.00		Weld joint efficiency per the Code of construction.
	TS	1.00		
Heat Tracing		Yes		Is the component heat traced?

2. Tube Side Thinning Calculation

STEP 1

Determining the furnished thickness, t, and age for the component from the installation date.

t = 0.083 inch

= 2.11 mm

age = 6 years

(it is assumed from the default date for the first installement in a plant on June 1st 2014 (06/01/2014) until this date on January 1st 2020

STEP 2

Determining the corrosion rate for base material, $C_{r,bm}$ based on the material construction and environment, and cladding/weld overlay corrosion rate, $C_{r,cm}$

Based on the explanation from Section 4.5.2 that the corrosion rate is **CALCULATED** using the approach of Annex 2B. Then, first of all, the corrosion screening question must be done as Table 4.2.2 (Refer to Table 2.B.1.1 API RP 581 Part 2)

Table 4.2.2-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion	Screening Question		Yes/No	Action
1.	Hydrochloric Acid (HCl) Corrosion	1.	Does the process contain HCl?	N	No
		2.	Is free water present in the process stream (including initial condensing condition)?	Y	
		3.	Is the pH < 7.0?	N	
			Actual relatively pH is 7.83		
2.	High Temperature Sulfidic/Naphtenic Acid Corrosion	1.	Does the process contain oil with sulfur compounds?	N	No
		2.	Is the operating temperature > 204°C (400°F)?	N	
			The operating temperature is 128.89°C.		
3.	Sulfuric Acid Corrosion	1.	Does the process contain H_2SO_4	N	No
4.	High Temperature H_2S/H_2 Corrosion	1.	Does the process contain H_2S and Hydrogen?	N	No
		2.	Is the operating temperature >204°C (400°F)?	N	
			The operating temperature is 128.89°C.		
5.	Hydrifluoric Corrosion	1.	Does the process contain HF	N	No
6.	Sour Water Corrosion	1.	Is free water with H_2S present?	N	No
7.	Amine Corrosion	1.	Is equipment exposed to acid gas treaating amines (MEA, DEA, DIPA, or MDEA)?	N	No
8.	High Temperature Oxidation Corrosion	1.	Is the temperature ≥482°C (900°F)?	N	No
			The operating temperature is 128.89°C.		
		2.	Is the oxygen present?	N	
9.	Acid Sour Water Corrosion	1.	Is free water with H_2S present and pH < 7.0?	N	No
			Actual relatively pH is 7.83		
		2.	Does the proocess contain < 50 ppm chlorides?	N	
10.	Cooling Water	1.	Is equipment in cooling water service?	N	No

Table 4.2.2-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion	Screening Question		Yes/No	Action
11.	Soil Side Corrosion	1.	Is equipment in contact with soil (buried or partially buried)?	N	No
		2.	Is the material of construction carbon steel?	Y	
12.	CO_2 Corrosion	1.	Is the free water with CO_2 present (including consideration for dew point condensation)?	N	No
		2.	Is the material of construction carbon steel or < 13% Cr?	Y	
13.	AST Bottom	1.	Is the equipment item an AST tank bottom?	N	No

T = 232.22 C
= 350 F
P = 448.18 Kpa
Therminol 55 Concentration = 100.00 % mole
Material = Carbon Steel (SA 179 Smls)

Basically, there are 3 types of Corrosion Rate (Cr) calculation which are based on the RLA data from the last inspection, based on the calculation referred to the API 581 Annex 2B, and the last is based on worst case scenario.

None of Screening Questions Suitable for Corrosion Rate Calculation

*) Based on other reference as DNV-RP-G101 for Carbon Steel Material with Operating Temperature > 100°C : **Refer to a specialist**

Based on Naganath Deshpande, "Failure analysis of heat exchanger tube due to corrosion," International Research Journal of Advanced Engineering and Science, Volume 3, Issue 1, pp. 133-136, 2018 the corrosion rate for Carbon Steel is 0.12 mpy.

CR assumed = 0.12 mpy
CR assumed = 0.003 mm/y

STEP 3

Determine the time in service, age_{tk}, since the last known inspection, t_{rdi}.

Because the inspection never been held. Then, the thickness used in this calculation is based on manufactured-thickness from datasheet.

t_{rdi} = 2.11 mm

age at the RBI Date

age_{tk} = RBI Date - Last Inspection Date
(Last inspection date using the installment date)

age_{tk} = 1/1/2020 - 6/1/2014
= 6 year

age at the RBI Plan Date

age_{tk} = RBI Plan Date - Last Inspection Date

(Last inspection date using the installment date)

age_{tk} = 1/1/2024 - 6/1/2014

= 10 year

STEP 4

For cladding/weld overlay pressure vessel components, calculate the age from the date starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using equation 48 below:

$$age_{rc} = \max\left[\left(\frac{t_{rdi} - tbm}{C_{r\,cm}}\right), 0.0\right] \quad \text{...............................(equation 48)}$$

This equipment does not have cladding, so this step are skipped

STEP 5

Determine the t_{min}

Actually there are 4 methods used to determine the minimum thickness of the equipment (t_{min}). Based on the condition, the method used by the author is the first method which is for cylindrical, spherical, or head components, determine the allowable Stress, S, weld joint efficiency, E, and the minimum thickness, t_{min}.

t_{min}	=	0.28	mm
S	=	132000	Kpa
E	=	1.00	

STEP 6

Determine the A_{rt} Parameter

For component without clading/weld overlay then use the equation 49.

at RBI Date

$$A_{rt} = \frac{Cr_{b,m} \cdot age_{tk}}{t_{rdi}} \quad \text{...............................(equation 49)}$$

= 0.0087

at RBI Plan Date

$$A_{rt} = \frac{Cr_{b,m} \cdot age_{tk}}{t_{rdi}}$$

= 0.0145

STEP 7

Calculate the Flow Stress, FS^{Thin}, using E from STEP 5 and equation 50 below.

$$FS^{Thin} = \frac{(YS+TS)}{2} \cdot E.1,1 \quad \text{...................................(equation 50)}$$

Where;

YS = 180000 KPa

TS = 325000 KPa

E = 1.00

$FS^{Thin} = \frac{(YS+TS)}{2}.$ E.1,1

= 277750

STEP 8

Calculate the strength ratio parameter, SR_P^{Thin}, using the equation 51.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}} \cdot \frac{Max\,(t_{min}, t_c)}{t_{rdi}} \quad \text{...(equation 51)}$$

Where;

t_c = is the minimum structural thickness of the component base material (t_{min})

= 0.28 mm

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}} \cdot \frac{Max\,(t_{min}, t_c)}{t_{rdi}}$$

= 0.0631

STEP 9

Determine the number of inspections for each of the correspondesing inspection effectiveness, N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}, using Section 4.5.6 of the API RP 581 Part 2 for past inspections performed during in-service time.

N_A^{Thin} = 0

N_B^{Thin} = 0

N_C^{Thin} = 0

N_D^{Thin} = 0

STEP 10

Determine the inspection effectiveness factors, $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$, using eq. 52, 53, 54 below, Prior Probabilities, $Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}$ from Table 4.2.3 (Refer to Table 4.5 API RP 581 Part 2), Conditional Probabilities, $Co_{p1}^{Thin}, Co_{p2}^{Thin}, Co_{p3}^{Thin}$, from Table 4.2.4 (Refer to Table 4.6 API RP 581 Part 2), and the number of inspections, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, in each effectiveness level obtained from STEP 9.

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}} \quad \text{..(eq. 52)}$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_A^{Thin}} \quad \text{..(eq. 53)}$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_A^{Thin}} \quad \text{..(eq. 54)}$$

Table 4.2.3 - Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Conf. Data	High Conf. Data
Pr_{P1}^{Thin}	0.5	0.7	0.8
Pr_{P2}^{Thin}	0.3	0.2	0.15
Pr_{P3}^{Thin}	0.2	0.1	0.05

Table 4.2.4 - Conditional Probability for Inspection Effectiveness

Conditional P. of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B-Usually Effective	A-Highly Effective
Co_{P1}^{Thin}	0.33	0.4	0.5	0.7	0.9
Co_{P2}^{Thin}	0.33	0.33	0.3	0.2	0.09
Co_{P3}^{Thin}	0.33	0.27	0.2	0.1	0.01

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$
$$= 0.50$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_A^{Thin}}$$
$$= 0.30$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_A^{Thin}}$$
$$= 0.20$$

STEP 11

Calculate the Posteroir Probability, Po_{p1}^{Thin}, Po_{p2}^{Thin} and Po_{p3}^{Thin} , using equation 55, equation 56, equation 57 below

$$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad \text{.......................................(equation 55)}$$
$$= 0.5$$

$$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad \text{.......................................(equation56)}$$
$$= 0.3$$

$$Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad \text{.......................................(equation 57)}$$
$$= 0.2$$

STEP 12

Calculate the parameters, $ß_1$, $ß_2$, and $ß_3$ using equation 58, 59 and 60 below and also assigning $COV_{\Delta t} = 0.20$, $COV_{sf} = 0.20$, and $COV_P = 0.05$.

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad \text{....(equation 58)}$$

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad \text{....(equation 59)}$$

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad \text{....(equation 60)}$$

Where;

$COV_{\Delta t}$ = The thinning coefficient of variance ranging from $0.1 \leq COV_{\Delta t} \leq 0.2$

= 0.2

COV_{sf} = The flow stress coefficient of variance

= 0.2

COV_P = Pressure coeffficient of variance

= 0.05

D_{s1} = Damage State 1

= 1

D_{s2} = Damage State 2

= 2

D_{s3} = Damage State 3

= 4

at RBI Date

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 4.6809

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 4.6775

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 4.6694

at RBI Plan Date

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 4.6787

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 4.6723

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= 4.6556

STEP 13

For tank bottom components, determine the base damage factor for thining using Table 4.8 in API RP 581 Part 2 and based on Art parameter from STEP 6.

STEP 14

For all components (excluding tank bottoms covered in STEP 13), calculate the base damage factor, D_{fB}^{Thin} using equation 61.

at RBI Date

$$D_{fB}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4} \quad \text{....(equation 61)}$$

= 0.0093065

at RBI Plan Date

$$D_{fB}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4}$$

= 0.0095616

STEP 15

Determine the DF for thinning,D_f^{Thin} using equation equation 62.

$$D_f^{Thin} = \text{Max}[(\frac{(D_{fb}^{Thin}.F_{IP}.F_{DL}.F_{WD}.F_{AM}.F_{SM})}{F_{OM}}),0.1] \quad \text{.....................(equation 62)}$$

Where;

F_{IP} = DF adjustent for injection points (for piping circuit)

= 0

F_{DL} = DF adjustment for dead legs (for piping only used to intermittent service)

= 0

F_{WD} = DF adjustment for welding construction (for only AST Bottom)

= 0

F_{AM} = DF adjustment for AST maintenance per API STD 653 (for only AST)

= 0

F_{SM} = DF adjustment for settlement (for only AST Bottom)

= 0

F_{OM} = DF adjustment for online monitoring based on Table 4.8 API RP 581 Part 2

Other Corrosion Mechanism = 1

F_{OM} = 1

at RBI Date

$$D_f^{Thin} = \text{Max}[(\frac{(D_{fb}^{Thin}.}{F_{OM}}),0.1]$$

= 0.10

at RBI Plan Date

$$D_f^{Thin} = \text{Max}[(\frac{D_{fb}^{Thin}}{F_{OM}}),0.1]$$

$$= 0.10$$

DETERMINE THE TYPE OF THINNING

The type of thinning (wheter it is local or general) can be determined from Table 4.2.5 (Refer to 2.B.1.2 from API RP 581 3rd Edition Part 2 - Annex 2.B), as follow:

Table 4.2.5 Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
Hydrochloric Acid (HCl) Corrosion	-	Local
High Temperature Sulfidic/Naphthenic Acid Corrosion	TAN ≤ 0.5	General
	TAN > 0,5	Local
High Temperature H_2S/H_2 Corrosion	-	General
Sulfuric Acid (H_2SO_4) Corrosion	Low Velocity ≤0.61 m/s (2ft/s) for CS, ≤1.22 m/s (2ft/s) for SS, and ≤1.83m/s(6ft/s) for higher alloys	General
	High Velocity ≥0.61 m/s (2ft/s) for CS, ≥1.22 m/s (2ft/s) for SS, and ≥1.83m/s(6ft/s) for higher alloys	Local
Hydrofluoric Acid (HF) Corrosion	-	Local
Sour Water Corrosion	Low Velocity: ≤6.1m/s(20ft/s)	General
	High Velocity: >6.1m/s(20ft/s)	Local
Amine Corrosion	Low Velocity <1.5 m/s (5ft/s) rich amine <6.1 m/s (20ft/s) lean amine	General
	High Velocity >1.5 m/s (5ft/s) rich amine >6.1 m/s (20ft/s) lean amine	Local
High Temperature Oxidation	-	General
Acid Sour Water Corrosion	<1.83 m/s (6 ft/s)	General
	≥1.83 m/s (6 ft/s)	Local
Cooling Water Corrosion	≤0.91 m/s (3 ft/s)	Local
	0.91-2.74 m/s (3-9 ft/s)	General
	>2.74 m/s (9 ft/s)	Local
Soil Side Corrosion	-	Local

Table 4.2.5 Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
CO_2 Corrosion	-	Local
AST Bottom	Product Side	Local
	Soil Side	Local

If both general and localized thinning mechanisms are possible, then the type of thinning should be designated as localized. The type of thinning designated will be used to determine the effectiveness of inspection performed.

Thinning mechanism on the HEXTS SNO-E-6060 is not defined in Table 4.2.5 above. Because the equipment has never been inspected, it is assumed that all thinning that occurs is *localized* .

Type of Thinning DF : **Localized**

Probability of Failure

External Corrosion Damage Factor Calculation

Attachment 4-2-2

CALCULATION OF EXTERNAL DAMAGE FACTOR

The tube side of the Amine Reboiler ABC-E-0101 is in the process fluid environment of the Amine Reboiler ABC-E-0101 shell side. Thus, the external factor of the tube side is adjusted to the process fluid on the shell side, Lean Amine. The chemical composition of Lean Amine in equipment can be seen in Attachment 2.

Based on Table 3.2 the damage factor screening question in Attachment 3, it is known that DF affecting the DF external to the tube side is as follows:

1) Thinning Damage Factor
2) Stress Corrosion Cracking Damage Factor
   1.1) Amine Cracking
   1.2) Sulfide Stress Cracking
   1.3) HIC/SOHIC-H_2S

Probability of Failure

External Corrosion: Thinning Damage Factor Calculation

Attachment 4-2-2-1

CALCULATION OF EXTERNAL THINNING DAMAGE FACTOR

1. Required Data

Basic data yang dibutuhkan pada analisis ini tercantum pada API RP 581 Part 2 Table 4.1. Sedangkan component dan geometry type berdasarkan jenis equipment ditunjukkan oleh Table 4.2, Geometry data yang dibutuhkan dalam analsis berdasarkan geometry type tercantum pada Table 4.3. Dalam menentukan data yang diperlukan untuk analisis Thinning Damage Factor, dapat menggunakan Table 4.4.

Table 4.2.6 – Basic Component Data Required for Analysis (Refer to Table 4.1 API RP 581 Part 2)

Basic Data		Value	Unit	Comments
Start Date		6/1/2014		The date the component was placed in service.
Thickness	SS	12.00	mm	Thickness used for DF is either the furnished thickness or the measured thickness
	TS	2.11		
Corrosion Allowance	SS	5.02	mm	The corrosion allowance is the specified design or actual corrosion allowance upon being placed in the current service.
	TS	1.83		
Design Temperature	SS	148.89	°C	The design temperature, shell side and tube side for heat exchanger.
	TS	232.22		
Design Pressure	SS	586.08	Kpa	The design pressure, shell side and tube side for heat exchanger.
	TS	1447.95		
Operating Tempearture	SS	128.67	°C	The highest expected operating temperature expected during operation including normal and unusual operating conditions, shell side and tube side for heat exchanger.
	TS	176.67		
Operating Pressure	SS	142.73	Kpa	The highest expected operating pressure expected during operation including normal and unusual operating conditions, shell side and tube side for heat exchanger.
	TS	448.18		
Design Code		ASME Section VIII Division I Edition 2010		The designing of the component containing the component.
Equipment Type		Heat Exchanger		The type of equipment.
Component Type		HEXSS		The type of component.
		HEXTS		
Geometry Data		ELL (Elliptical Head)		Component geometry data depending on the type of component.

Table 4.2.6 – Basic Component Data Required for Analysis (Refer to Table 4.1 API RP 581 Part 2)

<table>
<tr><th colspan="2">Basic Data</th><th>Value</th><th>Unit</th><th>Comments</th></tr>
<tr><td rowspan="2">Material Specification</td><td>SS</td><td colspan="2">SA-516 Gr.70N</td><td rowspan="2">The specification of the material of construction, the ASME SA or SB specification for pressure vessel components or for ASTM specification for piping and tankage components. Data entry is based on the material specification, grade, year, UNS Number, class /condition /temper /size /thickness; this data is readdily available in the ASME Code.</td></tr>
<tr><td>TS</td><td colspan="2">SA 179 Smls</td></tr>
<tr><td rowspan="2">Yield Strength</td><td>SS</td><td>260000</td><td rowspan="2">Kpa</td><td rowspan="2">The design yield strength of the material based on material specification.</td></tr>
<tr><td>TS</td><td>180000</td></tr>
<tr><td rowspan="2">Tensile Strength</td><td>SS</td><td>485000</td><td rowspan="2">Kpa</td><td rowspan="2">The design tensile strength of the material based on material specification.</td></tr>
<tr><td>TS</td><td>325000</td></tr>
<tr><td rowspan="2">Weld Joint Efficiency</td><td>SS</td><td colspan="2">1.00</td><td rowspan="2">Weld joint efficiency per the Code of construction.</td></tr>
<tr><td>TS</td><td colspan="2">1.00</td></tr>
<tr><td colspan="2">Heat Tracing</td><td colspan="2">Yes</td><td>Is the component heat traced?</td></tr>
</table>

2. Tube Side External Thinning Calculation

STEP 1

Determining the furnished thickness, t, and age for the component from the installation date.

t = 0.083 inch

= 2.11 mm

age = 6 years

(it is assumed from the default date for the first installement in a plant on June 1st 2014 (06/01/2014) until this date on January 1st 2020)

STEP 2

Determining the corrosion rate for base material, $C_{r,bm}$ based on the material construction and environment, and cladding/weld overlay corrosion rate, $C_{r,cm}$

Based on the explanation from Section 4.5.2 that the corrosion rate is **CALCULATED** using the approach of Annex 2B. Then, first of all, the corrosion screening question must be done as Table 4.2.7 (Refer to Table 2.B.1.1 API RP 581 Part 2)

Table 4.2.7-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion	Screening Question		Yes/No	Action
1.	Hydrochloric Acid (HCl) Corrosion	1.	Does the process contain HCl?	N	No
		2.	Is free water present in the process stream (including initial condensing condition)?	Y	
		3.	Is the pH < 7.0?	N	
			Actual relatively pH is 7.83		
2.	High Temperature Sulfidic/Naphtenic Acid Corrosion	1.	Does the process contain oil with sulfur compounds?	N	No
		2.	Is the operating temperature > 204°C (400°F)?	N	
			The operating temperature is 128.67°C.		
3.	Sulfuric Acid Corrosion	1.	Does the process contain H_2SO_4	N	No
4.	High Temperature H_2S/H_2 Corrosion	1.	Does the process contain H_2S and Hydrogen?	Y	No
		2.	Is the operating temperature >204°C (400°F)?	N	
			The operating temperature is 128.67°C.		
5.	Hydrifluoric Corrosion	1.	Does the process contain HF	N	No
6.	Sour Water Corrosion	1.	Is free water with H_2S present?	Y	Yes
7.	Amine Corrosion	1.	Is equipment exposed to acid gas treaating amines (MEA, DEA, DIPA, or MDEA)?	Y	Yes
8.	High Temperature Oxidation Corrosion	1.	Is the temperature ≥482°C (900°F)?	N	No
			The operating temperature is 128.67°C.		
		2.	Is the oxygen present?	N	
9.	Acid Sour Water Corrosion	1.	Is free water with H_2S present and pH < 7.0?	N	No
			Actual relatively pH is 7.83		
		2.	Does the proocess contain < 50 ppm chlorides?	N	
10.	Cooling Water	1.	Is equipment in cooling water service?	N	No

Table 4.2.7-Screening Questions for Corrosion Rate Calculations

No.	Type of Corrosion	Screening Question		Yes/No	Action
11.	Soil Side Corrosion	1.	Is equipment in contact with soil (buried or partially buried)?	N	No
		2.	Is the material of construction carbon steel?	Y	
12.	CO_2 Corrosion	1.	Is the free water with CO_2 present (including consideration for dew point condensation)?	Y	Yes
		2.	Is the material of construction carbon steel or < 13% Cr?	Y	
13.	AST Bottom	1.	Is the equipment item an AST tank bottom?	N	No

T	=	128.67	C
	=	300	F
P	=	142.73	Kpa
H_2S Concentration	=	0.0119	% mole
CO_2 Concentration	=	0.2894	% mole
H_2O Concentration	=	90.5763	% mole
aMDEA Concentration	=	9.1224	% mole
Material	=	Carbon Steel (SA 179 Smls)	

Basically, there are 3 types of Corrosion Rate (Cr) calculation which are based on the RLA data from the last inspection, based on the calculation referred to the API 581 Annex 2B, and the last is based on worst case scenario.

If multiple thinning mechanisms are possible, the **maximum corrosion rate should be used.**

A. Corrosion Rate (Cr) based on the Annex 2B Alkaline Sour Water Corrosion

The steps required to determine the corrosion rate are shown in Figure 2.B.7.1. API RP 581 Annex 2B. The corrosion rate may be determined using the basic data in Table 4.2.8(Refer to Table 2.B.7.1) in conjunction with the baseline corrosion rates and equations in Table 2.B.7.2 to correct for H_2S partial pressure.

Table 4.2.8 – Alkaline Sour Water Corrosion – Basic Data Required for Analysis (Refer to Table 2.B.7.1 API RP 581 Annex 2B)		
Basic Data	**Value**	**Comments**
NH_4HS concentration (wt%)	0.0357	Determine the NH_4HS concentration of the condensed water. It is suggested to determine this value with ionic process models. However, approximate values may be calculated from analyses of H_2S and NH_3 as follows
		If wt% H_2S < 2 x (wt% NH_3), wt% NH_4HS =1.5 x (wt% H_2S)

Table 4.2.8 – Alkaline Sour Water Corrosion – Basic Data Required for Analysis (Refer to Table 2.B.7.1 API RP 581 Annex 2B)		
Basic Data	**Value**	**Comments**
		If wt% H_2S > 2 x (wt% NH_3), wt% NH_4HS =3.0 x (wt% H_2S)
Stream Velocity (m/s)	0.0097	The vapor phase velocity should be used in a two-phase system. The liquid phase velocity should be used in a liquid full system.
H_2S partial pressure, psia (kPa)	1.6984	Determine the partial pressure of H_2S by multiplying the mole% of H_2S in the gas phase by the total system pressure.

Determining NH4HS Concentration

to determine NH_4HS concentration, we must first determine if wt% H_2S

wt% H_2S = 0.0119

wt% NH_3 = 0

Since the value of H_2S is higher than NH_3, the wt% of NH_4HS can be determined by the formula of: wt% NH_4HS = 3.0 x (wt% H_2S)

NH_4HS= 3.0 x (wt% H_2S)

NH_4HS Concentration = 0.0357 wt%

Stream Velocity = 0.0316 m/s

H_2S partial pressure = 1.6984 KPa

Baseline CR based on Table 2.B.7.2M for Carbon Steel

Baseline CR = 0.08 mm/y

$$\text{Adjusted } CR = \max\left[\left\{\left(\frac{Baseline\ CR}{173}\right) . (pH2S\ - 345) + Baseline\ CR\right\}, 0\right] \quad \text{.......(equation 63)}$$

Adjusted CR = 0.0000 mm/y

B. Corrosion Rate (Cr) based on the Annex 2B Amine Corrosion

The steps required to determine the corrosion rate are shown in Figure 2.B.8.1 in API RP 581 Annex 2B. The corrosion rate may be determined using the basic data in Table 4.2.9 (Refer to Table 2.B.8.1 in conjunction with Tables 2.B.8.3 for 50% MDEA in carbon steel material API RP 581 Annex 2B)

Table 4.2.9 – Amine Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Material of Construction	CS	Determine the material of construction of equipment/piping.
Amine Concentration (wt%)	9.1224	Determine the amine concentration in the equipment or piping. Due to vaporization of water, a local increase in amine concentration may need to be considered in evaluating the corrosion of some reboilers and declaimers.

Table 4.2.9 – Amine Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Maximum Process Temp. (°C)	128.67	Determine the maximum process temperature. In reboilers and reclaimers, tube metal temperatures may be higher than the bulk process temperature.
Acid Gas Loading (mole acid gas/mole active amine)	0.091	Determine the acid gas loading in the amine. If analytical results are not available, it should be estimated by a knowledgeable process engineer.
Velocity (m/s)	0.0097	Determine the maximum velocity of the amine
Heat Stable Amine Salt (HSAS) Concentration: MDEA (<500, 500-4000, >4000, wppm)	<500	In MDEA "HSAS" refers to organic acid contaminants, mainly formate, oxalate, and acetate

Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MDEA (≤ 50 wt%) (mm/y) based on Table 4.2.10 (Refer to Table 2.B.3.M API RP 581 Annex 2B)

Table 4.2.10 - Amine Corrosion Estimated Corrosion Rate of Carbon Steel in MDEA (≤50 wt%) (mm/y)

Acid Gas Loading (mol/mol)	**HSAS (wt%)**	**Temperature (°C)**											
		88		93		104		116		127		132	
		Velocity (m/s)											
		≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1	≤6.1	>6.1
<0.1	0.5	0	0.1	0	0.1	0.1	0.3	0.1	0.4	0.3	0.64	0.4	1.02
	2.25	0.1	0.2	0.1	0.2	0.2	0.5	0.4	1	0.5	1.14	0.8	2.30
	4.0	0.1	0.3	0.1	0.4	0.4	1	0.8	1.5	1	2.29	1.5	3.05

Amine CR = 0.2500 mm/y

C. Corrosion Rate (Cr) based on the Annex 2B CO_2 Corrosion

The steps required to determine the corrosion rate are shown in Figure 2.B.13.1. The corrosion rate may be determined using the basic data in Table 4.2.11 (Refer to Table 2.B.13.1 API RP 581 Annex 2B) in conjunction with Equation below.

Table 4.2.11 – CO_2 Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Temperature (°C)	128.67	The corrosion phenomenon is highly temperature dependent. The maximum temperature of the process is required. Temperatures above 140°C (284°F) are not considered.

Table 4.2.11 – CO_2 Corrosion – Basic Data Required for Analysis		
Basic Data	**Value**	**Comments**
Pressure (Kpa)	142.73	Total pressure of the system. The total pressure of the gas is a big contributor in the corrosion rate up to about 250 psig.
CO2 concentration (mole %)	0.2894	Determine the CO2 partial pressure (pCO2) = (mol fraction of CO2 × total pressure), a maximum 4 MPa (580 psi) partial CO2 pressure is considered.
Material of Construction	SA 179 Smls	Determine the material of construction of equipment or piping. Stainless steels and copper alloys are assumed to be resistant to CO2 corrosion
pH	4.36	If known explicitly, the pH of the stream should be used; otherwise Equations(2.B.27), (2.B.28), and (2.B.29), can be used to estimate the pH based on the CO2 partial pressure, whether the water in the stream is Fe++ saturated or water with salinity slightly larger than seawater
Stream properties: bulk density, ρm, viscosity, mm, gas to liquid ratios (cP)	0.515	Guidance with respect to typical values properties expected in natural gas-oil mixtures (i.e. reservoir fluids) is provided. Estimation of densities can be made on the basis of the oil density (°API), gas oil ratio (GOR) and pressure, P and temperature, T. For other streams, a process engineer should assess these parameters.

$$CR = CR_B \,.\, \min[F_{glycol}, F_{inhib}] \qquad \text{................................(equation 64)}$$

<u>Base Corrosion Rate</u>

$$CR_B = f(T,pH) \,.\, f_{CO2}^{\;0.62} \,.\, (\frac{S}{19})^{0.146+0.0324\, fco2}$$

Where:

CR_B = Base corrosion rate (mm/y)

f(T,pH) = Temperature-pH function tabulated in Table 2.B.13.2

f_{CO2} = CO_2 fugacity

S = Shear stress yo calculate the flow velocity (Pa)

a. Determine the calculated pH

For RBI purposes, the pH termin temperature-pH function tabulated in Table 2.B.13.2 may be calculated using the following equation approximation for SATURATED WATER, because it is asssumed that in temperature of 100°C is placed on the transition condition and there will be some mixture between liquid phase and gas phase (saturated water and saturated steam).

$pH = 2.5907 + 0.8668.log_{10}[T] - 0.49log_{10}[p_{CO2}]$......(equation 65)

T = 128.67 C

263.60 F

p_{CO2} = Partial pressure of carbon dioxide

= (mol fraction of CO2 × total pressure) ....(equation 66)

p_{CO2} = 41.31 Kpa

= 5.991 psi

$pH = 2.5907 + 0.8668.log_{10}[T] - 0.49log_{10}[p_{CO2}]$

= 4.36

b. Determine the CO_2 fugacity

$log_{10}\,[f_{CO2}] = log_{10}[p_{CO2}] + \min[250, p_{CO2}].(0.0031\text{-}\frac{1.4}{T+273})$

$log_{10}\,[f_{CO2}] = log_{10}[5.410] + \min[250{,}5.410].(0.0031\text{-}\frac{1.4}{128.89+273})$

= 0.775

c. Determine the flow velocity

To determine the flow velocity, the API 581 reffers to the NORSOK M-506. and both of the Recommended Practice use the fluid flow shear stress, S, to model the effect of flow velocity n the base corrosion rate.

$S = \frac{f.\rho m.um^2}{2}$ ....…….....……....…….......…...…….(equation 67)

In the calculation for the corrosion rate, the shear stress need not exceed 150 Pa.

Where;

f = Friction factor

ρ_m = Mixture mass density kg/m^3

= 958.707 kg/m^3

u_m = Mixture flow velocity m/s

= 0.00974 m/s

$f = 0.001375\,[\,1\text{+}\,(20000(\frac{e}{D}) + (\frac{10^6}{Re})^{0.33}]$ ....…...…….(equation 68)

$\frac{\varepsilon}{D}$ = Relative roughness of the material

0.1

Based on the Table 4.1.8 (Refer to https://www.nuclear-power.net/nuclear-engineering/fluid-dynamics/major-head-loss-friction-loss/relative-roughness-of-pipe/) that for the Carbon Steel (SA-516 Gr.70N) material of construction which is assumed as new is approximately ranging from 0.05-0.15

Table 4.2.12 Material Absolute Rougness

Material	Absolute Roughness (mm)
Copper, Lead, Brass, Aluminium (new)	0.001 -0.002
PVC and Plastic Pipes	0.0015 - 0.007
Flexible Rubber Tubing - Smooth	0.006 - 0.07
Stainless Steel	0.0015
Steel Commercial Pipe	0.045 - 0.09
Weld Steel	0.0045
Carbon Steel (New)	0.02 - 0.05
Carbon Steel (Slightly Corroded)	0.05 - 0.15
Carbon Steel (Moderately Corroded)	0.15 - 1

$$Re = \frac{D.\rho m.um}{\mu m}$$ ……………………………...…...…….(equation 69)

Re	=	Reynolds number	
D	=	Diameter	mm
	=	914.40	mm
	=	0.9144	m
µm	=	Viscosity of the mixture	cp
	=	0.515	Cp
	=	0.000515	Pa.s
Re	=	16583.62902	

f = 0.001375 [1+ (20000($\frac{e}{D}$) + ($\frac{10^6}{Re}$)$^{0.33}$]

f = 0.00863

$$S = \frac{f.\rho m.um^2}{\mu m}$$

S = 1.5246385 Pa

Those calculated pH, CO_2 fugacity, and also flow velocity have been known. So, the value of Base Corrosion Rate (Cr_{base}) can be determined.

CR_B = f(T,pH) . $f_{CO2}^{0.62}$. $(\frac{S}{19})^{0.146+0.0324\, fco2}$

f(T,pH) = Temperature-pH function tabulated in Table 2.B.13.2

= 3.98

Cr_{base} = 3.20516 mpy

= 0.08141 mm/y

Because there is no any mixture for glycol and the other inhibitors inside the Production Separator, then, Cr is equal to Cr_{base}.

Where;

CO_2 CR = $CR_B.\min[F_{glycol}, F_{inhib}]$

= Cr_{base}

= 0.08141 mm/y

Based on API RP 581 Annex 2B, if multiple thinning mechanisms are possible, the **maximum corrosion rate should be used.**

CR = 0.25000 mm/y

STEP 3

Determine the time in service, age_{tk}, since the last known inspection, t_{rdi}.

Because the inspection never been held. Then, the thickness used in this calculation is based on manufactured-thickness from datasheet.

t_{rdi} = 2.11 mm

age at the RBI Date

age_{tk} = RBI Date - Last Inspection Date

(Last inspection date using the installment date)

age_{tk} = 1/1/2020 - 6/1/2014

= 6 year

age at the RBI Plan Date

age_{tk} = RBI Plan Date - Last Inspection Date

(Last inspection date using the installment date)

age_{tk} = 1/1/2024 - 6/1/2014

= 10 year

STEP 4

For cladding/weld overlay pressure vessel components, calculate the age from the date starting thickness from STEP 3 required to corrode away the cladding/weld overlay material, age_{rc}, using equation below:

$$age_{rc} = \max\left[\left(\frac{t_{rdi} - tbm}{C_{r\,cm}}\right), 0.0\right] \quad \text{.......................(equation 70)}$$

This equipment does not have cladding, so this step are skipped

STEP 5

Determine the t_{min}

Actually there are 4 methods used to determine the minimum thickness of the equipment (t_{min}). Based on the condition, the method used by the author is the first method which is for cylindrical, spherical, or head components, determine the allowable Stress, S, weld joint efficiency, E, and the minimum thickness, t_{min}.

t_{min} = 0.28 mm

S = 132000 Kpa

E = 1.00

STEP 6

Determine the A_{rt} Parameter

For component without clading/weld overlay then use the equation below.

at RBI Date

$$A_{rt} = \frac{Cr_{b,m}.age_{tk}}{t_{rdi}}$$ ……………………......…....…….(equation 71)

$$= 0.7115$$

at RBI Plan Date

$$A_{rt} = \frac{Cr_{b,m}.age_{tk}}{t_{rdi}}$$

$$= 1.1858$$

STEP 7

Calculate the Flow Stress, FS^{Thin}, using E from STEP 5 and equation below.

$$FS^{Thin} = \frac{(YS+TS)}{2}.\ E.1,1$$ …...…………………......…....…….(equation 72)

Where;

YS = 180000 KPa

TS = 325000 KPa

E = 1.00

$$FS^{Thin} = \frac{(YS+TS)}{2}.\ E.1,1$$

$$= 277750$$

STEP 8

Calculate the strength ratio parameter, SR_P^{Thin}, using the appropriate equation.

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}}.\frac{Max\ (t_{min},t_c)}{t_{rdi}}$$ …...…………………......…….(equation 73)

Where;

t_c = is the minimum structural thickness of the component base material (t_{min})

= 0.28 mm

$$SR_P^{Thin} = \frac{S.E}{FS^{Thin}}.\frac{Max\ (t_{min},t_c)}{t_{rdi}}$$

$$= 0.0631$$

STEP 9

Determine the number of inspections for each of the correspondesing inspection effectiveness, N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}, using Section 4.5.6 of the API RP 581 Part 2 for past inspections performed during in-service time.

N_A^{Thin} = 0
N_B^{Thin} = 0
N_C^{Thin} = 0
N_D^{Thin} = 0

STEP 10

Calculate the inspection effectiveness factors, $I_1^{Thin}, I_2^{Thin}, I_3^{Thin}$, using eq.74, eq.75 eq.76, prior probabilities, $Pr_{p1}^{Thin}, Pr_{p2}^{Thin}, Pr_{p3}^{Thin}$, from Table 4.2.13. The Conditional Probabilities , $Co_{p1}^{Thin}, Co_{p2}^{Thin}, Co_{p3}^{Thin}$, from Table 4.2.14, and the number of inspection, $N_A^{Thin}, N_B^{Thin}, N_C^{Thin}, N_D^{Thin}$, in each effectiveness level from STEP 9.

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}} \quad ..(eq. 74)$$

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_A^{Thin}} \quad ..(eq. 75)$$

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_A^{Thin}} \quad ..(eq.76)$$

Table 4.2.13 - Prior Probability for Thinning Corrosion Rate

Damage State	Low Confidence Data	Medium Conf. Data	High Conf. Data
Pr_{P1}^{Thin}	0.5	0.7	0.8
Pr_{P2}^{Thin}	0.3	0.2	0.15
Pr_{P3}^{Thin}	0.2	0.1	0.05

Table 4.2.14 - Conditional Probability for Inspection Effectiveness

Conditional P. of Inspection	E-None or Ineffective	D-Poorly Effective	C-Fairly Effective	B-Usually Effective	A-Highly Effective
Co_{P1}^{Thin}	0.33	0.4	0.5	0.7	0.9
Co_{P2}^{Thin}	0.33	0.33	0.3	0.2	0.09
Co_{P3}^{Thin}	0.33	0.27	0.2	0.1	0.01

$$I_1^{Thin} = Pr_{P1}^{Thin}(Co_{P1}^{ThinA})^{N_A^{Thin}}(Co_{P1}^{ThinB})^{N_B^{Thin}}(Co_{P1}^{ThinC})^{N_C^{Thin}}(Co_{P1}^{ThinD})^{N_D^{Thin}}$$
= 0.50

$$I_2^{Thin} = Pr_{P2}^{Thin}(Co_{P2}^{ThinA})^{N_A^{Thin}}(Co_{P2}^{ThinB})^{N_B^{Thin}}(Co_{P2}^{ThinC})^{N_C^{Thin}}(Co_{P2}^{ThinD})^{N_A^{Thin}}$$
= 0.30

$$I_3^{Thin} = Pr_{P3}^{Thin}(Co_{P3}^{ThinA})^{N_A^{Thin}}(Co_{P3}^{ThinB})^{N_B^{Thin}}(Co_{P3}^{ThinC})^{N_C^{Thin}}(Co_{P3}^{ThinD})^{N_A^{Thin}}$$
= 0.20

STEP 11

Calculate the Posteroir Probability, Po_{p1}^{Thin}, Po_{p2}^{Thin} and Po_{p3}^{Thin} , using equation 77 equation 78, equation 79 below

$$Po_{p1}^{Thin} = \frac{I_1^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad ....(equation\ 77)$$
= 0.5

$$Po_{p2}^{Thin} = \frac{I_2^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad \text{......(equation 78)}$$

$$= 0.3$$

$$Po_{p3}^{Thin} = \frac{I_3^{Thin}}{I_1^{Thin} + I_2^{Thin} + I_3^{Thin}} \quad \text{......(equation 79)}$$

$$= 0.2$$

STEP 12

Calculate the parameters, $ß_1$, $ß_2$, and $ß_3$ using equation 80, 81 and 82 below and also assigning $COV_{\Delta t} = 0.20$, $COV_{sf} = 0.20$, and $COV_P = 0.05$.

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}^2.A_{rt}^2.COV_{\Delta t}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad \text{....(equation 80)}$$

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}^2.A_{rt}^2.COV_{\Delta t}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad \text{....(equation 81)}$$

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}^2.A_{rt}^2.COV_{\Delta t}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}^2+(SR_P^{Thin})^2.(COV_P)^2}} \quad \text{....(equation 82)}$$

Where;

$COV_{\Delta t}$	=	The thinning coefficient of variance ranging from $0.1 \le COV_{\Delta t} \le 0.2$
	=	0.2
COV_{sf}	=	The flow stress coefficient of variance
	=	0.2
COV_P	=	Pressure coeffficient of variance
	=	0.05
D_{s1}	=	Damage State 1
	=	1
D_{s2}	=	Damage State 2
	=	2
D_{s3}	=	Damage State 3
	=	4

at RBI Date

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}^2.A_{rt}^2.COV_{\Delta t}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

$$= 1.4674$$

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= -1.6372

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= -2.8139

at RBI Plan Date

$$ß_1^{Thin} = \frac{1-D_{S1}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S1}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S1}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= -1.0370

$$ß_2^{Thin} = \frac{1-D_{S2}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S2}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S2}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= -2.6184

$$ß_3^{Thin} = \frac{1-D_{S3}.A_{rt}-SR_P^{Thin}}{\sqrt{D_{S3}{}^2.A_{rt}{}^2.COV_{\Delta t}{}^2+(1-D_{S3}.A_{rt})^2.COV_{sf}{}^2+(SR_P^{Thin})^2.(COV_P)^2}}$$

= -3.1497

STEP 13

For tank bottom components, determine the base damage factor for thining using Table 4.8 in API RP 581 Part 2 and based on Art parameter from STEP 6.

STEP 14

For all components (excluding tank bottoms covered in STEP 13), calculate the base damage factor, D_{fB}^{Thin} using equation 83.

at RBI Date

$$D_{fB}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4} \quad \text{....(equation 83)}$$

= 3332.3044222

at RBI Plan Date

$$D_{fB}^{Thin} = [\frac{\left(Po_{P1}^{Thin}\Phi(-\beta_1^{Thin})\right)+\left(Po_{P2}^{Thin}\Phi(-\beta_2^{Thin})\right)+\left(Po_{P3}^{Thin}\Phi(-\beta_3^{Thin})\right)}{1.56E-0.4}$$

= 5920.3617590

STEP 15

Determine the DF for thinning, D_f^{Thin} using equation equation 84.

$$D_f^{Thin} = \mathrm{Max}[(\frac{(D_{fb}^{Thin} . F_{IP} . F_{DL} . F_{WD} . F_{AM} . F_{SM})}{F_{OM}}),0.1]$$ ……………….....(equation 84)

Where;

F_{IP} = DF adjustent for injection points (for piping circuit)

= 0

F_{DL} = DF adjustment for dead legs (for piping only used to intermittent service)

= 0

F_{WD} = DF adjustment for welding construction (for only AST Bottom)

= 0

F_{AM} = DF adjustment for AST maintenance per API STD 653 (for only AST)

= 0

F_{SM} = DF adjustment for settlement (for only AST Bottom)

= 0

F_{OM} = DF adjustment for online monitoring based on Table 4.8

Sour Water Corrosion for Low Velocity (≤ 20 ft/s)	=	20
Amine Corrosion for Low Velocity (≤ 20 ft/s)	=	20
Other Corrosion Mechanism	=	1

If more than one monitoring method is used, only the **highest** monitoring factor should be used

F_{OM} = 20

<u>at RBI Date</u>

$$D_f^{Thin} = \mathrm{Max}[(\frac{(D_{fb}^{Thin}.}{F_{OM}}),0.1]$$

= 166.62

<u>at RBI Plan Date</u>

$$D_f^{Thin} = \mathrm{Max}[(\frac{(D_{fb}^{Thin}.}{F_{OM}}),0.1]$$

= 296.02

DETERMINE THE TYPE OF THINNING

The type of thinning (wheter it is local or general) can be determined from Table 4.2.15 (Refer to 2.B.1.2 from API RP 581 3rd Edition Part 2 - Annex 2.B), as follow:

Table 4.2.15 Type of Thinning

Thinning Mechanism	Condition	Type of Thinning
Hydrochloric Acid (HCl) Corrosion	-	Local
High Temperature Sulfidic/Naphthenic Acid Corrosion	TAN ≤ 0.5	General
	TAN > 0,5	Local
High Temperature H_2S/H_2 Corrosion	-	General
Sulfuric Acid (H_2SO_4) Corrosion	Low Velocity ≤0.61 m/s (2ft/s) for CS, ≤1.22 m/s (2ft/s) for SS, and ≤1.83m/s(6ft/s) for higher alloys	General
	High Velocity ≥0.61 m/s (2ft/s) for CS, ≥1.22 m/s (2ft/s) for SS, and ≥1.83m/s(6ft/s) for higher alloys	Local
Hydrofluoric Acid (HF) Corrosion	-	Local
Sour Water Corrosion	Low Velocity: ≤6.1m/s(20ft/s)	General
	High Velocity: >6.1m/s(20ft/s)	Local
Amine Corrosion	Low Velocity <1.5 m/s (5ft/s) rich amine <6.1 m/s (20ft/s) lean amine	General
	High Velocity >1.5 m/s (5ft/s) rich amine >6.1 m/s (20ft/s) lean amine	Local
High Temperature Oxidation	-	General
Acid Sour Water Corrosion	<1.83 m/s (6 ft/s)	General
	≥1.83 m/s (6 ft/s)	Local
Cooling Water Corrosion	≤0.91 m/s (3 ft/s)	Local
	0.91-2.74 m/s (3-9 ft/s)	General
	>2.74 m/s (9 ft/s)	Local
Soil Side Corrosion	-	Local
CO_2 Corrosion	-	Local
AST Bottom	Product Side	Local
	Soil Side	Local

If both general and localized thinning mechanisms are possible, then the type of thinning should be designated as localized. The type of thinning designated will be used to determine the effectiveness of inspection performed.

Type of Thinning DF : **Localized**

Probability of Failure

External Corrosion: SCC- Amine Cracking Damage Factor Calculation

Attachment 4-2-2-2

CALCULATION OF EXTERNAL SCC-AMINE CRACKING DAMAGE FACTOR

1. Required Data

The basic component data required for analysis is given in Table 4.1 and the specific data required for determination of the amine cracking DF is provided in Table 4.2.16 (Refer to Table 7.1 API RP 581 Part 2).

Table 4.2.16 – Data Required for Determination of the Damage Factor – Amine Cracking

Basic Data	Value	Unit	Comments
Susceptibility	Low		The susceptibility is determined by expert advice or using the procedures in this section.
Amine Solution Composition	Lean Amine		Determine what amine solution composition is being handled in this component. Fresh amine has not been exposed to H_2S or CO_2. Lean amine contains low levels of H_2S or CO_2. Rich amine contains high levels of H_2S or CO_2. For components exposed to both lean and rich amine solutions (i.e., amine contactors and regenerators), indicate lean.
Maximum Process Temperature	128.67	°C	Determine the maximum process temperature in this component.
Steam out	Yes		Determine whether the component has been steamed out prior to water flushing to remove residual amine.
Age	6	years	Use inspection history to determine the time since the last SCC inspection.
Inspection Effectiveness Category	E-None or Ineffective		The effectiveness category that has been performed on the component.
Number of Inspections	0	times	The number of inspections in each effectiveness category that have been performed.

2. SCC-Amine Cracking Calculation

STEP 1

Determine the susceptibility for cracking using Figure 4.1 (Refer to Figure 7.1. API RP 581 Part 2 Note that a HIGH susceptibility should be used if cracking is confirmed to be present.

Suscpetibility : Low

STEP 2

Based on the susceptibility in STEP 3, determine the severity index, S_{VI} from Table 4.2.17 (Refer to Table 7.2 API RP 581 Part 2)

Suscpetibility from STEP 1 : Low

Severity Index - S_{VI} : 10

Table 4.2.17 – Determination of Severity Index - Amine Cracking

Susceptibility	Severity Index - S_{VI}
High	1000
Medium	100
Low	10
None	0

STEP 3

Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation.

Determine the time in service, age, since the last inspection.

age at the RBI Date

age_{RI} = RBI Date - Last Inspection Date

(Last inspection date using the installment date)

age_{RI} = 1/1/2020 - 6/1/2014

= 6 year

age at the RBI Plan Date

age_{RI} = RBI Plan Date - Last Inspection Date

(Last inspection date using the installment date)

age_{RI} = 1/1/2024 - 6/1/2014

= 10 year

STEP 4

Determine the number of inspections, and the corresponding inspection effectiveness category using Section 7.6.2 for past inspections performed during the in-service time. Combine the inspections to the highest effectiveness performed using Section 3.4.3.

Damage Mechanism : SCC

Inspection Performed : 0

Inspection Category : E

Inspection Effectiveness : Ineffective / No Inspection

STEP 5

Determine the base DF for amine cracking, D_{fB}^{Amine} , using Table 4.2.18 (Refer to Table 6.3 API RP 581 Part 2) based on the number of, and the highest inspection effectiveness determined in STEP 4, and the severity index, S_{VI} , from STEP 2.

Inspection Effectiveness : Ineffective / No Inspection

Inspection Performed : 0

Inspection Category : E

S_{VI} according to susceptibility to SCC : 10

Table 4.2.18 - SCC Damage Factors - All SCC Mechanisms

S_{VI}	E	Inspection Effectiveness											
		1 Inspection				2 Inspections				3 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	8	3	1	1	6	2	1	1	4	1	1	1
50	50	40	17	5	3	30	10	2	1	20	5	1	1
100	100	80	33	10	5	60	20	4	1	40	10	2	1
500	500	400	170	50	25	300	100	20	5	200	50	8	1
1000	1000	800	330	100	50	600	200	40	10	400	100	16	2
5000	5000	4000	1670	500	250	3000	1000	250	50	2000	500	80	10
S_{VI}	E	Inspection Effectiveness											
		4 Inspections				5 Inspections				6 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	2	1	1	1	1	1	1	1	1	1	1	1
50	50	10	2	1	1	5	1	1	1	1	1	1	1
100	100	20	5	1	1	10	2	1	1	5	1	1	1
500	500	100	25	2	1	50	10	1	1	25	5	1	1
1000	1000	200	50	5	1	100	25	2	1	50	10	1	1
5000	5000	1000	250	25	2	500	125	5	1	250	50	2	1

Base Damage factor

$D_{fB}^{amine} =$ 10

STEP 6

Calculate the escalation in the DF based on the time in-service since the last inspection using the age from STEP 3 and equation 85. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

Damage Factor at RBI Date

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[age, 1.0])^{1.1} \qquad \text{……………....(equation 85)}$$

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[6{,}1.0])^{1.1}$$

$$D_f^{amine} = \quad 71.7739$$

Damage Factor at RBI Plan Date

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[age, 1.0])^{1.1}$$

$$D_f^{amine} = D_{fB}^{Amine} \cdot (Max\,[10{,}1.0])^{1.1}$$

$$D_f^{amine} = \quad 125.8925$$

Probability of Failure

External Corrosion: SCC-Sulfide Stress Cracking Damage Factor Calculation

Attachment 4-2-2-3

CALCULATION OF EXTERNAL SULFIDE STRESS CRACKING DAMAGE FACTOR

1. Required Data

The basic component data required for analysis is given in Table 4.1 and the specific data required for determination of the sulfide stress cracking DF is provided in Table 4.2.19 (Refer to Table 8.1 API RP 581 Part 2)

Table 4.2.19 – Data Required for Determination of the Damage Factor – SSC

Basic Data	Value	Unit	Comments
Susceptibility	None		The susceptibility is determined by expert advice or using the proceduresin this section.
Presence of Water	Yes		Determine whether free water is present in the component. Consider not only normal operating conditions, but also startup, shutdown, process upsets, etc.
H_2S Content of Water	119	ppm	Determine the H_2S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore
pH of Water	7.83		Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Presence of Cyanides	No		Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also startup and shutdown conditions.
Max Brinnell Hardness	<200	HB	Determine the maximum Brinnell hardness actually measured at the weldments of the steel components. Report readings actually taken as Brinnell, not converted from finer techniques (e.g., Vickers, Knoop, etc.) If actual readings are not available, use the maximum allowable hardness permitted by the fabrication specification.
Age	6	years	Use inspection history to determine the time since the last SCC inspection.
Inspection Effectiveness Category	E-None or Ineffective		The effectiveness category that has been performed on the component.
Number of Inspections	0	times	The number of inspections in each effectiveness category that have been performed.

2. SCC-Sulfide Stress Cracking Calculation

STEP 1

Determine the environemental severity (potential level of hydrogen flux) for cracking based on the H_2S Content of water and its pH using Table 4.2.20 (Refer to Table 8.2 API RP 581 Part 2)

pH : 7.83

Content of water : 119.00 ppm

Table 4.2.20 - Environmental Severity - SSC

pH of Water	**Environmental Severity as Function of H_2S Content of Water**			
	<50 ppm	50 to 1000 ppm	1000 to 10000 ppm	>10000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate	High
>9.0	Low	Moderate	High	High

Environmental Severity of H_2S : Moderate

STEP 2

Determine the susceptibility for cracking using figure 8.1 API RP 581 Part 2 and Table 4.2.21 (Refer to Table 8.3 API RP 581 Part 2) based on the environmental severity from STEP 1, the maximum brinnel hardness of weldments, and knowledge of whether the component was subject to PWHT.

Table 4.2.21 - Susceptibility to SSC - SSC

Environmental Severity	**Susceptibility to SSC as a Function of Heat Treatment**					
	As-Welded Max Brinnell Hardness			**PWHT Max Brinnell Hardness**		
	< 200	**200-237**	**> 237**	**< 200**	**200-237**	**> 237**
High	Low	Medium	High	Not	Low	Medium
Moderate	Low	Medium	High	Not	Not	Low
Low	Low	Low	Medium	Not	Not	Not

Maximum allowable hardness for material ASME SA-179 Smls is under 130HB (Refer to http://www.sunnysteel.com/astm-a179.php)

Maximum Brinell Hardness : <200 hB

PWTH : Yes

Susceptibility to SSC : None

STEP 3

Based on the susceptibility in STEP 3, determine the severity index, S_{VI}, from Table 4.2.22 (Refer to Table 8.4 API RP 581 Part 2).

S_{VI} according to susceptibility to SSC : 0

Table 4.2.22 - Determination of Severity Index - SSC

Susceptibility	Severity Index - S_{VI}
High	100
Medium	10
Low	1
None	0

STEP 4

Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation

age at the RBI Date

age_{RBI} = RBI Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2020 - 6/1/2014

= 6 years

age at the RBI Plan Date

age_{RBI} = RBI Plan Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2024 - 6/1/2014

= 10 years

STEP 5

Determine the number of inspections, and the corresponding inspection using Section 8.6.2 for past inspections performed during the in-service time. Combine the inspections toeffectiveness category the highest effectiveness performed using Section 3.4.3.

Damage Mechanism : SCC

Inspection Performed : 0

Inspection Category : E

Inspection Effectiveness : Ineffective / No Inspection

STEP 6

Determine the base DF for sulfide stress cracking, D_{fB}^{SCC} , using Table 4.2.23 (Refer to Table 6.3 API RP 581 Part 2) based on the number of, and the highest inspection effectiveness determined in STEP 5, and the severity index, S_{VI}, from STEP 3.

Inspection Effectiveness : Ineffective / No Inspection

Inspection Performed : 0

Inspection Category : E

S_{VI} according to susceptibility to SCC : 0

Table 4.2.23 - SCC Damage Factors - All SCC Mechanisms

S_{VI}	Inspection Effectiveness												
	E	1 Inspection				2 Inspections				3 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	8	3	1	1	6	2	1	1	4	1	1	1
50	50	40	17	5	3	30	10	2	1	20	5	1	1
100	100	80	33	10	5	60	20	4	1	40	10	2	1
500	500	400	170	50	25	300	100	20	5	200	50	8	1
1000	1000	800	330	100	50	600	200	40	10	400	100	16	2
5000	5000	4000	1670	500	250	3000	1000	250	50	2000	500	80	10
S_{VI}	Inspection Effectiveness												
	E	4 Inspections				5 Inspections				6 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	2	1	1	1	1	1	1	1	1	1	1	1
50	50	10	2	1	1	5	1	1	1	1	1	1	1
100	100	20	5	1	1	10	2	1	1	5	1	1	1
500	500	100	25	2	1	50	10	1	1	25	5	1	1
1000	1000	200	50	5	1	100	25	2	1	50	10	1	1
5000	5000	1000	250	25	2	500	125	5	1	250	50	2	1

Base Damage factor

$D_{fB}^{SCC}=$ 0

STEP 7

Calculate the escalation in the DF based on the time in-service since the last inspection using the age from STEP 4 and equation 86. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions.

Damage factor at RBI Date

$D_f^{SSC}= D_{fB}^{SCC}.(Max[age, 1.0])^{1.1}$ ……………….....………......(equation 86)

$D_f^{SCC}= 0.(Max[6,1.0])^{1.1}$

$D_f^{SCC}=$ 0.0000

Damage factor at RBI Plan Date

$D_f^{SSC} = D_{fB}^{SCC}.(Max[age, 1.0])^{1.1}$

$D_f^{SCC} = 0.(Max[10,1.0])^{1.1}$

$D_f^{SCC} =$ 0.0000

Probability of Failure

External Corrosion: SCC-HIC/SOHIC-H_2S Damage Factor Calculation

Attachment 4-2-2-4

CALCULATION OF EXTERNAL SCC-HIC/SOHIC-H_2S CRACKING DAMAGE FACTOR

1. Required Data

The basic component data required for analysis is given in Table 4.1 and the specific data required for determination of the HIC/SOHIC-H2S cracking DF is provided in Table 4.2.24 (Refer to Table 9.1 API RP 581 Part 2).

Table 4.2.24 – Data Required for Determination of the Damage Factor – HIC/SOHIC-H_2S Cracking

Basic Data	Value	Unit	Comments
Susceptibility	Medium		The susceptibility is determined by expert advice or using the procedures in this section.
Presence of Water	Yes		Determine whether free water is present in the component. Consider not only normal operating conditions, but also startup, shutdown, process upsets, etc.
H2S Content of Water	119	ppm	Determine the H2S content of the water phase. If analytical results are not readily available, it can be estimated using the approach of Petrie & Moore
pH of Water	7.83		Determine the pH of the water phase. If analytical results are not readily available, it should be estimated by a knowledgeable process engineer.
Presence of Cyanides	No		Determine the presence of cyanide through sampling and/or field analysis. Consider primarily normal and upset operations but also startup and shutdown conditions.
Sulfur Content of Plate Steel	0.035	%	Determine the sulfur content of the steel used to fabricate the component. This information should be available on MTR's in equipment files. If not available, it can be estimated from the ASTM or ASME specification of the steel listed on the U-1 form in consultation with materials engineer.
Steel Product Form (Plate or Pipe)	Plate		Determine what product form of steel was used to fabricate the component. Most components are fabricated from rolled and welded steel plates (e.g. A285, A515, A516,, etc.), but some small-diameter components is fabricated from steel pipe and piping components. Most small-diameter piping is fabricated from steel pipe (e.g. A106, A53, API 5L, etc.) and piping components (e.g. A105, A234, etc.), but most large diameter piping (above approximately NPS 16 diameter) is fabricated from rolled and welded plate steel.

Table 4.2.24 – Data Required for Determination of the Damage Factor – HIC/SOHIC-H_2S Cracking

Basic Data	Value	Unit	Comments
Age	6	years	Use inspection history to determine the time since the last SCC inspection.
Inspection Effectiveness Category	E-None or Ineffective		The effectiveness category that has been performed on the component.
On-Line Monitoring	Key Process Variables		The type of proactive corrosion monitoring methods or tools employed such as hydrogen probes and/or process variable monitoring.
Number of Inspections	0	times	The number of inspections in each effectiveness category that have been performed.

2. SCC- HIC/SOHIC-H_2S Cracking Calculation

STEP 1

Determine the environmental severity (potential level of hydrogen flux) for cracking based on the H_2S content of the water and its pH using Table 4.2.25 (Refer to Table 9.2 API RP 581 Part 2)

pH : 7.83
H2S Content of water : 119 ppm

Table 4.2.25 - Environmental Severity - HIC/SOHIC-H_2S Content of Water

pH of Water	Environmental Severity as Function of H_2S Content of Water			
	<50 ppm	50 to 1000 ppm	1000 to 10000 ppm	>10000 ppm
<5.5	Low	Moderate	High	High
5.5 to 7.5	Low	Low	Low	Moderate
7.6 to 8.3	Low	Moderate	Moderate	Moderate
8.4 to 8.9	Low	Moderate	Moderate	High
>9.0	Low	Moderate	High	High

Enviromental Severity : Moderate

STEP 2

Determine the susceptibility for cracking using Figure 9.1 API RP 581 Part 2 and Table 4.2.26 (Refer to Table 9.3 API RP 581 Part 2) based on the environmental severity from STEP 1, the maximum brinnel hardness of weldments, and knowledge of whether the component was subject to PWHT.

Steel sulphur content for material ASME SA-179 Smls is not exceed 0.035% (Refer to https://www.leoscoralloypipes.com/carbon-steel-astm-a179-asme-sa179-tubes-supplier-exporter/)
Steel sulfur content: : 0.035%
Environmental severity: : Moderate
Post Weld Heat Treatment (PWHT) : Yes

Susceptibility for Cracking: : Medium

Table 4.2.26 - Susceptibility to Cracking - HIC/SOHIC-H_2S

Environmental Severity	Susceptibility to Cracking as a Function of Steel Sulfur Content					
	High Sulfur Steel > 0.01% S		Low Sulfur Steel ≤ 0.01% S		Product Form - Seamless/Extruded Pipe	
	As-Welded	PWHT	As-Welded	PWHT	As-Welded	PWHT
High	High	High	High	Medium	Medium	Low
Moderate	High	Medium	Medium	Low	Low	Low
Low	Medium	Low	Low	Low	Low	Low

STEP 3

Based on the susceptibility in STEP 2, determine the severity index, S_{VI}, from Table 4.2.27 (Refer to Table 9.4 API RP 581 Part 2).

Table 4.2.27 - Determination of Severity Index - HIC/SOHIC-H_2S

Susceptibility	Severity Index - S_{VI}
High	100
Medium	10
Low	1
None	0

Suscpetibility from STEP 2 : Medium

S_{VI} according to susceptibility : 10

STEP 4

Determine the time in-service, age , since the last Level A, B or C inspection was performed with no cracking detected or cracking was repaired. Cracking detected but not repaired should be evaluated and future inspection recommendations based upon FFS evaluation

age at the RBI Date

age_{RBI} = RBI Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2020 - 6/1/2014

= 6 year

age at the RBI Plan Date

age_{RBI} = RBI Plan Date - Last Inspection Date

(Last Inspection Date using the Installment Date)

age_{RBI} = 1/1/2024 - 6/1/2014

= 10 year

STEP 5

Determine the number of inspections, and the corresponding inspection using Section 9.6.2 for past inspections performed during the in-service time. Combine the inspections toeffectiveness category the highest effectiveness performed using Section 3.4.3.

Damage Mechanism	:	SCC
Inspection Performed	:	0
Inspection Category	:	E
Inspection Effectiveness	:	Ineffective / No Inspection

STEP 6

Determine the base DF for sulfide stress cracking $D_{fB}^{HIC/SOHIC-H_2S}$ using Table 4.2.28 (Refer to Table 6.3 API RP 581 Part 2) based on the number of, and the highest inspection effectiveness determined in STEP 5, and the severity index S_{VI} from STEP 3.

Inspection Effectiveness	:	Ineffective / No Inspection
Inspection Performed	:	0
Inspection Category	:	E
S_{VI} according to susceptibility to SCC	:	10

Table 4.2.28 - SCC Damage Factors - All SCC Mechanisms

S_{VI}	Inspection Effectiveness												
	E	1 Inspection				2 Inspections				3 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	8	3	1	1	6	2	1	1	4	1	1	1
50	50	40	17	5	3	30	10	2	1	20	5	1	1
100	100	80	33	10	5	60	20	4	1	40	10	2	1
500	500	400	170	50	25	300	100	20	5	200	50	8	1
1000	1000	800	330	100	50	600	200	40	10	400	100	16	2
5000	5000	4000	1670	500	250	3000	1000	250	50	2000	500	80	10
S_{VI}	Inspection Effectiveness												
	E	4 Inspections				5 Inspections				6 Inspections			
		D	C	B	A	D	C	B	A	D	C	B	A
0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	10	2	1	1	1	1	1	1	1	1	1	1	1
50	50	10	2	1	1	5	1	1	1	1	1	1	1
100	100	20	5	1	1	10	2	1	1	5	1	1	1
500	500	100	25	2	1	50	10	1	1	25	5	1	1
1000	1000	200	50	5	1	100	25	2	1	50	10	1	1
5000	5000	1000	250	25	2	500	125	5	1	250	50	2	1

Base Damage factor

$D_f^{HIC/SOHIC-H_2S}$ = 10

STEP 7

Determine the on-line adjustment factor, F_{OM} , from Table 4.2.29 (Refer to Table 9.5 API RP 581 Part 2)

Table 4.2.29 - On-Line Monitoring Adjustment Factors for HIC/SOHIC-H_2S

On-Line Monitoring Method	Adjustment Factors as a Function of On-Line Monitoring - F_{OM}
Key Process Variables	2
Hydrogen Probes	2
Key Process Variables and Hydrogen Probes	4

On-Line Monitoring Method : Key Process Variables

Adjustment Factor (F_{OM}) : 2

STEP 8

Calculate the final DF accounting for escalation based on the time in-service since the last inspection using the age from STEP 4 and equation 87. In this equation, it is assumed that the probability for cracking will increase with time since the last inspection as a result of increased exposure to upset conditions and other non-normal conditions. The equation also applies the adjustment factor for online monitoring

Damage Factor at RBI Date

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} . (Max[age, 1.0])^{1.1}}{Fom} \quad \text{...(equation 87)}$$

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} . (Max[6, 1.0])^{1.1}}{Fom}$$

$$D_f^{HIC/SOHIC-H_2S} = 35.8869$$

Damage Factor at RBI Plan Date

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} . (Max[age, 1.0])^{1.1}}{Fom}$$

$$D_f^{HIC/SOHIC-H_2S} = \frac{D_{fB}^{HIC/SOHIC-H_2S} . (Max[81.0])^{1.1}}{Fom}$$

$$D_f^{HIC/SOHIC-H_2S} = 62.9463$$

Probability of Failure

Probability of Failure Calculation

Attachment 4-3

Probability of Failure Calculation

The probability of failure can be calculated using the equation of:

$P_f(t) = gff_{total}.D_f(t).F_{MS}$ ……………….……………………...(equation 88)

Where,

$P_f(t)$ = Probability of Failure (POF)

gff_{total} = Generic failure frequency

$D_f(t)$ = Total damage factors

F_{MS} = Management system factors

1) Determining General Failure Frequency (gff)

To determine the value of gff, we can use the recommended list from Table 4.3.1 (Refer to Table 3.1 of API RP 581 Part 2)

Table 4.3.1 - Suggested Component Generic Failure Freuencies

Equipment Type	Component Type	*gff* as a Function of Hole Size (failures/yr)				gff_{total} (failures/yr)
		Small	Medium	Large	Rupture	
Compressor	COMPC	8.00E-06	2.00E-05	2.00E-06	0	3.06E-05
Compressor	COMPR	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05
Heat Exchanger	HEXSS HEXTS	8.00E-06	2.00E-05	2.00E-06	6.00E-07	3.06E-05

gff_{total} = 3.06E-05

2) Determining Damage Factor (Df)

In the case of multiple damage mechanisms, the combination of those damage mechanims is explained in section 3.4.2 API RP 581 Part 2 3rd Edition. Total DF, Df-total - If more than one damage mechanism is present, the following rules are used to combine the DFs. The total DF is given by equation 89 when the external and/or thinning damage are classified as local and therefore, unlikely to occur at the same location

*) Note that the summation of DFs can be less than or equal to 1.0. This means that the component can have a POF less than the generic failure frequency.

2.1 Determine the governing thinning DF

a. Local Thinning Damage Factor

$$D_{f-total} = \max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{SSC} + D_{f-gov}^{htha} + D_{f-gov}^{brit} + D_{f-gov}^{mfat}$$

(equation 89)

b. General Thinning Damage Factor

$$D_{f-total} = D_{f-gov}^{Thin} + D_{f-gov}^{extd} + D_{f-gov}^{SSC} + D_{f-gov}^{htha} + D_{f-gov}^{brit} + D_{f-gov}^{mfat}$$

(equation 90)

Acccording to the observation to Amine Reboiler (Shell and Tube Heat Exchangers) equipment is categorized as **localized thinning** and also it **doesn't** likely occur at the same location. So, we used equation correlated to **local thinning** and **internal liner** is **not occur**.

$$D_{f-gov}^{Thin} = D_{f}^{Thin} \quad \textit{(Internal liner is not present)}$$ ...(equation 90)

at RBI Date

a) Shell Side (HEXSS)

D_{f-gov}^{Thin} = 1.0563

b) Tube Side (HEXTS)

D_{f-gov}^{Thin} = 0.1000

at RBI Plan Date

a) Shell Side (HEXSS)

D_{f-gov}^{Thin} = 36.7808

b) Tube Side (HEXTS)

D_{f-gov}^{Thin} = 0.1000

2.2 Determine the governing Stress Corrosion Cracking (SCC) DF

Calculation of damage factor for stress corrosion cracking (SCC) explained in section 3.4.2 - API RP 581 Part 2 3rd Edition. For multipe SCC damage factor mechanisms case, determined using equation 91.

$$D_{f-gov}^{scc} = max\begin{bmatrix} D_f^{caustic}, D_f^{amine}, D_f^{scc}, D_f^{HIC/SOHIC-H_2S}, D_f^{ACSCC}, \\ D_f^{PASCC}, D_f^{CLSCC}, D_f^{HSC\_HF}, D_f^{HIC/SOHIC-HF} \end{bmatrix}$$ ..(eq. 91)

at RBI Date

a) Shell Side (HEXSS)

D_{f-gov}^{scc} = 71.77387193

at RBI Plan Date

a) Shell Side (HEXSS)

D_{f-gov}^{scc} = 125.8925412

2.3 Determine the governing External DF

Calculation of damage factor for external damage factor explained in section 3.4.2 - API RP 581 Part 2 3rd Edition. The governing external DF is determined from equation below.

$$D_{f-gov}^{extd} = max\left[D_f^{extf}, D_f^{CUIF}, D_f^{ext-CLSCC}, D_f^{CUI-CLSCC}\right]$$ ……...(equation 92)

at RBI Date

a) Shell Side (HEXSS)

D_{f-gov}^{extd} = 0.3636

b) Tube Side (HEXTS)

D_{f-gov}^{extd} = 166.6152

at RBI Plan Date

a) Shell Side (HEXSS)

D_{f-gov}^{extd} = 1.1121

b) Tube Side (HEXTS)

D_{f-gov}^{extd} = 296.0181

2.4 Calculate Total Damage Factor

$$D_{f-total} = \max\left[D_{f-gov}^{thin}, D_{f-gov}^{extd}\right] + D_{f-gov}^{SSC} + D_{f-gov}^{htha} + D_{f-gov}^{brit} + D_{f-gov}^{mfat}$$

at RBI Date

a) Shell Side (HEXSS)

$D_{f-total} =$ **72.830**

b) Tube Side (HEXTS)

$D_{f-total} =$ **166.615**

at RBI Plan Date

a) Shell Side (HEXSS)

$D_{f-total} =$ **162.673**

b) Tube Side (HEXTS)

$D_{f-total} =$ **296.018**

3) Determining Management System Factor (Fms)

To determine the value of Fms, we use a series of question and survey given by API RBI 581 to determine Fms value

Management system factor score for the scale recommended for converting a management systems evaluation score to a management systems factor is based on the assumption that the “average” plant would score 50% (500 out of a possible score of 1,000) on the management systems evaluation.

Score = 500

$$pscore = \frac{Score}{1000} \,.\, 100 \text{ [unit is 100\%]}$$ ……………….……..(equation 93)

$pscore =$ 50 %

To determine the value of Fms we can use the equation:

$$Fms = 10^{(-0.02\,.pscore+1)}$$ …………………….…………..(equation 94)

$$Fms = 10^{(-0.02\,.50\%+1)}$$

$Fms =$ **0.9333**

Probability of Failure (POF)

$$P_f(t) = gff_{total}.\, D_f(t).\, F_{MS}$$

POF at RBI Date

a) Shell Side (HEXSS)

$P_f(t)$ = **2.080E-03**

b) Tube Side (HEXTS)

$P_f(t)$ = **4.758E-03**

POF at RBI Plan Date

a) Shell Side (HEXSS)

$P_f(t)$ = **4.646E-03**

b) Tube Side (HEXTS)

$P_f(t)$ = **8.454E-03**

	ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

ATTACHMENT 05

Consequence of Failure

Amine Reboiler

<table>
<tr><td rowspan="4">Rev</td><td rowspan="4">Tanggal</td><td rowspan="4">Deskripsi</td><td rowspan="2">Disiapkan</td><td colspan="2">Disetujui</td></tr>
<tr><td colspan="2">Dosen Pembimbing</td></tr>
<tr><td>Khoirunnisa M.S.</td><td rowspan="2">Ir. Dwi Priyanta, M.SE</td><td rowspan="2">Nurhadi Siswantoro, S.T., M.T.</td></tr>
<tr><td>0421164000021</td></tr>
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</table>

Consequence of Failure

Calculation of Shell Side (HEXSS) CoF

Attachment 5-1

HEXSS Consequence of Failure Area Based Calculation

Table 5.1 -Steps in Consequence Analysis (Refer to Table 3.1 API RP 581 Part 3)

Step	Description
Step-1	Determine the released fluid and its properties, including the release phas
Step-2	Select a set of release hole sizes to determine the possible range of consequence in the risk calculation.
Step-3	Calculate the theoretical release rate.
Step-4	Estimate the total amount of fluid available for release.
Step-5	Determine the type of release, continuous or instantaneous, to determine the method used for modeling the dispersion and consequence.
Step-6	Estimate the impact of detection and isolation systems on release magnitude
Step-7	Determine the release rate and mass for the consequence analysis
Step-8	Calculate flammable/explosive consequence
Step-9	Calculate toxic consequences
Step-10	Calculate non-flammable, non-toxic consequence
Step-11	Determine the final probability weighted component damage and personnel injury consequence areas

STEP 1: RELEASE PHASE CALCULATION

Determine the released fluid and its properties, including the release phase.

STEP 1.1 Select a representative fluid

A representative fluid that most closely matches the fluid contained pressurized system being evaluated is selected from the representative fluids table shown in to Table 5.2 (Refer to 4.1 API 581 Part 3 of COF) based on Table 2.1 Fluid Composition.

Table 2.1 Fluid Composition

Stream Number	Stream Name	Composition	Symbol	Amount	Unit
158	Liquid to Amine Regenerator Reboiler	Hydrogen Sulfide	H_2S	0.0119	% mole
		Carbondioxide	CO_2	0.2894	% mole
		Water	H_2O	90.5763	% mole
		Methyl diethanolamine	aMDEA	9.1224	% mole

The representative fluid is **water** but for fluid mixture, there are some other considerations of representative fluid in API RP 581 - Annex 3.A section 3.A.3.1.2 Choice of Representative Fluids of Mixtures stated in the following paragraph.

If a mixture contains inert materials such as CO_2 or water, the choice of representative fluid should be based on the flammable/toxic materials of concern, excluding these materials. This is a conservative assumption that will result in higher COF results, but it is sufficient for risk prioritization. The best selection from the materials in the representative fluids list would be fluids with lower NBP, since the property of first importance is the NBP.

Select the representative fluid group shown in Table 5.2 (Refer to Table 4.1 API RP 581 Part 3)

Table 5.2 - List of Representative Fluids Available for Level 1 Consequence Analysis

Representative Fluid	Fluid Type	Examples of Applicable Materials
H_2S	TYPE 0	Hydrogen Sulfide
Water	TYPE 0	Water

The representative fluid is : H_2S

STEP 1.2 Determine the stored fluid phase

The properties of the fluids required for each representative fluid depend on the fluid storage phase as below:

A). Stored Liquid

1. Normal Boiling Point (NBP)
2. Density (ρ_l)
3. Auto-iIgnition Temperature (AIT)

B). Stored Vapor or Gas

1. Normal Boiling Point (NBP)
2. Morcular Weight (MW)
3. Ideal Gas Specific Heat Capacity Ratio (ƙ)
4. Constant Pressure Specific Heat (C_p)
5. Auto-iIgnition Temperature (AIT)

Stored fluid phase : Liquid

STEP 1.3 Determine the stored fluid properties

The stored fluid properties determined based on Table 5.3 (Refer to Table 4.2M API RP 581 Part 3) below:

Table 5.3 - Properties of the Representative Fluids

Fluid	MW	Liq. Density (kg/m^3)	NBP (°C)	Ambient State	Ideal Gas Spec. Heat Eq.	Cp		
						Gas Constant A	Gas Constant B	Gas Constant C
H_2S	34	993.029	-59	Gas	Note 1	3.19E+01	1.44E-03	2.43E-05
Fluid	MW	Liq. Density (kg/m^3)	NBP (°C)	Ambient State	Ideal Gas Spec. Heat Eq.	Cp		Auto Ignition Temp. (°C)
						Gas Constant D	Gas Constant E	
H_2S	34	993.029	-59	Gas	Note 1	-1.18E-08	N/A	260

1) Normal Boiling Point (NBP)

NBP = -59 (°C)

NBP = 214 (K)

NBP = -47.2 (°R)

2) Density *(ρ_l)*

ρ_l = 958.707225 kg/m^3 (based Table 2.2 Fluid Properties)

3) Auto-Ignition Temperature (AIT)

AIT = 260 (°C)

AIT = 533 (K)

AIT = 208 (°R)

STEP 1.4 Determine the steady state phase of the liquid after release to the atmosphere

Determine the steady state phase of the liquid after release to the atmosphere using Table 5.4 (Refer to Table 4.3 API RP 581 Part 3)

Table 5.4 - Level 1 Guidelines for Determining the Phase of a Fluid

Phase of Fluid at Normal Operating (Storage) Conditions	**Phase of Fluid at Ambient (after release) Conditions**	**Det. of Final Phase for Consequence Calculation**
Gas	Gas	model as gas
Gas	Liquid	model as gas

Table 5.4 - Level 1 Guidelines for Determining the Phase of a Fluid

Phase of Fluid at Normal Operating (Storage) Conditions	Phase of Fluid at Ambient (after release) Conditions	Det. of Final Phase for Consequence Calculation
Liquid	Gas	model as gas unless the fluid boiling point at ambient conditions is greater than 80°F, then model as a liquid
Liquid	Liquid	model as liquid

The fluid being analyzed is stored in liquid form and change into a gas phase when released into atmosphere.

STEP 2: RELEASE HOLE SIZES CALCULATION

Select a set of release hole sizes to determine the possible range of consequence in the risk calculation.

STEP 2.1 Determine the release hole size diameters

Based on the component type and Table 5.5 (Refer to Table 4.4 API RP 581 Part 3), determine the release hole size diameters, d_n.

Table 5.5 - Release Hole Sizes and Areas Used in Level 1 and 2 Consequences Analysis

Release Hole Number	Release Hole Sizes	Range of Hole Diameter (inch)	Release Hole Diameter, d_n (inch)
1	Small	0 - 1/4	$d_1 = 0.25$
2	Medium	> 1/4 - 2	$d_2 = 1$
3	Large	> 2 - 6	$d_3 = 4$
4	Rupture	. 6	$d_4 = \min[D,16]$

STEP 2.2 Determine the generic failure frequency

Determine the generic failure frequency (gff_n) for the n^{th} release hole size based on Table 4.3.1 in Attachment 4-3. The values obtained from Table

Small (gff_1) = 8.00E-06 failures/year

Medium (gff_2) = 2.00E-05 failures/year

Large (gff_3) = 2.00E-06 failures/year

Rupture (gff_4) = 6.00E-07 failures/year

The total of generic failuure frequency (gff) can be taken from the table value or calculated using the equation below:

$$gff_{total} = \sum_{n=1}^{4} gffn \quad \text{(equation 95)}$$

Because the total value of generic failure frequency has been available from the table. So, we can directly put the value from the table into the calculation.

gff_{total} = 3.06E-05 failures/year

STEP 3: THEORETICAL RELEASE RATE CALCULATION

STEP 3.1 Determine the release hole size diameters

Select the appropriate release rate equation as described above using the stored fluid phase determined in STEP 1.2.

Stored fluid type : Liquid

STEP 3.2 Calculate the release hole size area An

Compute the release hole size area A_n in mm^2, using equation below based on d_n

$$An = \frac{\pi d_n^2}{4} \quad \text{.. (equation 96)}$$

1) **Small Release Hole Area**

d_1 = 0.25 inch

π = 3.14

$A_1 = \dfrac{\pi\,(0.25)^2}{4}$

= 0.04906 $inch^2$

= 3.17E-05 m^2

2) **Medium Release Hole Area**

d_2 = 1 inch

π = 3.14

$A_2 = \dfrac{\pi\,(1)^2}{4}$

= 0.785 $inch^2$

= 5.06E-04 m^2

3) **Large Release Hole Area**

d_3 = 4 inch

π = 3.14

$A_3 = \dfrac{\pi\,(1)^2}{4}$

= 12.560 $inch^2$

= 8.10E-03 m^2

4) **Rupture Release Hole Area**

d_4 = 16 inch

π = 3.14

$A_4 = \dfrac{\pi\,(1)^2}{4}$

= 200.96 $inch^2$

= 1.30E-01 m^2

STEP 3.3 Calculate Viscosity Correction Factor

For liquid releases, for each release hole size, calculate the viscosity correction factor, $K_{v,n}$ using equation below. Another option, the conservative value of viscosity correction factor may be used the value of 1.0

$$K_{v,n} = \left(0.9935 + \frac{2.878}{Re_n^{0.5}} + \frac{342.75}{Re_n^{1.5}}\right)^{-1.0} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

Because the releases phase determined in STEP 1.2 is gaseous or vapor phase, then, this step is no neeed to be considered.

STEP 3.4 Calculate Release Rate

For Vapour release rate, we must first find the transition pressure (P_{trans}).

$$Ptrans = Patm\left(\frac{k+1}{2}\right)^{\frac{\kappa}{k-1}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad \text{(equation 97)}$$

Where,

$$k = \frac{Cp}{Cp - R} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad \text{(equation 98)}$$

$$Cp = A + BT + CT^2 + DT^3 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad \text{(equation 99)}$$

	=	35.63	J/kmol-K
R	=	8.314	J/kg-mol-K
k	=	1.30	
Patm	=	101.325	kPa

So,

Ptrans	=	185.935	kPa
Pstorage	=	142.73	kPa

Since P_s is less than P_{trans}, we can use equation below to determine vapour flow rate

$$Wn = \frac{C_d}{C_2}.An.Ps\sqrt{\left(\frac{MW.gc}{R.Ts}\right)\left(\frac{2.k}{k+1}\right)\left(\frac{P_{atm}}{P_S}\right)^{\frac{2}{k}}\left(1-\left(\frac{P_{atm}}{P_S}\right)^{\frac{k-1}{k}}\right)} \quad \text{(eq. 100)}$$

Where,

C_d	=	Discharge coefficient, for turbulent liquid flow from the sharp-edge orifices in the range of $0.85 \leq C_d \leq 1.00$		
	=	0.9		
k	=	Ideal gas specific heat capacity ratio	=	1.30
A_1	=	Release hole sized area 1	=	3.17E-05 m^2
A_2	=	Release hole sized area 2	=	5.06E-04 m^2
A_3	=	Release hole sized area 3	=	8.10E-03 m^2
A_4	=	Release hole sized area 4	=	1.30E-01 m^2
Ps	=	Storage pressure	=	142.73 kPa

P_{atm}	=	Atmosphere pressure	=	101.325	kPa
C_2	=	SI and US conversion factors	=	1	
R	=	Universal gas constant	=	8.314	J/(kgmolK)
g_c	=	Gravitational constant	=	9.8	m/s^2
T_s	=	Storage operating temperature	=	128.67	°C
			=	401.67	K
MW	=	Molecular weight	=	34.00	(kg/kg-mol)

So,

1) Small Release Hole Area

W_1 = 0.0003 kg/s

2) Medium Release Hole Area

W_2 = 0.0047 kg/s

3) Large Release Hole Area

W_3 = 0.0746 kg/s

4) Rupture Release Hole Area

W_4 = 1.1930 kg/s

STEP 4: INVENTORY MASS CALCULATION

Estimate the total amount of fluid available for release.

STEP 4.1 Determine Group components and equipment items

Group components and equipment items into inventory groups based on Table 3.A.3.2 API RP 581 Annex 3A.

Default Liquid Volume Percent for Shell and Tube Heat Exchangers

HEXSS	=	50%	of total volume
HEXTS	=	25%	of total volume

For area-based consequence calculation, **tube side** is **not considered** in this calculation.

STEP 4.2 Calculate the fluid mass, masscomp , in the component being evaluated.

based on Amine Reboiler General Assembly, mass component of Shell Side of Amine Reboiler is calculated as below.

Weight Operation	=	8500	kg
Weight Empty	=	4500	kg
$Mass_{comp}$	=	2000	kg

STEP 4.3 Calculate the fluid mass in other components

Calculate the fluid mass in each of the other components that are included in the inventory group, $mass_{comp,i}$.

Based on the design of the plant, there is no other component or equipment type that can be combined to contribute the fluid mass to the leaking

STEP 4.4 Calculate the fluid mass in the inventory group (massinv)

The $mass_{inv}$ of Amine Reboiler shell side is calculated using equation below.

$$Mass_{inv} = \sum_{i=1}^{N} \left(Mass_{comp,i}\right) \quad \text{.................................... (equation 101)}$$

Where,

$Mass_{comp}$	=	is the inventory fluid mass for the component or piece of equipment being evaluated (kg)
$Mass_{inv}$	=	is the inventory group fluid mass (kg)
$Mass_{inv}$	=	2000 kg

STEP 4.5 Calculate the flow rate from a 203 mm (8 inch) diameter hole, W_{max8}

Calculate the flow rate from a 203 mm (8 inch) diameter hole, W_{max8}, using the equation at STEP 3.4 as applicable with $A_n = A_8 = 32.450\ mm^2$ (50.3 $inch^2$). This is the maximum flow rate that can be added to the equipment fluid mass from the surrounding equipment in the inventory group.

$$Wn = \frac{C_d}{C_2}\,.An\,.Ps\,\sqrt{\left(\frac{MW\,.gc}{R\,.Ts}\right)\left(\frac{2.k}{k+1}\right)\left(\frac{P_{atm}}{P_S}\right)^{\frac{2}{k}}\left(1-\left(\frac{P_{atm}}{P_S}\right)^{\frac{k-1}{k}}\right)}$$

Where,

C_d	=	Discharge coefficient, for turbulent liquid flow from the sharp-edge orifices in the range of $0.85 \le C_d \le 1.00$			
	=	0.9			
k	=	Ideal gas specific heat capacity ratio	=	1.30	
A_n	=	Release hole sized area	=	3.25E-05	m^2
Ps	=	Storage pressure	=	142.73	kPa
P_{atm}	=	Atmosphere pressure	=	101.325	kPa
C_2	=	SI and US conversion factors	=	1	
R	=	Universal gas constant	=	8.314	J/(kgmolK)
g_c	=	Gravitational constant	=	9.8	m/s^2
T_s	=	Storage operating temperature	=	128.667	°C
			=	401.667	K
MW	=	Molecular weight	=	34	(kg/kg-mol)

So,

W_{max8} = 0.000299 kg/s

STEP 4.6 Calculate the added fluid mass, $W_{add,n}$,for each release hole size

Determining the additional fluid mass for each release hole size resulting from three minutes of flow from the inventory group using equation below:

$Mass_{add,n}$ = $180\,.\min[W_n\,,W_{max8}\,]$ ……………………. (equation 102)

Where,

W_1 = 0.0003 kg/s

W_2 = 0.0047 kg/s

W_3 = 0.0746 kg/s

W_4 = 1.1930 kg/s

So,

1) Small Release Hole Area

$Mass_{add,1}$ = 0.05243 kg

2) Medium Release Hole Area

$Mass_{add,2}$ = 0.05375 kg

3) Large Release Hole Area

$Mass_{add,3}$ = 0.053746904 kg

4) Rupture Release Hole Area

$Mass_{add,4}$ = 0.053746904 kg

STEP 4.7 Calculate the available mass for each release hole size

For each release hole size, calculate the available mass for release using equation below.

$Mass_{avail,n} = \min[\{Mass_{comp} + Mass_{add,n}\}, Mass_{inv}]$ ……… (equation 103)

1) Small Release Hole Area

$Mass_{avail,1}$ = 2000 kgs

2) Medium Release Hole Area

$Mass_{avail,2}$ = 2000 kgs

3) Large Release Hole Area

$Mass_{avail,3}$ = 2000 kgs

4) Rupture Release Hole Area

$Mass_{avail,4}$ = 2000 kgs

STEP 5: RELEASE TYPE CALCULATION

Determine the type of release, continuous or instantaneous, to determine the method used for modeling the dispersion and consequence.

5.1 RELEASE TYPE

The release is modeled as one of these two following types:

5.1.1 INSTANTANEOUS RELEASE

An instantaneous or puff release is one that occurs so rapidly that the fluid disperses as a single large cloud or pool.

5.1.2 CONTINUOUS RELEASE

A continous or plume release is one that occurs over a longer period of time, allowing the fluid to dispers in the shape of elongated ellipse (dependening in the weather conditions).

STEP 5.1 Calculate the time required to release 4536 kgs (10000 lbs) of fluid for each hole size.

To determine the time required to release 4536 kgs (10000 lbs) of fluid for each hole size can be adopted from the equation below:

$$t_n = \frac{C_3}{W_n} \quad \text{(equation 104)}$$

Where,

t_n = time required to release 4536 kgs (10000 lbs) of fluid

C_3 = SI and US customary conversion factors
= 4536 kgs
= 10000 lbs

W_n = Theoretical release rate associated with the n^{th} release hole size,kg/s

W_1 = 0.0003 kg/s

W_2 = 0.0047 kg/s

W_3 = 0.0746 kg/s

W_4 = 1.1930 kg/s

1) **Small Release Hole Area**

t_1 = 15573624 s

2) **Medium Release Hole Area**

t_2 = 973352 s

3) **Large Release Hole Area**

t_3 = 60834 s

4) **Rupture Release Hole Area**

t_4 = 3802 s

STEP 5.2 Determine the release type for each release hole size.

For each release hole size, determine the release type either instataneous or continous using this following criteria:

a) If the release hole size is 6.35 mm(0.25 inch) or less, then the release type is continous

b) If t_n<180 sec and the release mass is gretaer than 4536 kgs (100000 lbs), then the release is instantaneous otherwise the release is continuous

1) Small Release Hole Area

d_1	=	0.25	inch	
t_1	=	15573624	s	(Continuous)

2) Medium Release Hole Area

d_2	=	1.0	inch	
t_2	=	973352	s	(Continuous)

3) Large Release Hole Area

d_3	=	4	inch	
t_3	=	60834	s	(Continuous)

4) Rupture Release Hole Area

d_4	=	16	inch	
t_4	=	3802	s	(Continuous)

STEP 6: IMPACT OF DETECTION AND ISOLATION SYSTEMS ON RELEASE MAGNITUDE ESTIMATION

Estimate the impact of detection and isolation systems on release magnitude.

STEP 6.1 **Determine the detection and isolation systems present in the unit using Table 5.6 and Table 5.7 (Refer to Table 4.5 and Table 4.6 API RP 581 Part 3)**

Table 5.6 - Detection and Isolation System Rating Guide

Type of Detection System	Det. Classification
Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e. loss of pressure or flow) in the system	A
Suitably located detectors to determine when the material is present outside the pressure-containing envelope	B
Visual detection, cameras, or detectors with marginal coverage	C
Type of Isolation System	**Iso. Classification**
Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention	A
Isolation or shutdown systems activated by operators in the control room or other suitable location remote from the leak	B
Isolation dependent on manually operated valves	C

Table 5.7 - Adjustment to Release Based on Detection and Isolation Systems

System Classification		Release Magnitude Adjustment	Reduction Factor, $fact_{di}$
Detection	Isolation		
A	A	Reduce release rate or mass by 25%	0.25
A	B	Reduce release rate or mass by 20%	0.20
A or B	C	Reduce release rate or mass by 10%	0.10
B	B	Reduce release rate or mass by 15%	0.15
C	C	No adjustment to release rate or mass	0.00

Detection systems present = Safety instrument systems
Isolation systems present = Automated SDV system

STEP 6.2 Using table 5.6, select the appropriate classification (A,B,C) for the detection system.

Type of detection system = Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e. loss of pressure or flow) in the

Detection Classification = A

STEP 6.3 Using table 5.6, select the appropriate classification (A,B,C) for the isolation system.

Type of isolation system = Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention

Isolation Classification = A

STEP 6.4 Using table 5.7, and the classification determined in STEP 6.2 and STEP 6.3, determine the release reduction factor.

Release Magnitude Adjustment = Reduce release rate or mass by 25%

$fact_{di}$ = 0.25

STEP 6.5 Determine the total leak durations for each release hole sizes using Table 5.8 (Refer to Table 4.7 API RP 581 Part 3).

Table 5.8 - Leak Durations Based on detection and Isolation Systems

Detection System Rating	Isolation System Rating	*Maximum Leak Duration, ld_{max}*
A	A	20 minutes for 1/4 inch leaks
		10 minutes for 1 inch leaks
		5 minutes for 4 inch leaks
A	B	30 minutes for 1/4 inch leaks
		20 minutes for 1 inch leaks
		10 minutes for 4 inch leaks
A	C	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	A or B	40 minutes for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
B	C	1 hour for 1/4 inch leaks
		30 minutes for 1 inch leaks
		20 minutes for 4 inch leaks
C	A, B, or C	1 hour for 1/4 inch leaks
		40 minutes for 1 inch leaks
		20 minutes for 4 inch leaks

1) **Small Release Hole Area**

d_1 = 0.25 inch

t_1 = 15573624.11 s (Continuous)

$ld_{max,1}$ = 20 minutes

2) **Medium Release Hole Area**

d_2 = 1.00 inch

t_2 = 973351.51 s (Continuous)

$ld_{max,2}$	=	10	minutes	

3) Large Release Hole Area

d_3	=	4.00	inch	
t_3	=	60834.47	s	(Continuous)
$ld_{max,3}$	=	5	minutes	

4) Rupture Release Hole Area

d_4	=	16.00	inch	
t_4	=	3802.15	s	(Continuous)
$ld_{max,4}$	=	5	minutes	

STEP 7: DETERMINE THE RELEASE RATE AND MASS FOR CONSEQUENCE OF FAILURE

Determine the release rate and mass for the consequence analysis

STEP 7.1 Calculate the adjusted release rate, $rate_n$ For each release hole size.

For each release hole size, determine the adjusted release rate, raten, using equation below where the theoreical release rate, W_n, and also note that the release reduction factor, $fact_{di}$, account for any detection and isolation systemss that are present.

$$rate_n = W_n\,(1 - fact_{di}) \quad \text{(equation 105)}$$

Where,

$fact_{di}$	=	Reduction factor	=	0.25	
W_1	=	Theoretical release rate1	=	0.0003	kg/s
W_2	=	Theoretical release rate2	=	0.0047	kg/s
W_3	=	Theoretical release rate3	=	0.0746	kg/s
W_4	=	Theoretical release rate4	=	1.1930	kg/s

So,

1) **Small Release Hole Area**

$Rate_1$ = 0.000218 kg/s

2) **Medium Release Hole Area**

$Rate_2$ = 0.003495 kg/s

3) **Large Release Hole Area**

$Rate_3$ = 0.055922 kg/s

4) **Rupture Release Hole Area**

$Rate_4$ = 0.89476 kg/s

STEP 7.2 Calculate the leak duration, ld_n, for each release hole size

For each release hole size, calculate the leak duration, ld_n, of the release using this equation below. Note that the leak duration cannot exceed the maximum duration $ld_{max,n}$.

$$ld_n = min\,.\left[\left\{\frac{Mass_{avail,n}}{Rate_n}\right\},\left\{60\,.\,ld_{max,n}\right]\right. \quad \text{(equation 106)}$$

Where,

$ld_{max,1}$	=	20	minutes	(for 1/4 inch leak)
$ld_{max,2}$	=	10	minutes	(for 1 inch leak)
$ld_{max,3}$	=	5	minutes	(for 4 inch leak)
$ld_{max,4}$	=	5	minutes	(for 16 inch leak)
$Mass_{avail,1}$	=	2000	kgs	
$Mass_{avail,2}$	=	2000	kgs	
$Mass_{avail,3}$	=	2000	kgs	
$Mass_{avail,4}$	=	2000	kgs	

So,

1) Small Release Hole Area

ld_1 = 1200 s

2) Medium Release Hole Area

ld_2 = 600 s

3) Large Release Hole Area

ld_3 = 300 s

4) Rupture Release Hole Area

ld_4 = 300 s

STEP 7.3 Calculate the release mass, $mass_n$, for each release hole size

For each release hole size, calculate the release mass, $mass_n$, using equation below based on the release rate, $rate_n$, the leak duration, Id_n, and the available mass, $mass_{avail,n}$.

$$Mass_n = min\,.\,[\{Rate_n\,.\,ld_n\},Mass_{avail,n}] \quad \text{(equation 107)}$$

Where,

$Mass_{avail,1}$ = 2000 kgs

$Mass_{avail,2}$ = 2000 kgs

$Mass_{avail,3}$ = 2000 kgs

$Mass_{avail,4}$ = 2000 kgs

So,

1) Small Release Hole Area

$Mass_1$ = 0.262136 kgs

2) Medium Release Hole Area

$Mass_2$ = 2.097084 kgs

3) Large Release Hole Area

$Mass_3$ = 16.776673 kgs

4) Rupture Release Hole Area

$Mass_4$ = 268 kgs

STEP 8: DETERMINE FLAMMABLE AND EXPLOSIVE CONSEQUENCE

Calculate flammable/explosive consequence

8.1 CONSEQUENCE AREA EQUATIONS

The following equations are used to determine the flammable consequence areas for comoponent damage and personnel injury. There are two kind of equantions explained based on its type of release, either continous release or instantaneous release as mentioned below.

8.1.1 CONTINUOUS RELEASE

$$CA_n^{CONT} = \alpha(rate_n)^b$$ .... (equation 108)

8.1.2 INSTANTANEOUS RELEASE

$$CA_n^{INST} = \alpha(mass_n)^b$$ .... (equation 109)

STEP 8.1 Select the consequence area mitigation reduction factor, $fact_{mit}$

Select the consequence area mitigation reduction factor, $fact_{mit}$ is determined from Table 5.9 (Refer to Table 4.10 API RP 581 Part 3)

Table 5.9 - Adjustment to Flammable Consequence For Mitigation System

Mitigation System	Consequence Area Adjustment	Consequence Area Reduction Factor, factor mit
Inventory blowdown , couple with isolation system classification B or higher	Reduce consequence area by 25 %	0.25
Fire water deluge system and monitors	Reduce consequence area by 20%	0.2
Fire water monitor only	Reduce consequence area by 5%	0.05
Foam spray system	Reduce consequence area by 15%	0.15

Mitigation system = Fire water monitor only

Consequence Area = Reduce consequence area by 5%

$fact_{mit}$ = 0.05

STEP 8.2 Calculate the energy efficiency correction factor, $eneff_n$, for each release hole size.

$$eneff_n = 4.\,log_{10}[C_{4A}\,.mass_n] - 15$$ .... (equation 110)

Where,

C_4 = 2205 1/kg

The equation above only applies for instantaneous events exceeding a release mass of 4,536 kgs (10,000 Ibs). This equation is **not applied to continuous releases**.

STEP 8.3 Determine the fluid type

Determine the fluid type, either TYPE 0 or TYPE 1 based on Table 5.2 at STEP 1

Based on Table 5.2 the representative fluids is H_2S.

H_2S = TYPE 0

STEP 8.4 Calculate the component damage consequence area, for each release hole size

For each release hole size, calculate the component damage consequence areas for Auto-Ignition Not Likely, Continous Release (AINL-CONT).

8.4.1. Determine the appropriate constant a and b from the Table 5.10 (Refer to Table 4.8M API RP 581 Part 3)

Table 5.10 - Component Damage Flammable Consequence Equation Constants

Fluid	Continuous Release Constant								Instantaneous Release Constant							
	Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto-Ignition Not Likely (IAINL)				Auto Ignition Likely (IAIL)			
	Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
	α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
H_2S	6.6	1.00			38.1	0.89			22.6	0.63			53.72	0.61		

$$\alpha = \alpha_{cmd}^{AINL-CONT} = 6.6$$

$$b = b_{cmd}^{AINL-CONT} = 1.00$$

8.4.2. Calculate the consequence of area using equation below

$$CA_{cmd,n}^{AINL-CONT} = \alpha(rate_n)^b \cdot (1 - fact_{mit}) \quad \text{(equation 111)}$$

Where,

$Rate_1$ = 0.000218 kg/s

$Rate_2$ = 0.003495 kg/s

$Rate_3$ = 0.055922 kg/s

$Rate_4$ = 0.894756 kg/s

So,

1) **Small Release Hole Area**

$CA_{cmd,1}^{AINL-CONT}$ = 0.001360 m^2

2) **Medium Release Hole Area**

$CA_{cmd,2}^{AINL-CONT}$ = 0.021762 m^2

3) **Large Release Hole Area**

$CA_{cmd,3}^{AINL-CONT}$ = 0.348189 m^2

4) **Rupture Release Hole Area**

$CA_{cmd,4}^{AINL-CONT}$ = 5.571019 m^2

STEP 8.5 Calculate the component damage consequence areas for Autoignition likely Continous Release

For ech release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Continous Release (AIL-CONT).

8.5.1. Determine the appropriate constant a and b from the Table 5.10 (Refer to Table 4.8M API RP 581 Part 3)

$\alpha = \alpha_{cmd}^{AIL-CONT} = 38.1$

$b = b_{cmd}^{AIL-CONT} = 0.89$

8.5.2. Calculate the consequence of area using equation below

$CA_{cmd,n}^{AIL-CONT} = \alpha(rate_n)^b \,.\, (1 - fact_{mit})$ .... (equation 112)

Where,

$Rate_1$ = 0.000218 kg/s

$Rate_2$ = 0.003495 kg/s

$Rate_3$ = 0.055922 kg/s

$Rate_4$ = 0.894756 kg/s

So,

1) **Small Release Hole Area**

$CA_{cmd,1}^{AIL-CONT}$ = 0.019988 m^2

2) **Medium Release Hole Area**

$CA_{cmd,2}^{AIL-CONT}$ = 0.235747 m^2

3) **Large Release Hole Area**

$CA_{cmd,3}^{AIL-CONT}$ = 2.780436 m^2

4) **Rupture Release Hole Area**

$CA_{cmd,4}^{AIL-CONT}$ = 32.792885 m^2

STEP 8.6 Calculate the component damage consequence areas for Auto-ignition Not Likely, Instaneous Release

For each release hole size, calculate the component damage consequence areas for Auto-ignition Not Likely, Instaneous Release, (AINL-INST).

8.6.1. Determine the appropriate constant a and b from the Table 5.10 (Refer to Table 4.8M API RP 581 Part 3)

$\alpha = \alpha_{cmd}^{AINL-INST} = 22.6$

$b = b_{cmd}^{AINL-INST} = 0.63$

8.6.2. Calculate the consequence of area using equation below

$CA_{cmd,n}^{AINL-INST} = \alpha(mass_n)^b \,.\, \left(\frac{1-fact_{mit}}{eneff_n}\right)$ .... (equation 113)

Based on release rate at STEP 4, **no instantaneous release** in this calculation

STEP 8.7 Calculate the component damage consequence areas for Auto-ignition Likely, Instantaneous Release (AIL-INST)

For ech release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Instantaneous Release (AIL-INST).

8.7.1. Determine the appropriate constant a and b from the Table 5.10 (Refer to Table 4.8M API RP 581 Part 3)

$\alpha = \alpha_{cmd}^{AIL-INST} = 53.7$

$b = b_{cmd}^{AIL-INST} = 0.61$

8.7.2. Calculate the consequence of area using equation below

$$CA_{cmd,n}^{AIL-INST} = \alpha(mass_n)^b \cdot \left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{(equation 114)}$$

STEP 8.8 Calculate the personnel injury consequence areas for Auto-ignition Not Likely, Continuous Release (AINL-CONT)

For ech release hole size, calculate the component damage consequence areas for Auto-Ignition Likely, Instantaneous Release (AIL-INST).

8.8.1. Determine the appropriate constant a and b from the Table 5.11 (Refer to Table 4.9M API RP 581 Part 3)

Table 5.11 - Personnel Injury Flammable Consequence Equation Constants

Fluid	Continuous Release Constant								Instantaneous Release Constant							
	Auto Ignition Not Likely (CAINL)				Auto Ignition Likely (CAIL)				Auto-Ignition Not Likely (IAINL)				Auto Ignition Likely (IAIL)			
	Gas		Liquid		Gas		Liquid		Gas		Liquid		Gas		Liquid	
	α	b	α	b	α	b	α	b	α	b	α	b	α	b	α	b
H_2S	10.7	1.00			73	0.94			41.4	0.63			192	0.63		

$\alpha = \alpha_{inj}^{AINL-CONT} = 10.7$

$b = b_{inj}^{AINL-CONT} = 1.00$

8.8.2. Calculate the consequence of area using equation below

$$CA_{inj,n}^{AINL-CONT} = [\alpha . (rate_n^{AINL-CONT})^b] . (1 - fact_{mit}) \quad \text{(equation 115)}$$

Where,

$Rate_1 = 0.000218$ kg/s

$Rate_2 = 0.003495$ kg/s

$Rate_3 = 0.055922$ kg/s

$Rate_4 = 0.894756$ kg/s

So,

1) **Small Release Hole Area**
   $CA_{inj,1}^{AINL-CONT}=$ 0.002210 m^2
2) **Medium Release Hole Area**
   $CA_{inj,2}^{AINL-CONT}=$ 0.035362 m^2
3) **Large Release Hole Area**
   $CA_{inj,3}^{AINL-CONT}=$ 0.565793 m^2
4) **Rupture Release Hole Area**
   $CA_{inj,4}^{AINL-CONT}=$ 9.052693 m^2

STEP 8.9 Calculate the personnel injury consequence areas for Auto-ignition Likely, Continuous Release (AIL-CONT)

For ech release hole size, calculate the personnel injury consequence areas for Auto-ignition Likely, Continuous Release (AIL-CONT).

8.9.1. Determine the appropriate constant a and b from the Table 5.11 (Refer to Table 4.9M API RP 581 Part 3)

α = $\alpha_{inj}^{AIL-CONT}$ = 73.3

b = $b_{inj}^{AIL-CONT}$ = 0.94

8.9.2. Calculate the consequence of area using equation below

$$CA_{inj,n}^{AIL-CONT} = [\alpha.(rate_n^{AINL-CONT})^b].(1 - fact_{mit}) \quad \text{(equation 116)}$$

Where,

$Rate_1$ = 0.000218 kg/s

$Rate_2$ = 0.003495 kg/s

$Rate_3$ = 0.055922 kg/s

$Rate_4$ = 0.894756 kg/s

So,

1) **Small Release Hole Area**
   $CA_{inj,1}^{AIL-CONT}=$ 0.025207 m^2
2) **Medium Release Hole Area**
   $CA_{inj,2}^{AIL-CONT}=$ 0.341498 m^2
3) **Large Release Hole Area**
   $CA_{inj,3}^{AIL-CONT}=$ 4.626587 m^2
4) **Rupture Release Hole Area**
   $CA_{inj,4}^{AIL-CONT}=$ 62.680655 m^2

STEP 8.10 **Calculate the personnel injury consequence areas for Auto-ignition Not Likely, Instantaneous Release (AINL-INST)**

For each release hole size, calculate the personnel injury consequence areas for Auto-ignition Not Likely, Instantaneous Release (AINL-INST).

8.10.1. **Determine the appropriate constant a and b from the Table 5.10 (Refer to Table 4.8M API RP 581 Part 3)**

$\alpha = \alpha_{inj}^{AINL-INST} = 41.4$

$b = b_{inj}^{AINL-INST} = 0.63$

8.10.2. **Calculate the consequence of area using equation below**

$$CA_{inj,n}^{AINL-INST} = \alpha(mass_n)^b \cdot \left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{.................... (equation 117)}$$

Based on release rate at STEP 4, **no instantaneous release** in this calculation

STEP 8.11 **Calculate the personnel injury consequence areas for Auto-ignition Likely, Instantaneous Release (AIL-INST)**

For ech release hole size, calculate the personnel injury consequence areas for Auto-ignition Likely, Instantaneous Release (AIL-INST).

8.11.1. **Determine the appropriate constant a and b from the Table 5.10 (Refer to Table 4.8M API RP 581 Part 3)**

$\alpha = \alpha_{inj}^{AIL-INST} = 191.5$

$b = b_{inj}^{AIL-INST} = 0.63$

8.11.2. **Calculate the consequence of area using equation below**

$$CA_{cmd,n}^{AIL-INST} = \alpha(mass_n)^b \cdot \left(\frac{1-fact_{mit}}{eneff_n}\right) \quad \text{.................... (equation 118)}$$

Based on release rate at STEP 4, **no instantaneous release** in this calculation

STEP 8.12 **Calculate the instataneous/continous blending factor**

For each release hole size, calculate the instataneous/continous blending factor, $fact_n^{IC}$.

8.12.1. **For Continuous Releases**

To smooth out the results for releases that are near the continuous to instantaneous transition point (4,536 kgs (10,000 lbs) in 3 minutes, or a release rate of 25.2 kg/s (55.6 lb/s)), the blending factor given by equation below is used.

$$fact_n^{IC} = \min\left[\left\{\frac{rate_n}{C_5}\right\}, 1.0\right] \quad \text{(equation 119)}$$

Where,

$Rate_1$	=	0.000218	kg/s
$Rate_2$	=	0.003495	kg/s
$Rate_3$	=	0.055922	kg/s
$Rate_4$	=	0.894756	kg/s
C_5	=	25.2	kg/s

So,

1) **Small Release Hole Area**

$fact_1^{IC}$ = 0.000009

2) **Medium Release Hole Area**

$fact_2^{IC}$ = 0.000139

3) **Large Release Hole Area**

$fact_3^{IC}$ = 0.002219

4) **Rupture Release Hole Area**

$fact_4^{IC}$ = 0.035506

8.12.1. For Instantaneous Releases

Blending is not required. Since the definition of an instantaneous release is one with a adjusted release rate, $rate_n$, greater than 25.2 kg/s (55.6 lb/s) (4,536 kg (10,000 lbs) in 3 minutes), the blending factor, $fact_n^{IC}$, is equal to 1.0.

Based on release rate at STEP 4, **no instantaneous release** in this calculation

STEP 8.13 Calculate the AIT blending factor

Calculate the AIT blending factor, $fact^{AIT}$, using Equations 120, 121, or 122, as applicable.

$$fact^{AIT} = 0 \quad \text{for, } T_S + C_6 \leq AIT \quad \text{(equation 120)}$$

$$fact^{AIT} = \frac{(T_s - AIT + C_6)}{2\,.\,C_6} \quad \text{for, } T_S + C_6 > AIT > T_S - C_6 \quad \text{(eq. 121)}$$

$$fact^{AIT} = 1 \quad \text{for, } T_S - C_6 \geq AIT \quad \text{(equation 122)}$$

Where,

Ts	=	128.67	°C
Ts	=	401.67	K
C_6	=	55.6	K
$Ts+C_6$	=	457.27	K
$Ts-C_6$	=	346.07	K

AIT	=	260	°C
AIT	=	533	K
$\frac{(T_s - AIT + C_6)}{2 \,.\, C_6}$	=	-0.681	K

So,

$fact^{AIT}$ = 0

STEP 8.14 **Calculate the continuous/instantaneous blended consequence area**

Calculate the continuous/instantaneous blended consequence area for the component based on the consequence areas calculated in previous steps.

8.14.1. **Consequence Area for Auti-Ignition Likely for Component Damage**

$$CA_{cmd,n}^{AIL} = CA_{cmd,n}^{AIL-INST} \,.\, fact_n^{IC} + CA_{cmd,n}^{AIL-CONT} \,.\, (1 - fact_n^{IC}) \qquad \text{(eq. 123)}$$

1) **Small Release Hole Area**

$CA_{cmd,1}^{AIL-INST}$	=	0.00	m^2
$fact_1^{IC}$	=	0.000009	
$CA_{cmd,1}^{AIL-CONT}$	=	0.0200	m^2
$CA_{cmd,1}^{AIL}$	=	0.0200	m^2

2) **Medium Release Hole Area**

$CA_{cmd,2}^{AIL-INST}$	=	0.00	m^2
$fact_2^{IC}$	=	0.000139	
$CA_{cmd,2}^{AIL-CONT}$	=	0.2357	m^2
$CA_{cmd,2}^{AIL}$	=	0.2357	m^2

3) **Large Release Hole Area**

$CA_{cmd,3}^{AIL-INST}$	=	0.00	m^2
$fact_3^{IC}$	=	0.002219	
$CA_{cmd,3}^{AIL-CONT}$	=	2.7804	m^2
$CA_{cmd,3}^{AIL}$	=	2.7743	m^2

4) **Rupture Release Hole Area**

$CA_{cmd,4}^{AIL-INST}$	=	0.00	m^2
$fact_4^{IC}$	=	0.035506	
$CA_{cmd,4}^{AIL-CONT}$	=	32.7929	m^2
$CA_{cmd,4}^{AIL}$	=	31.6285	m^2

8.14.2. Consequence Area for Auti-Ignition Likely for Personnel Injury

$CA_{inj,n}^{AIL} = CA_{inj,n}^{AIL-INST} . fact_n^{IC} + CA_{inj,n}^{AIL-CONT} . (1 - fact_n^{IC})$ (equation 124)

1) Small Release Hole Area

$CA_{inj,1}^{AIL-INST}$	=	0.00	m^2
$fact_1^{IC}$	=	0.000009	
$CA_{inj,1}^{AIL-CONT}$	=	0.0252	m^2
$CA_{inj,1}^{AIL}$	=	0.0252	m^2

2) Medium Release Hole Area

$CA_{inj,2}^{AIL-INST}$	=	0.00	m^2
$fact_2^{IC}$	=	0.000139	
$CA_{inj,2}^{AIL-CONT}$	=	0.3415	m^2
$CA_{inj,2}^{AIL}$	=	0.3415	m^2

3) Large Release Hole Area

$CA_{inj,3}^{AIL-INST}$	=	0.00	m^2
$fact_3^{IC}$	=	0.002219	
$CA_{inj,3}^{AIL-CONT}$	=	4.6266	m^2
$CA_{inj,3}^{AIL}$	=	4.6163	m^2

4) Rupture Release Hole Area

$CA_{inj,4}^{AIL-INST}$	=	0.00	m^2
$fact_4^{IC}$	=	0.035506	
$CA_{inj,4}^{AIL-CONT}$	=	62.6807	m^2
$CA_{inj,4}^{AIL}$	=	60.4551	m^2

8.14.3. Consequence Area for Auti-Ignition Not Likely for Component Damage

$CA_{cmd,n}^{AINL} = CA_{cmd,n}^{AINL-INST} . fact_n^{IC} + CA_{cmd,n}^{AINL-CONT} . (1 - fact_n^{IC})$ (eq. 125)

1) Small Release Hole Area

$CA_{cmd,1}^{AINL-INST}$	=	0.00	m^2
$fact_1^{IC}$	=	0.000009	
$CA_{cmd,1}^{AINL-CONT}$	=	0.0014	m^2
$CA_{cmd,1}^{AINL}$	=	0.0014	m^2

2) Medium Release Hole Area

$CA_{cmd,2}^{AINL-INST}$	=	0.00	m^2

$fact_2^{IC}$	=	0.000139	
$CA_{cmd,2}^{AINL-CONT}$	=	0.0218	m^2
$CA_{cmd,2}^{AINL}$	=	0.0218	m^2

3) Large Release Hole Area

$CA_{cmd,3}^{AINL-INST}$	=	0.00	m^2
$fact_3^{IC}$	=	0.002219	
$CA_{cmd,3}^{AINL-CONT}$	=	0.3482	m^2
$CA_{cmd,3}^{AINL}$	=	0.3474	m^2

4) Rupture Release Hole Area

$CA_{cmd,4}^{AINL-INST}$	=	0.00	m^2
$fact_4^{IC}$	=	0.035506	
$CA_{cmd,4}^{AINL-CONT}$	=	5.5710	m^2
$CA_{cmd,4}^{AINL}$	=	5.3732	m^2

8.14.4. Consequence Area for Auti-Ignition Not Likely for Personnel Injury

$$CA_{inj,n}^{AINL} = CA_{inj,n}^{AINL-INST} . fact_n^{IC} + CA_{inj,n}^{AINL-CONT} . (1 - fact_n^{IC}) \quad \text{(eq. 126)}$$

1) Small Release Hole Area

$CA_{inj,1}^{AINL-INST}$	=	0.00	m^2
$fact_1^{IC}$	=	0.000009	
$CA_{inj,1}^{AINL-CONT}$	=	0.0022	m^2
$CA_{inj,1}^{AINL}$	=	0.0022	m^2

2) Medium Release Hole Area

$CA_{inj,2}^{AINL-INST}$	=	0.00	m^2
$fact_2^{IC}$	=	0.000139	
$CA_{inj,2}^{AINL-CONT}$	=	0.0354	m^2
$CA_{inj,2}^{AINL}$	=	0.0354	m^2

3) Large Release Hole Area

$CA_{inj,3}^{AINL-INST}$	=	0.00	m^2
$fact_3^{IC}$	=	0.002219	
$CA_{inj,3}^{AINL-CONT}$	=	0.5658	m^2
$CA_{inj,3}^{AINL}$	=	0.5645	m^2

4) **Rupture Release Hole Area**

$CA_{inj,4}^{AINL-INST}$	=	0.00	m^2
$fact_4^{IC}$	=	0.035506	
$CA_{inj,4}^{AINL-CONT}$	=	9.0527	m^2
$CA_{inj,4}^{AINL}$	=	8.7313	m^2

STEP 8.15 **Calculate the AIT blended consequence areas for each release hole size**

Calculate the AIT blended consequence areas for the component using equations below based on the consequence areas determined in STEP 8.14 and the AIT blending factors, $fact^{AIT}$, calculate in STEP 8.13. the resulting consequence areas are the component damage and personnel injury flammable consequence areas, $CA_{icmd,n}^{flam}$ and $CA_{inj,n}^{flam}$ for each release hole size selected in STEP 2.2.

8.15.1. AIT Blended Consequence Areas for Component Damage

$$CA_{cmd,n}^{flam} = CA_{smd,n}^{AIL} . fact^{AIT} + CA_{cmd,n}^{AINL} . (1 - fact^{AIT}) \quad \text{(equation 127)}$$

1) **Small Release Hole Area**

$CA_{cmd,1}^{AIL}$	=	0.0200	m^2
$fact^{AIT}$	=	0	
$CA_{cmd,1}^{AINL}$	=	0.0014	m^2
$CA_{cmd,1}^{flam}$	=	0.0014	m^2

2) **Medium Release Hole Area**

$CA_{cmd,2}^{AIL}$	=	0.2357	m^2
$fact^{AIT}$	=	0	
$CA_{cmd,2}^{AINL}$	=	0.0218	m^2
$CA_{cmd,2}^{flam}$	=	0.0218	m^2

3) **Large Release Hole Area**

$CA_{cmd,3}^{AIL}$	=	2.7743	m^2
$fact^{AIT}$	=	0	
$CA_{cmd,3}^{AINL}$	=	0.3474	m^2
$CA_{cmd,3}^{flam}$	=	0.3474	m^2

4) **Rupture Release Hole Area**

$CA_{cmd,4}^{AIL}$	=	31.6285	m^2
$fact^{AIT}$	=	0	
$CA_{cmd,4}^{AINL}$	=	5.3732	m^2
$CA_{cmd,4}^{flam}$	=	5.3732	m^2

8.15.2. AIT Blended Consequence Areas for Personnel Injury

$$CA_{inj,n}^{flam} = CA_{inj,n}^{flam-AIL} \cdot fact^{AIT} + CA_{inj,n}^{AINL} \cdot (1 - fact^{AIT}) \quad \text{(equation 128)}$$

1) Small Release Hole Area

$CA_{inj,1}^{AIL}$	=	0.0252	m^2
$fact^{AIT}$	=	0	
$CA_{inj,1}^{AINL}$	=	0.0022	m^2
$CA_{inj,1}^{flam}$	=	0.0022	m^2

2) Medium Release Hole Area

$CA_{inj,2}^{AIL}$	=	0.3415	m^2
$fact^{AIT}$	=	0	
$CA_{inj,2}^{AINL}$	=	0.0354	m^2
$CA_{inj,2}^{flam}$	=	0.0354	m^2

3) Large Release Hole Area

$CA_{inj,3}^{AIL}$	=	4.6163	m^2
$fact^{AIT}$	=	0	
$CA_{inj,3}^{AINL}$	=	0.5645	m^2
$CA_{inj,3}^{flam}$	=	0.5645	m^2

4) Rupture Release Hole Area

$CA_{inj,4}^{AIL}$	=	60.4551	m^2
$fact^{AIT}$	=	0	
$CA_{inj,4}^{AINL}$	=	8.7313	m^2
$CA_{inj,4}^{flam}$	=	8.7313	m^2

STEP 8.16 Determine the final consequence areas for component damage and personnel injury

Determine the consequence areas (probability weighted on release hole size) for component damage and personnel injury using equations 129 and 130. The generic failure frequency (gff) from Table 4.3.1 in Attachment 4.3.

Small (gff_1)	=	8.00E-06	failures/year
Medium (gff_2)	=	2.00E-05	failures/year
Large (gff_3)	=	2.00E-06	failures/year
Rupture (gff_4)	=	6.00E-07	failures/year

The total of generic failuure frequency (gff) can be taken from the table 4.3.1 in Attachment 4.3.

gff_{total} = 3.06E-05 failures/year

8.16.1. Consequence Areas for Component Damage

$$CA_{cmd}^{flam}=\left(\frac{\sum gff_n \,.\, CA_{cmd,n}^{flam}}{gff_{total}}\right) \text{..............................} \quad \text{(equation 129)}$$

$$CA_{cmd}^{flam}=\left(\frac{(gff_{1}.\, CA_{cmd,1}^{flam})+(gff_{2}.\, CA_{cmd,2}^{flam})+(gff_{3}.\, CA_{cmd,3}^{flam})+(gff_{4}.\, CA_{cmd,4}^{flam})}{gff_{total}}\right)$$

= 0.1426 m^2

8.16.2. Consequence Areas for Personnel Injury

$$CA_{inj}^{flam}=\left(\frac{\sum gff_n \,.\, CA_{inj,n}^{flam}}{gff_{total}}\right) \text{..............................} \quad \text{(equation 130)}$$

$$CA_{inj}^{flam}=\left(\frac{\left(gff_1 \,.\, CA_{inj,1}^{flam}\right)+\left(gff_2 \,.\, CA_{inj,2}^{flam}\right)+\left(gff_3 \,.\, CA_{inj,3}^{flam}\right)+\left(gff_4 \,.\, CA_{inj,4}^{flam}\right)}{gff_{total}}\right)$$

= 0.2318 m^2

STEP 9:DETERMINE TOXIC CONSEQUENCES

Calculate toxic consequences

STEP 9.1 Calculate the effective duration of release

For each release hole size selected in STEP 2.2, calculate the effective duration of release using equation below.

$$ld_n^{tox} = \min\left(3600, \left\{\frac{mass_n}{W_n}\right\}, \left\{60.\, ld_{max,n}\right\}\right) \qquad \text{(equation 131)}$$

Where,

$Mass_1$	=	0.26214	kgs
$Mass_2$	=	2.09708	kgs
$Mass_3$	=	16.77667	kgs
$Mass_4$	=	268.42677	kgs
W_1	=	0.00029	kg/s
W_2	=	0.00466	kg/s
W_3	=	0.07456	kg/s
W_4	=	1.19301	kg/s
$ld_{max,1}$	=	20	minutes
$ld_{max,2}$	=	10	minutes
$ld_{max,3}$	=	5	minutes
$ld_{max,4}$	=	5	minutes

So,

1) **Small Release Hole Area**

$$ld_1^{tox} = \min\left(3600, \left\{\frac{mass_1}{W_1}\right\}, \left\{60.\, ld_{max,1}\right\}\right)$$
$$= 900 \text{ s}$$

2) **Medium Release Hole Area**

$$ld_2^{tox} = \min\left(3600, \left\{\frac{mass_2}{W_2}\right\}, \left\{60.\, ld_{max,2}\right\}\right)$$
$$= 450 \text{ s}$$

3) **Large Release Hole Area**

$$ld_n^{tox} = \min\left(3600, \left\{\frac{mass_n}{W_n}\right\}, \left\{60.\, ld_{max,n}\right\}\right)$$
$$= 225 \text{ s}$$

4) **Rupture Release Hole Area**

$$ld_n^{tox} = \min\left(3600, \left\{\frac{mass_n}{W_n}\right\}, \left\{60.\, ld_{max,n}\right\}\right)$$
$$= 225 \text{ s}$$

STEP 9.2 Determine the toxic percentage of the toxic component in the release material

Determine the toxic percentage of the toxic component, $mfrac^{tox}$, in the release material. The release fluid is a pure fluid, $mfrac^{tox}$= 1.0. note that if there is more than one toxic component in the release fluid mixture, this procedure can be repeated for each toxic component.

H_2S	=	0.0119%	Ammonia	=	9.1224%
$mfrac^{tox}$	=	0.000119	$mfrac^{tox}$	=	0.091224

STEP 9.3 Calculate the release the release rate and release mass for each release hole

For each release hole size, calculate the release the release rate, $rate_n^{tox}$, and release mass, $mass_n^{tox}$,to be used in the toxic analysis

$$rate_n^{tox} = mfrac^{tox}.W_n \quad \text{(equation 132)}$$

$$mass_n^{tox} = mfrac^{tox}.mass_n \quad \text{(equation 133)}$$

9.3.1 for H_2S

1) Small Release Hole Area

$rate_1^{tox} = mfrac^{tox}.W_1$
= 3.47E-08 kg/s

$mass_1^{tox} = mfrac^{tox}.mass_1$
= 3.12E-05 kgs

2) Medium Release Hole Area

$rate_2^{tox} = mfrac^{tox}.W_2$
= 5.55E-07 kg/s

$mass_2^{tox} = mfrac^{tox}.mass_2$
= 2.50E-04 kgs

3) Large Release Hole Area

$rate_3^{tox} = mfrac^{tox}.W_3$
= 8.87E-06 kg/s

$mass_3^{tox} = mfrac^{tox}.mass_3$
= 2.00E-03 kgs

4) Rupture Release Hole Area

$rate_4^{tox} = mfrac^{tox}.W_4$
= 1.42E-04 kg/s

$mass_4^{tox} = mfrac^{tox}.mass_4$
= 3.19E-02 kgs

9.3.2 for Ammonia

1) **Small Release Hole Area**

$rate_1^{tox} = mfrac^{tox}.W_1$

= 2.66E-05 kg/s

$mass_1^{tox} = mfrac^{tox}.mass_1$

= 2.39E-02 kgs

2) **Medium Release Hole Area**

$rate_2^{tox} = mfrac^{tox}.W_2$

= 4.25E-04 kg/s

$mass_2^{tox} = mfrac^{tox}.mass_2$

= 1.91E-01 kgs

3) **Large Release Hole Area**

$rate_3^{tox} = mfrac^{tox}.W_3$

= 6.80E-03 kg/s

$mass_3^{tox} = mfrac^{tox}.mass_3$

= 1.53E+00 kgs

4) **Rupture Release Hole Area**

$rate_4^{tox} = mfrac^{tox}.W_4$

= 1.09E-01 kg/s

$mass_4^{tox} = mfrac^{tox}.mass_4$

= 2.45E+01 kgs

STEP 9.4 Calculate the toxic consequence area for each of the release hole size.

For each release hole size, calculate the toxic consequence area for each of the release hole size.

9.4.1 Calculate toxic consequence areas for continuous and instantaneous releases for HF Acid and H_2S

Calculate $CA_{inj,n}^{toxCONT}$ for HF acid and H_2S , using equation 134 for continous release or equation 135 for instantaneous releasing Table 5.12 (Refer to Table 4.11M API RP 581 Part 3).

Table 5.12 - Gas Release Toxic Consequence Equation Constants for HF Acid and H_2S

Continous Release Duration (minutes)	HF Acid		H_2S	
	c	*d*	*c*	*d*
5	1.1401	3.5683	1.2411	3.9686
10	1.1031	3.8431	1.241	4.0948
20	1.0816	4.104	1.237	4.238
40	1.0942	4.3295	1.2297	4.3626
60	1.4056	4.4576	1.2266	4.4365
Instantaneous	1.4056	33606	0.9674	2.784

For continous release (equation 134) or instantaneous release (equation 135).

$$CA_{inj,n}^{toxCONT} = C_8.10^{(c.log_{10}[C_{4B}.rate_n^{tox}]+d)} \quad \text{(equation 134)}$$

$$CA_{inj,n}^{toxINST} = C_8.10^{(c.log_{10}[C_{4B}.mass_n^{tox}]+d)} \quad \text{(equation 135)}$$

Where,

C_8	=	0.0929	m^2.sec
C_{4B}	=	2.25	sec/kg

9.4.1.1 For Continous Release

1) **Small Release Hole Area**

$$CA_{inj,1}^{toxCONT} = C_8.10^{(c.log_{10}[C_{4B}.rate_1^{tox}]+d)}$$

$CA_{inj,1}^{toxCONT}$ = 2.59E-06 m^2

2) **Medium Release Hole Area**

$$CA_{inj,2}^{toxCONT} = C_8.10^{(c.log_{10}[C_{4B}.rate_2^{tox}]+d)}$$

$CA_{inj,2}^{toxCONT}$ = 5.45E-05 m^2

3) **Large Release Hole Area**

$$CA_{inj,3}^{toxCONT} = C_8.10^{(c.log_{10}[C_{4B}.rate_3^{tox}]+d)}$$

$CA_{inj,3}^{toxCONT}$ = 1.27E-03 m^2

4) **Rupture Release Hole Area**

$$CA_{inj,4}^{toxCONT} = C_8.10^{(c.log_{10}[C_{4B}.rate_4^{tox}]+d)}$$

$CA_{inj,4}^{toxCONT}$ = 3.96E-02 m^2

9.4.1.2 For Instantaneous Release

Based on release rate at STEP 4, **no instantaneous release** in this calculation. So this step is skipped.

9.4.2 Calculate toxic consequence areas for continuous and instantaneous releases for Ammonia and Chlorine

Calculate $CA_{inj,n}^{toxCONT}$ for Ammonia and Chlorine, using equation 136 for continous release or equation 137 for instantaneous releasing Table 5.13 (Refer to Table 4.12M API RP 581 Part 3).

Table 5.13 - Gas Release Toxic Consequence Equation Constants for Ammonia and Chlorine

Continous Release Duration (minutes)	Ammonia		Chlorine	
	e	*f*	*e*	*f*
5	2690	1.183	15150	1.097
10	3581	1.181	15934	1.095
20	5326	1.178	19704	1.089
Instantaneous	14.171	0.9011	14.976	1.177

For continous release (equation 136) or instantaneous release (equation 137).

$CA_{inj,n}^{toxCONT} = e(Rate_{n}^{tox})^{f}$ .... (equation 136)

$CA_{inj,n}^{toxINST} = e(Mass_{n}^{tox})^{f}$ .... (equation 137)

9.4.2.1 For Continous Release

1) Small Release Hole Area

$CA_{inj,1}^{toxCONT} = e(Rate_{1}^{tox})^{f}$

$CA_{inj,1}^{toxCONT}$ = 2.17E-02 m^2

2) Medium Release Hole Area

$CA_{inj,2}^{toxCONT} = e(Rate_{2}^{tox})^{f}$

$CA_{inj,2}^{toxCONT}$ = 3.73E-01 m^2

3) Large Release Hole Area

$CA_{inj,3}^{toxCONT} = e(Rate_{3}^{tox})^{f}$

$CA_{inj,3}^{toxCONT}$ = 7.34E+00 m^2

4) Rupture Release Hole Area

$CA_{inj,4}^{toxCONT} = e(Rate_{4}^{tox})^{f}$

$CA_{inj,4}^{toxCONT}$ = 1.95E+02 m^2

9.4.2.2 For Instantaneous Release

Based on release rate at STEP 4, **no instantaneous release** in this calculation. So this step is skipped.

STEP 9.5 Calculate the toxic consequence area for each of the release hole size

If there are additional toxic component in the released fluid mixture, the STEP 9.2 througt 9.4 should be repeated for each toxic component.

There is no other additional toxic component.

STEP 9.6 Determine the final toxic consequence areas for personnel injury

$$CA_{inj}^{tox} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{tox}}{gff_{total}}\right) \qquad \text{.................................... (equation 138)}$$

$$CA_{inj}^{tox} = \left(\frac{(gff_1 \cdot CA_{inj,1}^{tox}) + (gff_2 \cdot CA_{inj,2}^{tox}) + (gff_3 \cdot CA_{inj,3}^{tox}) + (gff_4 \cdot CA_{inj,4}^{tox})}{gff_{total}}\right)$$

Where,

Small (gff_1)	=	8.00E-06	failures/year
Medium (gff_2)	=	2.00E-05	failures/year
Large (gff_3)	=	2.00E-06	failures/year

Rupture (gff_4) = 6.00E-07 failures/year

gff_{total} = 3.06E-05 failures/year

So,

$$CA_{inj}^{tox} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{tox}}{gff_{total}}\right)$$

= 4.55574 m^2

STEP 10: NON-FLAMMABLE & NON-TOXIC CONSEQUENCE

Calculation of non-flammable, non-toxic consequence areas.

STEP 10.1 Calculate the non-flammable, non-toxic consequence area, for each release hole

10.1.1 For Steam

Steam represents a hazard to personnel who are exposed to it at high temperatures. In general, steam is at 100°C (212°F) immediately after exiting a hole in an equipment item. Within a few feet, the steam will begin to mix with air cool, and condensed. The approach used here is that injury occurs above 60°C (140°F). In this case of Amine Reboiler, the temperatur inside the presssure vessel is working around 128.67°C. So, steam leaks is potentially occur at this situation.

For steam -calculate using equation 137, $CA_{inj,N}^{CONT}$ for continous release or equation 138, $CA_{inj,N}^{INST}$ for instantaneous release.

Where,

$Rate_1$	=	0.0002	kg/s
$Rate_2$	=	0.0035	kg/s
$Rate_3$	=	0.0559	kg/s
$Rate_4$	=	0.8948	kg/s
$Mass_1$	=	0.2621	kgs
$Mass_2$	=	2.0971	kgs
$Mass_3$	=	16.7767	kgs
$Mass_4$	=	268.4268	kgs
C_9	=	0.123	m^2.sec/kg
C_{10}	=	9.744	$m^2/kg^{0.06384}$
$fact_1^{IC}$	=	0.000009	
$fact_2^{IC}$	=	0.000139	
$fact_3^{IC}$	=	0.002219	
$fact_4^{IC}$	=	0.035506	

10.1.1.1 Continous Release

$CA_{inj,n}^{CONT} = C_9 \cdot Rate_n$ .... (equation 139)

1) **Small Release Hole Area**

$CA_{inj,1}^{CONT} = C_9 \cdot Rate_1$

= 0.00003 m^2

2) **Medium Release Hole Area**

$CA_{inj,2}^{CONT} = C_9 \cdot Rate_2$

= 0.00043 m^2

3) **Large Release Hole Area**

$CA_{inj,3}^{CONT} = C_9 \cdot Rate_3$

= 0.00688 m^2

4) Rupture Release Hole Area

$CA_{inj,4}^{INST}$ = C_{10} . $(Mass_4)^{0.6384}$

= 0.11005 m^2

10.1.1.2 Instantaneous Release

$CA_{inj,n}^{INST}$ = C_{10} . $(Mass_n)^{0.6384}$........................ (equation 140)

= 0 m^2

Based on release rate at STEP 4, **no instantaneous release** in this calculation. So the consequence is 0.

10.1.2 For Acids and Caustic

No acid or caustic, thus value is 0.

$CA_{inj,N}^{CONT}$ = 0 m^2

STEP 10.2 Calculate the instantaneous/continuous blending factor, for each release hole

For each release hole size, calculate the instantaneous/continuous blending factor . For steam, use equation 139, for acids or caustics, $fact_n^{IC} = 0$

$$fact_n^{IC} = min\left[\left\{\frac{rate_n}{C_5}\right\}, 1.0\right] \quad \text{(equation 141)}$$

Where,

C_5 = 25.2 kg/s

So,

1) Small Release Hole Area

$$fact_1^{IC} = \min\left[\left\{\frac{rate_1}{C_5}\right\}, 1.0\right]$$

= 8.67E-06 m^2

2) Medium Release Hole Area

$$fact_2^{IC} = \min\left[\left\{\frac{rate_2}{C_5}\right\}, 1.0\right]$$

= 1.39E-04 m^2

3) Large Release Hole Area

$$fact_3^{IC} = \min\left[\left\{\frac{rate_3}{C_5}\right\}, 1.0\right]$$

= 2.22E-03 m^2

4) Rupture Release Hole Area

$$fact_4^{IC} = \min\left[\left\{\frac{rate_4}{C_5}\right\}, 1.0\right]$$

= 3.55E-02 m^2

STEP 10.3 **Calculate the blended non-flammable, non-toxic personnel injury consequence area for steam or acid leaks in each release hole size**

For each release hole size , compute the blended non-flammable , non-toxic personnel injury consequence area for steam or acid leaks, $CA_{inj,n}^{leak}$, using equation 140 based on the consequence area from STEP 10.1 and the blending factor , $fact_n^{IC}$, from STEP 10.2. Note that there is no need to calculate component damage area for the level 1 non-flammable release (steam or acid/caustic).

$CA_{cmd,n}^{leak}$ = 0 m^2

$$CA_{inj,n}^{leak} = CA_{inj,n}^{INST} . fact_n^{IC} + CA_{inj,n}^{CONT} . (1 - fact_n^{IC}) \quad \text{...... (equation 142)}$$

1) **Small Release Hole Area**

$$CA_{inj,1}^{leak} = CA_{inj,1}^{INST} . fact_1^{IC} + CA_{inj,1}^{CONT} . (1 - fact_1^{IC})$$

= 0.00003 m^2

2) **Medium Release Hole Area**

$$CA_{inj,2}^{leak} = CA_{inj,2}^{INST} . fact_2^{IC} + CA_{inj,2}^{CONT} . (1 - fact_2^{IC})$$

= 0.00043 m^2

3) **Large Release Hole Area**

$$CA_{inj,3}^{leak} = CA_{inj,3}^{INST} . fact_3^{IC} + CA_{inj,3}^{CONT} . (1 - fact_3^{IC})$$

= 0.00686 m^2

4) **Rupture Release Hole Area**

$$CA_{inj,4}^{leak} = CA_{inj,4}^{INST} . fact_4^{IC} + CA_{inj,4}^{CONT} . (1 - fact_4^{IC})$$

= 0.10615 m^2

STEP 10.4 **Determine the final non-flammable, non-toxic consequence areas for personnel injury**

Determine the final non-flammable, non toxic consequence areas for personnil injury, CA_{inj}^{nfnt} using equation 141 based on consequence areas calculated for each release hole size in STEP 10.3 . Note that there is no need to calculate a final-flammable, non-toxic consequence area for component damage area for the level 1 non-flammable release (steam or acid/caustic).

10.4.1 For Component Damage

$CA_{cmd,n}^{lnfnt}$ = 0 m^2

10.4.2 For Personnel Injury

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \, . CA_{inj,n}^{leak}}{gff_{total}} \right) \quad \text{.............................. (equation 143)}$$

$$CA_{inj}^{nfnt} = \left(\frac{(gff_1 \cdot CA_{inj,1}^{leak}) + (gff_2 \cdot CA_{inj,2}^{leak}) + (gff_3 \cdot CA_{inj,3}^{leak}) + (gff_4 \cdot CA_{inj,4}^{leak})}{gff_{total}} \right)$$

Where,

Small (gff_1)	=	8.00E-06	failures/year
Medium (gff_2)	=	2.00E-05	failures/year
Large (gff_3)	=	2.00E-06	failures/year
Rupture (gff_4)	=	6.00E-07	failures/year
gff_{total}	=	3.06E-05	failures/year

So,

$$CA_{inj}^{nfnt} = \left(\frac{\sum gff_n \cdot CA_{inj,n}^{leak}}{gff_{total}} \right)$$

$$= \quad 0.00282 \quad m^2$$

STEP 11: FINAL CONSEQUENCE AREA

Determine the final probability weighted component damage and personnel injury consequence areas.

STEP 11.1 Calculate the final component damage consequence area

The final component damage consequence area is:

$$CA_{cmd} = \max\left[CA_{cmd}^{flam}, CA_{cmd}^{tox}, CA_{cmd}^{nfnt}\right] \quad \text{(equation 144)}$$

Note that since the component damage consequence areas for toxic releases, $CAcmd^{tox}$, and non-flammable, non-toxic releases, $CAcmd^{nfnt}$, are both equal to zero. Then, the final component damage consequence area is equal to the consequence area calculated for flammable releases, $CAcmd^{flam}$.

$$CA_{cmd} = CA_{cmd}^{flam}$$

$= \quad 0.14264 \quad m^2$

STEP 11.2 Calculate the final personnel injury consequence area

$$CA_{inj} = \max\left[CA_{inj}^{flam}, CA_{inj}^{tox}, CA_{inj}^{nfnt}\right] \quad \text{(equation 145)}$$

$CA_{inj}^{flam} = \quad 0.23179 \quad m^2$

$CA_{inj}^{tox} = \quad 4.55574 \quad m^2$

$CA_{inj}^{nfnt} = \quad 0.00282 \quad m^2$

$CA_{inj} = \quad 4.55574 \quad m^2$

STEP 11.3 Calculate the final consequence area

$$CA = \max\left[CA_{cmd}, CA_{inj}\right] \quad \text{(equation 146)}$$

$= \quad 4.555737 \quad m^2$

$= \quad 49.037547 \quad ft^2$

Consequence of Failure

Calculation of Tube Side (HEXTS) CoF

Attachment 5-2

HEXTS Consequence of Failure Financial Based Calculation

Bundle failure is defined as a tube leak. Financial consequences are determined based on the bundle criticality which includes costs associated with lost opportunity due to production downtime, environmental impact costs, and costs associated with maintenance and replacement of the bundle. The consequence of an unplanned shutdown due to a bundle tube leak is determined using equation (147).

Where, the financial data is assumed using calculation example from API RP 581 Part 1, Section 8.4.2.

$$C_f^{tube} = Cost_{prod} + Cost_{env} + Cost_{bundle} + Cost_{maint} \quad \text{(equation 147)}$$

The unit production or lost opportunity cost, $Cost_{prod}$, is determined using equation (148).

$$Cost_{prod} = Unit_{prod} \cdot \left(\frac{Rate_{red}}{100}\right) \cdot D_{sd} \quad \text{(equation 148)}$$

Where,

$Rate_{red}$ = Bypass with rate reduction

$Unit_{prod}$ = Unit production cost (see Table 5.14)

D_{sd} = Days to repair during unplanned failure (see Table 5.15)

Table 5.14 Component Damage Cost (Refer to Table 4.15 API RP 581 Part 3)

Equip. Type	Component Type	Damage Cost (2001 US Dollars), *holecost*			
		Small	**Medium**	**Large**	**Rupture**
Heat Exchanger	HEXTS, HEXTUBE	$ 1,000	$ 2,000	$ 20,000	$ 60,000

Table 5.15 Estimated Equipment Outage (Refer to Table 4.17 API RP 581 Part 3)

Equip. Type	Component Type	Estimated Outage in Days, $Outage_n$			
		Small	**Medium**	**Large**	**Rupture**
Heat Exchanger	HEXTS	2	3	3	10
	HEXTUBE	N/A	N/A	N/A	N/A

Table 5.16 Calculation of Unit Production Cost ($Cost_{prod}$)

Hole Size	$Unit_{prod}$ ($/day)	$Rate_{red}$	Dsd (days)	$Cost_{prod}$ ($)
Small	1000	25%	2	500
Medium	2000		3	1500
Large	20000		3	15000
Rupture	60000		10	150000

In this calculation environmental cost is estimated as:

$Cost_{env}$ = $ -

Equation (149) may be used to estimate the bundle replacement costs, $Cost_{bundle}$. This equation assumes a typically sized carbon steel bundle, 800 mm (31.5 inch) diameter x 6 m (20 ft) long with a volume of 3.016 m^3 (106.5 ft^3), costs $22,000 to replace. Bundle costs are prorated as a function of size (volume) and tube material of construction. The material of construction is SA-179 Smls or Carbon Steel.

$$Cost_{bundle} = \frac{22000 \cdot \left(\frac{\pi D_{shell}^2}{4}\right) \cdot L_{tube} \cdot M_f}{C_1} \quad \text{.................. (equation 149)}$$

Where,

D_{shell}	=	36	inch
L_{tube}	=	18	feet
M_f	=	1.0	(refer to Table 4.16 API RP 581 Part 3 for Carbon Steel Material)
C_1	=	15592.5	

So,

$Cost_{bundle}$ = $ 25,837.71

The maintenance cost ($Cost_{maint}$) is associated with bundle replacement ($cost_{bundle}$) so,

$Cost_{maint}$ = $ 25,837.71

Final tube consequence cost (C_f^{tube})

$C_f^{tube} = Cost_{prod} + Cost_{env} + Cost_{bundle} + Cost_{maint}$

C_f^{tube} = $ 218,675.43

ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

ATTACHMENT 06

Risk Analysis

Amine Reboiler

Rev	Tanggal	Deskripsi	Disiapkan	Disetujui	
				Dosen Pembimbing	
			Khoirunnisa M.S. 0421164000021	Ir. Dwi Priyanta, M.SE	Nurhadi Siswantoro, S.T., M.T.

Determination of Risk

In general, the calculation of risk is determined in accordance with equation 149 and 150, as a function of time. The equation combines the POF and the COF.

$$R(t) = P_f(t) \cdot CA \quad \text{(equation 149)}$$

$$R(t) = P_f(t) \cdot FC \quad \text{(equation 150)}$$

Where;

$R(t)$ = Risk of Failure

$P_f(t)$ = Probability of Failure

CA = Consequence impact area expressed in units of area

FC = Consequence impact area expressed in economic terms

Table 6.1 Risk Calculation

Description	Shell Side		Tube Side	
P_f(RBI date)	2.080E-03		4.758E-03	
P_f(RBI plan date)	4.646E-03		8.454E-03	
Consequence	4.56	m^2	218675.43	$
Risk at RBI date	9.48E-03	m^2/year	1040.49	$/year
Risk at RBI plan date	2.12E-02	m^2/year	1848.59	$/year

ANALISIS PROGRAM PENJADWALAN INSPEKSI AMINE REBOILER HEAT EXCHANGER MENGGUNAKAN METODE RISK-BASED INSPECTION API 581

ATTACHMENT 07

Inspection Planning

Amine Reboiler

<table>
<tr><td rowspan="4">Rev</td><td rowspan="4">Tanggal</td><td rowspan="4">Deskripsi</td><td rowspan="2">Disiapkan</td><td colspan="2">Disetujui</td></tr>
<tr><td colspan="2">Dosen Pembimbing</td></tr>
<tr><td>Khoirunnisa M.S.</td><td rowspan="2">Ir. Dwi Priyanta, M.SE</td><td rowspan="2">Nurhadi Siswantoro, S.T., M.T.</td></tr>
<tr><td>0421164000021</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

INSPECTION PLAN

1. GENERAL INFORMATION

Type of Equipment	=	Heat Exchanger Shell Side (HEXSS)
Equipment Service	=	Amine Reboiler
Material	=	SA-516 Gr.70N
Process Fluids	=	Lean Amine
Insulation	=	Yes
Operating Pressure (Pa)	=	142726.5
Operating Temperature (°C)	=	128.67

2. RISK-BASED INSPECTION SUMMARY

2.1 Probability of Failure

Active Damage Mechanism	=	Thining
	=	SCC Damage Factor-Amine Cracking
	=	SCC Damage Factor-Sulfide Stress Cracking
	=	SCC Damage Factor HIC/SOHIC-H2S
	=	Corrosion Under Insulation Damage Factor-Ferritic Commponent

Table 7.1 Probability of Failure Summary

Description	RBI Date	RBI Plan Date
	(1/1/2020)	(1/1/2024)
Total Damage Factor	72.830	162.673
Probability	2.080E-03	4.646E-03
Probability Category	3	4

2.2 Consequence of Failure

Fluid Representative	=	H_2S
Fluid Storage Phase	=	Liquid
Fluid Release Phase	=	Gas
Consequence Area (m^2)	=	4.556
Consequence Area (ft^2)	=	49.038
Consequence Category	=	A

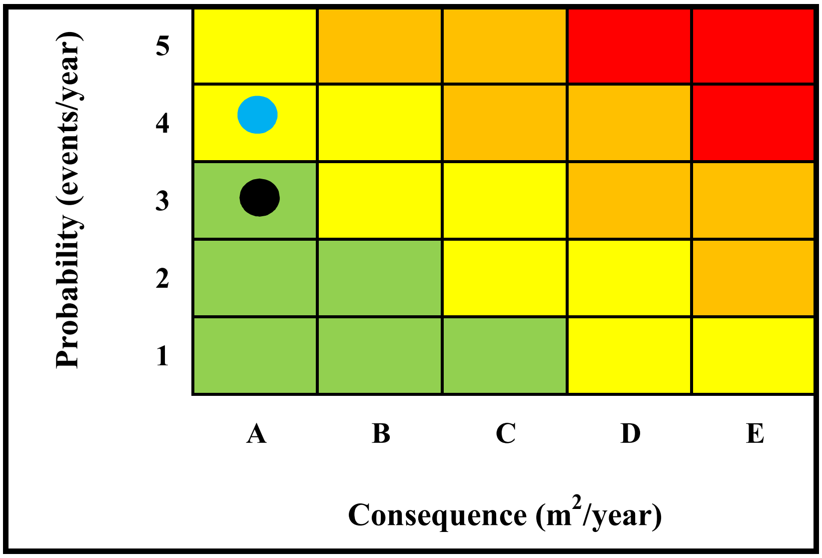
2.3 Risk Ranking

Risk Ranking (RBI Date)	=	3A	
Risk Ranking (RBI Plan Date)	=	4A	
Area Risk (RBI Date)	=	9.48E-03	(m^2/year)
Area Risk (RBI Plan Date)	=	2.12E-02	(m^2/year)
Risk Ranking (RBI Date)	=	Low Risk	
Risk Ranking (RBI Plan Date)	=	Medium Risk	
Risk Target	=	3.71	(m^2/year)

2.4 Risk Matrix

Table 7.2 Numerical Value Associated with POF and Area based COF Categories (Refer to Table 4.1M API RP 581 Part 1)

Category	Probability Category		Consequence Category	
	Probability Range	DF Range	Category	Range (m^2)
1	$P_f(t,I_E) \leq 3.06E\text{-}05$	$D_{f\text{-}total} \leq 1$	**A**	$CA \leq 9.29$
2	$3.06E\text{-}05 < P_f(t,I_E) \leq 3.06E\text{-}$	$1 < D_{f\text{-}total} \leq 10$	**B**	$9.29 < CA \leq 92.9$
3	$3.06E\text{-}04 < P_f(t,I_E) \leq 3.06E\text{-}$	$10 < D_{f\text{-}total} \leq 100$	**C**	$92.9 < CA \leq 929$
4	$3.06E\text{-}03 < P_f(t,I_E) \leq 3.06E\text{-}$	$100 < D_{f\text{-}total} \leq 1000$	**D**	$929 < CA \leq 9290$
5	$P_f(t,I_E) > 3.06E\text{-}02$	$D_{f\text{-}total} > 1000$	**E**	$CA > 9290$



Risk

High Risk
Medium-High Risk
Medium Risk
Low Risk

● = RBI Date
● = RBI Plan Date

2.5 Risk Targets

A target is defined as the maximum level acceptable for continued operation without requiring a mitigating action. To determine the target date, the risk target is using 40 ft^2 (3.71 m^2).

Table 7.3 Risk Target

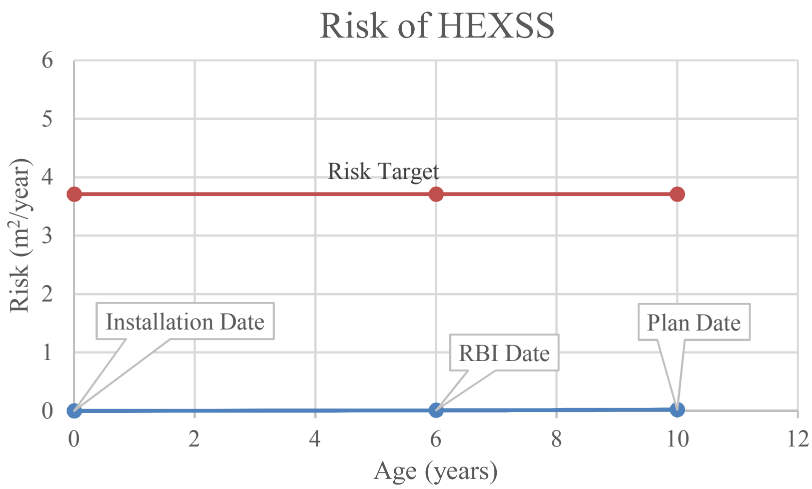
Data	Date	Age	Risk (m^2/yr)
RBI Date	1/1/2020	6	9.48E-03
Risk Target	?	?	3.71
RBI Plan Date	1/1/2024	10	2.12E-02

$$\frac{y - y_1}{y_2 - y_1} = \frac{x - x_1}{x_2 - x_1}$$

$$\frac{y - 6}{10 - 6} = \frac{3.71 - 9.35E\text{-}03}{1.64E\text{-}02 - 9.35E\text{-}03}$$

$$\frac{y - 6}{4} = \frac{3.701}{1.17E\text{-}02}$$

$$y = 1272.362$$



1. GENERAL INFORMATION

Type of Equipment = Heat Exchanger Tube Side (HEXTS)
Equipment Service = Amine Reboiler
Material = SA-179 Smls
Process Fluids = Hot Oil (Therminol 55)
Insulation = No
Operating Pressure (Pa) = 448175
Operating Temperature (°C) = 176.67

2. RISK-BASED INSPECTION SUMMARY

2.1 Probability of Failure

Active Damage Mechanism = Thining
= External Corrosion
- Thinning
- Amine Cracking
- Stress Sulfide Cracking
- HIC-SOHIC/H_2S Cracking

Table 7.4 Probability of Failure Summary

Description	RBI Date (1/1/2020)	RBI Plan Date (1/1/2024)
Total Damage Factor	166.615	296.018
Probability	4.758E-03	8.454E-03
Probability Category	4	4

2.2 Consequence of Failure

Fluid Representative = Therminol 55
Fluid Storage Phase = Liquid
Fluid Release Phase = Liquid
Consequence Cost = $ 218,675.43
Consequence Category = C

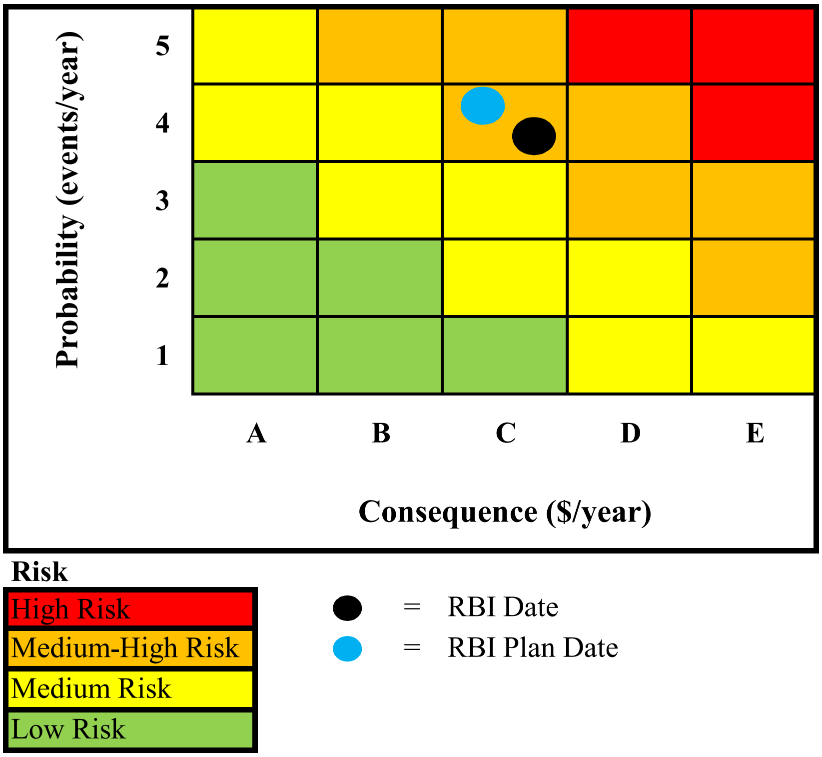
2.3 Risk Ranking

Risk Ranking (RBI Date) = 4C
Risk Ranking (RBI Plan Date) = 4C
Financial Risk (RBI Date) = 1040.49 ($/year)
Financial Risk (RBI Plan Date) = 1848.59 ($/year)
Risk Ranking (RBI Date) = Medium-High Risk
Risk Ranking (RBI Plan Date) = Medium-High Risk
Financial Risk Target = 75000.00 ($/year)
(assummed as API RP 581, Part 1 Section 8.4.2)

2.4 Risk Matrix

Table 7.5 Numerical Values Associated with POF and Financial-Based COF Categories (Refer to Table 4.2 API RP 581 Part 1)

Category	Probability Category		Consequence Category	
	Probability Range	DF Range	Category	Range ($)
1	$P_f(t,I_E) \le 3.06E\text{-}05$	$D_f \le 1$	**A**	FC ≤ 10,000
2	$3.06E\text{-}05 < P_f(t,I_E) \le 3.06E\text{-}$	$1 < D_f \le 10$	**B**	10,000 < FC ≤ 100,000
3	$3.06E\text{-}04 < P_f(t,I_E) \le 3.06E\text{-}$	$10 < D_f \le 100$	**C**	100,000 < FC ≤ 1,000,000
4	$3.06E\text{-}03 < P_f(t,I_E) \le 3.06E\text{-}$	$100 < D_f \le 1000$	**D**	10,000,000
5	$P_f(t,I_E) > 3.06E\text{-}02$	$D_f > 1000$	**E**	FC > 10,000,000



2.5 Risk Targets

A target is defined as the maximum level acceptable for continued operation without requiring a mitigating action. To determine the target date, the risk target is using $75,000.

Table 7.6 Risk Target

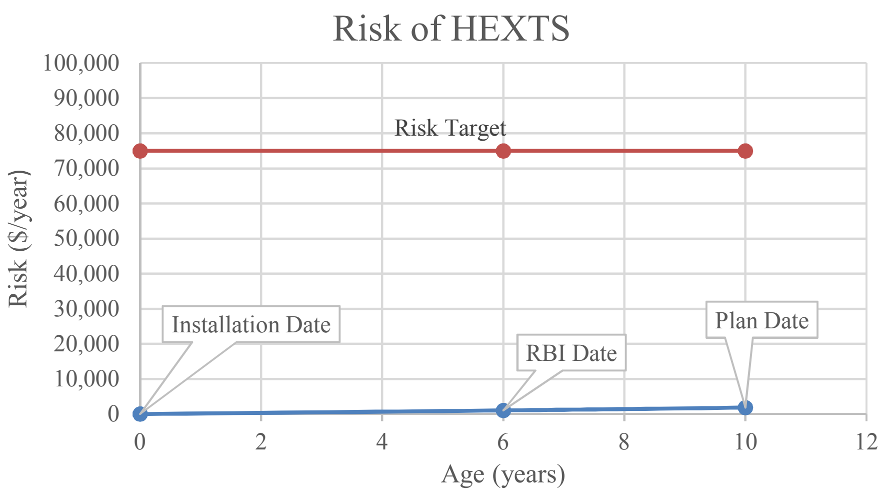
Data	Date	Age	Risk ($/yr)
RBI Date	1/1/2020	6	1040.49
Risk Target	?	?	75000.00
RBI Plan Date	1/1/2024	10	1848.59

$$\frac{y - y_1}{y_2 - y_1} = \frac{x - x_1}{x_2 - x_1}$$

$$\frac{y - 6}{10 - 6} = \frac{75{,}000 - 653.19}{1145.70 - 653.19}$$

$$\frac{y - 6}{4} = \frac{73959.514}{8.08E+02}$$

$$y = 372.091$$



3. RECOMMENDATION

3.1 Local Thinning Damage Factor

Inspection Planning Category

Recommendation of inspection planning category for local thinning damage factor written at Table 6.7 (Refer to Table 2.C.8.2 API RP 581 Annex 2C).

Table 6.7 Inspection Effectiveness for Local Thinning Damage Factor

<table>
<tr><th rowspan="2">Damage Factor</th><th rowspan="2">Effecti-veness</th><th rowspan="2" colspan="2">Description</th><th colspan="2">Due date</th></tr>
<tr><th>HEXSS</th><th>HEXTS</th></tr>
<tr><td rowspan="4">Local Thinning</td><td rowspan="4">C</td><td colspan="2">for the total surface area:</td><td rowspan="4">1/1/2024</td><td rowspan="4">1/1/2024</td></tr>
<tr><td>1</td><td>>50% Visual Examination</td></tr>
<tr><td colspan="2">AND</td></tr>
<tr><td>2</td><td>100% 100% follow-up at locally thinned areas</td></tr>
</table>

Inspection Planning Methods

Refer to API 571, the following are recommendation of inspection planning methods for local thinning damage factor.

a. Visual Testing (VT) Inspection

Visual inspection is the simplest inspection method without the use of tools. Visual impairment can be known from this method both internally and externally surfaces.

- Direct Visual Examination
- Remote Visual Examination
- Translucent Visual Examination

b. Ultrasonic Testing (UT)

This method of inspection is a non-destructive test method (NDE) that utilizes high-frequency ultrasonic waves (> 20.000 Hz). By emitting ultrasonic waves on the equipment, the thickness and defects in the equipment can be

- Phased Array Ultrasonic Testing (PAUT)
- Long Range Ultrasonic Testing (LRUT)
- Internal Rotating Inspection Systems (IRIS)
- Time of Flight Diffraction (TOFD)
- Dry-Coupled Ultrasonic Testing (DCUT)

c. Radiographic Testing (RT)

Radiography test is a non-destructive examination method of inspection that uses X-rays or gamma rays to see the inner structure of a piece of equipment.

- Conventional Radiographic
- Digital Radiographic
    - Computed Radiography
    - Direct Radiography
    - Real-Time Radiography
    - Computed Topography

3.2 Amine Stress Corrosion Cracking Damage Factor

Inspection Planning Category

cracking damage factor written at Table 6.8 (Refer to Table 2.C.9.1 API RP 581 Annex 2C).

Table 6.8 Inspection Effectiveness for Amine Cracking Damage Factor

Damage Factor	Effecti-veness	Description		Due date	
				HEXSS	HEXTS
SCC-Amine Cracking	C	For selected welds/ weld area:		1/1/2024	1/1/2024
		1	>35% WMFT/ACFM		
		AND			
		2	UT follow-up of all relevant indications		

Inspection Planning Methods

Refer to API 571, the following are recommendation of inspection planning methods for amine stress corrosion cracking damage factor.

a. Visual Testing (VT) Inspection

Visual inspection is the simplest inspection method without the use of tools. Visual impairment can be known from this method both internally and externally surfaces.

- Direct Visual Examination
- Remote Visual Examination
- Translucent Visual Examination

b. Wet Fluorescent Magnetic Test (WFMT)

Inspection using fluorescent can detect defects and cracks in more detail than using powders. Fluorescent fluid enables to increase the visibility of cracks on the surface of the material.

c. Alternating Current Field Measurement (ACFM)

Electromagnetic methods that use alternating current on the surface of the equipment to detect cracks at material. The cracks will interfere with the electromagnetic field and give the converted signal so that the inspectors can be aware of cracks or defects.

d. External Shear Wave Ultrasonic Testing (SWUT)

If the cracks have minimum branching, crack depths can be measured with a suitable UT technique.

e Acoustic Emission Testing (AET)

Can also be used for monitoring crack growth and locating growing cracks.

3.3 Sulfide Stress Cracking Damage Factor

Inspection Planning Category

Recommendation of inspection planning category for sulfide stress cracking damage factor written at Table 6.9 (Refer to Table 2.C.9.6 API RP 581 Annex 2C).

Table 6.9 Inspection Effectiveness for Sulfide Stress Cracking Damage Factor

<table>
<tr><th rowspan="2">Damage Factor</th><th rowspan="2">Effecti-veness</th><th rowspan="2" colspan="2">Description</th><th colspan="2">Due date</th></tr>
<tr><th>HEXSS</th><th>HEXTS</th></tr>
<tr><td rowspan="4">SCC-Sulfide Stress Cracking</td><td rowspan="4">C</td><td colspan="2">For selected welds/ weld area:</td><td rowspan="4">1/1/2024</td><td rowspan="4">1/1/2024</td></tr>
<tr><td>1</td><td>>35% WMFT/ACFM</td></tr>
<tr><td colspan="2">AND</td></tr>
<tr><td>2</td><td>UT follow-up of all relevant indications</td></tr>
</table>

Inspection Planning Methods

Refer to API 571, the following are recommendation of inspection planning methods for sulfide stress cracking damage factor.

a. Visual Testing (VT) Inspection

Visual inspection is the simplest inspection method without the use of tools. Visual impairment can be known from this method both internally and externally surfaces.

- Direct Visual Examination
- Remote Visual Examination
- Translucent Visual Examination

b. Wet Fluorescent Magnetic Test (WFMT)

Inspection using fluorescent can detect defects and cracks in more detail than using powders. Fluorescent fluid enables to increase the visibility of cracks on the surface of the material.

c. Alternating Current Field Measurement (ACFM)

Electromagnetic methods that use alternating current on the surface of the equipment to detect cracks at material. The cracks will interfere with the electromagnetic field and give the converted signal so that the inspectors can be aware of cracks or defects.

d. Eddy Current (EC)

The EC method is implemented by supplying electrical current to the coil until the magnetic field is formed. If the magnetic field is attached to the material that is inspected will be formed Eddy current.

e. Radiographic Test (RT)

Radiography test is a non-destructive examination method of inspection that uses X-rays or gamma rays to see the inner structure of a piece of equipment.

- Conventional Radiographic
- Digital Radiographic
    - o Computed Radiography

   - Direct Radiography
   - Real-Time Radiography
   - Computed Topography

f. External Shear Wave Ultrasonic Testing (SWUT)

   If the cracks have minimum branching, crack depths can be measured with a suitable UT technique.

g. Acoustic Emission Testing (AET)

   Can also be used for monitoring crack growth and locating growing cracks.

3.4 HIC/SOHIC-H_2S Cracking

Inspection Planning Category

Recommendation of inspection planning category for HIC/SOHIC-H_2S cracking damage factor written at Table 6.10 (Refer to Table 2.C.9.7 API RP 581 Annex

Table 6.10 Inspection Effectiveness for HIC/SOHIC-H_2S Cracking DF

<table>
<tr><th rowspan="2">Damage Factor</th><th rowspan="2">Effecti-veness</th><th rowspan="2" colspan="2">Description</th><th colspan="2">Due date</th></tr>
<tr><th>HEXSS</th><th>HEXTS</th></tr>
<tr><td rowspan="9">SCC-HIC/SOHIC-H_2S</td><td rowspan="9">C</td><td colspan="2">For the total surface area:</td><td rowspan="9">1/1/2024</td><td rowspan="9">1/1/2024</td></tr>
<tr><td>1</td><td>>35% A or C scan with straight beam</td></tr>
<tr><td>2</td><td>Followed by TOFD/Shear Wave</td></tr>
<tr><td>3</td><td>100% Visual</td></tr>
<tr><td colspan="2">OR</td></tr>
<tr><td>4</td><td>>50% WFMT/ACFM</td></tr>
<tr><td>5</td><td>UT Follow-up of indications</td></tr>
<tr><td>6</td><td>100% Visual of total surface area</td></tr>
</table>

Inspection Planning Methods

Refer to API 571, the following are recommendation of inspection planning methods for HIC/SOHIC-H_2S cracking damage factor.

a. Visual Testing (VT) Inspection

Visual inspection is the simplest inspection method without the use of tools. Visual impairment can be known from this method both internally and externally surfaces.

- Direct Visual Examination
- Remote Visual Examination
- Translucent Visual Examination

b. Wet Fluorescent Magnetic Test (WFMT)

Inspection using fluorescent can detect defects and cracks in more detail than using powders. Fluorescent fluid enables to increase the visibility of cracks on the surface of the material.

c. Alternating Current Field Measurement (ACFM)

Electromagnetic methods that use alternating current on the surface of the equipment to detect cracks at material. The cracks will interfere with the electromagnetic field and give the converted signal so that the inspectors can be aware of cracks or defects.

d. Eddy Current (EC)

The EC method is implemented by supplying electrical current to the coil until the magnetic field is formed. If the magnetic field is attached to the material that is inspected will be formed Eddy current.

e. Radiographic Test (RT)

Radiography test is a non-destructive examination method of inspection that uses X-rays or gamma rays to see the inner structure of a piece of equipment.

- Conventional Radiographic
- Digital Radiographic
  - Computed Radiography
  - Direct Radiography
  - Real-Time Radiography
  - Computed Topography

f. External Shear Wave Ultrasonic Testing (SWUT)

If the cracks have minimum branching, crack depths can be measured with a suitable UT technique.

g. Acoustic Emission Testing (AET)

Can also be used for monitoring crack growth and locating growing cracks.

3.5 Corrosion Under Insulation (CUI)

Inspection Planning Category

Recommendation of inspection planning category for CUI damage factor written at Table 6.11 (Refer to Table 2.C.10.3 API RP 581 Annex 2C).

Table 6.11 Inspection Effectiveness for CUI Damage Factor

Damage Factor	Effectiveness	Description	Due date HEXSS	Due date HEXTS
Corrosion Under Insulation (CUI)	C	For the total surface area: 1 100% external visual inspection prior to removal of insulation AND 2 Remove >25% of suspect areas AND 3 100% visual inspection as follow-up of corroded areas with UT, RT or pit gauge	1/1/2024	-

Inspection Planning Methods

Refer to API 571, the following are recommendation of inspection planning methods for corrosion under insulation damage factor.

a. Partial and/or full stripping of insulation for visual examination

b. Ultrasonic Testing (UT) for thickness verification
   - Phased Array Ultrasonic Testing (PAUT)
   - Long Range Ultrasonic Testing (LRUT)
   - Internal Rotating Inspection Systems (IRIS)
   - Time of Flight Diffraction (TOFD)
   - Dry-Coupled Ultrasonic Testing (DCUT)

c. Neutron Backscatter

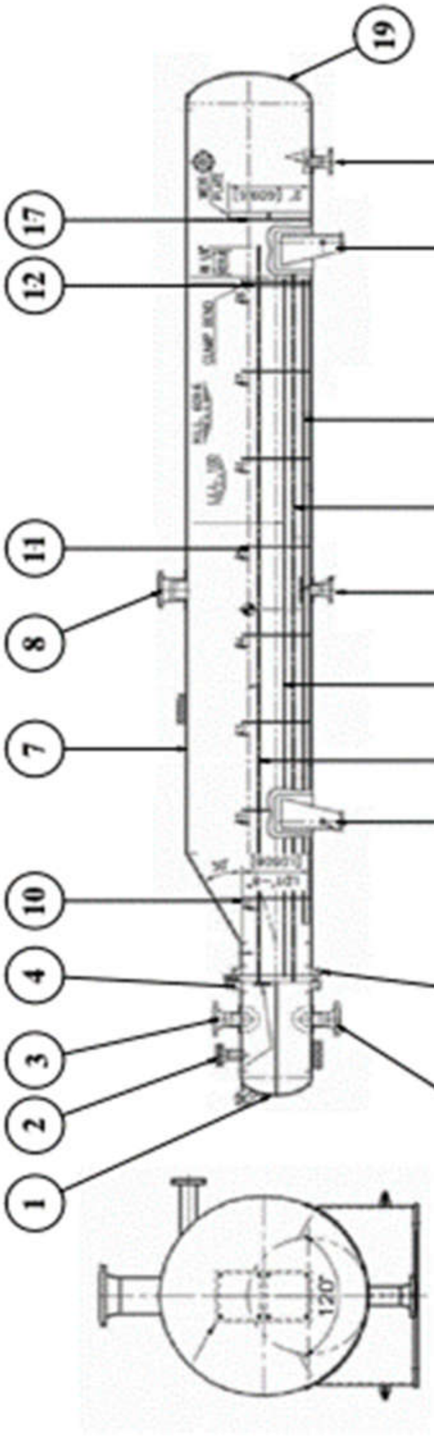
   This method uses neutron as detecting the presence of CUI. The radioactive source radiates neutrons with high energy (rapidly) to the area to be measured (the desired isolation area). Throughout the journey, neutrons will be monitored through a partial sensitive detector for low energy neutrons. If the neutron energy collides with hydrogen then the neutron will be reduced (low energy). It will be detected by the detector tool. The lower the neutron energy detected the more hydrogen in the area.

d. Deep Penetrating Eddy-Current Inspection

e. Infrared Thermography

   This method of inspection is used to identify the abnormal temperature conditions of the equipment. An increase in temperature can be an indication of failure or defect.

4. INSPECTION POINT



CORROSION MONITORING SHEET								
Point Number	Part Name	Nom. Thick (mm)	Dia. (in)	Point of Measurement				Min. Thick (mm)
				1	2	3	4	
1	Head 1							
2	Vent							
3	Head nozzle 1							
4	Head flange							
5	Head nozzle 2							
6	Shell flange							
7	Shell							
8	Shell nozzle 1							
9	Shell nozzle 2							
10	Support plates 1							
11	Support plates 2							
12	Support plates 3							
13	Tubes 1							
14	Tubes 2							
15	Tubes 3							
16	Tubes 4							
17	Weir							
18	Shell nozzle 3							
19	Head 2							
20	Support saddle 1							
21	Support saddle 2							

BIOGRAFI PENULIS

Penulis lahir di Malang pada tanggal 22 Januari 1999 dengan nama Khoirunnisa Mahdiyah Syawalina. Penulis merupakan anak kedua dari tiga bersaudara. Penulis menempuh pendidikan mulai dari SD Negeri 16 Mataram, SMP Negeri 1 Lawang, dan SMA Negeri 1 Lawang. Setelah lulus dari jenjang Pendidikan SMA, penulis diterima di Departemen Teknik Sistem Perkapalan, Fakultas Teknologi Kelautan, Institut Teknologi Sepuluh Nopember melalui jalur SNMPTN. Selama menempuh masa studi penulis aktif di kepanitiaan UKM bahasa dan budaya ITS, IFLS dan UKM seni tari dan karawitan, UKTK ITS. Selain aktif di kegiatan UKM, penulis juga aktif dalam kegiatan organisasi Lembaga Minat dan Bakat ITS sebagai bendahara II. Penulis merupakan anggota Digital Marine Operation and Maintenance Laboratory, asisten laboratorium Marine Electrical and Automation Systems. Penulis pernah melaksanakan kerja praktek di PT. Dok dan Perkapalan Surabaya dan PT. Antakesuma Inti Raharja. Selain itu, penulis juga berabung dalam tim project Ir. Dwi Priyanta, M.SE selaku dosen di Departemen Teknik Sistem Perkapalan sebagai *research assistant*.