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Offshore oil and gas operators increasingly use Coiled Tubing (CT) technology to conduct well interventions with greater safety and efficiency. To enhance oversight of these operations, the Bureau of Safety and Environmental Enforcement (BSEE) partnered with Argonne National Laboratory and industry representatives to develop a risk-informed inspection approach focused on CT equipment and well control practices. Using Argonne's Risk-Informed Decision-Making (RIDM) framework—centered on Multiple Physical Barriers and Success Path analysis—the project identified critical components and conditions that elevate risk during CT operations. A Failure Modes, Effects, and Criticality Assessment (FMECA) highlighted the need for an independent hydraulic safety system and informed revisions to the upcoming 2nd Edition of API RP 16ST.

A major project outcome was a comprehensive, risk-informed CT Equipment and Operations Checklist to support BSEE inspectors and engineers during permitting and field inspections. This tool formed the basis of a 32-hour CT training program delivered across the Gulf of Mexico Region, improving staff understanding of CT configurations, operational hazards, and emerging safety issues. The collaboration strengthened industry awareness of risk-based equipment specification and redundant safety elements, offering a model for future risk-informed regulatory partnerships.

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Application of Risk-Informed Decision-Making Techniques to the Inspection of Coiled Tubing Operations in Offshore Oil and Gas Facilities

Argonne NATIONAL LABORATORY

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Executive Summary

Offshore oil and gas facilities have increasingly utilized Coiled Tubing (CT) technology to perform well intervention services in a safe and efficient manner. The main benefits of CT are its versatility, efficiency, ability to maintain continuous fluid circulation throughout the well service, and the capability to deploy and retrieve the CT workstring with wellbore pressure present.

In order to achieve the goal of improving the safety on the offshore oil and gas facilities that utilize Coiled Tubing equipment and operations, this project was developed with the vision of creating a BSEE inspection program based on risk-informed principles that can be used to promote overall improvements to safety, consistency, and information-sharing. Through this project, BSEE sought to improve its overall knowledge of CT equipment and operations by enabling its engineering and inspection staff to become more aware of the best practices for CT-related activities employed throughout the industry. It is envisioned that this knowledge will heighten BSEE's awareness of the risks related to CT well control equipment performance and operations so that it could improve its permitting and inspection activities.

BSEE teams examined how the use of risk-informed decision-making (RIDM) techniques, developed by Argonne National Laboratory (Argonne), can help inspectors, engineers, and rule-makers as they develop policies and inspection protocols including, but not limited to, Potential Incidents of Non-Compliance (PINCs).

The Argonne RIDM approach places heavy emphasis on the concept of *Multiple Physical Barriers* (*MPB*s) and the *Success Path* approach to achieving robust physical barriers that prevent the release of hydrocarbons and other hazardous materials to the environment and expose personnel to unsafe conditions. According to this approach, the absence or unavailability of a key component in a Success Path is a clear indicator of increased risk.

This project was a combined effort between BSEE and the Oil and Gas industry with Argonne acting as a neutral technical advisor. Both BSEE and the American Petroleum Institute (API) Subcommittee (SC) 16 Task Group 5, which developed API Recommended Practice (RP) 16ST "Coiled Tubing Well Control Equipment Systems," adopted the Argonne RIDM approach to examine the function and performance of coiled tubing well control equipment and work practices.

The API RP 16ST Task Group, led by Mr. Alexander Sas-Jaworsky PE, conducted an extensive review of the current version of RP 16ST with the goal of identifying and emphasizing the key elements that need to be in place in order to achieve successful operation under all expected conditions, such as pressures, temperatures, fluid chemistry, rheology, etc., for a given well.

This effort included the Argonne-led risk-based Failure Modes, Effects, and Criticality Assessment (FMECA) technique, which identified areas where risks can be reduced. A major finding of this study included the identified necessity of an additional safety system within the CT well control equipment circuit, which must rely on a separate, dedicated hydraulic power system. This and other findings have been incorporated into 2nd Edition Draft of API RP 16ST, which is expected to be balloted by API in CY2018.

One of the major deliverables of this project is the development of a Coiled Tubing Equipment and Operations Checklist to be potentially used by BSEE inspectors and engineers during field inspections, permitting activities, and other CT-related applications. This checklist, based on a checklist previously developed by Mr. Sas-Jaworsky, was revised and expanded to include risk-informed inspection practices. It is designed with the vision that in the future, BSEE staff will continue to add to it based on their experiences with risk-informed practices.

This checklist was the key item in a BSEE-Argonne Workshop held in July of 2017. This workshop was followed by a trial run for what was ultimately expanded into a 32-hour BSEE training course on coiled tubing for inspectors and engineers. This course was taught to three different audiences of BSEE engineers and inspectors in three venues in the Gulf of Mexico Region during the first half of 2018.

The 32-hour course describes the CT configurations that should be expected in different operating conditions, such as pressure ranges, and helps the BSEE staff to understand the importance of, and risks associated with, the many components found in a given Coiled Tubing operation.

The July workshop, and the training courses that followed, have made the BSEE staff aware of emerging safety issues in the area of CT well control. These kinds of activities help the staff to keep abreast of important safety issues in the industry that may eventually become part of future offshore safety regulations.

A major outcome of this effort was the recognition by industry of the need to include risk considerations when specifying the equipment configurations needed for successful coiled tubing operations. This led to new thinking in inspection and permitting activities, especially in ensuring the presence of redundant or back-up safety elements. It also led to a decision that continuously wearing non-sealing elements, such as the stripper assembly, should not be relied upon, or considered a physical barrier, for well control purposes.

Based on the relative success of this program, Argonne makes the following recommendations to BSEE:

- Continue to offer the 32-hour coiled tubing equipment and operations training course to inspectors and engineers;
- Use the Coiled Tubing Checklist developed in this project as a tool for current CT activities, and add to it based on the experiences and training of individual inspectors and engineers;
- Support future effort by the industry to collect and analyze reliability data in order to gain further insights into the safety of the coiled tubing equipment. Some companies are reluctant to share their component failure information because it might be released to the public.

Finally, this ongoing risk-informed collaboration between the offshore oil industry and BSEE, with Argonne acting as a neutral technical intermediary, is, in itself, a significant development, and could act as a model for similar risk-informed collaborations in the future.

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Introduction

Coiled Tubing (CT) is a widely used and important technology used for performing workovers in a safe and effective manner on offshore oil and gas facilities. Within this project, the Bureau of Safety and Environmental Enforcement (BSEE) sought to improve its overall knowledge of CT equipment and operations by making its engineering and inspection staff more aware of the best practices for the CT-related activities throughout the industry and heighten their awareness of risks associated with these activities. In particular, the BSEE has sought to understand how the use of risk-informed decision-making techniques can help inspectors, engineers, and rule-makers as they develop policies and regulatory protocols including, but not limited to, Potential Incidents of Non-Compliance (PINCs).

Background

In order to achieve the goal of improving the safety on the offshore oil and gas facilities that utilize Coiled Tubing equipment and operations, this project was developed with the vision of creating an inspection program based on risk-informed principles. These principles enhance overall equipment performance through more reliable well control systems, consistency in implementation, information sharing and enable necessary operator actions to be taken sooner in order to ensure safety. To realize this program, BSEE enlisted the assistance of Argonne National Laboratory (Argonne) in helping to identify past CT equipment failures in order to help identify trends and raise awareness of potential problems that may require action to prevent failures. In accordance with BSEE's vision, Argonne helped by developing a set of risk-based tools, such as inspector checklists, diagrams, processes and manuals supported by real examples within the scope of this project. This collaboration was designed to increase BSEE staff's understanding of the overall perspective and issues as well as some of the more safety-significant details related to CT operations and equipment.

Through this program, BSEE can improve its inspection activities by making inspectors and engineers more knowledgeable of CT equipment and operations, related regulations, relevant PINCs and appropriate CT working practices throughout the industry. It is believed that inspector knowledge can be improved at a reasonable cost by having industry experts on risk principles and on CT operations conduct education and training for the regulatory inspectors. Therefore, the scope of this program has also involved technical training of BSEE inspectors and engineers.

Technical Scope

The technical scope of this project consisted of the following activities carried out by Argonne:

- Development of a preliminary set of risk-based tools which defined:
    - Physical CT well control barriers
    - Success Path framework for well control equipment and the support system
    - Physical barrier configurations for identified CT well pressure categories
    - Risk-informed coiled tubing inspection checklist

- Conducting an introductory seminar at the BSEE Inspector's Meeting (held on March 22-24, 2017);
- Further refining the risk-based tools and developing them into knowledge-transfer workshop materials;
- Conducting a series of in-depth training courses for BSEE inspectors and engineers;
- Assembling a draft oversight guide book for BSEE review; and
- Assembling and delivering a final version of the oversight book.

Argonne approached completing the above activities by (1) identifying the critical physical barrier elements and barrier support systems in coiled tubing, (2) developing success paths for the identified physical barriers and barrier support systems, (3) developing a comprehensive inspection checklist for these elements, and (4) compiling these materials into for BSEE knowledge transfer workshop sessions.

Determination of Coiled Tubing Physical Barriers and Critical Barrier Support System

Identification of Barriers and Critical Barrier Support System
Argonne worked together with a coiled tubing subject matter expert, Alexander Sas-Jaworsky, PE, to identify the physical barriers in coiled tubing equipment that create an envelope to contain hydrocarbons and other hazardous process fluids. To do this, Argonne employed the *Argonne Multiple Physical Barrier Approach* (discussed in a later Section of this report).

In addition to identifying the barriers, it was recognized that there are a number of configurations of coiled tubing equipment used to perform workover operations on offshore facilities. In light of this fact, Argonne developed barrier configuration diagrams (full list presented in Appendix A) describing the barriers in 23 different coiled tubing well control stack configurations. These configurations correspond with the pressure categories identified in the 1st Edition of American Petroleum Institute (API) Recommended Practice RP 16ST, *"Coiled Tubing Well Control Equipment Systems."*

According to both BSEE regulations and API RP 16ST, there are certain requirements for having redundant physical barriers in place for different pressure categories. BSEE regulations (30 CFR 250.616(a)(1) and 30 CFR 250.1706(a)(1)) recognize two pressure scenarios:

(1) When the surface pressure is less than or equal to 3,500 psi; and
(2) When the surface pressure is greater than 3,500 psi;

An additional scenario recognized by the above regulation is when the returns are taken through an outlet on the BOP stack.

At the same time, API RP 16ST recognizes five pressure categories:

(1) PC-0 or 0 psig at surface;
(2) PC-1 or 1 psig to 1,500 psig;

(3) PC-2 or 1,501psig to 3,500 psig;
(4) PC-3 or 3,501psig to 7,500 psig; and
(5) PC-4 or 7,501psig to 12,500 psig.

The barrier requirements in accordance with the above parameters are described in Table 1 below:

Table 1: BSEE Regulations (30 CFR 250.616(a)(1)) and API RP 16ST Pressure Categories and Barriers Crosstab.

BOP[1] system when expected surface pressures are less than or equal to 3,500 psi	**BOP system when expected surface pressures are greater than 3,500 psi**	**BOP system for wells with returns taken through an outlet on the BOP stack**
Stripper or annular-type well control component	Stripper or annular-type well control component	Stripper or annular-type well control component
Hydraulically-operated blind rams	Hydraulically-operated blind rams	Hydraulically-operated blind rams
Hydraulically-operated shear rams	Hydraulically-operated shear rams	Hydraulically-operated shear rams
Kill line inlet	Kill line inlet	Kill line inlet
Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams Hydraulically-operated pipe rams
Hydraulically-operated pipe rams	Hydraulically-operated pipe rams Hydraulically-operated blind-shear rams These rams should be located as close to the tree as practical	A flow tee or cross Hydraulically-operated pipe rams Hydraulically-operated blind-shear rams on wells with surface pressures > 3,500 psi As an option, the pipe rams can be placed below the blind-shear rams. The blind-shear rams should be located as close to the tree as practical
COMPARISON WITH 1st Edition API RP 16ST RECOMMENDED WELL CONTROL STACK ASSEMBLIES		
PC - 1 for 1 psig - 1,500 psig ***(RP 16ST Para. 4.2.6.3)*** **PC - 2 for 1,501 psig - 3,500 psig** ***(RP 16ST Para. 4.2.6.4)***	**PC - 3 for 3,501 psig - 7,500 psig** ***(RP 16ST Para. 4.2.6.5)*** **PC- 4 (7,501 psig - 12,500 psig)** ***(RP 16ST Para. 4.2.6.6)***	**Pressure Categories 1 through 4** **where a flow tee or flow cross is installed within the well control stack**

[1] To clarify, the BSEE regulations refer to the well control equipment as "Blowout Preventer" or "BOP," while this report uses terminology similar to API RP 16ST referring to it as "Well Control Stack."

Success Path Development

Once the critical physical barriers were identified, Argonne developed success paths to describe systems and actions required to support these barriers. Additionally, Argonne developed success paths for barrier support systems—those that do not serve as immediate barriers but are necessary in order to actuate, support, and/or maintain barriers.

The success path evaluation of individual coiled tubing well control barriers and components addresses the performance requirements for the designated pressure control systems through the assessment of the following:

- Applicability;
- Critical safety function;
- Alternate success path;
- Critical support system; and
- Threat scenarios.

Within the scope of this project, Argonne developed success paths for 15 barriers and support systems. These barriers and systems include: (1) the stripper, (2) pipe ram, (3) coiled tubing string, (4) downhole flow check assembly, (5) blind rams as part of the shear and blind ram system, (6) shear rams as part of the shear and blind ram system, (7) *primary*[2] combination shear-blind ram, (8) *dedicated*[3] combination shear-blind ram, (9) hydraulic pump, (10) air-over hydraulic pump for the stripper, (11) primary accumulator system, (12) dedicated accumulator system, (13) injector, (14) tubing guide arch, and (15) service reel.

From the above items, it was determined that because the stripper assembly is a continuously degrading operational component, it should be re-classified as a pressure control device (rather than a barrier) when used for well control. Items two through eight are physical barriers or barrier elements. Barrier elements need to be used in combination with other barrier elements to comprise a pressure sealing barrier across the well. Finally, items nine through 15 are considered barrier support systems that are important to consider because their failure can lead to the failure of the physical barrier(s). The full set of the success paths developed during this project is in Appendix A on pages 34 through 49.

Later sections of this report discuss the methodology behind the success path development for this project.

Development of the Risk-Informed Coiled Tubing Equipment and Operations Checklist

SAS Industries, Inc. had developed a preliminary checklist for coiled tubing and service equipment in 2003 that was intended to focus on areas where equipment failures contributed to interruptions in service or quality of well control response. Since the initial creation, this checklist and process had been continuously updated by SAS Industries, Inc. to capture inspection observations, which

[2] Primary SBR is operated through the primary accumulator system discussed in a later section of this report.
[3] Dedicated SBR is operated through the dedicated accumulator system that is isolated from the primary accumulator system and is discussed in a later section of this report.

lead to corrective actions, intended to correct deficiencies or areas where reliable operation of the specified equipment component is at risk. As the CT industry worked to develop recommended practices for coiled tubing well control equipment and systems, the checklist was further expanded to address equipment that served as critical to well control components. When the 1st Edition of API RP 16ST was published, the recommended practices related to performance testing and confirmation were included, which provided a means for qualifying the well control equipment for a given well intervention service.

During early preparation of the 2nd Edition of API RP 16ST, Argonne collaborated with API Subcommittee 16 (SC16) Task Group 5 (TG-5) by introducing the Success Path approach and how the process can be used to enhance confidence in equipment performance and reliability. Within the scope of this project, using the Success Path approach, the CT equipment checklist was revised again to focus on inspection practices that can be used to confirm the proper operation of well control components and systems.

Appendix B includes the full checklist developed within the scope of this project.

Knowledge Transfer Material Development

Knowledge Transfer Workshop vs. Technical Training Scope Change

During the development stage of this project, BSEE had tasked Argonne with facilitating knowledge transfer workshop sessions that were meant to provide BSEE inspectors and engineers background knowledge on coiled tubing equipment and operations in order to improve the inspection and permitting activities. According to the initial requirement, Argonne was to conduct a preliminary (or "dry-run") Knowledge Transfer Workshop to ensure that the key material was included in the discussion, and that the presentation would be adequate for the intended audience (BSEE inspectors and engineers), scope, and level of information sought by BSEE. The BSEE GOMR subject matter experts / recommendation-makers who participated in this preliminary workshop were tasked with evaluating the material for fitness for the purpose of the "live" workshop series that would follow. Argonne would then incorporate this feedback into the "live" workshop presentations and other learning material.

During the actual preliminary workshop, held in July of 2017, several factors demonstrated that the amount of time initially allocated for the workshop was not sufficient to cover the scope of the prepared workshop material adequately. It was also determined that the scope and the breadth of the information also needed to be expanded in order to include more fundamental coiled tubing technology topics. Specifically, it was determined that the workshop session, initially planned for 12 hours (one and a half days) would need to be expanded to 32 hours to allow for coverage of all the intended material, discussion of the presented material, and providing answers to the questions from the participants. It was also determined that the new, revised scope of the knowledge transfer sessions would qualify as an official BSEE training course. The BSEE Offshore Training Branch Staff who also audited the preliminary workshop supported this decision.

With this change in scope, BSEE and Argonne collaborated on revising the project Statement of Work to expand the scope and objective of the knowledge transfer segment to include preparation for and presentation of three 32-hour training courses plus one preliminary (“dry-run”) course to precede the three “live” courses. The purpose of the preliminary training course would be, again, to get final feedback on the appropriateness of the material for a live training course. For participating in this training course, BSEE staff would receive 32 hours of training credit that would count towards meeting their annual training requirements.

Development of the Training and Guidance Materials

In the original scope of the knowledge transfer activity of this project, Argonne was to provide a CT well control equipment system checklist for potential use by BSEE inspectors and engineers. This checklist was originally prepared by SAS Industries, Inc. as part of an established CT inspection program and updated to complement the Argonne Success Path approach. Once the decision was made to expand the scope of training to a formal 32-hour course, SAS Industries, Inc. provided Argonne with relevant sections of their established, commercially-available CT training program (offered to CT User and Service Vendor personnel) to enhance understanding of the current state of CT well control barrier systems and where improvements are forthcoming within API RP 16ST.

Argonne assembled an oversight guideline book for BSEE inspectors and engineers on the topic of coiled tubing equipment and operations incorporating the following items:

- The presentation on the Argonne Risk-Informed Decision-Making approach;
- Coiled tubing barrier success paths and operational diagrams;
- Numerous presentations providing background on the coiled tubing technology; and
- The coiled tubing equipment and operations checklist.

For the purpose of conducting the workshop series, Argonne had also incorporated four exercises designed to reinforce the learned material.

When the scope of this activity was revised to include the preparation of training course materials, Argonne and SAS Industries, Inc. prepared a series of learning tools to satisfy the requirement for 32 hours of training. These materials comprised of nine core learning modules, exercises, and appendices that contain supplemental information. Appendix C includes a full list of the titles of the core Modules, class exercises, and supplemental appendices.

In addition, after the first live training course, Argonne and BSEE recognized the need to add quizzes to the training course materials. As the result, three quizzes were created and used to test for the participants’ proficiency in the current regulations and safety practices as well as the retention of the presented material that was not immediately followed by an exercise.

It should be noted that Appendices 1A, 1B, and 2 included in the training materials are courtesy of SAS Industries Inc., provided by Alexander Sas-Jaworsky for the purpose of enhancing the training material for this course.

These materials were provided to BSEE in electronic form via email. Physical copies of the material were prepared and compiled into 3-ring bound books and distributed to the training course participants. Additional copies of these books were provided to the BSEE TL, COR, the BSEE Risk Assessment and Analysis Branch Chief, and the BSEE Offshore Training Branch staff. The design of these books includes images of the presentation slides with writing space on each page, such that the training course participants have the ability to make their own notes in addition to the existing materials. An added benefit of the choice to go with a 3-ring binder was the fact that the BSEE inspectors and engineers could take out individual pages and use them in their daily activities and/or add pages to the existing material.

Discussion of the Risk-Informed Inspection Tools

Argonne Multiple Physical Barrier Approach

The concept of Multiple Physical Barriers (MPB, [1]) is widely used in high hazard industries—especially those where hazardous materials need to be kept from the environment in general, and in particular, kept from places where they can cause harm to people, the environment, and equipment. In the offshore oil and gas industry, the threat level from the release of hazardous materials also varies based on factors such as type and/or volume of released material. In this sense, some releases of hazardous materials can be more dangerous than others as they may be of explosive or flammable substances and could lead to very dangerous conditions on offshore oil and gas facilities.

The MPB approach focuses on the issues related to *process safety*. Argonne's definition of process safety deals with making sure that the necessary equipment and systems are in place to prevent significant accidents. Such accidents are ones where one or more fatality or permanent disability is caused to the personnel, severe impact is caused to the environment, or extensive damage is caused to the structures or installations. In contrast with process safety, *industrial safety* focuses on the safety of the individual.

The word "barrier" in process safety means a physical object. Elements that support the physical barriers include personnel, training, procedures, and equipment (e.g., communication equipment). These elements are necessary to ensure the proper function of the physical barriers, but they in themselves are not considered barriers. Furthermore, in process safety, the risk is directly related to barrier assurance because it is understood that if the barrier is breached, the consequences on the personnel, the environment, and facility are likely to be severe.

In the case of coiled tubing operations, a barrier is defined as a component or combination of components designed to keep hydrocarbons and hazardous fluids contained safely throughout the operation. For CT operations, the recognized barriers include the coiled tubing string, a single acting or combination ram, a valve or any other element designed to keep hydrocarbons within the prescribed containment area.

The basic idea behind the MPB approach can be simply presented as follows:

- Establish a robust physical barrier between people/environment and the hazardous materials;

- Establish a necessary number of robust backup barriers that will protect people and the environment from the hazardous material(s) if the first one fails; and
- Ensure that necessary actions are taken in order for the barrier to carry out its function.
    - These actions include automatic or human actions to actuate the barrier when it is needed as well as performing necessary testing, maintenance, and repairs to the component or system to ensure its proper function when needed.

The achievement of the above criteria—or the *safety goal*—is not always simple. Offshore oil and gas systems tend to be complex. The barriers may be exposed to substantial forces, due in part to the fluid pressures (either from the petroleum reservoir or from applied service pumping operations), and in part to the size, design and complex nature of the equipment components. It may sometimes be a challenge to identify the boundaries of the physical barrier. So, one of the key ingredients to establishing and maintaining multiple physical barriers is to understand which elements form the primary barrier, and which elements need to be in place or established to form the secondary or backup barrier(s). For example, in CT, regulation and API RP 16ST determine the number and kinds of redundant barriers for specific pressure categories.

It is important to recognize that some physical barriers are naturally *passive* elements—ones that are expected to carry out their safety goal without human action. The state of the passive barriers usually remains unchanged as they perform their barrier function.

Other physical barriers are *active* barriers, which must change their state (open, close, cut, seal) in order to carry out their safety function. Thus, a safe multiple physical barrier system is one where the physical barriers, passive and active, are able to perform their safety function under *all* expected and anticipated conditions. The oil and gas industry uses specific conditions, often described by pressures, to specify the loads that may be placed on the physical barrier(s). Such conditions include the maximum allowable surface pressure (MASP) and the maximum working pressure (MWP).

Furthermore, anticipating these pressures is an important part of the design process. In CT well control system, the CT string and the well control stack bore containment are passive barriers, while the active barriers are rams and the flow safety valve.

Besides the design of the proposed equipment, it is also critical to consider the construction (or installation and testing) of the various components, the operation of these components, and the maintenance of these components. The Argonne Multiple Physical Barrier Approach refers to these actions as four activities—design, construction, operation, and maintenance—or DCOM. In order for any set of multiple physical barriers (MPBs) to succeed, it is critically important that the activities of design, construction (including installation and testing), operation, and maintenance be planned and carried out thoughtfully and deliberately.

Whether passive or active, the physical barriers are components of an overall system. Their safety function in oil and gas facilities is to form a barrier to the uncontrolled release of hydrocarbons or hazardous fluids capable of harming personnel, the environment, and facilities. Contrary to the common misconception that a "barrier" is comprised of equipment that is relied upon only in an adverse situation (in the case of coiled tubing, it is the *well control stack*, or the “BOP”); the MPB approach focuses on the integrity of the elements forming the hydrocarbon-sealing envelope at all times. This concept is widely accepted and is most commonly defined by the NORSOK D-010 standard [2]. In coiled tubing operations, the equipment components that form a barrier must be able to isolate the full cross-sectional area of the well control stack bore ID. This area is typically defined as the area inside the coiled tube, as well as between the OD of the CT string and ID bore of the well control stack (i.e., the annulus). In addition, the coiled tube itself must maintain its mechanical and pressure-containing integrity in order to keep the hydrocarbons and hazardous fluids contained.

Success Path Development

The helpful message in employing success paths lies in not asking, “What can go wrong?” but instead asking, “What *must* go right?” This approach causes a change in the way that we address safety issues from a passive “What can go wrong?” to an active and more detailed description of “What must I/we do right?” It can lead not only to a different set of inspection questions and evaluation criteria in the practices of BSEE inspectors and engineers, but it can shift the industry’s mindset by promoting the overall safety of the equipment and operations. In the evaluation of barriers according to the Argonne Multiple Physical Barrier approach, every barrier is supported by a *success path* of hardware, software, and actions taken by trained and available personnel that are needed to enable it to perform its function.

For a passive component—one which does not need to change its state or involve human action in order to ensure safety—the elements of DCOM are important to its success. The industry recognizes this, and pays significant attention to all aspects of equipment design, construction, operation, and maintenance (e.g., see [3]). An example of a passive barrier in coiled tubing is the CT string, for which the success path involves a requirement to design and configure the string to isolate CT ID pressure/flow path from annulus pressure/flow path; to set up and validate the string to withstand external and internal pressure and loads; and to operate and monitor the string to ensure continued CT body integrity.

For an active component, active hardware and in some cases software systems are needed to make it function. This involves ensuring the presence and operability of the physical components and also the support systems (software, hydraulic power, and human action) required to actuate these components. For example, a pipe ram, whose job it is to close and seal on the outer diameter of the coiled tube in order to isolate the annulus, may under adverse conditions need to hold the hydrocarbon influx pressure in the well to prevent the hydrocarbons from reaching the facility and personnel. The success path for this physical barrier element would need a control system to send an actuation demand to one or more hydraulic valves. These valves should open and allow hydraulic power fluid, stored at high pressure in cylinders under nitrogen gas, to flow to two opposed pistons. Each of these pistons is inside of its own cylinder located on opposite sides of the coiled tubing well control stack. The pressurized hydraulic power fluid would force each piston to move the ram rod forward to advance the specially shaped ram toward the CT workstring and apply compressive force to seal against the coiled tube OD and hold pressure below the ram element. Additional components, such as ram locks, are installed on the pressure-sealing rams to hold the ram in the closed position.

Figure 1 below depicts a success path that Argonne developed to describe and communicate the critical actions and elements that must be present in order for the pipe ram barrier element to perform its critical safety function, which is to close on demand and isolate the annulus pressure. The success path is built based upon the DCOM principle and has the additional element of hydraulic power necessary to actuate it. Note the use of *AND* gates and *OR* gates, where the AND gates mean that <u>all</u> elements must be present and work as desired, while OR gates mean that it is enough for <u>any one</u> of the required and installed elements to work and function to succeed.

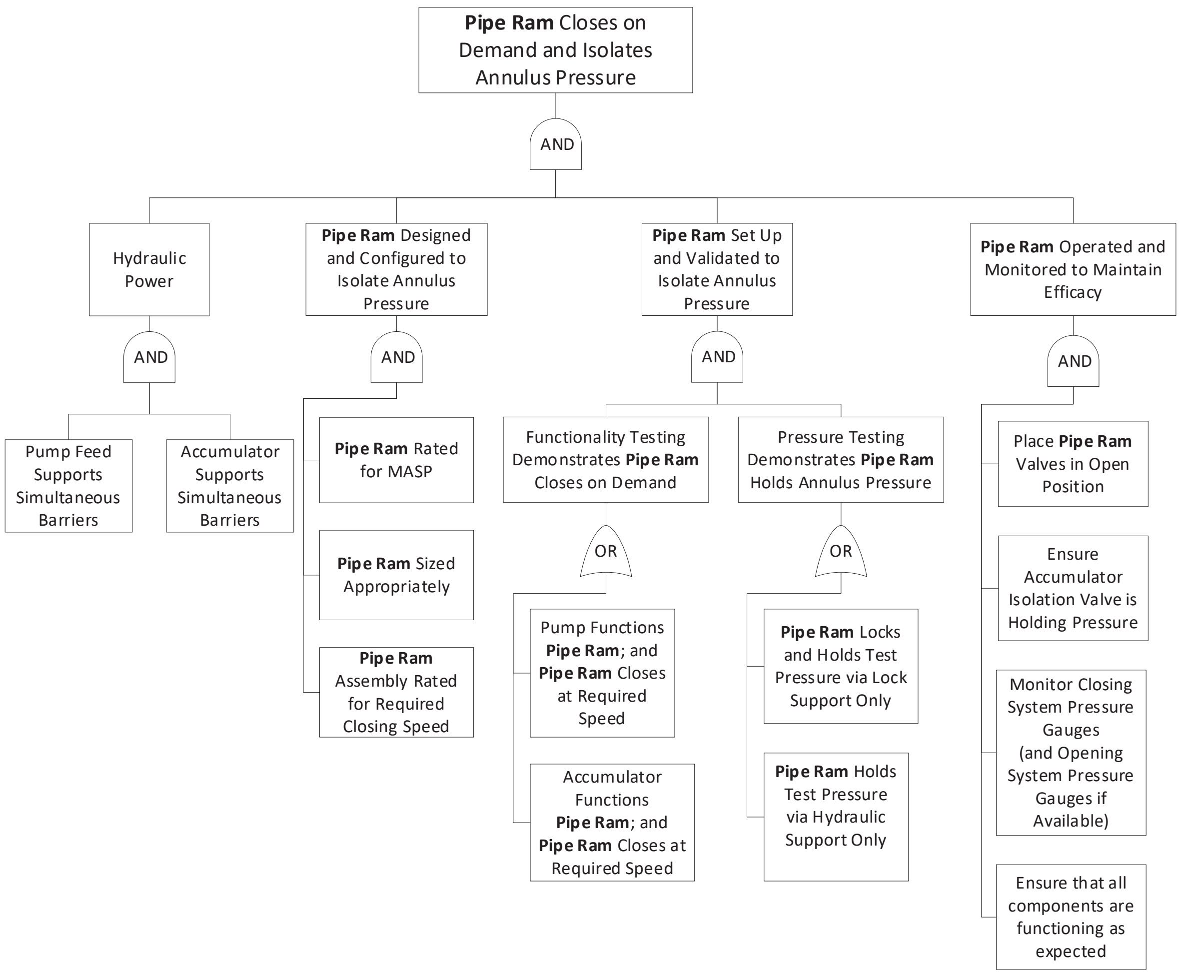

Figure 1: Example success path for the pipe ram barrier element.

As illustrated above, an active physical barrier may need an entire sequence of events to occur in order to perform its safety function. The successful operation of an active physical barrier *needs* the successful operation of the supporting systems to function and be available under all conditions in which the barrier is required to perform its function. This means that supporting systems must be identified and arranged so that they can reliably provide the necessary demand commands, whether electrical or hydraulic power, to the physical barrier at the right time, in the correct sequence for the barrier to perform its function. These systems are called *Success Paths* and if the success paths do not perform their function, then the physical barrier that they support cannot effectively perform its function. This is the fundamental idea of the Argonne Multiple Physical Barrier/ Success Path Approach.

Note that Figure 1 has several different elements collected under a single AND gate. These are hydraulic power and the four activities of design, construction (set-up), operation, and maintenance—or DCOM. These four strings (or *sub-paths*) of activities combine to form a single *Success Path*—as they must all be present to ensure the successful achievement of the safety function: "*Pipe Ram Closes on Demand and Isolates Annulus Pressure.*"

Sometimes a sketch or diagram will show additional complete Success Paths, possibly indicating an alternate way to achieve the safety function. A collection of Success Paths is sometimes called a *Success Tree*. Success trees tend to become rather complex and sometimes expand to several pages as needed to illustrate the full complexity of the situation at hand. The different Success Paths in a Success Tree are often collected under an OR gate to show that each Success Path indicates an alternate method of achieving the safety function.

The more success paths available to meet a safety function, the more reliable the system. And the more likely that the system will succeed in meeting the safety function. In other words, the absence or failure of any component of a success path is an indication that the risk of failure of the system has increased.

In the entire oil and gas industry—and in coiled tubing services in particular, the design, construction, operation, and maintenance success paths are critical to the successful operation of physical barriers. If one physical barrier cannot perform its function, then another physical barrier must be capable of performing its function in order to maintain control of the well and a safe operating configuration.

In the regulation of process safety, success paths and success trees can play a significant role in resolving the differences between the regulator and the industry on matters concerning the details of the equipment and its performance under all expected circumstances.

Independent, redundant, and diverse success paths are more robust and they dramatically enhance the reliability of the active physical barriers that they serve. Higher reliability means higher performance expectation, and lower risk from component failure.

Application of the MPB and Success Paths Approach to Coiled Tubing

Identification of Barriers and Critical Barrier Support Systems
As briefly discussed in the Technical Scope Section of this report, Argonne identified a number of critical barriers in coiled tubing operations. As Argonne discovered, what constitutes a barrier can be a combination of barrier elements—for example, the combination of ram functions, the coiled tubing string, and the downhole flow check assembly, where applicable—to ensure a seal across the ID bore of the well control stack. The combinations of barriers vary by design (i.e., coiled

tubing service vendor's choice) and by regulatory requirement for the specific conditions present at a given well (see Appendix A).

The diagram below illustrates a typical coiled tubing system installation and points to some of the well control barrier components, such as the coiled tube, the well control stack (which includes rams and a kill line inlet), the flow tee, pipe ram below the flow tee, and the wellhead (or "tree") valve.

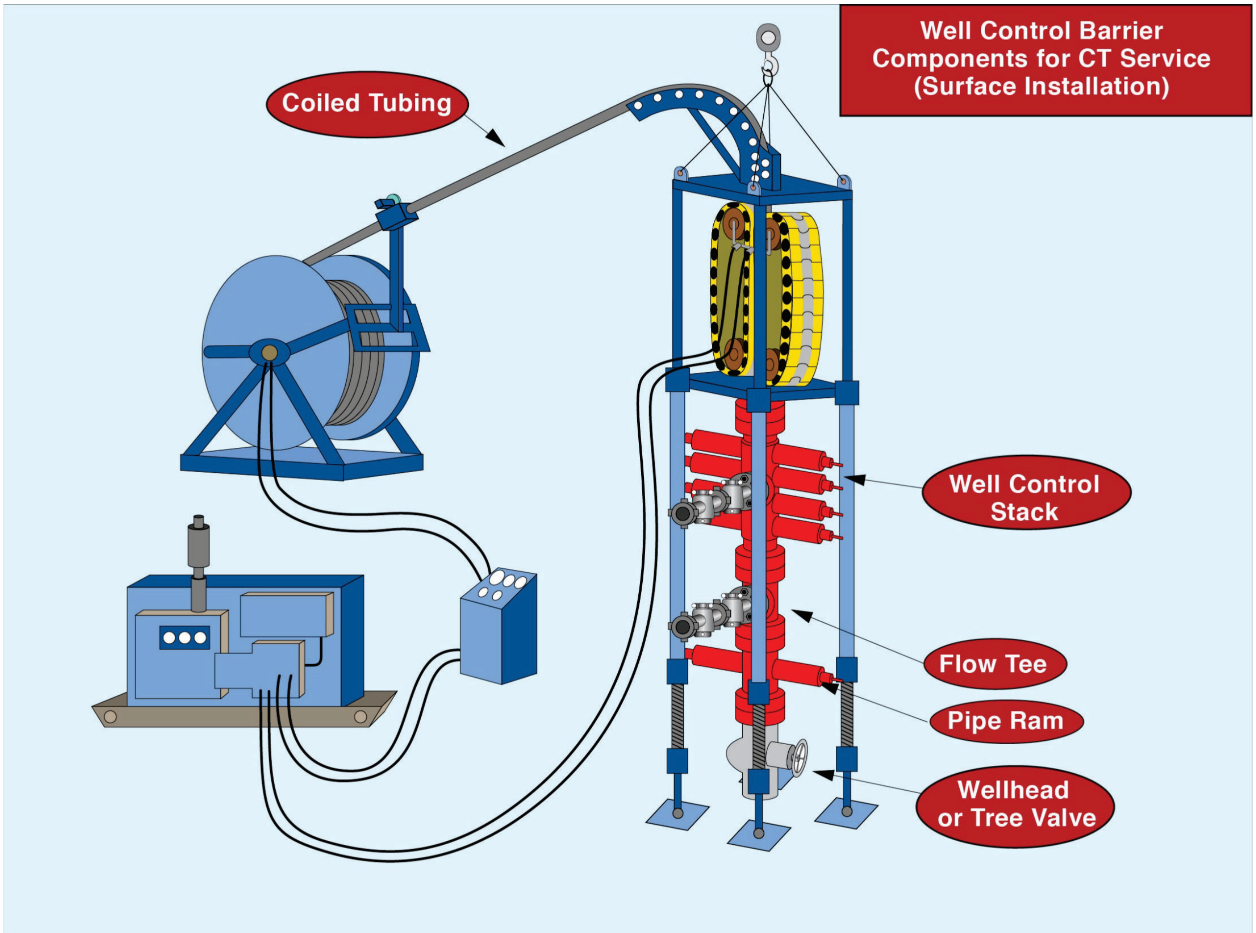

Figure 2: Typical coiled tubing setup that shows well control barrier components. Coiled tubing system diagram courtesy of SAS Industries, Inc.

In addition, Argonne identified elements that provide critical support to the physical barriers required for well control. These components include the coiled tubing reel, the tubing guide arch, the injector, the stripper assembly, the prime mover, the control console, and others. These elements are shown in Figure 3.

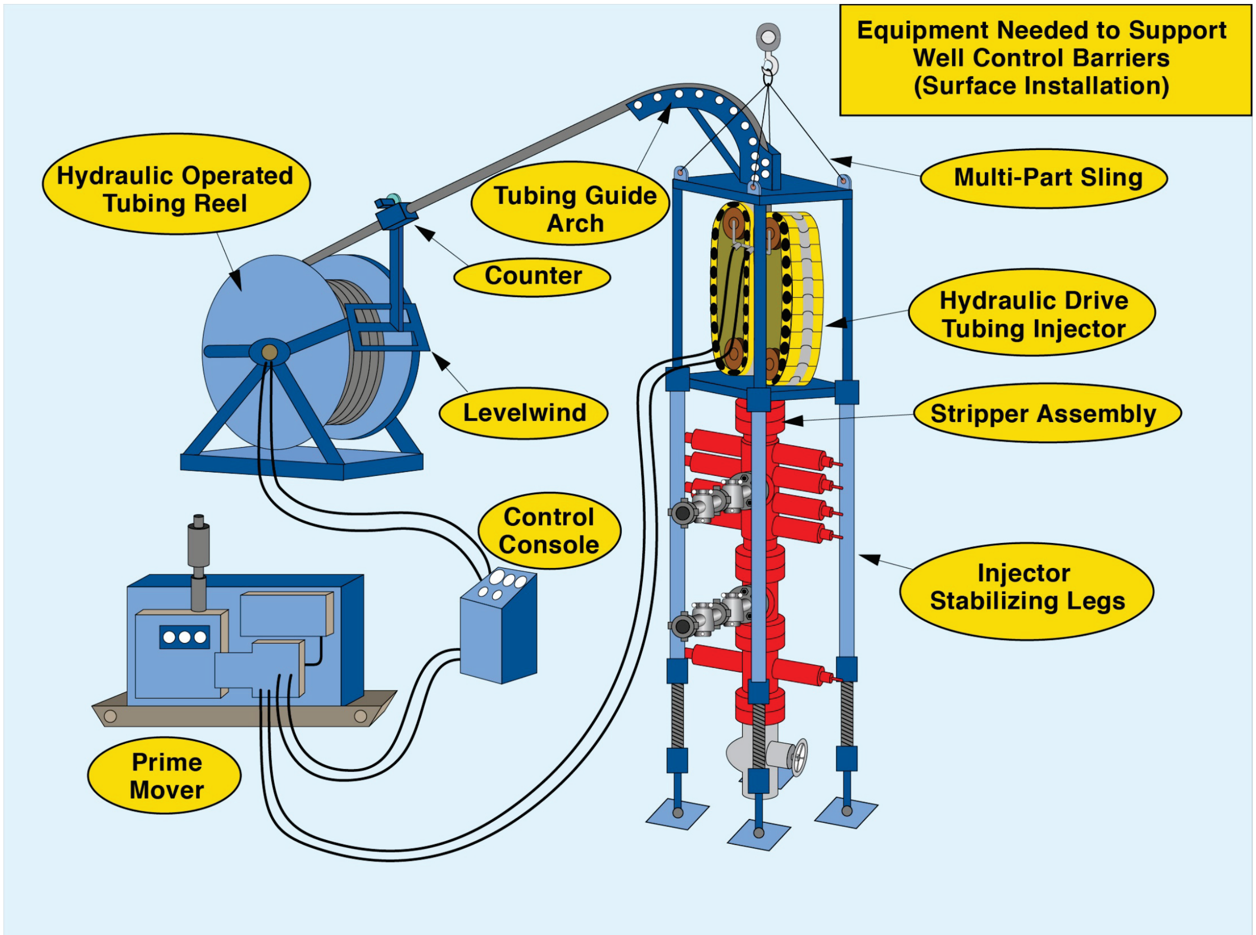

Figure 3: Typical coiled tubing setup that shows well control barrier component support elements. Coiled tubing system diagram courtesy of SAS Industries, Inc.

As part of this study, Argonne evaluated what could qualify as a barrier and what circumstances called for a specific number of redundancies. One of the later Sections of this report describes the Failure Modes, Effects, and Criticality Assessment (FMECA) technique that was employed in concurrence with the MPB and Success Paths approaches. Through these analyses, Argonne devised a way to describe the acceptable barrier configurations for a given situation. The illustration below is an example logic diagram that shows the barrier requirements for coiled tubing equipment setup under specific pressure conditions. This particular diagram corresponds to an acceptable setup for a 1st Edition API RP 16ST Pressure Category 3 (PC-3) condition, with MASP from 3,500 psig to 7,500 psig (see Appendix A).

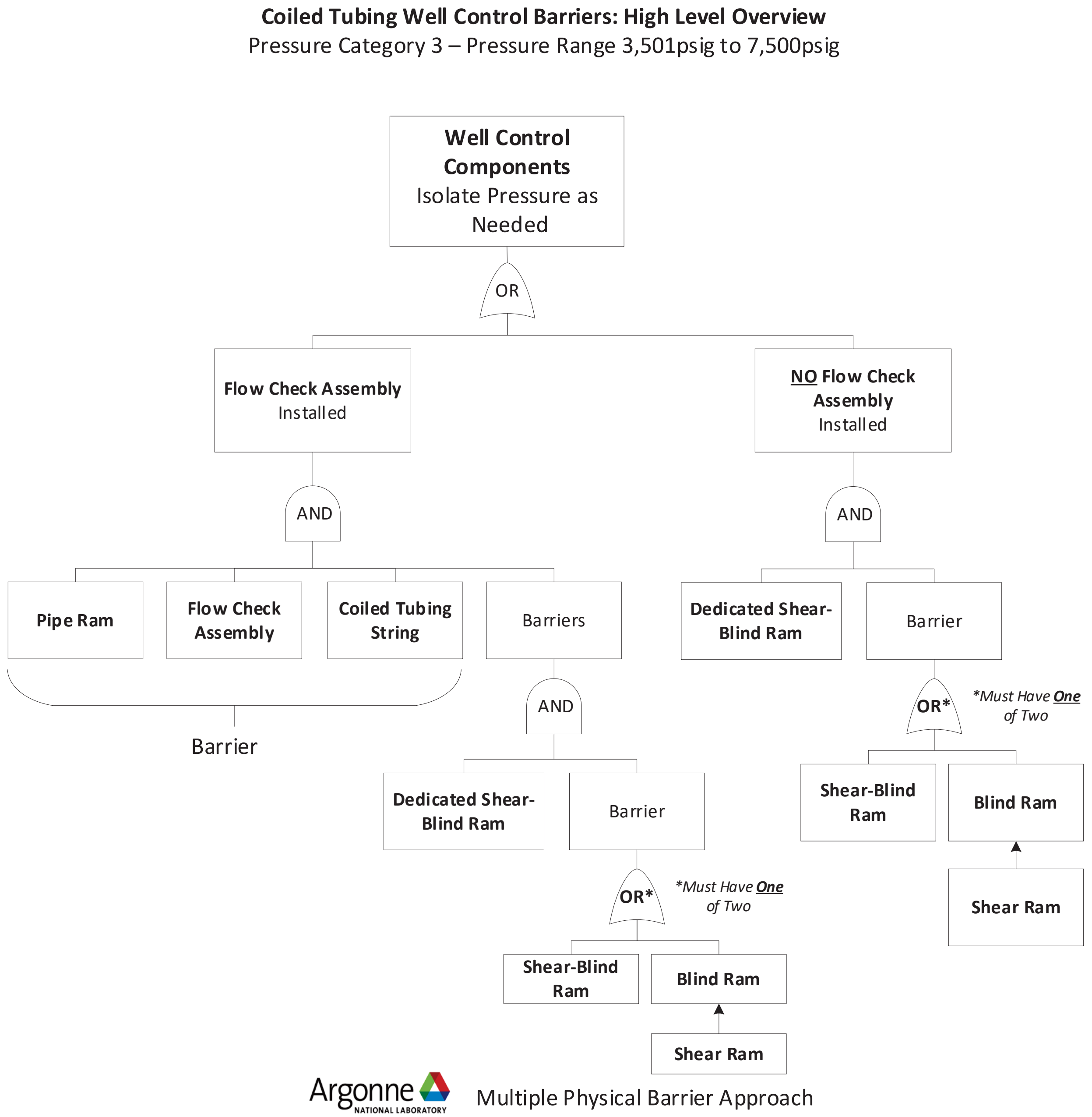

Figure 4: Barrier requirement diagram according to API RP 16ST PC-3.

This diagram depicts the options available to the operator for installing coiled tubing equipment in compliance with the proposed 2nd Edition of API RP 16ST,[4] which allows a number of options for installed physical barrier elements in the coiled tubing well control stack. Because of the high pressure in PC-3 per API RP 16ST, the barrier requirements must include a minimum of two

[4] Per the CFR a flow check is required (30 CFR 250.616(a)(4) or 30 CFR 250.1706(a)(4), Revised as of July 1, 2017, [4]). An alternate procedure or equipment request would be required for a configuration where a flow check is not installed.

barriers, one of which must be a *dedicated* shear-blind ram. The word “dedicated” means that it is the shear blind ram that is installed as close as practical to the wellhead and must be able to shear the coiled tube and seal the well cavity to prevent hydrocarbons from reaching the facility and personnel. Note that the dedicated shear-blind ram is operated through a hydraulic power fluid system completely independent of that used for the primary well control stack rams.

The below diagram corresponds to an example of a setup that is compliant with the requirements called for in Figure 4.

In Figure 5, the required barriers[5] are:

1. The combination of the flow check assembly, the coiled tubing string, and the pipe ram;
2. The combination of the shear ram and the blind ram; and
3. The Dedicated shear-blind ram.

Table 2 below describes the role of each barrier depicted in Figure 5 and provides brief information regarding its main function and the support equipment required to actuate it. The color-coding for CT Barrier Components 1, 2, and 3 corresponds with the color coding in the barrier diagram in Figure 5—the CT Barrier 1 components are colored in orange; the CT Barrier 2 components are colored in darker blue, and CT Barrier 3 is colored in lighter blue. The items with no color (or white color) are ones that are part of the coiled tubing equipment but are not relied upon in well control situations. The items in gray, such as the wellhead components, are ones that are outside the scope of coiled tubing operations, pertinent regulations, and API RP 16ST.

[5] Note that this list includes three required barriers instead of two. This is in accordance with API’s current debate on accepting the downhole flow check valve as a barrier given the fact that it can leak. This is discussed further in the Findings Section of this report.

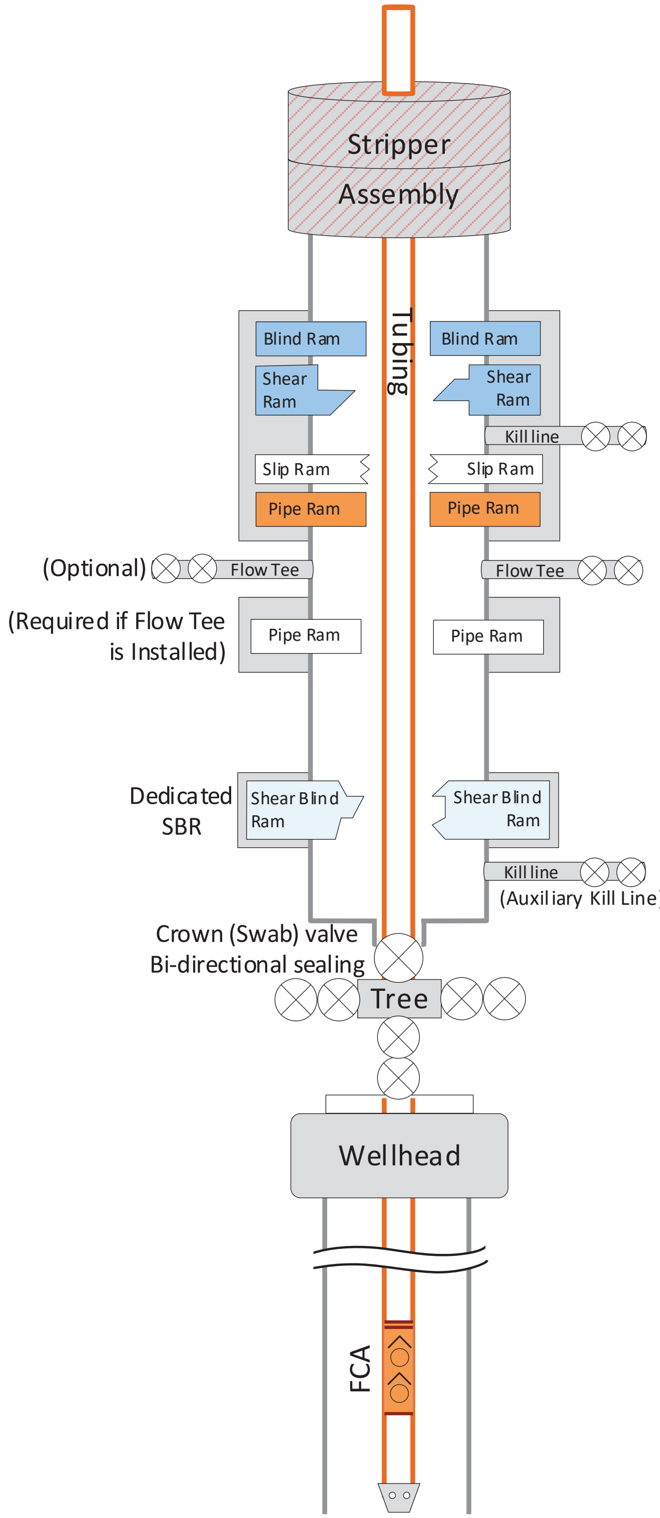

Figure 5: Example of a CT well control stack configuration compliant with draft 2nd Edition of API RP 16ST barrier requirements for PC-3.

Table 2: Example of a list of barriers, their functions, and support equipment for a well control stack configuration described in the Figure above.

	Barrier (component) / Operational Equipment	Main Function	Support Equipment
CT Barrier 1 Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Hydraulic Power, Ram Lock(s)
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems
CT Barrier 2 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Hydraulic Power, Ram Lock(s)
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Hydraulic Power
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Hydraulic Power, Seals on Blades, Ram Locks
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Hydraulic Power
	Slip Ram	Secures CT Within Well Control Stack	Hydraulic Power, Ram Lock(s)
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - Passive Barrier Component

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.

**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Wellhead Components (Not Part of CT Barrier	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli

The sequence of barrier actuation for this example is also shown in Table 3:

Table 3: Barrier actuation sequence in a well control situation for the configuration discussed in the above example.

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Shear Ram + Blind Ram
Third	Shear-Blind Ram ("Dedicated" SBR)
Fourth (Beyond the scope of 16ST)	CT Drop Procedure + Close Xmas Tree

A full list of the barrier configurations in coiled tubing well control stacks, together with the table descriptions of the barriers present in each configuration (similar to Table 2) is identified in Appendix A.

Success Path Discussion

As mentioned previously in this report, within the scope of this project, Argonne developed success paths for the well control barrier elements and their support equipment. A success path for the aforementioned Pipe Ram barrier element as part of the well control stack, which is designed to seal against the outer diameter of the coiled tube and provide isolation of the annulus pressure, is shown below.

Figure 6 shows a success path that accompanies the operation of the pipe ram found in a typical coiled tubing well control stack configuration, including the one discussed above and depicted in Figure 5. Figure 6 illustrates that successful operation of a physical barrier element such as the pipe ram, defined by its critical s*afety function* as "Pipe ram closes on demand and isolates annulus pressure," requires a number of elements, hardware, software (in some cases), and human action to perform successfully. In addition, the information below the success path discusses alternate success paths (that call for alternative physical barriers) in the event that the pipe ram fails. The *critical support system* section is a list showing one or more elements critical to the barrier's ability to perform its safety function. Lastly, the threat scenario can help the reviewer to understand the impact of external factors on the physical barrier's ability to perform its critical safety function. A framework of this type enables all involved parties to understand the things that are needed to succeed—that is the various success paths needed to achieve the critical function of closing and holding (in this case) annular pressure.

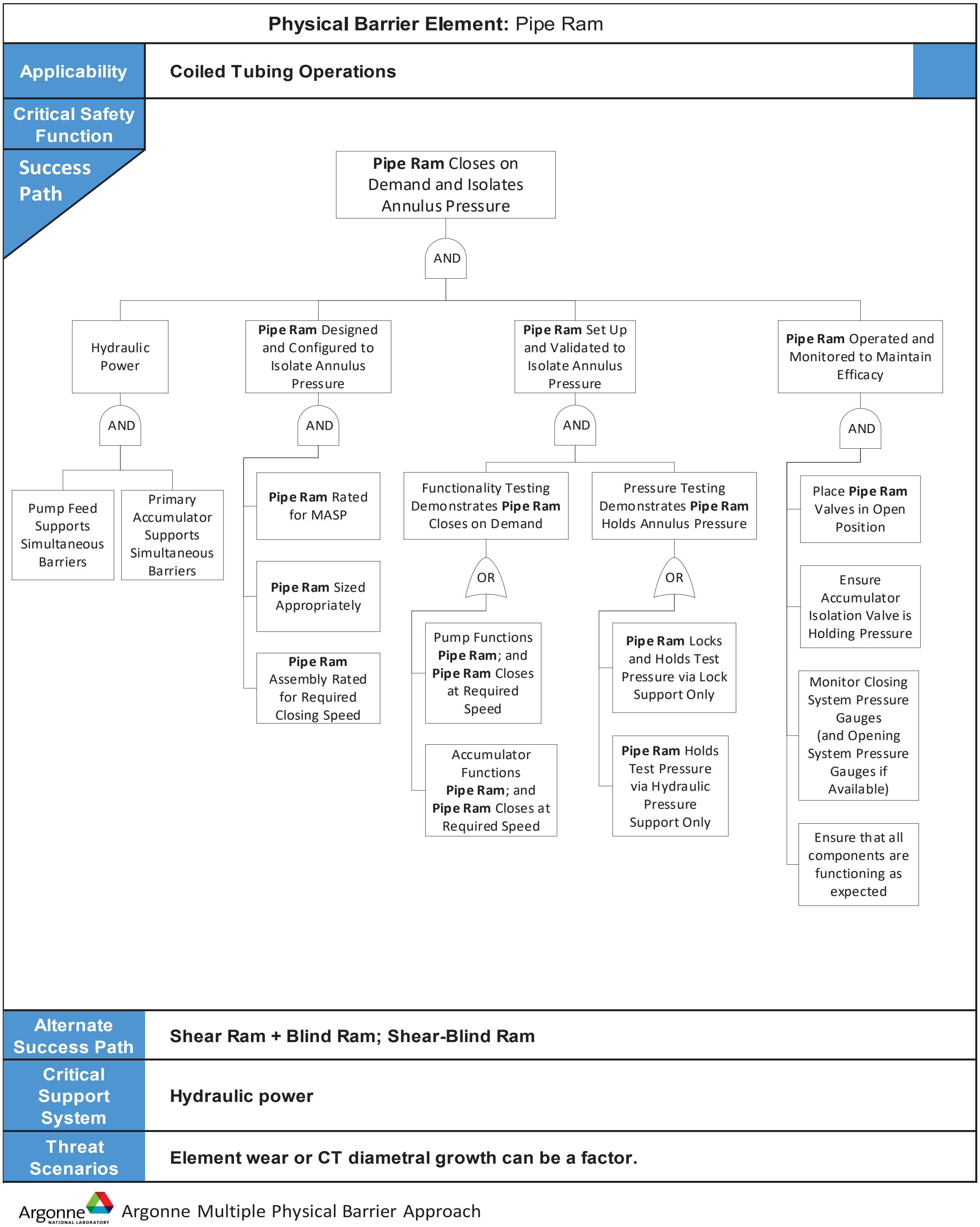

Figure 6: Pipe ram success path.

Coiled Tubing Equipment and Operations Inspection Checklist
Once the success paths for the physical barriers and the critical support system were developed, Argonne, together with Alexander Sas-Jaworsky, moved on to revising the coiled tubing equipment and operations inspection checklist. Despite its name, it should be noted that this checklist could potentially be used by BSEE not only for inspection, but also for confirming the compliance of the use of particular equipment proposed in a given application for permit to modify (APM) or it can have other uses by BSEE engineers. While the contents of the Checklist are far more specific and address individual elements on the Success Path in greater detail (for example, for a well control stack barrier element, the Checklist contains more specific requirements such as appropriate size, appropriate chemistry of the elastomeric sealing elements, etc.), each item on the checklist can be mapped back to elements on a pertinent success path from the list of those provided in Appendix A and vice-versa.

The full Checklist is provided in Appendix B.

Application of the Risk-Informed Inspection Tools

The technical scope of this Project called for the development of tools aimed at improving BSEE's knowledge of the coiled tubing equipment and systems. The tools developed within the scope of this project (e.g., Success Paths, barrier diagrams, and the Inspection Checklist) purposefully ease communication of the critical safety elements required for safe coiled tubing operations. This communication can happen at all levels, including communication within the industry (e.g., operators or service vendors and manufacturers), between the operator and BSEE, as well as between different sub-organizations within BSEE.

Furthermore, these tools provide the BSEE inspectors and engineers with an introductory understanding of the importance of thinking about physical barriers when addressing the safety of a given coiled tubing configuration. For this reason, the discussion of the Multiple Physical Barrier and Success Path approach presented in Module 0 of the BSEE Coiled Tubing Equipment and Operations Training Courses conducted by Argonne preceded the discussions about the actual equipment. In turn, the subsequent discussions circled back to thinking about how a particular piece of equipment affects physical barriers and the containment of hydrocarbons or other hazardous material. For example, where a downhole flow check assembly is used as a barrier for isolating the wellbore fluids from the ID of the CT workstring, the flow check assembly is pressure tested prior to deployment to confirm pressure-sealing integrity. However, the Success Path process identified concerns that if the CT flow check assembly is susceptible to leakage, then it cannot serve as a barrier with confidence. The following subsections describe the BSEE coiled tubing equipment and operation training courses in detail.

BSEE Coiled Tubing Equipment and Operations Training

Training Material
As described in the Technical Scope section of this report, Argonne and SAS Industries, Inc. prepared the training material for use in the 32-hour training courses on the topic of coiled tubing equipment and operations. This material was designed to focus on application of the Multiple

Physical Barrier approach and keeping in mind the process equipment—and the physical barriers—in making sure that the hydrocarbons and other process fluids remained properly contained and are not released into the environment. Furthermore, despite including considerable detail on the operation of coiled tubing equipment, the material was designed specifically for BSEE inspectors and engineers to be able to have enough introductory knowledge that an abnormal condition or an anomaly can be detected during an inspection or while reviewing an APM, such that an unsafe situation can be avoided.

A summary of each item provided in the training course material together with its purpose and learning objective is provided in Appendix C.

Preliminary Training Course

Prior to conducting the "live" training courses on coiled tubing equipment and operations, Argonne travelled to the BSEE GOMR office to conduct a preliminary course. The purpose of the preliminary course was to present the training material in its entirety to the BSEE subject matter experts and recommendation-makers with respect to this project and also to test it on a group of BSEE inspectors and engineers who were asked to audit the course (or parts of it) given their availability.

Judging by the feedback received during the daily evaluations and the course-end survey, the material presented during the preliminary training was viewed by most as being of the appropriate operational and technical content. BSEE participants deemed the level of complexity of the technical material and the presentation style conducive towards achieving a positive learning experience. The retention of the learned material by most participants was evidenced through their avid participation in the exercises designed to test and reinforce the learning process. This reaction was more or less expected by Argonne, which was one of the reasons to forgo the addition of tests and quizzes to the training course in the initial design.

At the end of the preliminary course, when the material was presented in its entirety, the BSEE inspection SME on this project requested that Argonne add training material to address pressure testing procedures. In response, Argonne limited the scope of several other modules by taking out material that was deemed less pertinent to BSEE operations (e.g., details about coiled tube manufacturing) in order to make time for the pressure testing material. This new material became the new Module 7, and what was Module 7 previously—Introduction to Coiled Tubing Well Control Barrier Equipment Inspection Guidelines—became the new Module 8.

It should be noted that the feedback received during this preliminary course may have been positive and the retention of the material was perhaps above average because a few of the BSEE staff that were present in the audience had been participating in the development of this material. The actual challenge lay in presenting the material to a live audience of BSEE inspectors and engineers within district offices who had not seen this material before. Argonne encountered this challenge during the subsequent first "live" training course.

Live Training Courses
Argonne conducted the Coiled Tubing Equipment and Operations Training Course in three locations across the Gulf of Mexico Region (one Eastern, one Central, and one Western) to reduce the travel costs associated with the training by locating an offering within 50 miles of each District office.

During the presentation of the first "live" training it became evident that without the presence of more animated participants who would ask a number of questions, interact with the instructor, and by doing so involve other participants in the discussion, it was difficult to capture the attention of the participant group as a whole. There also seemed to be a misunderstanding regarding the preliminary knowledge that one needed to possess in order to be able to understand the material presented in this course. It should also be noted that more than half of the participants in this course had between two and five years of experience working in the field, which may have contributed to a less than ideal learning experience. This created a situation where it was unclear to the Argonne presenters whether the material was being retained and at what level, which prompted the decision to add quizzes to the initial Modules that were not followed by exercises and a pre-quiz designed to refresh the participants' knowledge on the requirements of the BSEE regulations pertinent to coiled tubing. Naturally, the feedback provided in the daily evaluations and the course-end survey had mixed reviews on the presented material and the individual participants' expectations of the course.

During the second "live" course, it was evident that the addition of the exams helped to focus the participants' attention on the material and provide them a better understanding of the scope of the expectations of the course, which was reflected in the feedback from the participants.

The third and final live course further supported the observation that the preliminary knowledge and experience had high impact on understanding the presented technology and methodology. Coincidentally, more than half of the participants in this course had more than ten years of experience in the oil and gas activities. Additionally, the material was retained well by participants of various backgrounds of expertise, ranging from well operations to production.

Industry Impact

This report has mainly focused on the impact and application of the tools developed during this Project on BSEE's ability to promote safer practices in the offshore coiled tubing-related activities. However, the application of the Multiple Physical Barrier and Success Path approach has also made significant impact on how the industry views what is considered to be a safe practice.

Impact on Development of the 2nd Edition of API RP16ST

Failure Mode, Effects, and Criticality Analysis (FMECA)
Argonne worked with the API SC16 Task Group 5, which developed API RP 16ST "Coiled Tubing Well Control Equipment Systems," on providing technical support to evaluating the robustness of the recommended safety elements. To ensure the integrity of the physical systems that support or comprise the physical barriers or other critical operational components, the Task Group members

proposed performing a Failure Modes, Effects, and Criticality Assessment (FMECA), the results of which would be included in the justification of recommendations in the 2nd Edition of API RP 16ST that is expected to be balloted in CY2018.

Argonne's recommendation involved utilizing the FMECA to identify the effects of a component and/or system failure on the physical barriers; i.e., clearly indicate the failure effect and other consequences in terms of potentially compromising the physical barriers that protect from release of hydrocarbons.

To demonstrate the relationship of the FMECA to the success paths, Argonne linked the two by including a requirement in the success trees to *"Ensure that all relevant components are functioning as expected"* as part of each physical barrier's success path. This requirement can be interpreted as having an AND gate under it that contains individual key systems or components that must be in good working condition in order for this physical barrier to succeed. An example of the linking of the FMECA to the success paths is provided in Figure 7.

The elements under the "*Ensure that all relevant components are functioning as expected*" AND gate are analyzed in the FMECA and evaluated in terms of the FMECA metrics discussed below.

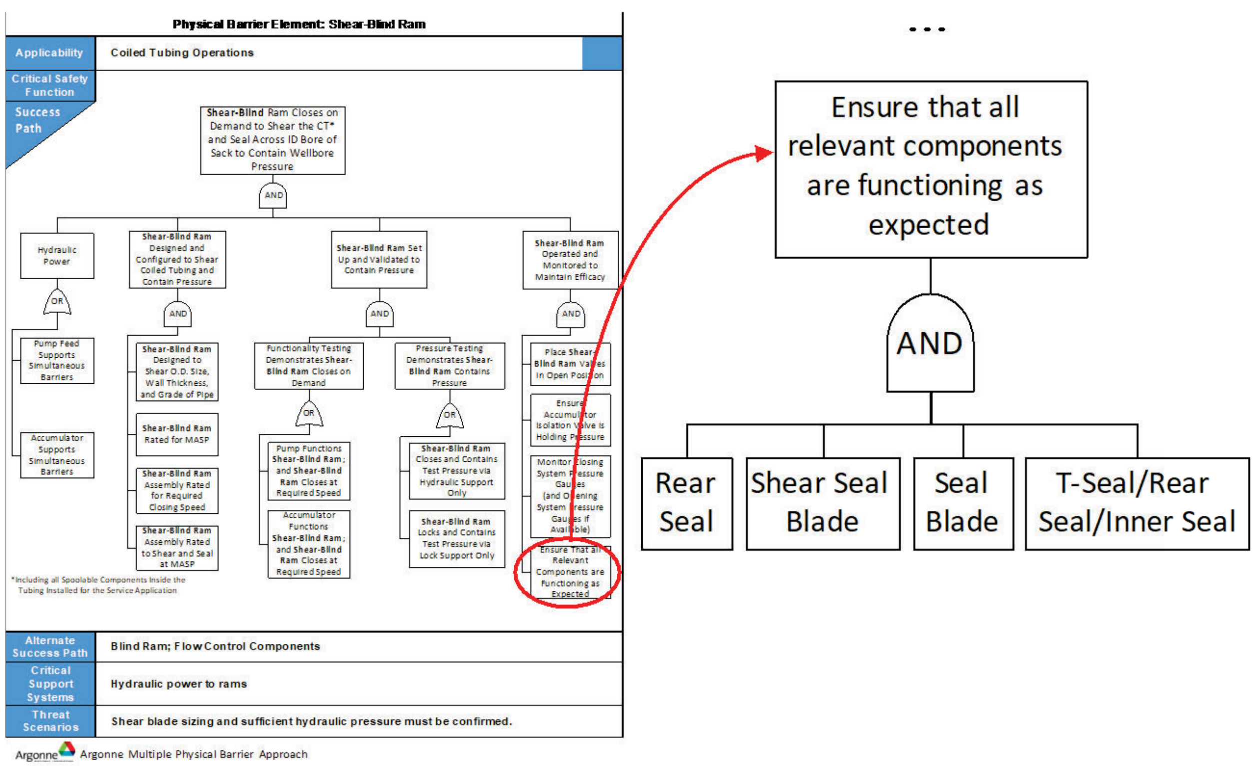

Figure 7: An example of the relationship between a barrier success path and barrier components evaluated in the FMECA.

The risk in terms of the safety and integrity of equipment and barriers included in the Success Path were determined using Argonne's approach for the FMECA, which included evaluating the effects of component failures on barrier integrity by considering the following metrics for each component analyzed:

- Identifying component failure modes for each major component;
- Determining the local consequence of each failure mode;
- Determining the consequence of failure modes on the effected barrier(s);
- Identifying cause(s)/mechanism(s) of failure;
- Ranking the consequences of each failure mode in terms of its effects on barrier(s);
- Assigning an occurrence ranking for each failure mode (based on average failure data provided by the industry);
- Calculating a risk ranking for each failure mode (which is the product of consequence- and occurrence ranking);
- Identifying failure detection mechanisms; and
- Identifying failure prevention controls.

The FMECA was developed within the API SC16 TG-5 Task Group, which included members from coiled-tubing component vendors, operators, experts in the field, and representatives from the Argonne, who served as the facilitators. When evaluating a given system, a consensus had to be reached by the group for determining the importance of each failure (i.e. its consequence, occurrence, and risk rankings).

The consequence, occurrence, and risk ranking are described in more detail here to provide clarity on each term and how/if they were able to be determined.

The *consequence ranking* as suggested by Argonne is provided in Table 4 below. It ranges from a ranking of "1" in which the failure being evaluated has no direct impact on the functionality of the barrier, to a ranking of "5" in which the final barrier to the environment has been disabled. Each failure mode identified was assigned a value from 1 to 5 based on a consensus of the FMECA group members.

Table 4: Example Failure Consequence Ranking

Consequence Ranking	
Rank	**Description**
1	System degraded but operational, no direct impact on barrier
2	System disabled, but alternative system available, no direct impact on barrier
3	System disabled/degraded with barrier degraded but operational
4	Barrier disabled, but alternative barrier(s) remains
5	Barrier(s) disabled, no barriers remaining

The ***occurrence ranking*** was also scaled to a 1 to 5 ranking system, where a ranking of "5" represented the most frequent types of events and a ranking of "1" represented the least frequent events. The actual frequency of each ranking was to be determined once representative data for the failure modes being considered in the FMECA were obtained. For events in which no data were available, the expectation was that expert judgment would be used to determine the occurrence ranking. While conducting the FMECA, it became apparent that sufficient data to determine the occurrence ranking of each failure was unavailable. With such a lack of data, it was also difficult to come to consensus on an occurrence ranking based on expert judgment. Due to these issues, the FMECA evaluations were performed for all of the major components, but the occurrence ranking for each failure mode identified was assigned a "to be determined (TBD)" ranking.

The ***risk ranking*** is the product of consequence and occurrence; i.e. a failure that occurs most frequently and has highest consequence in terms of barrier failure is calculated to have the highest risk ranking. Due to the consequence and occurrence ranking scales, the risk ranking values ranged from 1 to 25. Table 5 below provides an example risk ranking reference structure, where a decision can be made for classifying component failure risk as "Low", "Medium" or "High". The "Low", "Medium", and "High" assignments provided in the table are only provided as examples. The actually assignments were not determined during the FMECA due to the inability to assign occurrence rankings (explanation provided above in the "Occurrence Ranking" description).

Table 5: Example Failure Risk Ranking

Risk Ranking						
		Occurrence Ranking				
		1	**2**	**3**	**4**	**5**
Consequence Ranking	**1**	1	2	3	4	5
	2	2	4	6	8	10
	3	3	6	9	12	15
	4	4	8	12	16	20
	5	5	10	15	20	25

Low	Medium	High

Despite the lack of failure occurrence data, this study forced the SC16 TG-5 members to rethink the meaning of risk and safety and helped to make a number of safety recommendations that are included in the 2nd Edition Draft of API RP16ST.

Findings and Discussion

The Importance of Considering Risk-Informed Decision-Making Concepts

The use of an approach that involves thinking about multiple physical barriers in order to evaluate and ensure safety has proven effective in various industries that involve high-risk activities. The

Argonne Multiple Physical Barrier and Success Path approaches have been applied to a number of activities that BSEE oversees, for example the BOP risk assessment study performed in 2015 [5] and the BSEE-supported JIP focused on the application of Success Paths to plug and abandonment operations in 2017 [6]. In the case of coiled tubing specifically, the approach of considering the physical barriers and success paths that assure the critical functions of these barriers has shown to be useful in the ability to make sure that the equipment is set up properly and functioning safely. The coiled tubing industry has recognized this approach and has moved to recommending additional redundant safety systems that will assure a physical barrier between the hydrocarbons, and the people and the environment. Furthermore, this concept has also been found to be useful to BSEE when presented with or thinking about the safety of a coiled tubing system used offshore.

The Need for Redundant Safety Elements

One of the major findings that indirectly resulted from this study was the American Petroleum Institute's decision to recommend including a *dedicated accumulator system* that will support the *dedicated shear-blind ram*. The dedicated shear-blind ram is a physical barrier installed as close as practical to the wellhead and needs to be able to cut through the coiled tube and seal across the annulus in the event of uncontrolled flow and when other well control methods have failed. The 2nd Edition Draft of API RP 16ST is expected to go to ballot before the API committee during CY2018, and it will include recommendations on the options of accumulator system configuration that will ensure the true redundancy of the dedicated accumulator bottles.

Reclassification of the Stripper Assembly

As discussed in previous sections of this report, the definition of a barrier requires that it provides a seal and does not allow leaks into the environment. This distinction influenced the reclassification of the stripper considered to be a continuously degrading operational component classified as a pressure control device only when used for well control. In normal operations, the role of the stripper assembly is to provide a safe working "envelope," although it is recognized from operating experience that it tends to allow fluids to reach the environment (for example, bubbling and allowing fluids on the coiled tube retained by surface tension to escape). However, in well control situations, the physical barrier element that is able to provide a positive isolation of the annulus is a pipe ram (or pipe ram element in a pipe-slip ram) or a blind ram (or a blind sealing element in a shear-blind ram).

Recommendations

Based on the observations and findings discussed throughout this report, Argonne recommends the following:

1. It will be beneficial to both BSEE and the coiled tubing community that BSEE considers the benefits of risk-informed approaches when evaluating or inspecting coiled tubing equipment or operations. It is shown that using the Multiple Physical Barrier and Success Path approaches can help to foster safety on the offshore oil and gas facilities that utilize the coiled tubing technology. One example is the demonstrated benefit of considering physical barriers in the 2nd Edition of API RP 16ST.

2. The reaction and feedback of the participants of the Coiled Tubing Equipment and Operations training course showed the benefit of BSEE inspectors and engineers possessing the necessary and detailed technical knowledge about the equipment. Furthermore, the shift in attitude towards thinking about physical barriers reinforces the safety focus. Argonne recommends that BSEE offer this course to its staff on a periodic basis.

3. The Checklist presented to the BSEE Training Course participants was considered to be a useful tool in assessing coiled tubing equipment and operations by the training course participants. However, it must be recognized that the items identified in it may not encompass every scenario. Argonne recommends that BSEE use the Checklist as a tool and continues to add items to it based on individual inspectors' and engineers' experience.

4. This study included a Failure Modes, Effects, and Criticality Assessment (FMECA) of the coiled tubing equipment for the benefit of developing the 2nd Edition of API RP 16ST. It was initially planned that Argonne would be provided component reliability data in addition to failure modes and effects (i.e., consequences with respect to physical barriers), but after several iterations in conducting this study, it was interrupted. Currently, the oil and gas companies are reluctant to share their component failure information. This reluctance is partly due to fear that this failure data might be released to the public or may bear regulatory implications. However, in the process of conducting the FMECA, a number of significant safety findings, described in this report, were made. In order to obtain the full benefits of this analysis, Argonne recommends that BSEE support any future effort by the industry to collect and analyze reliability data in order to gain insights into the safety of the coiled tubing equipment. This will allow the improvement of the safety features and will help to ensure safety in coiled tubing operations.

Conclusions

The methodology behind the study presented in this report had been developed through an extensive collaboration between BSEE and Argonne. This project is one of the first ones where this methodology is being applied to the offshore operations, and where the effects of applying this methodology can potentially be evidenced through future improvements in process safety on the offshore facilities. As mentioned in the introductory sections of this report, the focus on process safety is important because in process safety, the risk is directly related to barrier assurance. It is understood that if the barrier is breached, the consequences on the personnel, the environment, and facility are likely to be severe. The application of the risk-informed decision-making tools is the beginning of a shift in the attitudes of both the industry and the regulator towards evaluating process safety. This ongoing risk-informed collaboration between the offshore oil industry and BSEE, with Argonne acting as a neutral technical intermediary, is, in itself, a significant development, and could act as a model for similar risk-informed collaborations in the future.

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Appendix A

Coiled Tubing Configuration Diagrams and Success Paths

Coiled Tubing Well Control Barrier Success Paths

(updated on March 9, 2018)

The diagrams in this document outline a network of the minimum well control barrier configurations required for safe and practical management of Coiled Tubing Well Intervention Well Control.

A well control barrier can be a single piece of equipment, but is often a combination of components that isolate the pressure in the annulus as well as the inside diameter (ID) of the tube.

API RP 16ST Para. 4.2.4 (1st Edition) defines an acceptable coiled tubing well control barrier as follows:

> *"A CT well control barrier is defined as a tested mechanical device, or combination of tested mechanical devices, capable of preventing uncontrolled flow of wellbore effluents to the surface. Tested barrier(s) shall be incorporated in the well control stack and bottomhole assembly for the prescribed service.*
>
> *The following mechanical devices, or combination of mechanical devices, are CT well control barriers:*
>
> *a) The combination of an annular sealing component, or a pipe ram seal component, and a flow check assembly installed within the CT BHA;*
>
> *b) a single blind ram and a single shear ram;*
>
> *c) a shear-blind combination ram."*

Barriers work in conjunction with critical operational components and are supported by their respective control systems needed for reliable and repeatable service. Note that through the Success Path Process Evaluation, the Stripper Assembly is found to be a "continuously degrading operational component" and is reclassified as a "pressure control device" when used in well control applications.

The minimum well control barrier requirements vary by well Pressure Category (PC), as described below:

For PC-0 conditions, where there is no pressure present at the surface of the well, a minimum of one well con-trol barrier is required.

For PC-1 (1 - 1,500 psig) or PC-2 (1,501-3,500 psig) surface well pressure conditions, a minimum of two well control barriers are required.

For PC-3 (3,501-7,500 psig) or PC-4 (7,501-12,500 psig) surface well pressure conditions, a minimum of three well control barriers are required. The exception to this recommendation is where two Shear-Blind Ram (SBR) well control barriers are installed within the coiled tubing well control stack, in which case two SBRs are suffi-cient.

1. Barriers Required for PC-0: No Pressure at the Surface of the Well

Success Path

The diagram below shows the combinations of well control barriers necessary for reliable and repeatable con-tainment of wellbore pressures and fluids during coiled tubing well intervention operations. These combina-tions can lead to a series of different operational configurations, as shown in the following diagrams.

Coiled Tubing Well Control Barriers: High Level Overview

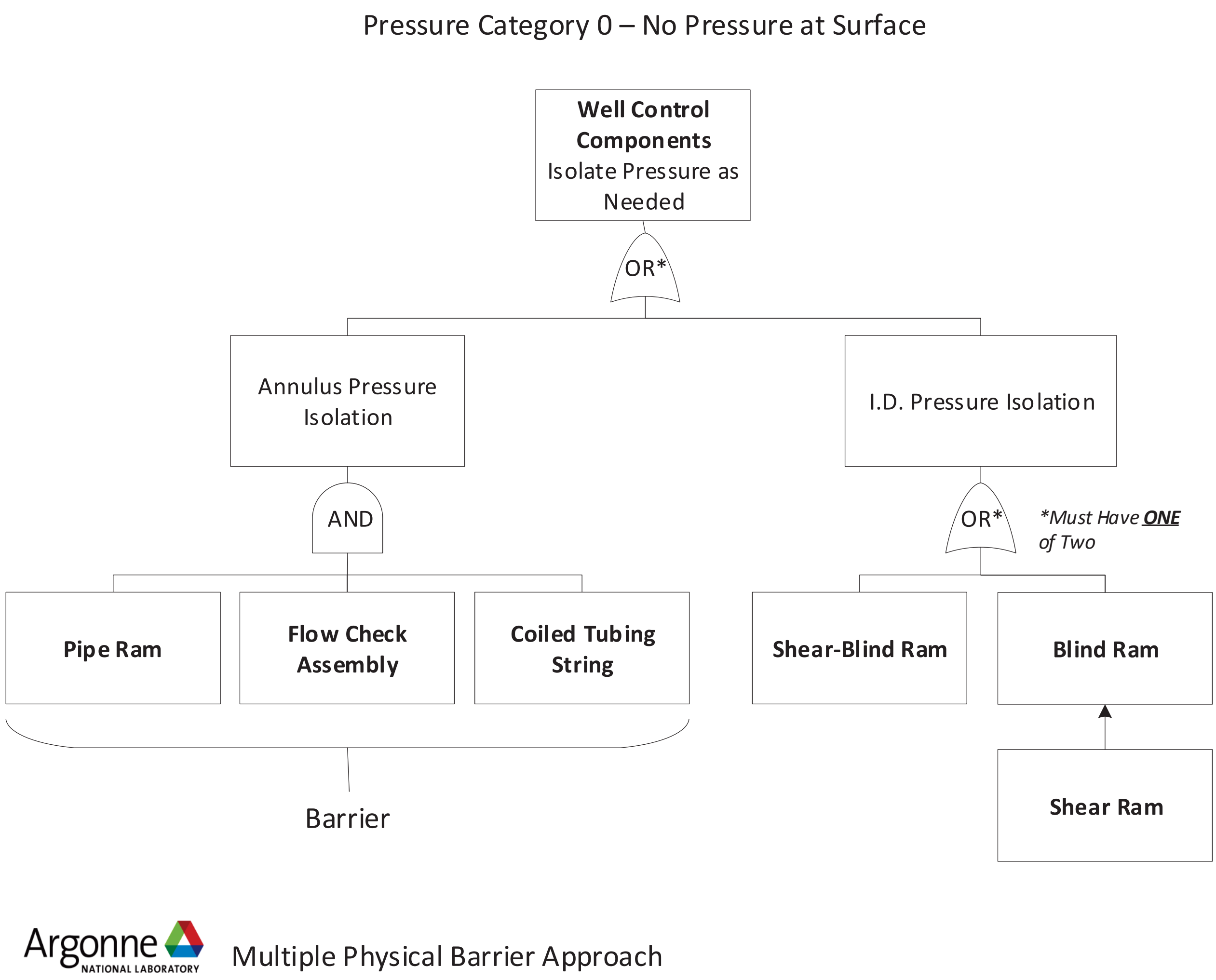
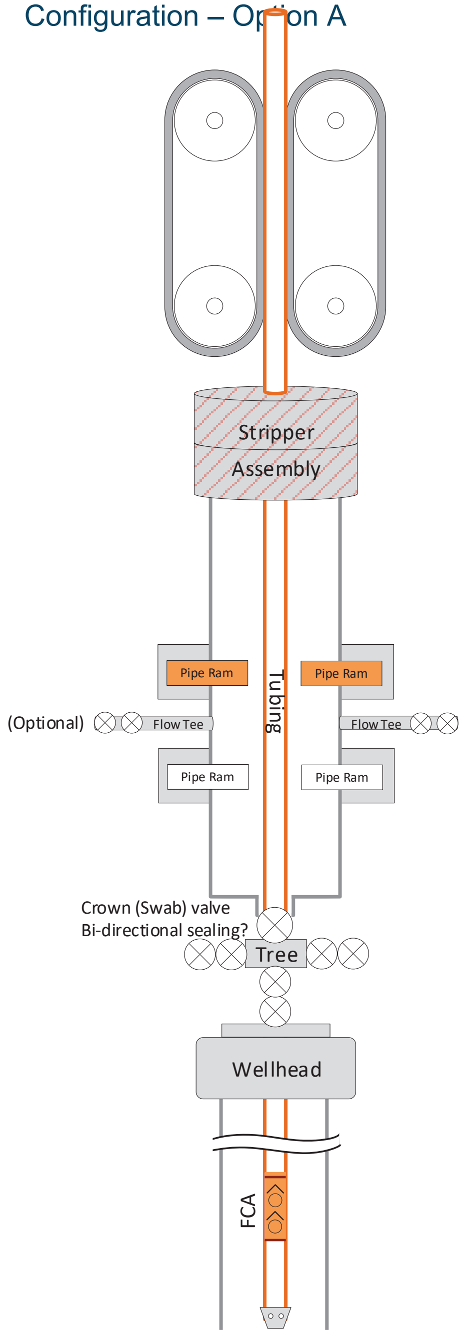


Figure 1: Success Path of minimum well control barriers required for PC-0.

PC-0 Operational Configuration – Option A



	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 47
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Hydraulic Power	p. 35, p. 43, p. 44
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String

Figure 2: Operational Configuration A for PC-0

PC-0 Operational Configuration – Option B

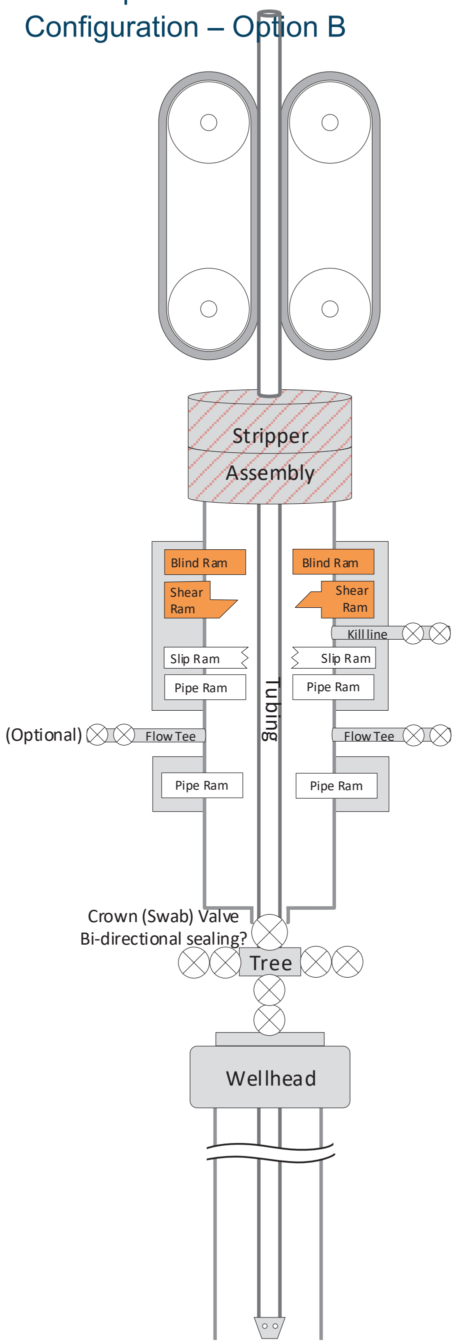


Figure 3: Operational Configuration B for PC-0

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Hydraulic Power	p. 40, p. 45
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Hydraulic Power, Ram Lock(s)	
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Shear Ram + Blind Ram
Second	Shear CT + CT Drop Procedure + Close Xmas Tree

PC-0 Operational Configuration – Option C

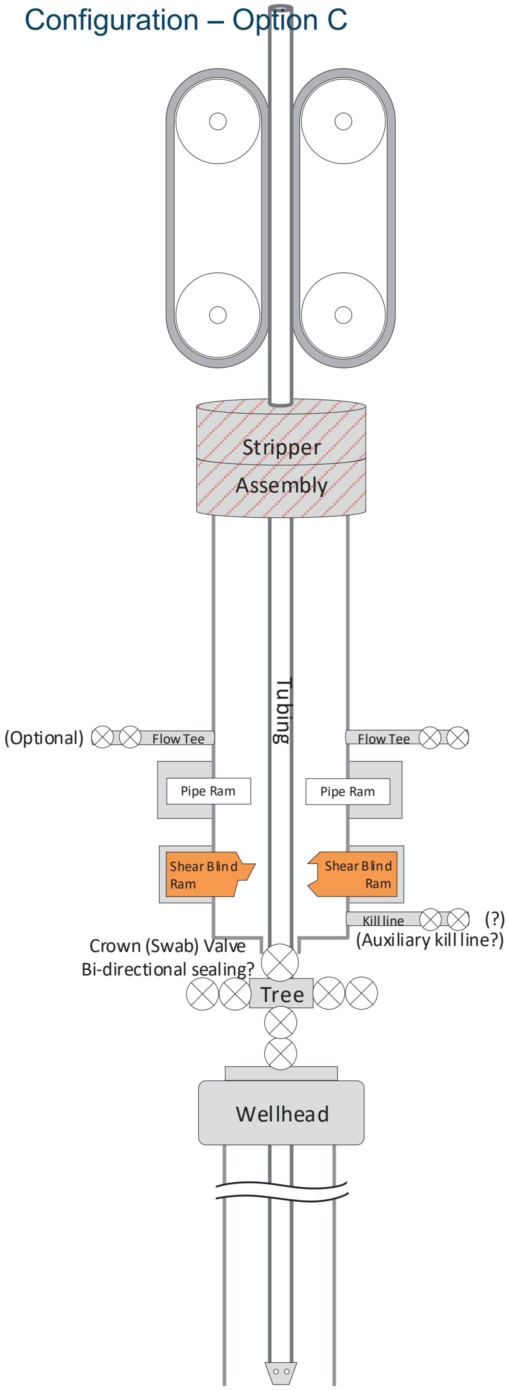


Figure 4: Operational Configuration C for PC-0

	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier	Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Powe	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.

**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Shear-Blind Ram
Second	CT Drop Procedure + Close Xmas Tree

2. Barriers Required for PC-1: 1 psig—1,500 psig

Success Path

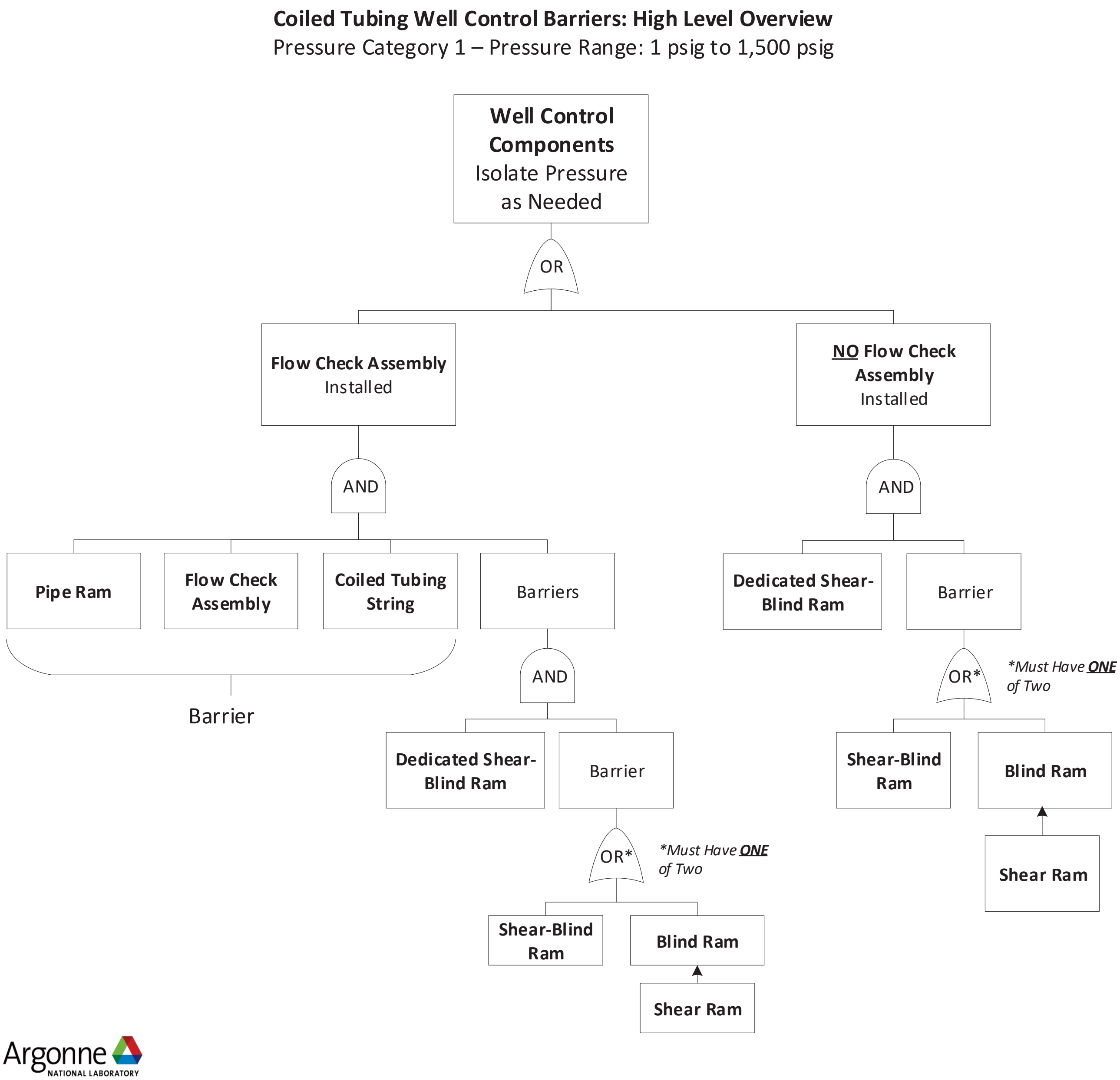


Figure 5: Success Path of minimum well control barriers required for PC-1.

PC-1 Operational Configuration – Option A

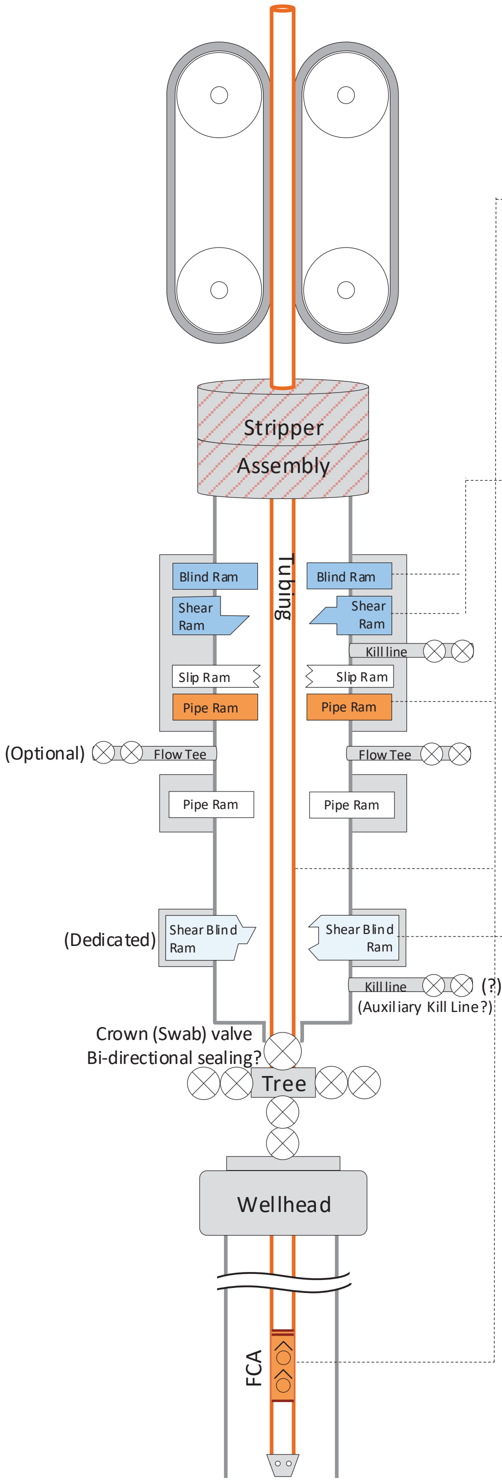


Figure 6: Operational Configuration A for PC-1

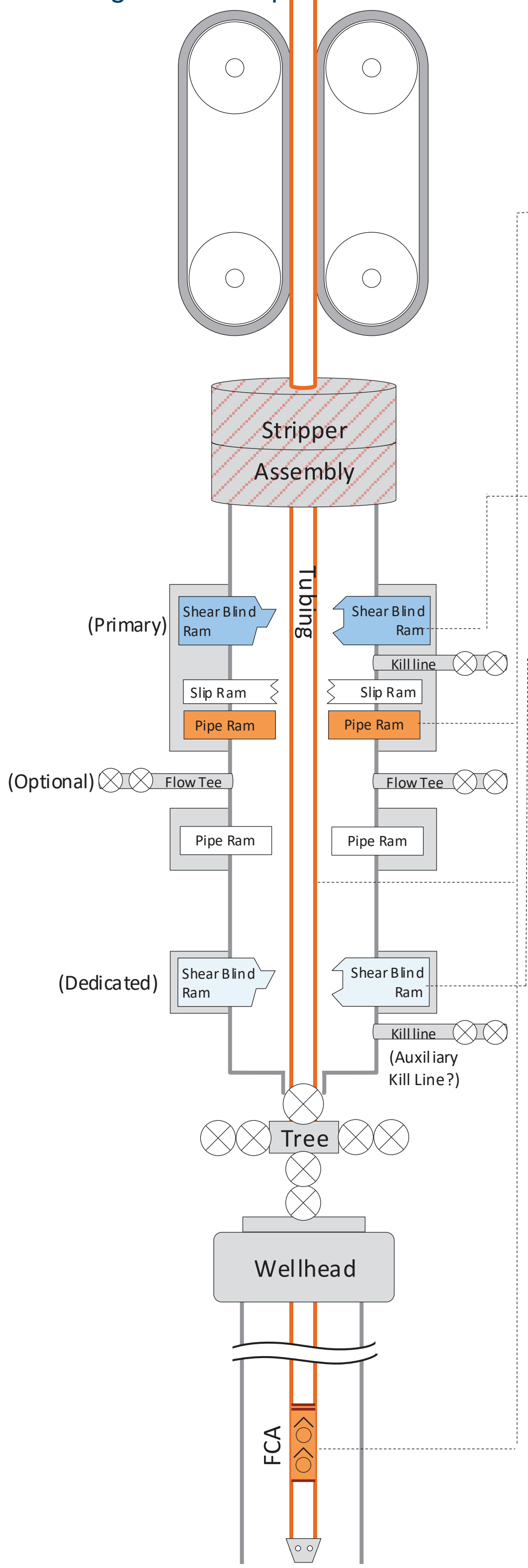
	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Dedicated Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

Second Shear Ram + Blind Ram

PC-1 Operational Configuration – Option B



	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

Figure 7: Operational Configuration B for PC-1

Pressure Category 1: 1 psig—1,500 psig.   API RP 16ST: Minimum Two Barriers Required

PC-1 Operational Configuration – Option C

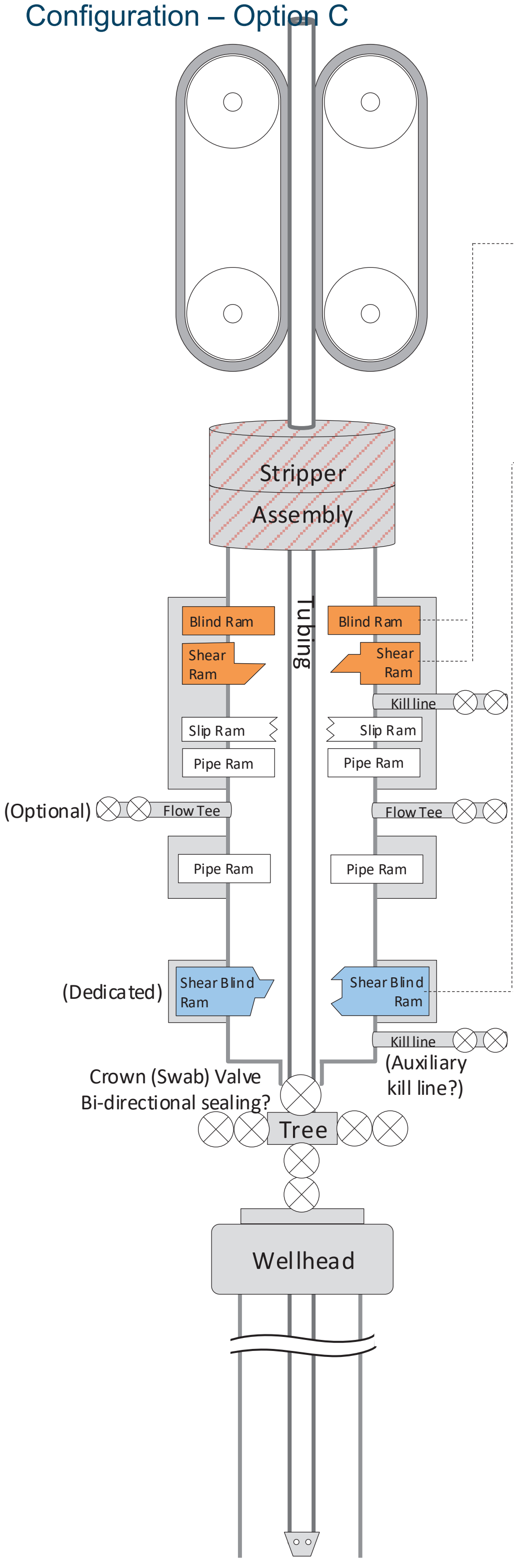


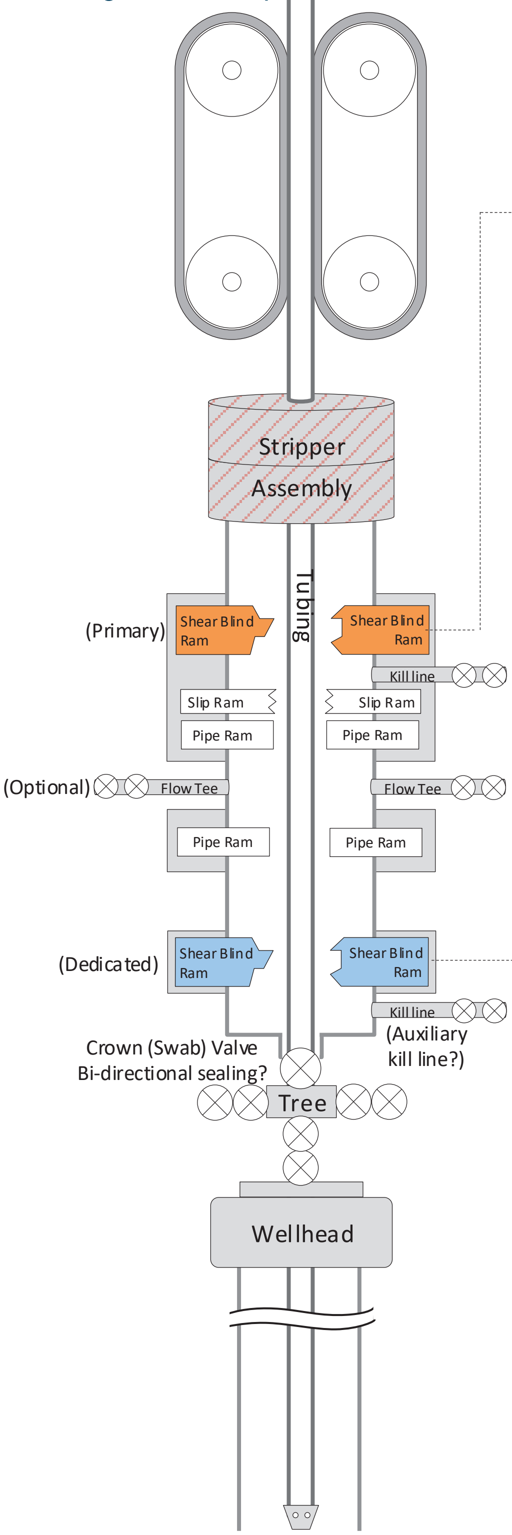
Figure 8: Operational Configuration C for PC-1

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Shear Ram + Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

PC-1 Operational Configuration – Option D



	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

Figure 9: Operational Configuration D for PC-1

PC-1 Operational Configuration – Option E

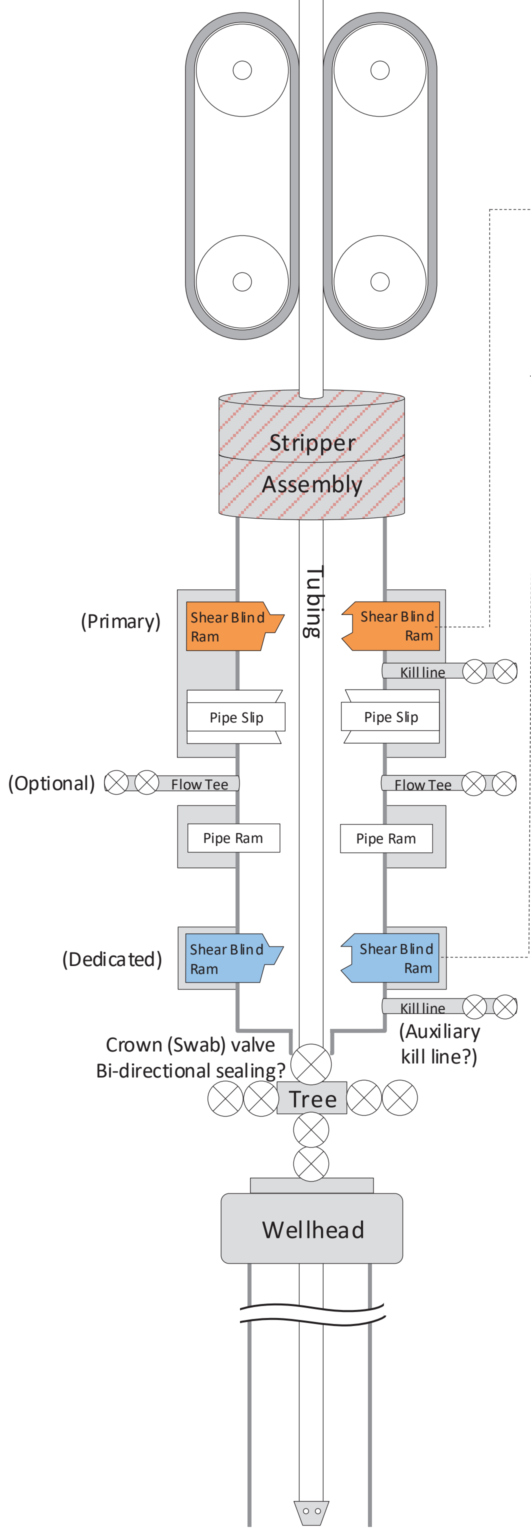


Figure 10: Operational Configuration E for PC-1

	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

PC-1 Operational Configuration – Option F

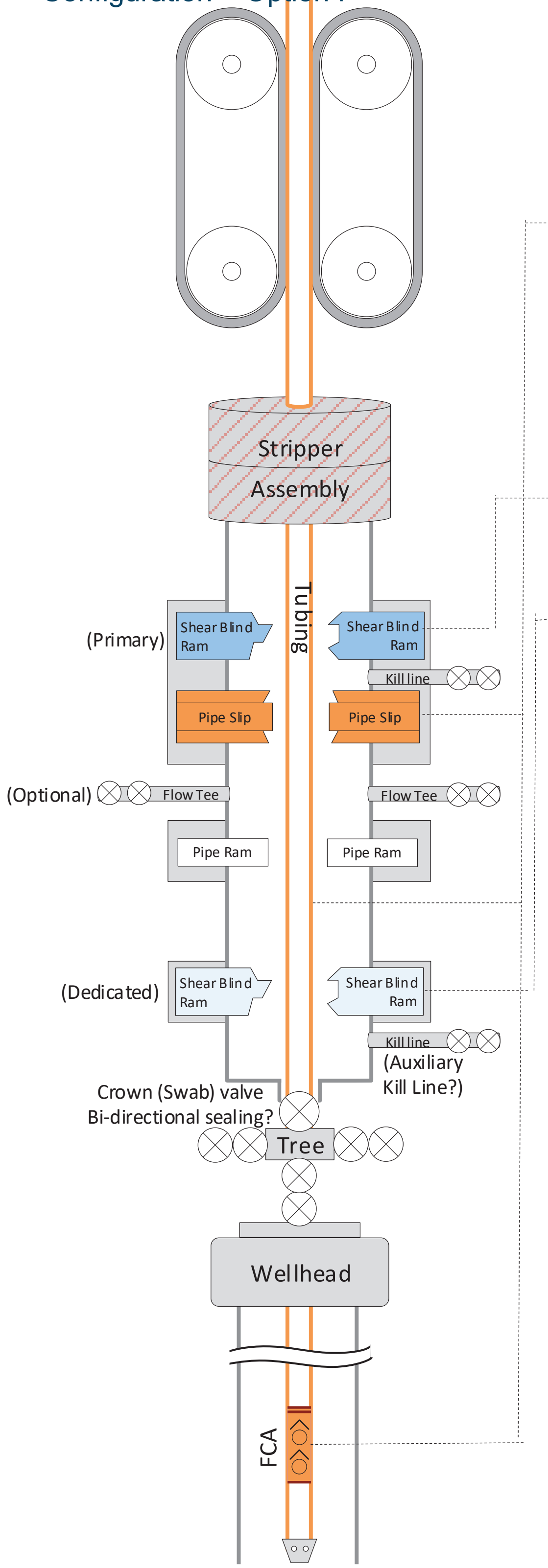


Figure 11: Operational Configuration F for PC-1

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe-Slip Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

3. Barriers Required for PC-2: 1,501 psig—3,500 psig

Success Path

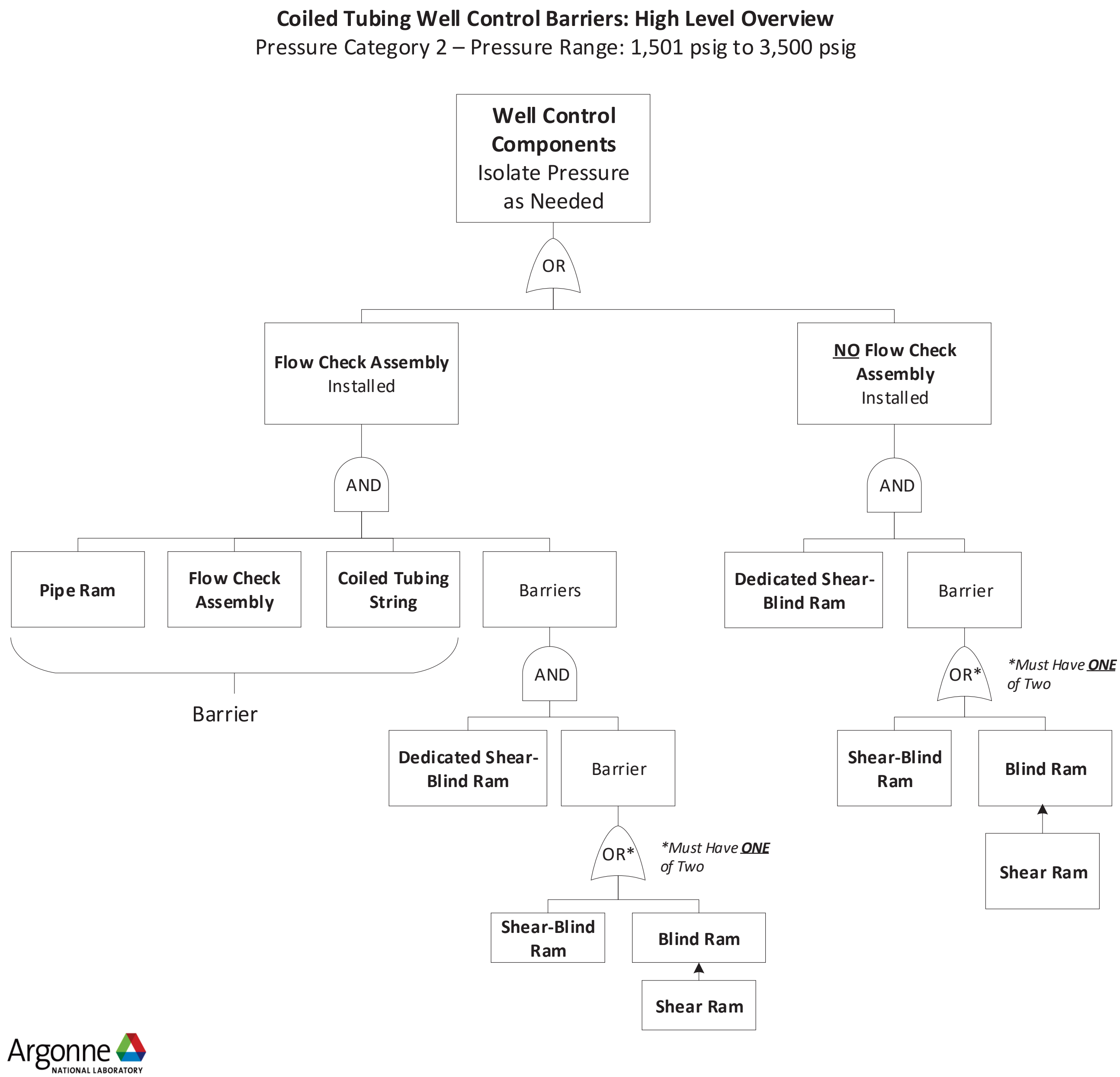


Figure 12: Success Path of minimum well control barriers required for PC-2

PC-2 Operational Configuration – Option A

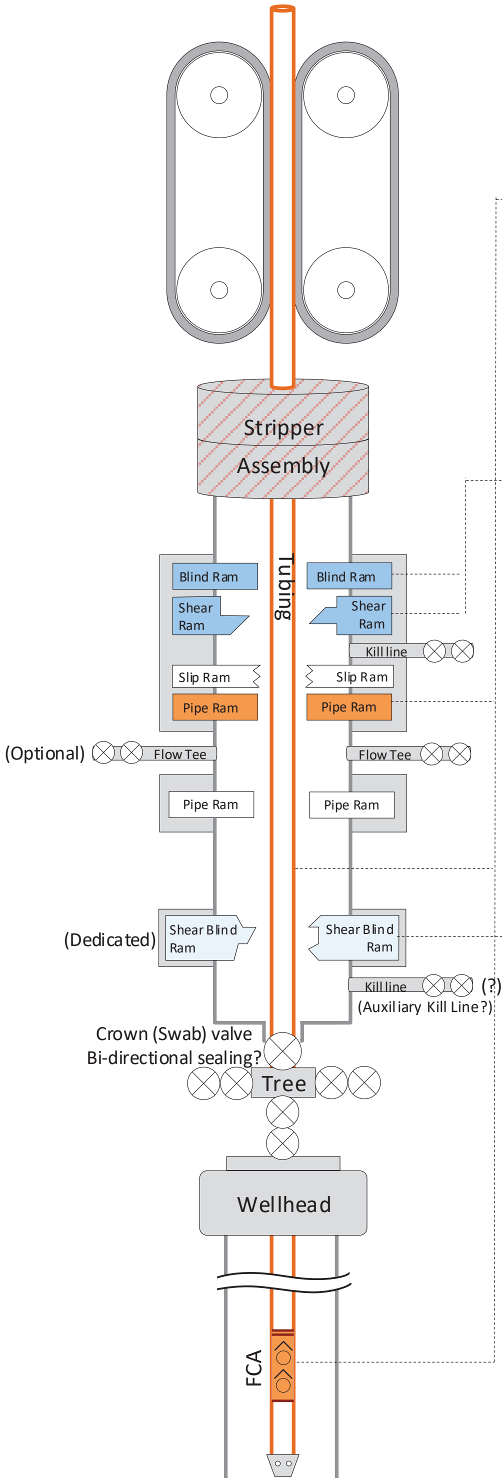


Figure 13: Operational Configuration A for PC-2

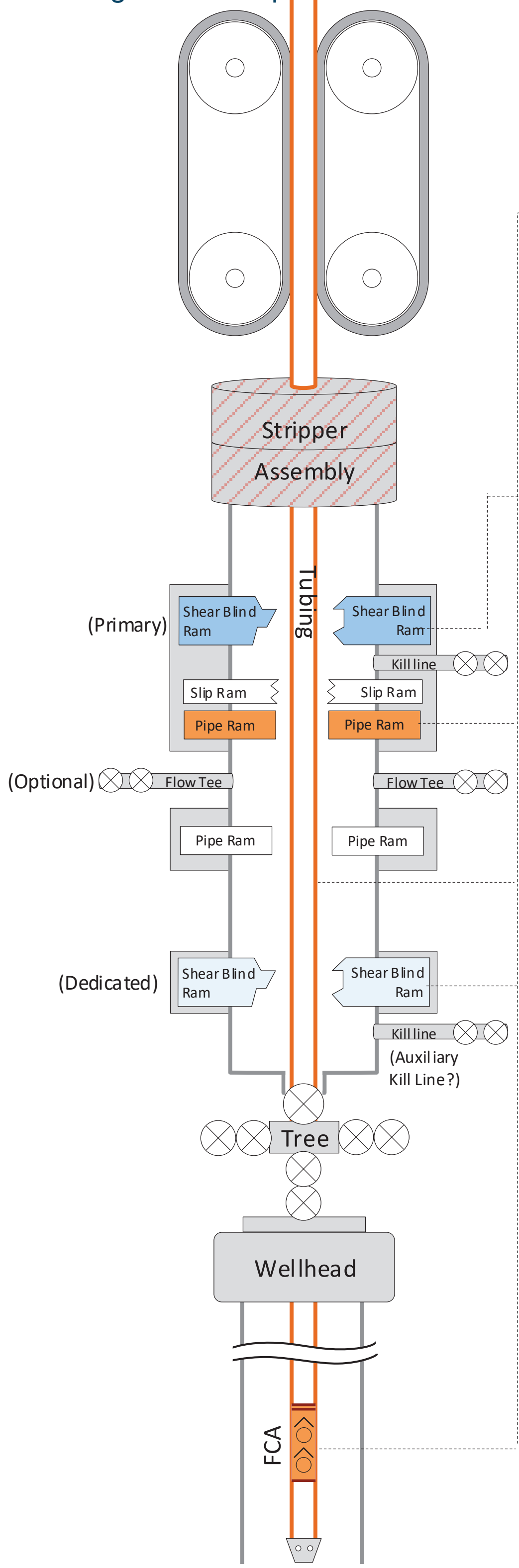
	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.

**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

PC-2 Operational Configuration – Option B



	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

Figure 14: Operational Configuration B for PC-2

Pressure Category 2: 1,501 psig—3,500 psig. API RP 16ST: Minimum Two Barriers Required

PC-2 Operational Configuration – Option C

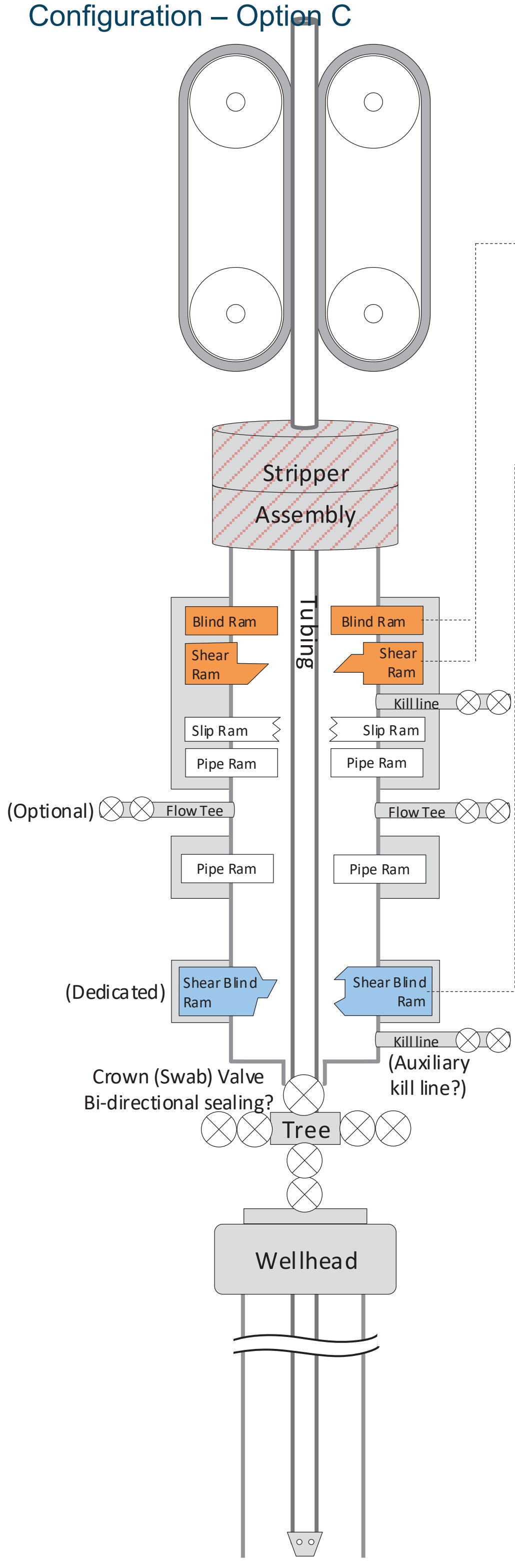


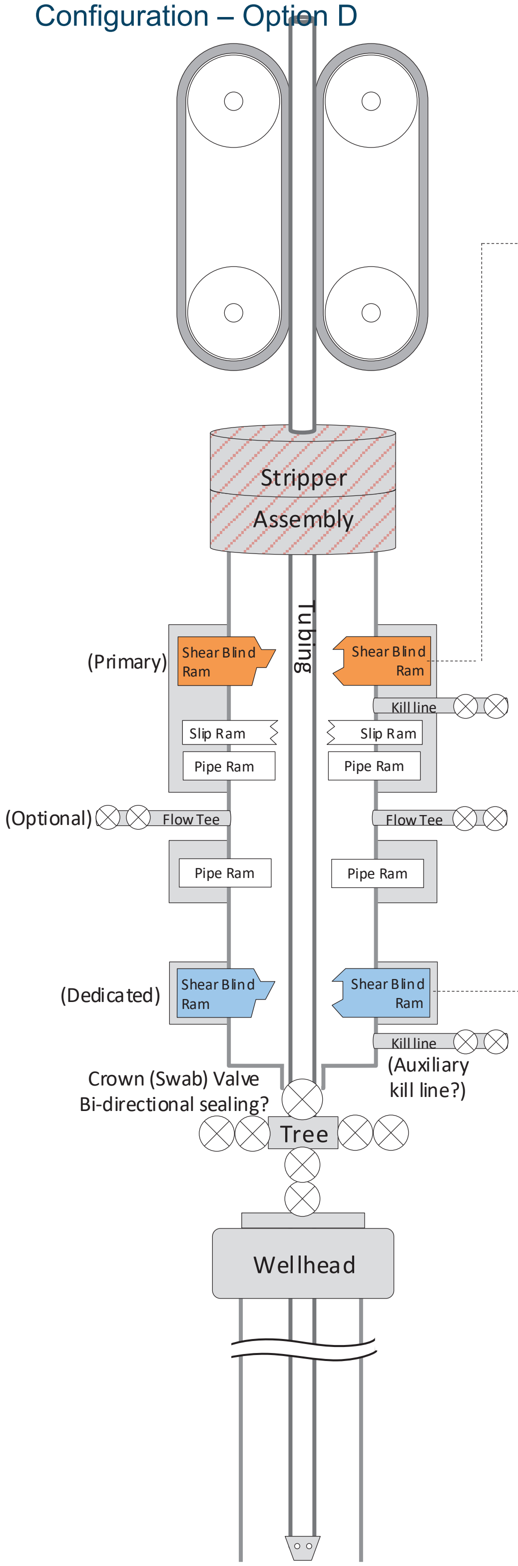
Figure 15: Operational Configuration C for PC-2

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Shear Ram + Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

PC-2 Operational Configuration – Option D



	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

Figure 16: Operational Configuration D for PC-2

PC-2 Operational Configuration – Option E

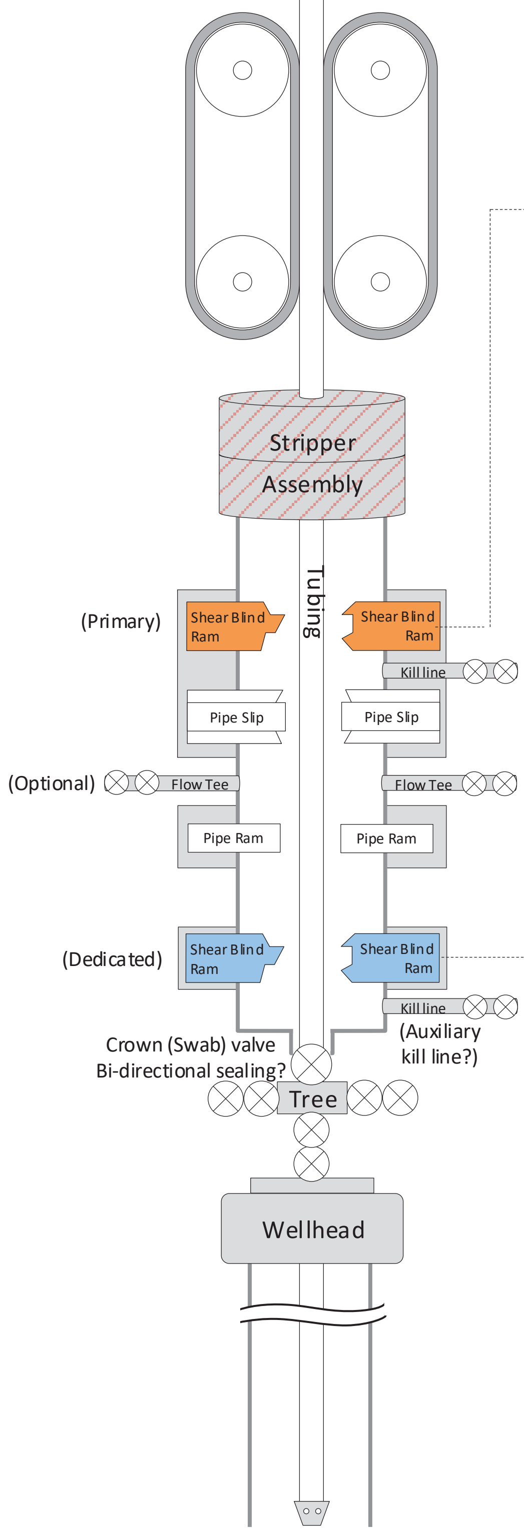


Figure 17: Operational Configuration E for PC-2

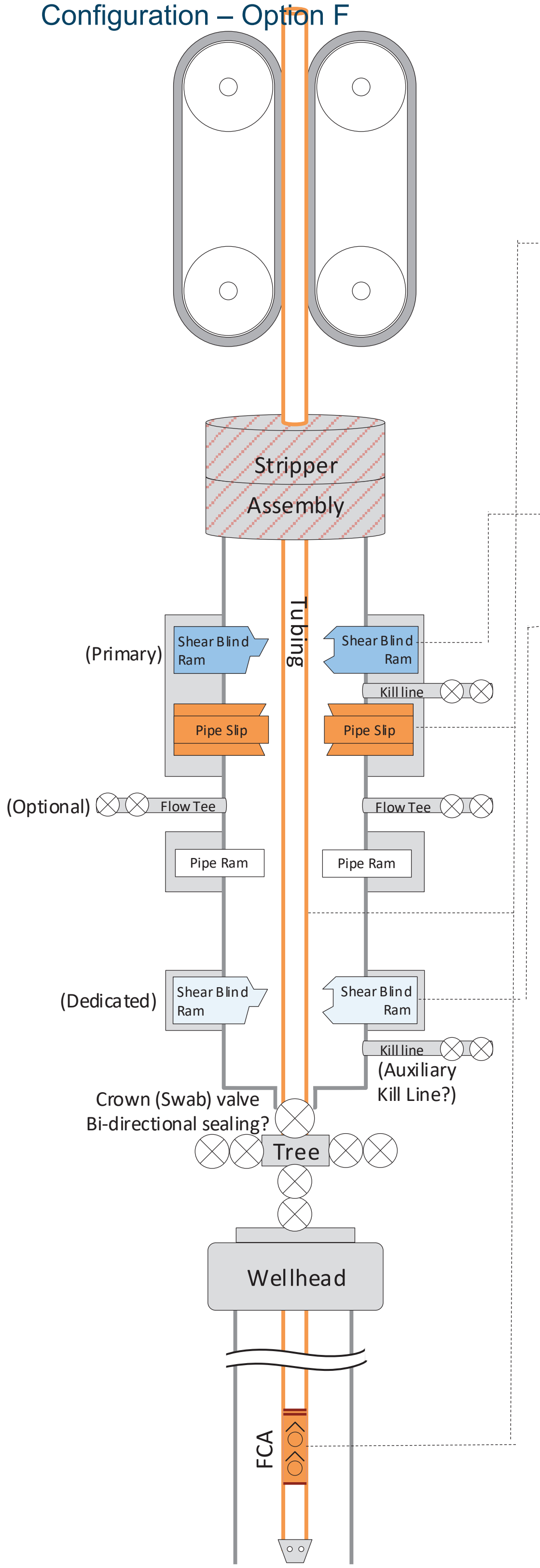
	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.

**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

PC-2 Operational Configuration – Option F



	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe-Slip Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

Figure 18: Operational Configuration F for PC-2

4. Barriers Required for PC-3: 3,501 psig—7,500 psig

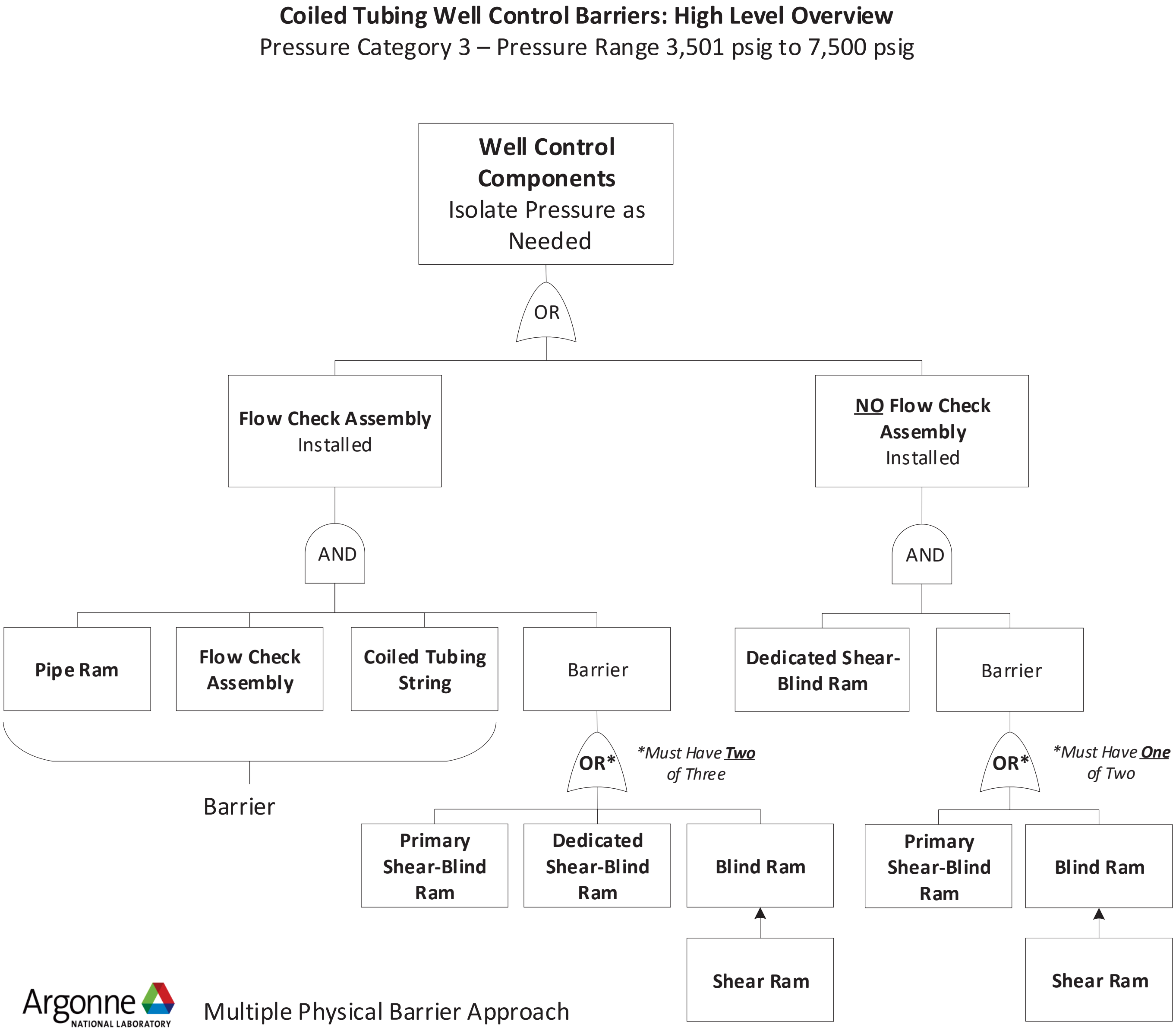


Figure 19: Success Path of minimum well control barriers required for PC-3

PC-3 Operational Configuration – Option A

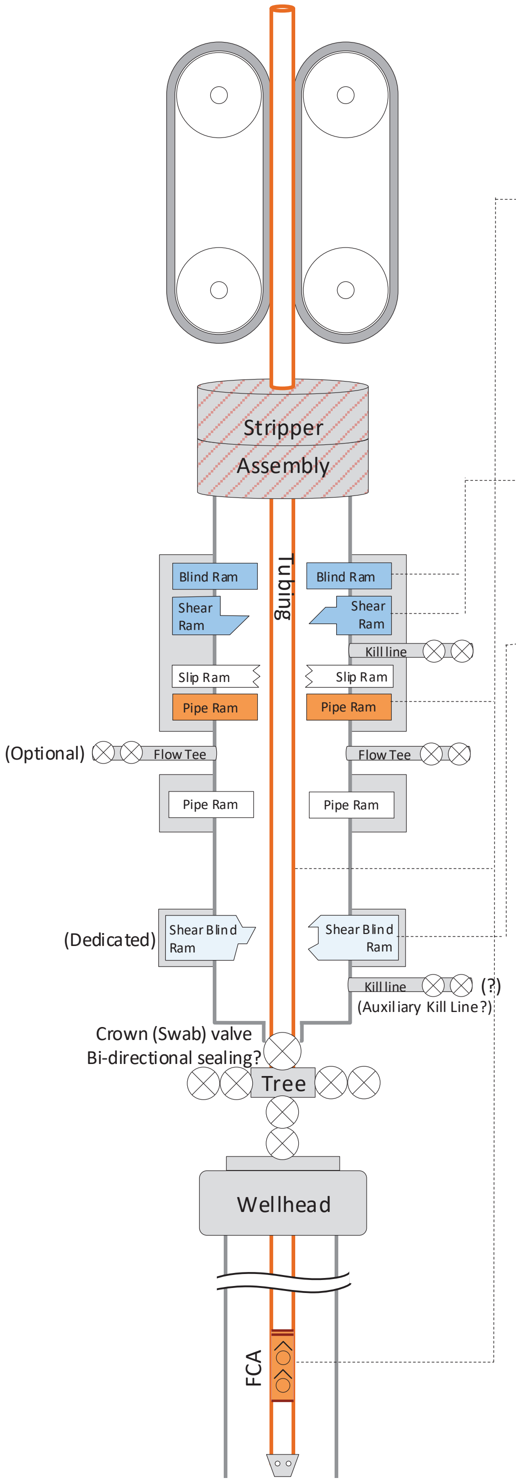


Figure 20: Operational Configuration A for PC-3

	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.

**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

PC-3 Operational Configuration – Option B

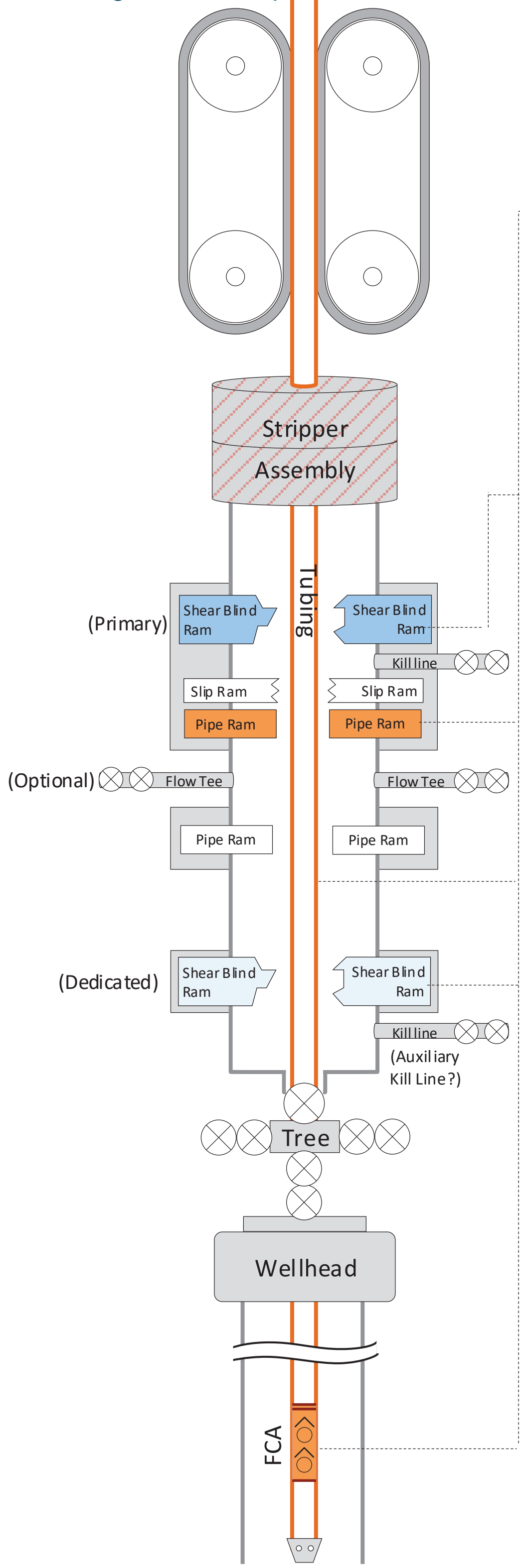


Figure 21: Operational Configuration B for PC-3

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.

**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

Pressure Category 3: 3,501 psig—7,500 psig. API RP 16ST: Minimum Two Barriers Required

PC-3 Operational Configuration – Option C

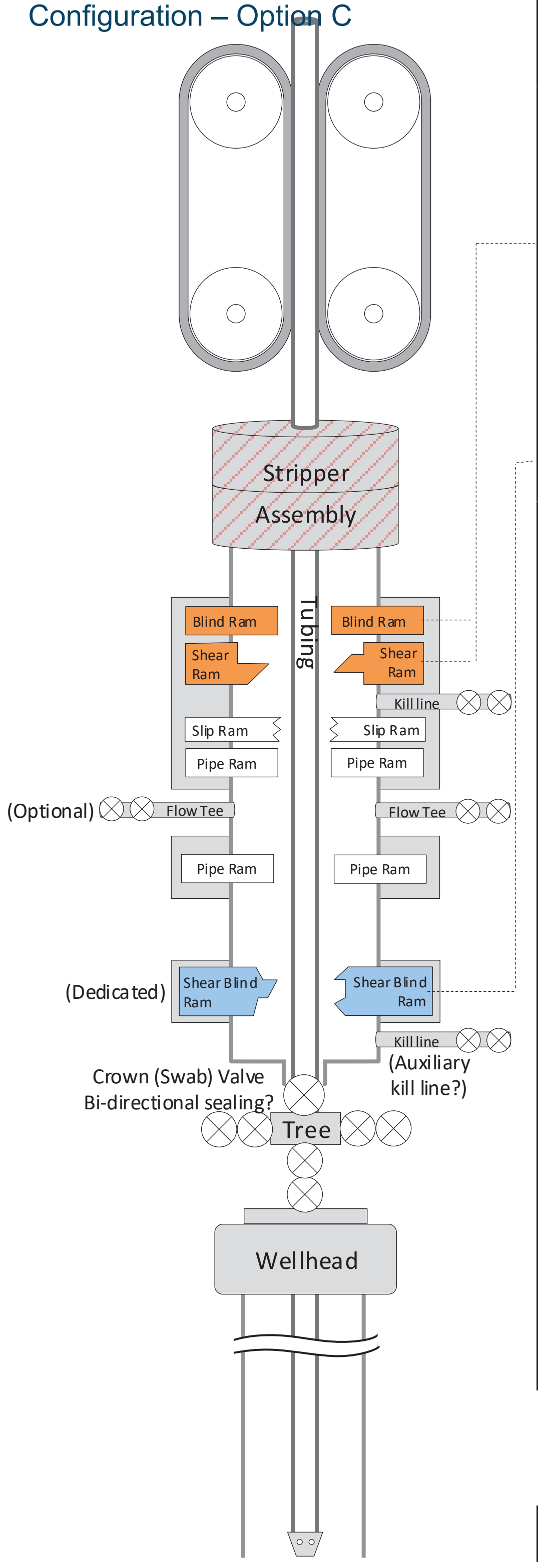


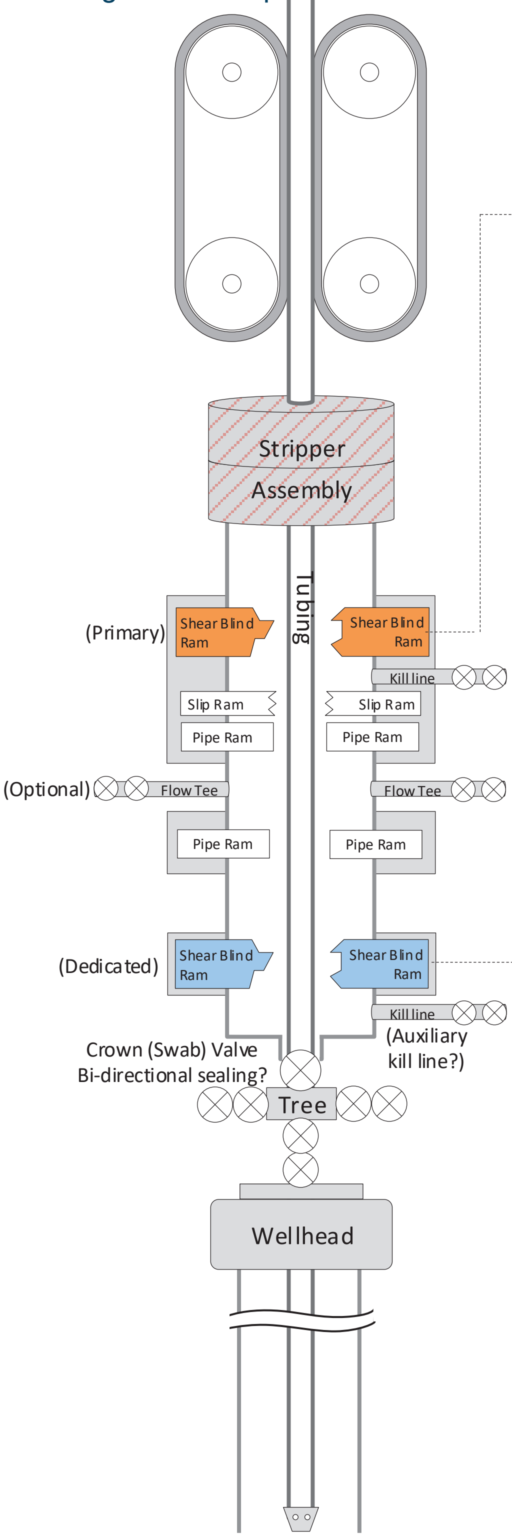
Figure 22: Operational Configuration C for PC-3

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Shear Ram + Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

PC-3 Operational Configuration – Option D



	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

Figure 23: Operational Configuration D for PC-3

PC-3 Operational Configuration – Option E

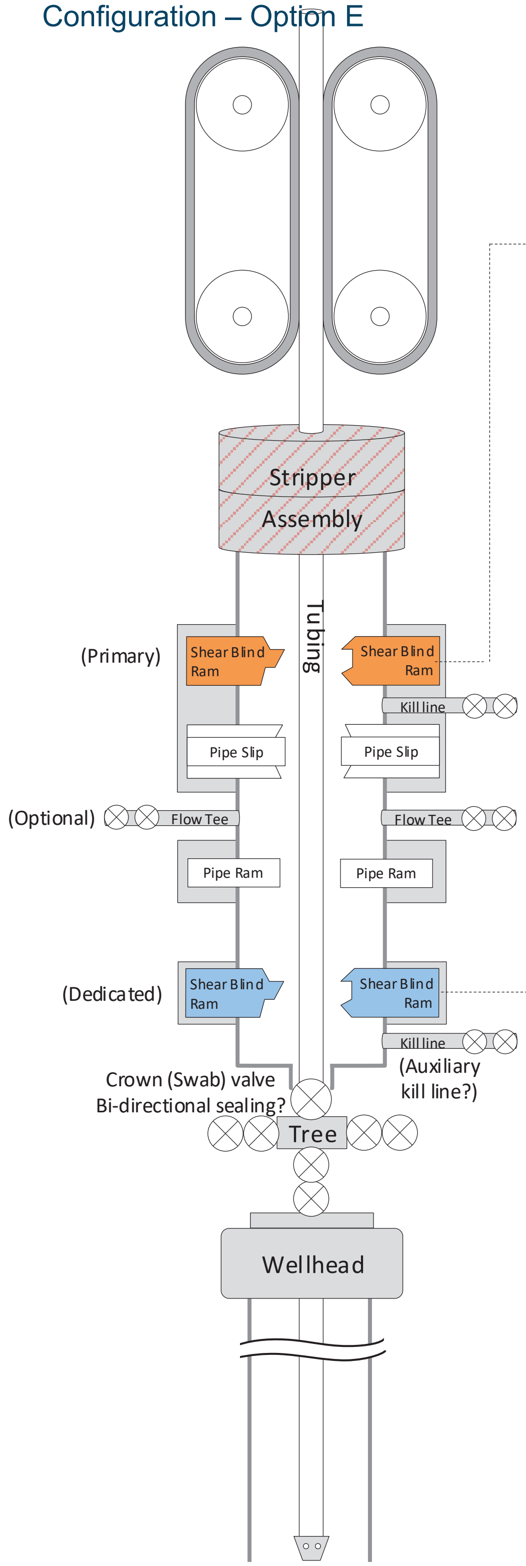


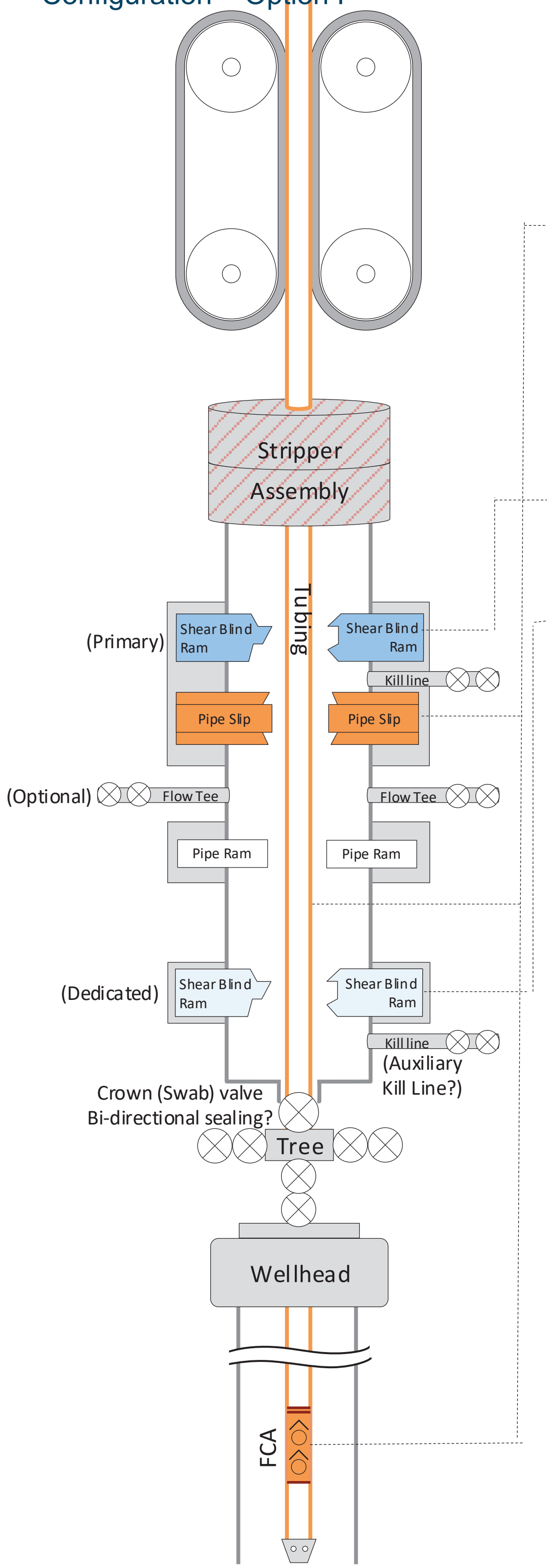
Figure 24: Operational Configuration E for PC-3

	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

PC-3 Operational Configuration – Option F



	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

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**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe-Slip Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

Figure 25: Operational Configuration F for PC-3

5. Barriers Required for PC-4: 7,501 psig—12,500 psig

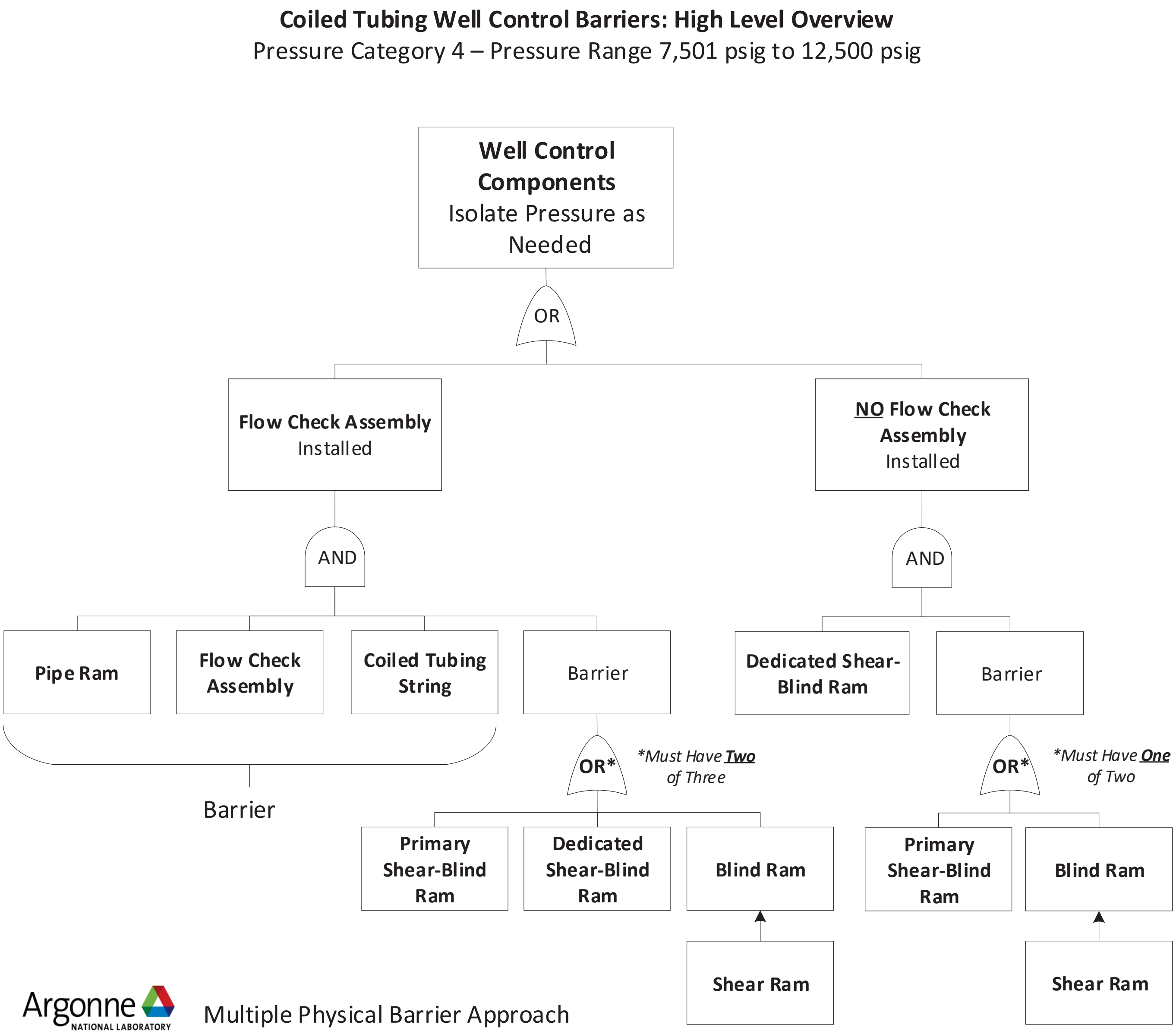


Figure 26: Success Path of minimum well control barriers required for PC-4

PC-4 Operational Configuration – Option A

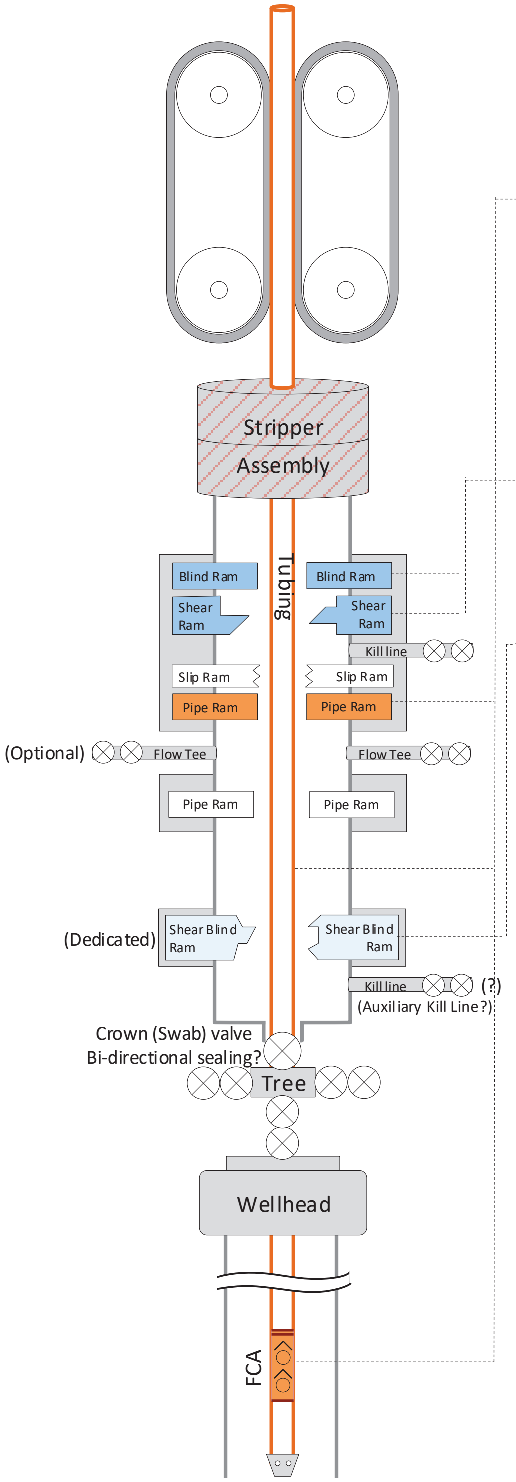


Figure 27: Operational Configuration A for PC-4

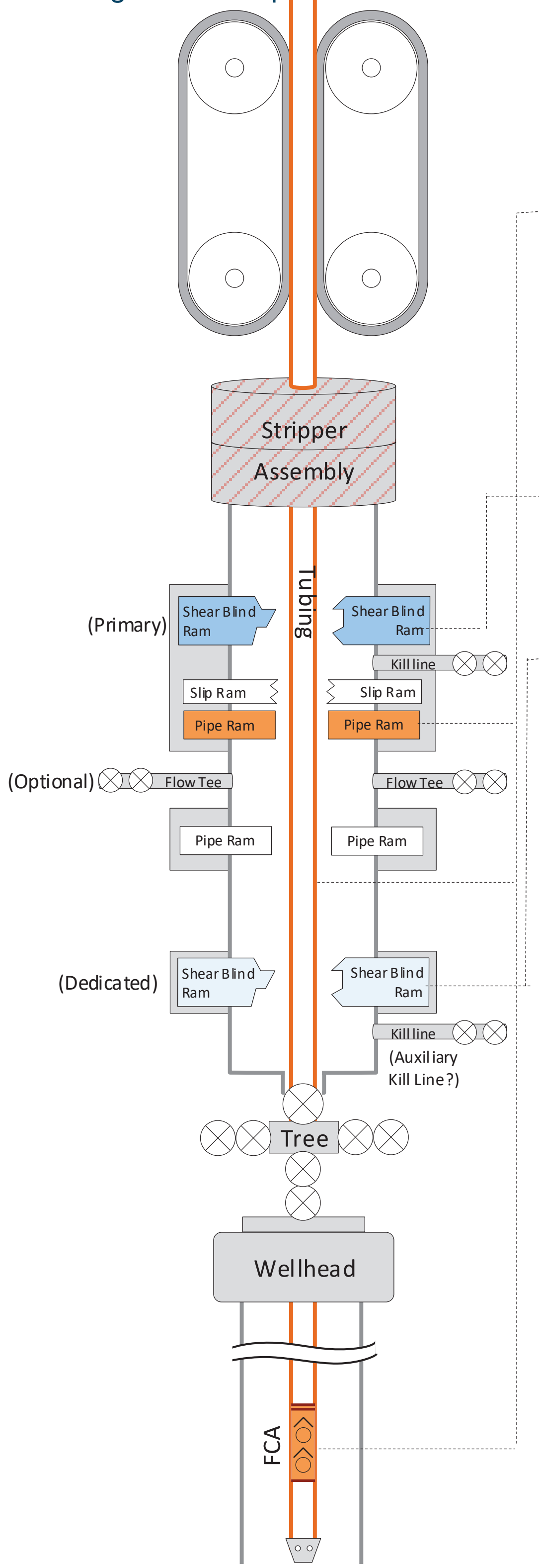
	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

*The stripper assembly is considered to be a continuously degrading operational component, and is classified as a pressure control device only when used for well control.

**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

PC-4 Operational Configuration – Option B



	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component **(PBC)**	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

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**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST

Sequence	Well Containment Components
First	Pipe Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

Figure 28: Operational Configuration B for PC-4

PC-4 Operational Configuration – Option C

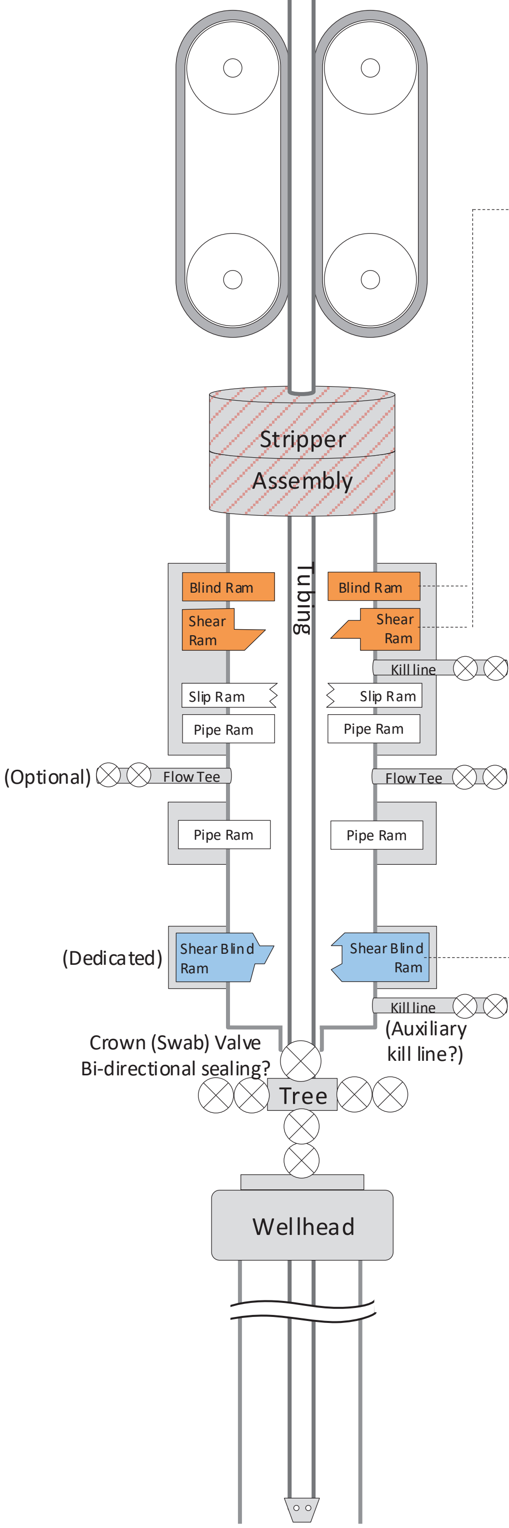

Figure 29: Operational Configuration C for PC-4

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1 Components	Blind Ram	Closes on Demand to Seal Across ID Bore of Stack and Contain Wellbore Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 39, p. 45
	Shear Ram	Closes on Demand to Shear the Tubing and Provides Means for Blind Ram to Properly Close and Seal Wellbore	Primary Hydraulic Power	p. 40, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

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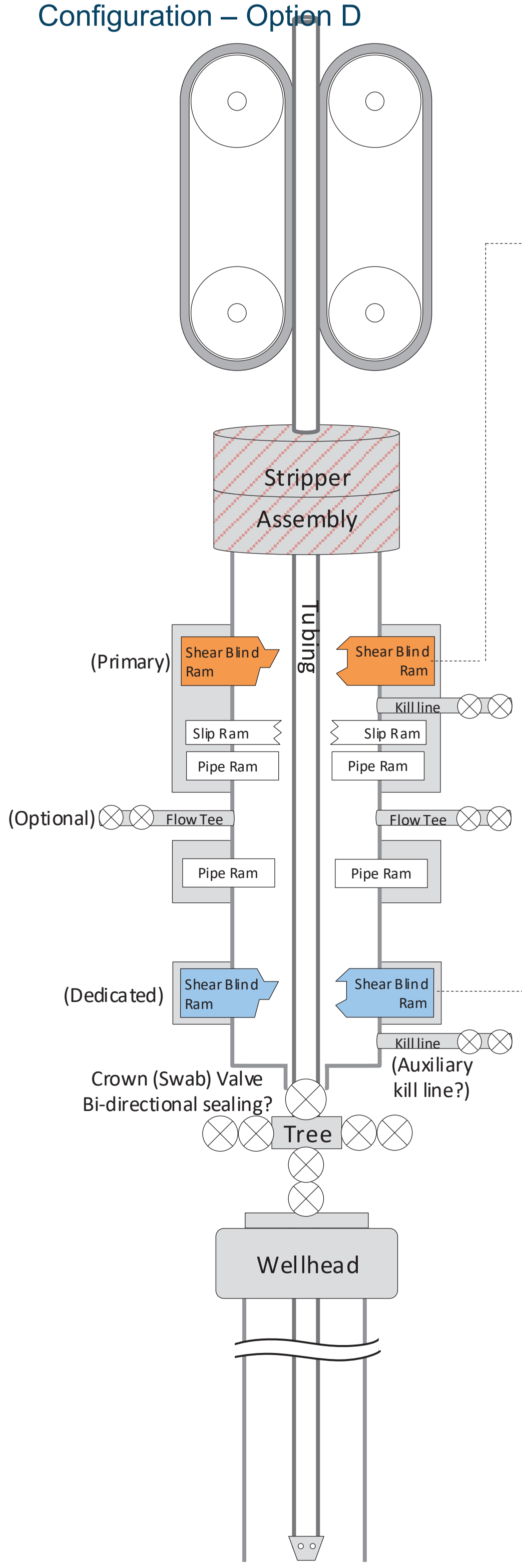
**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Shear Ram + Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

PC-4 Operational Configuration – Option D



	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Slip Ram	Secures CT Within Well Control Stack	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

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**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

Figure 30: Operational Configuration D for PC-4

Pressure Category 4: 7,501 psig—12,500 psig. API RP 16ST: Minimum Two Barriers Required

PC-4 Operational Configuration – Option E

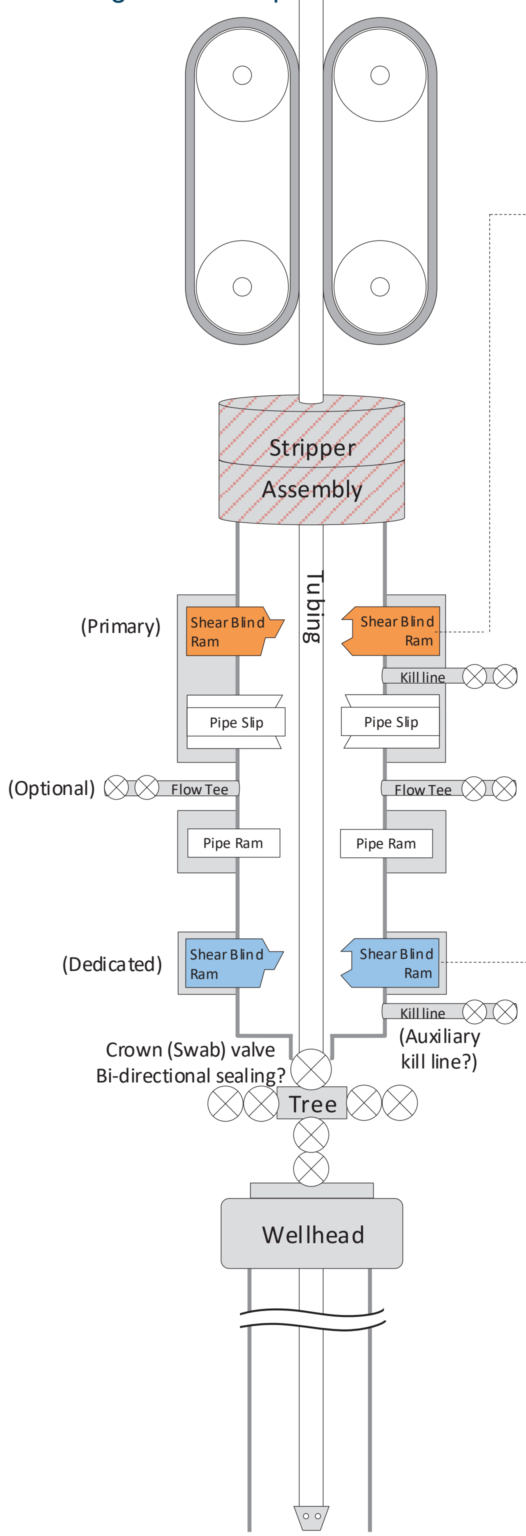

Figure 31: Operational Configuration E for PC-4

	Barrier (component) / Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barrier 1	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 2	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Coiled Tubing String	Isolates CT ID Pressure/Flow Path from Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic power, ram lock(s)	p. 36, p. 45
	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Bottom Hole Assembly	Attachment of Tools to End of CT String	No Pressure Isolation Implied	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

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**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Primary Shear-Blind Ram
Second	Dedicated Shear-Blind Ram
Third	CT Drop Procedure + Close Xmas Tree

Pressure Category 4: 7,501 psig—12,500 psig.   API RP 16ST: Minimum Two Barriers Required

PC-4 Operational Configuration – Option F

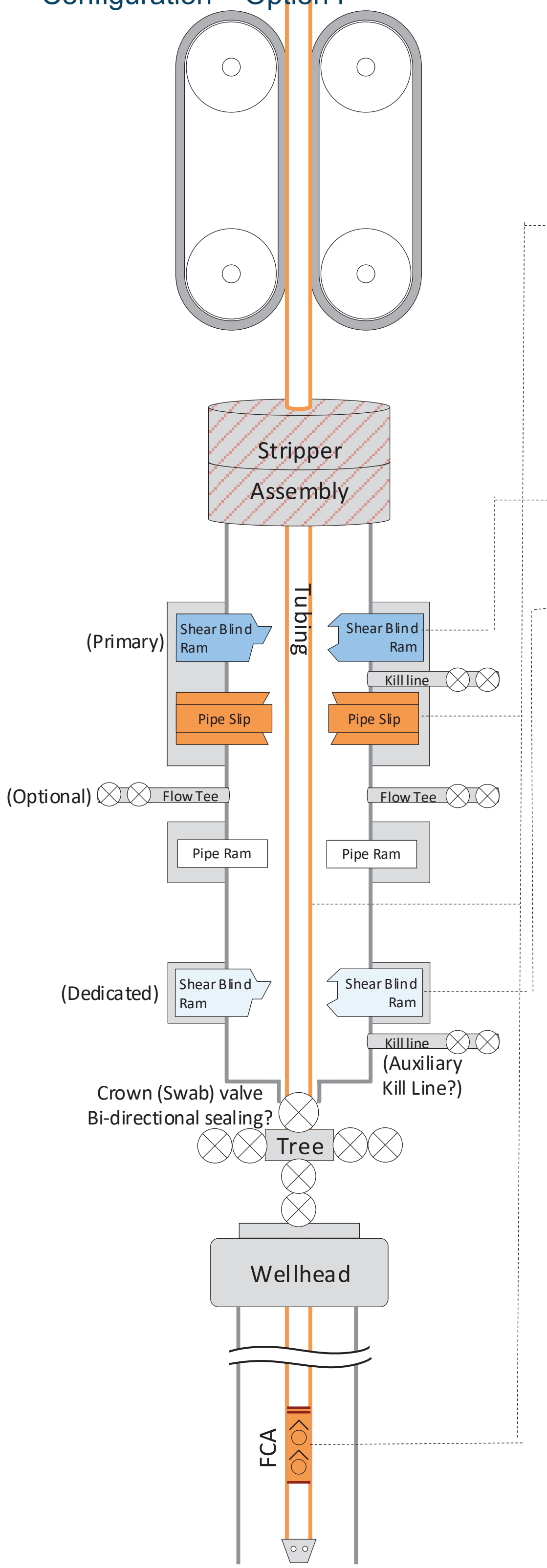

Figure 32: Operational Configuration F for PC-4

	Barrier (component)/ Operational Equipment	Main Function	Support Equipment	Success Path Reference
CT Barriers or Barrier Components	Pipe-Slip Ram	Closes on Demand onto CT OD to Secure CT Within Well Control Stack and Isolate Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 45
	Downhole Flow Check Device	Seals and Isolates Annulus Pressure From CT ID Pressure	N/A - Passive Barrier Component (**PBC**)	p. 38
	Coiled Tubing String	Isolates CT ID Pressure/ Flow Path From Annulus Pressure/Flow Path	Injector, Support Systems	p. 37
CT Barrier 2	Primary Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Primary Hydraulic Power, Seals on Blades, Ram Locks	p. 41, p. 45
CT Barrier 3	Dedicated Shear-Blind Ram	Closes on Demand to Shear the CT and Seal Across ID Bore of Stack to Contain Wellbore Pressure	Dedicated Hydraulic Power, Seals on Blades, Ram Locks	p. 42, p. 46
CT Operational Components	Stripper Assembly*	Contains Annulus Pressure at Surface During Normal Operation	Primary Hydraulic Power	p. 35, p. 43, p. 44
	Pipe Ram	Closes on Demand onto CT OD and Isolates Annulus Pressure	Primary Hydraulic Power, Ram Lock(s)	p. 36, p. 45
	Flow Cross (Flow Tee)	Allows for Fluid Circulation out of the Wellbore	Dual Pressure Isolation Valves on Each Branch	
	Kill Line	Provides Access for Flow of Kill Fluid Down the CT ID Into the Well	Dual Pressure Isolation Valves on Line	
	Flow Check Assembly	Isolates Annulus Pressure at CT BHA	N/A - **PBC**	
Wellhead Components (Not Part of CT Barrier Concept)**	Crown Valve (Connection)	Provides Access to the Tree and Initial Pressure Control Point Below the CT Well Control Stack		
	Xmas Tree	Provides Wellbore Pressure Isolation and Well Access		
	Tubing Hanger Spool	Provides Pressure Isolation of Annulus Between Production Casing and Production Tubing		
	Wellhead	Provides Means for Pressure Isolation of All Casing Annuli		

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**Items below the Wellhead used to establish pressure containment (e.g. casing and cement) are critical well control components, but are beyond the scope of API RP 16ST.

Sequence	Well Containment Components
First	Pipe-Slip Ram + Flow Check Assembly + Coiled Tubing String
Second	Primary Shear-Blind Ram
Third	Dedicated Shear-Blind Ram
Fourth	CT Drop Procedure + Close Xmas Tree

OVERVIEW OF SUCCESS PATH EVALUATION PROCESS

The Success Path Evaluations of Individual Coiled Tubing Well Control Barriers and Components Ad-dresses the Performance Requirements for the Designated Pressure Control Systems Through Assess-ment of:

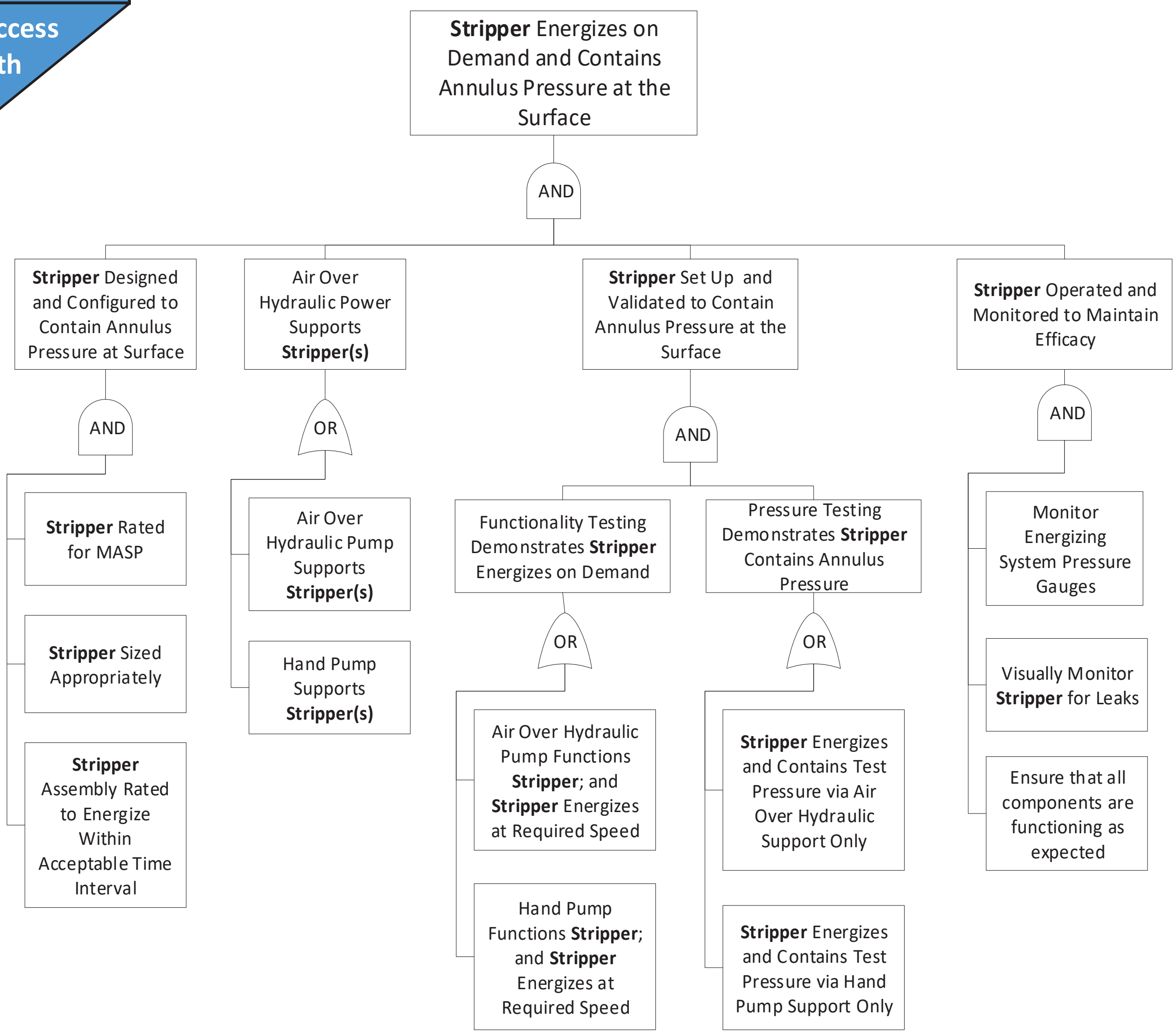
- – Applicability
- – Critical Safety Function
- – Alternate Success Path
- – Critical Support Systems
- – Threat Scenarios

The Following “Success Paths of Individual Barriers and Components” Processes Reflect the Risk Based Performance Requirement for Each Pressure Control System Used in Coiled Tubing Operations.

Each Success Path Process Can be Applied Equally Across any Coiled Tubing Pressure Category, Where the Performance Requirement is Implied to Meet the Expectations for the Rated Working Pressure of the Equipment Components.

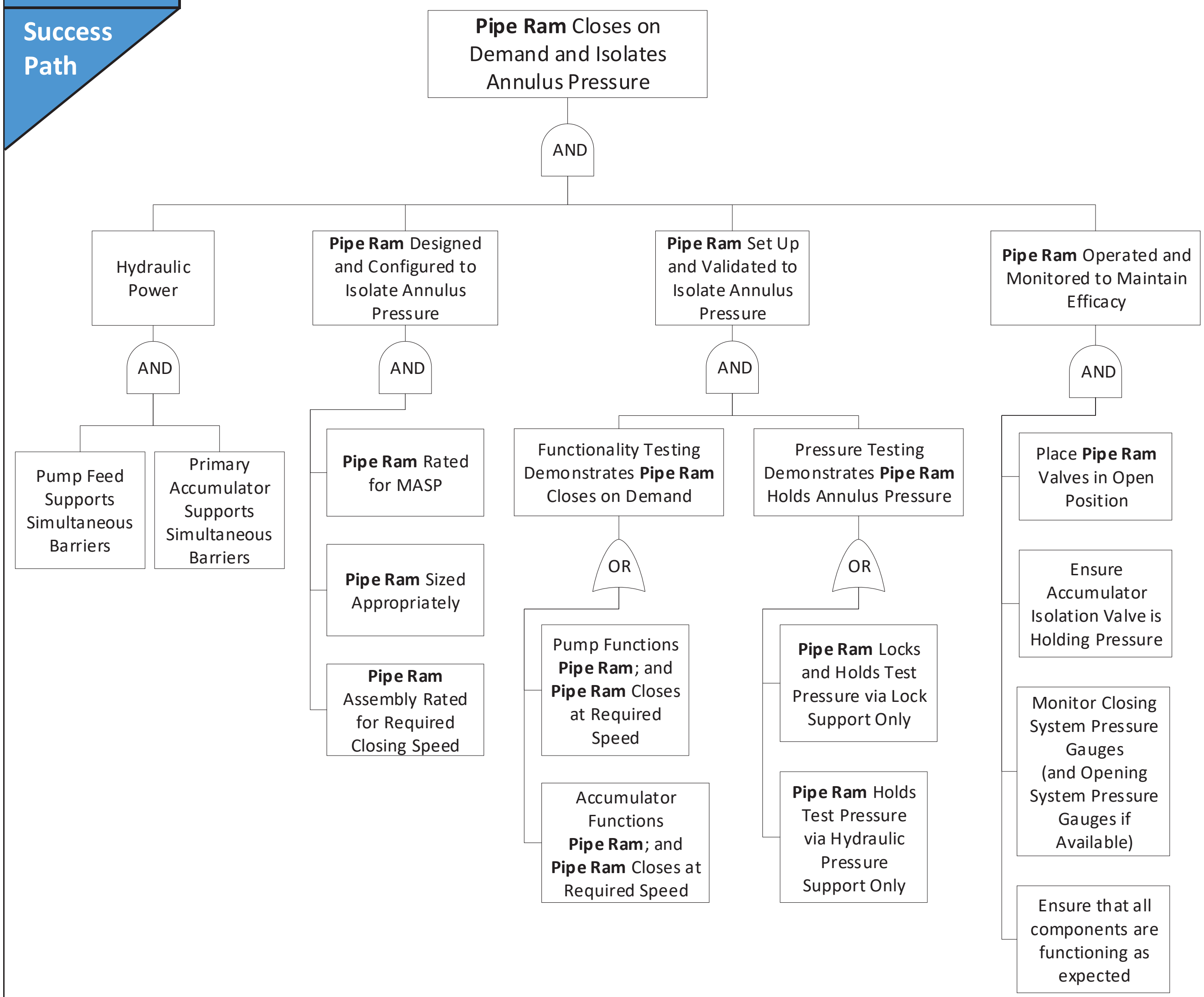
Pressure Control Component: Stripper

Applicability	**Coiled Tubing Operations**
Critical Safety Function	
Success Path	



Alternate Success Path	**Pipe Ram; other barriers (e.g. Shear and Blind Ram)**
Critical Support Systems	**Hydraulic power for controls and CT Console**
Threat Scenarios	**Stripper is constantly wearing during service. It should be anticipated to fail at any time.**

Physical Barrier Element: Pipe Ram

Applicability	**Coiled Tubing Operations**
Critical Safety Function	
Success Path	

Alternate Success Path	**Blind Ram; Shear-Blind Ram**
Critical Support Systems	**Hydraulic power**
Threat Scenarios	**Element wear or CT diametral growth can be a factor.**

Physical Barrier Element: Coiled Tubing String

Applicability: **Coiled Tubing Operations**

Critical Safety Function / Success Path

Coiled Tubing String Isolates CT I.D. Pressure/Flow Path from Annulus Pressure/Flow Path

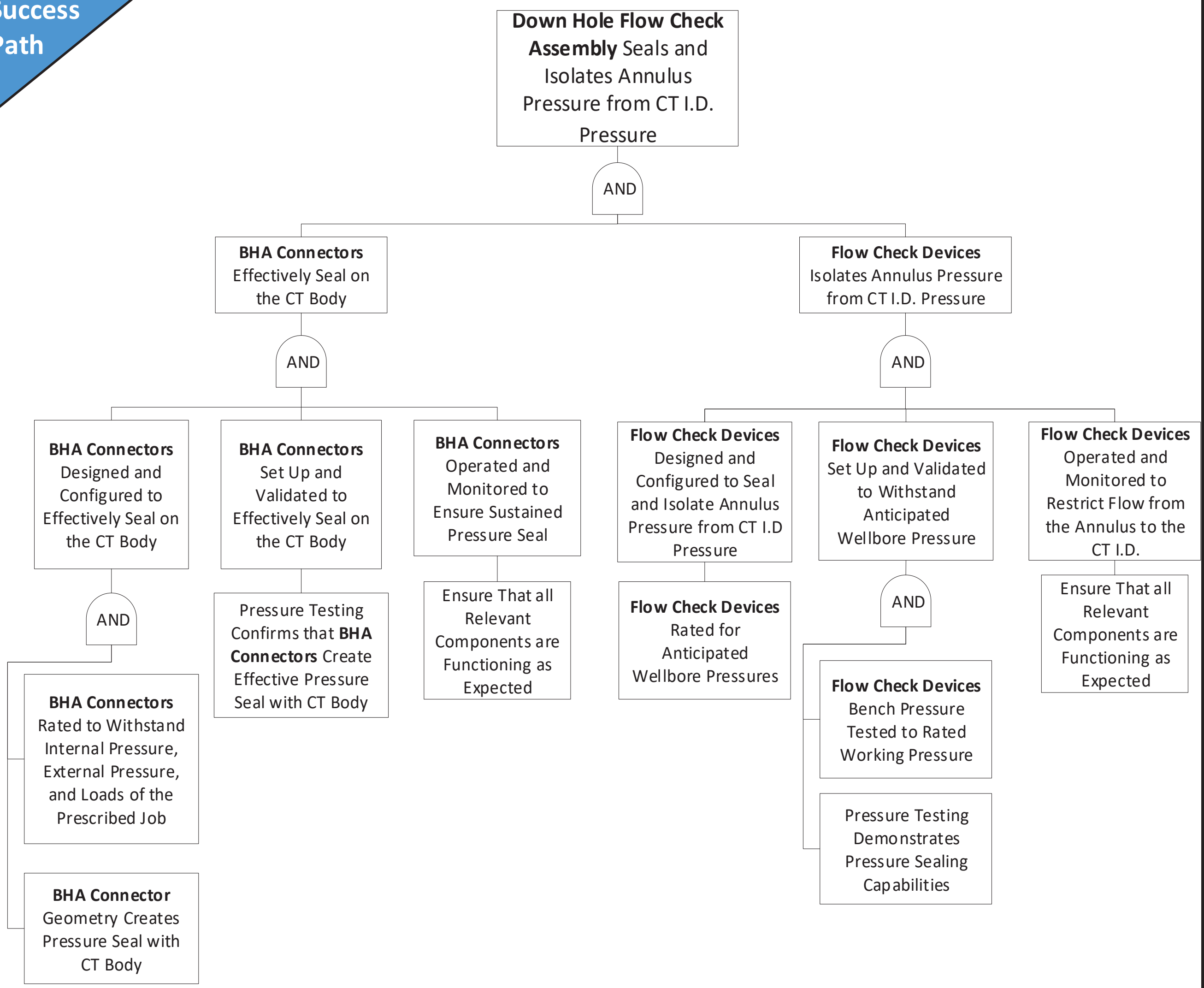
AND

- **Coiled Tubing String** Designed and Configured to Isolate CT I.D. Pressure/Flow Path from Annulus Pressure/ Flow Path
  - **Coiled Tubing String** Rated to Withstand Internal and External Pressures for the Prescribed Job
- **Coiled Tubing String** Set Up and Validated to Withstand External and Internal Pressure and Loads
  - AND
    - Inspect O.D. Surface of **Coiled Tubing String** Body
    - Confirm **Coiled Tubing String** Wall Thickness is Within Design Parameters
    - Pressure Testing Demonstrates **Coiled Tubing String** Holds Internal Pressure
    - Ensure Pressure or Load Rating Remains within Working Parameters Accounting for Bend Cycle Fatigue History, String History, or Service History
    - **Coiled Tubing Force Analyses** demonstrate fitness for purpose
- **Coiled Tubing String** Operated and Monitored to Ensure Continued Coiled Tubing Body Integrity
  - AND
    - Monitor and Record Bend Cycles and Internal Pressure
    - Monitor and Record String Repairs and Maintenence
    - Monitor and Record Service History
    - Utilize Bend Cycle Fatigue History to Anticipate Crack Initiation
    - Ensure That all Relevant Components are Functioning as Expected

Alternate Success Path	**Shear Ram and Blind Ram or Shear-Blind Ram**
Critical Support Systems	**Injector needs to be set to prevent buckling or parting**
Threat Scenarios	**Surface defects, bend cycle fatigue, and mechanical damage are major factors.**

Physical Barrier Element: Down Hole Flow Check Assembly

Applicability	**Coiled Tubing Operations**
Critical Safety Function	
Success Path	



Alternate Success Path	**Shear Ram and Blind Ram; Shear-Blind Ram (Primary and/or Dedicated)**
Critical Support Systems	• **Primary hydraulic power for Surface Rams** • **Coiled tubing body integrity**
Threat Scenarios	**Gasket wear or poor fit can prevent sealing**

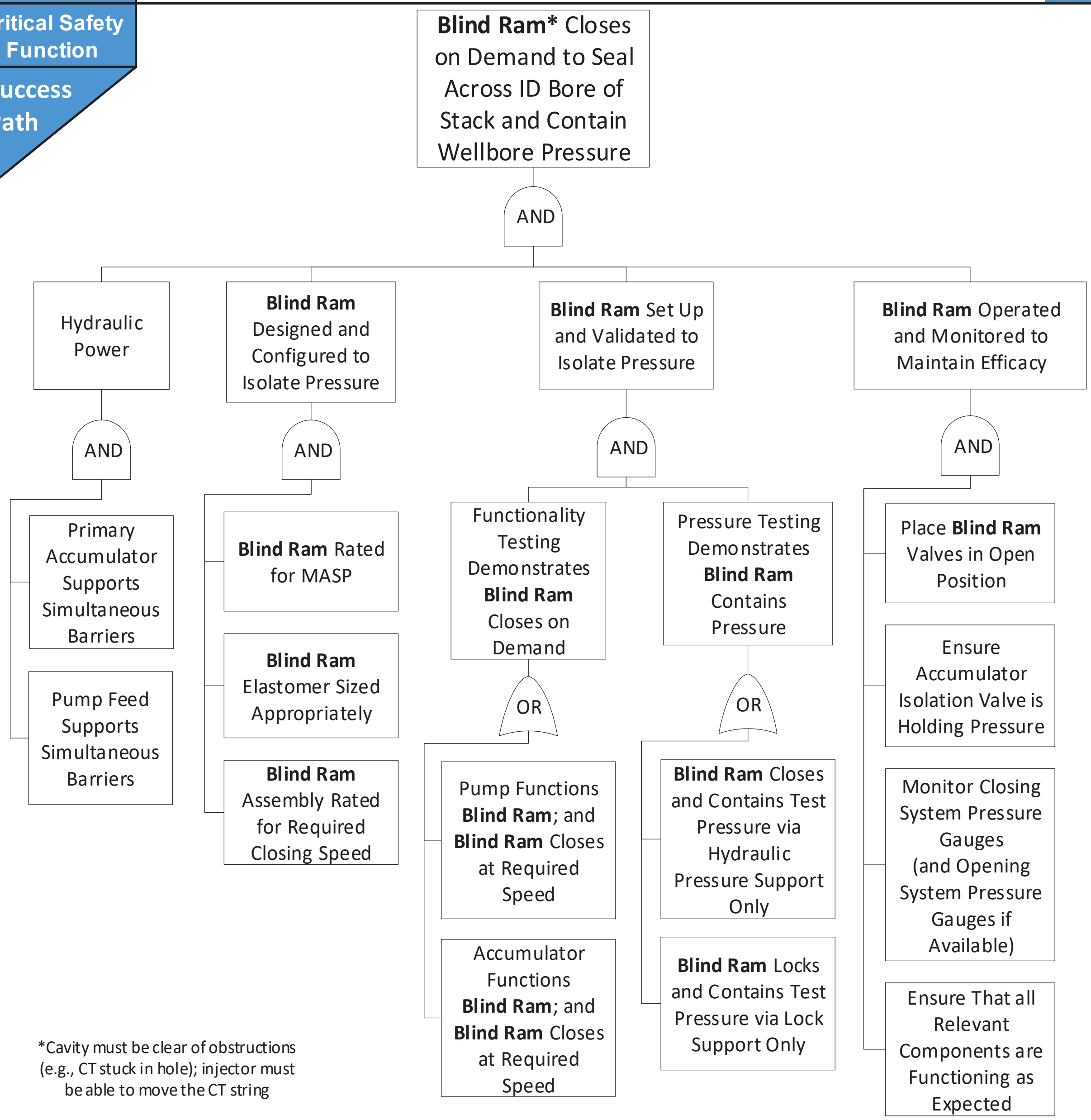
Argonne Multiple Physical Barrier Approach

Physical Barrier Element: Blind Ram as Part of Shear and Blind Ram System

Applicability	**Coiled Tubing Operations**

Critical Safety Function

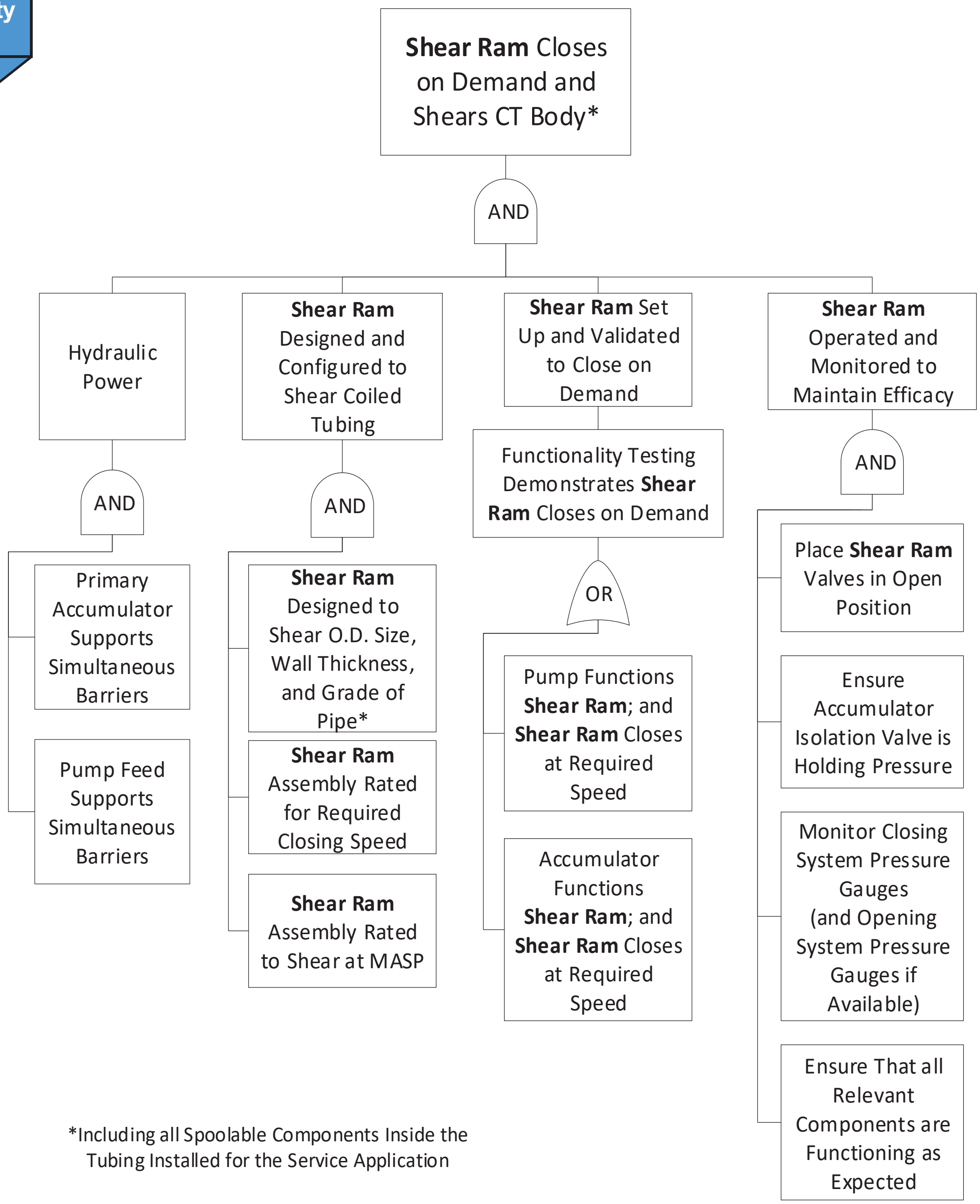
Success Path



*Cavity must be clear of obstructions (e.g., CT stuck in hole); injector must be able to move the CT string

Alternate Success Path	**Shear-Blind Ram (Primary and/or Dedicated)**
Critical Support Systems	**Primary hydraulic power to rams and Injector able to move pipe**
Threat Scenarios	**Sequence of Shear Ram closure followed by inability to pick up CT using injector after shear ram closing**

Critical Support Element: Shear Ram as Part of Shear and Blind Ram System

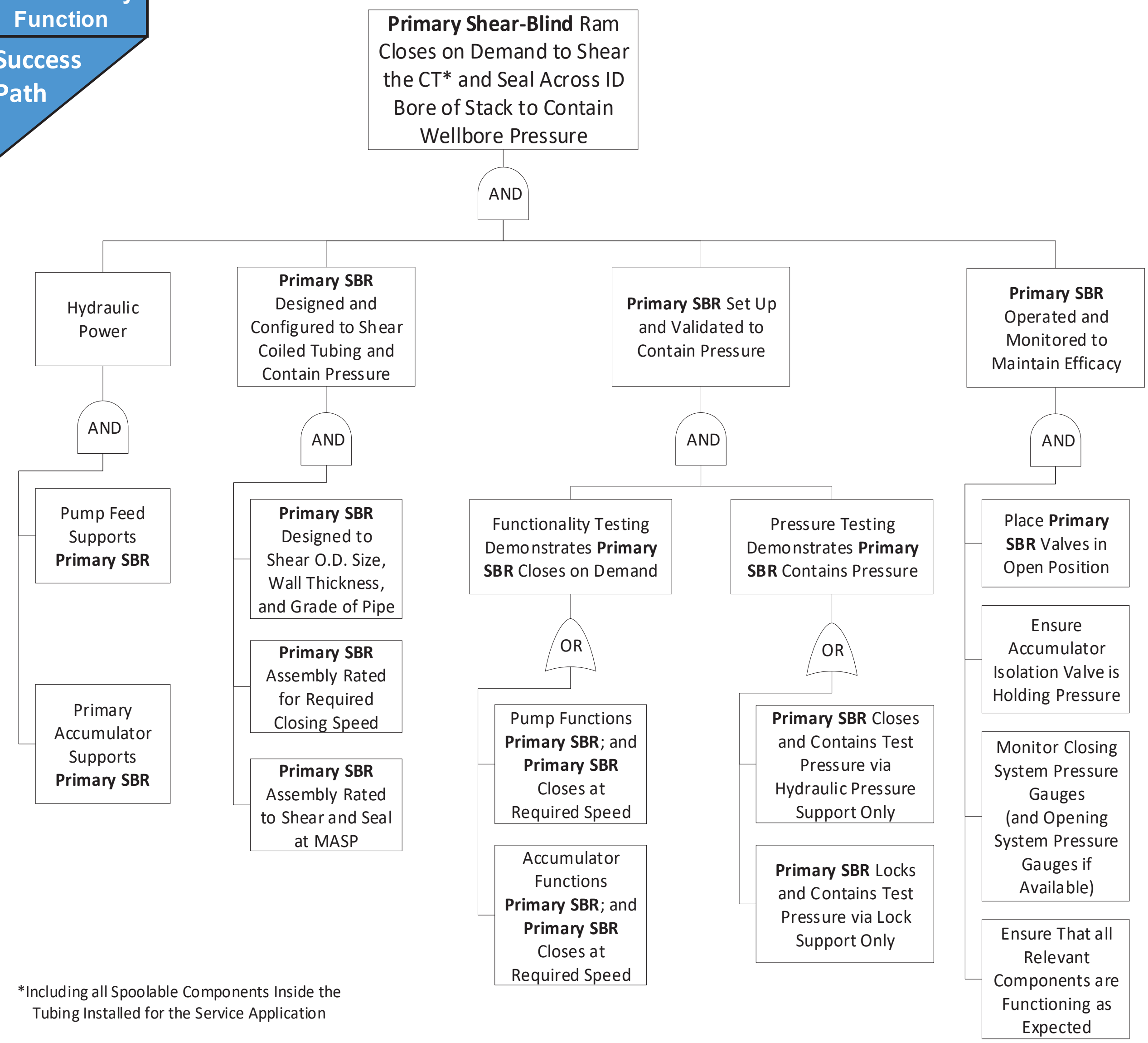
Applicability	**Coiled Tubing Operations**
Critical Safety Function / **Success Path**	

Alternate Success Path	**Shear-Blind Ram (primary and/or dedicated); Flow Control Components**
Critical Support Systems	• **Primary hydraulic power to rams and Injector** • **Slip ram supports CT string in post-shearing well control operations**
Threat Scenarios	**Sequence of Shear Ram closure, cavity clearance using Injector and Blind Ram closure is critical.**

Argonne Multiple Physical Barrier Approach

Physical Barrier Element: Primary Shear-Blind Ram
(SBR Operated Through the *Primary* Accumulator System - see p. 45)

Applicability	**Coiled Tubing Operations**
Critical Safety Function	
Success Path	



*Including all Spoolable Components Inside the Tubing Installed for the Service Application

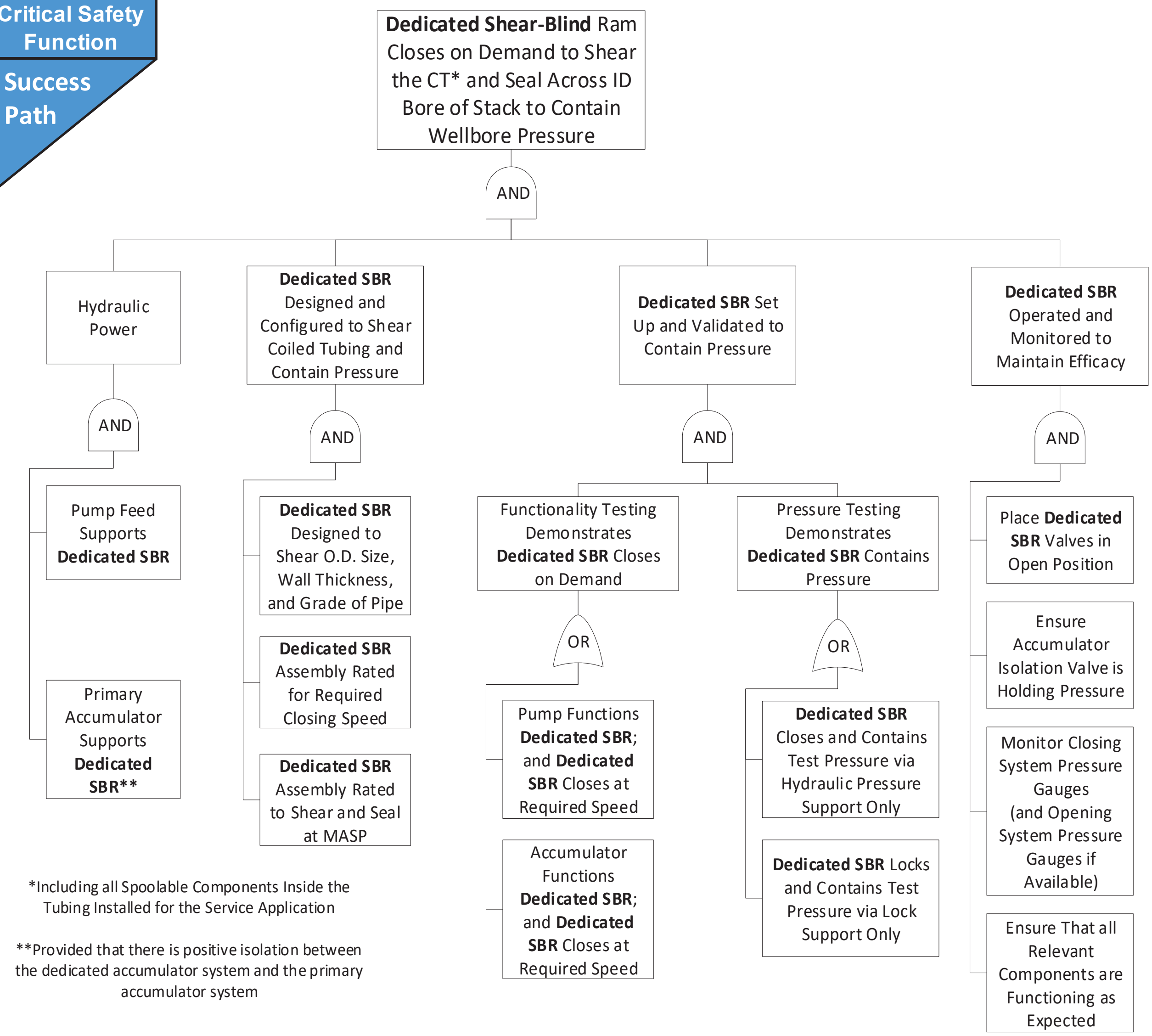
Alternate Success Path	**Blind Ram and Shear Ram; Flow Control Components; Dedicated Shear-Blind Ram**
Critical Support Systems	**Hydraulic power to rams; pipe-slip rams support CT string in post-shearing well control operations**
Threat Scenarios	**Shear blade sizing and sufficient hydraulic pressure must be confirmed.**

Physical Barrier Element: Dedicated Shear-Blind Ram
(SBR Operated Through the *Dedicated* Accumulator System - see p. 46)

Applicability	**Coiled Tubing Operations**

Critical Safety Function

Success Path

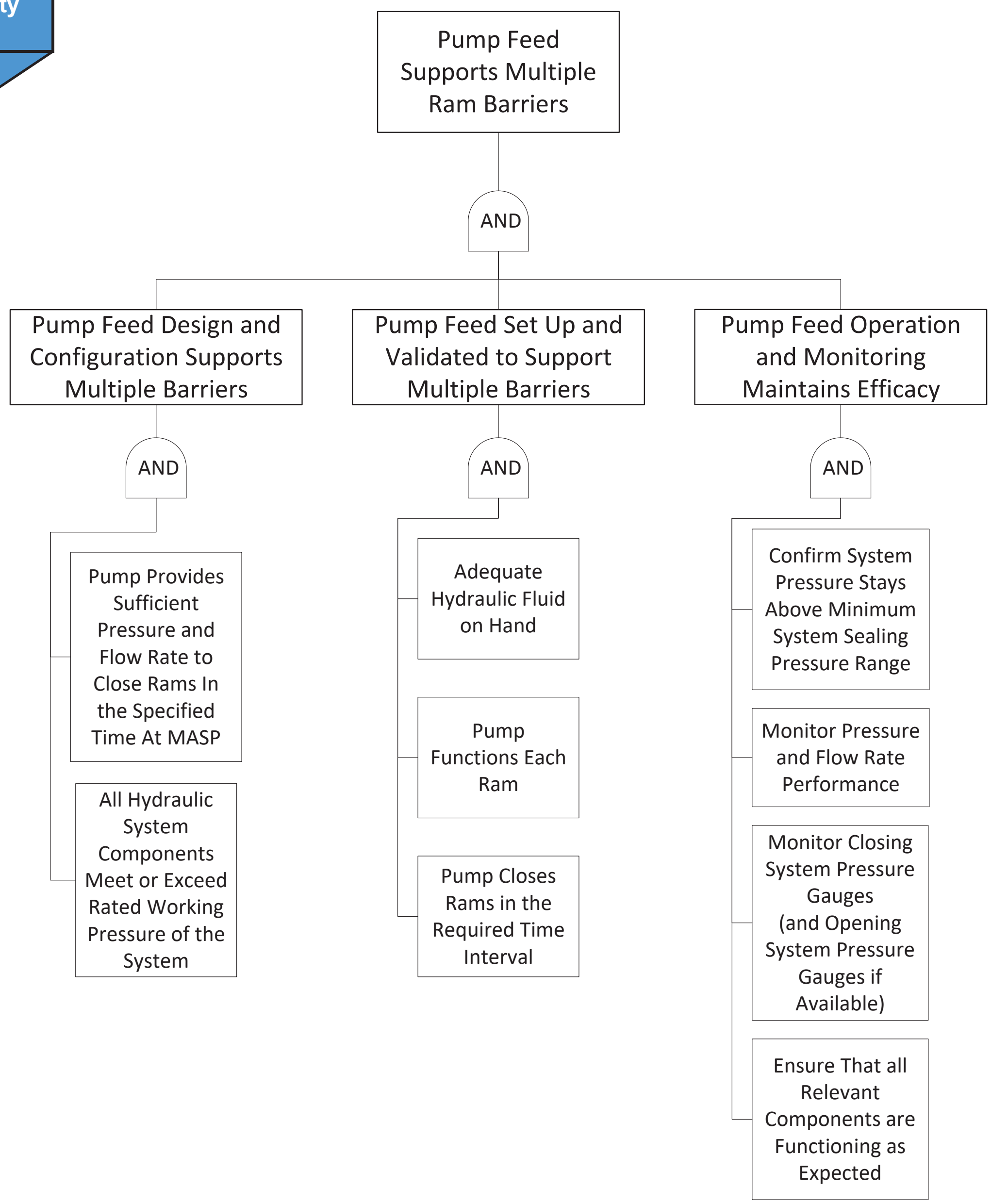


*Including all Spoolable Components Inside the Tubing Installed for the Service Application

**Provided that there is positive isolation between the dedicated accumulator system and the primary accumulator system

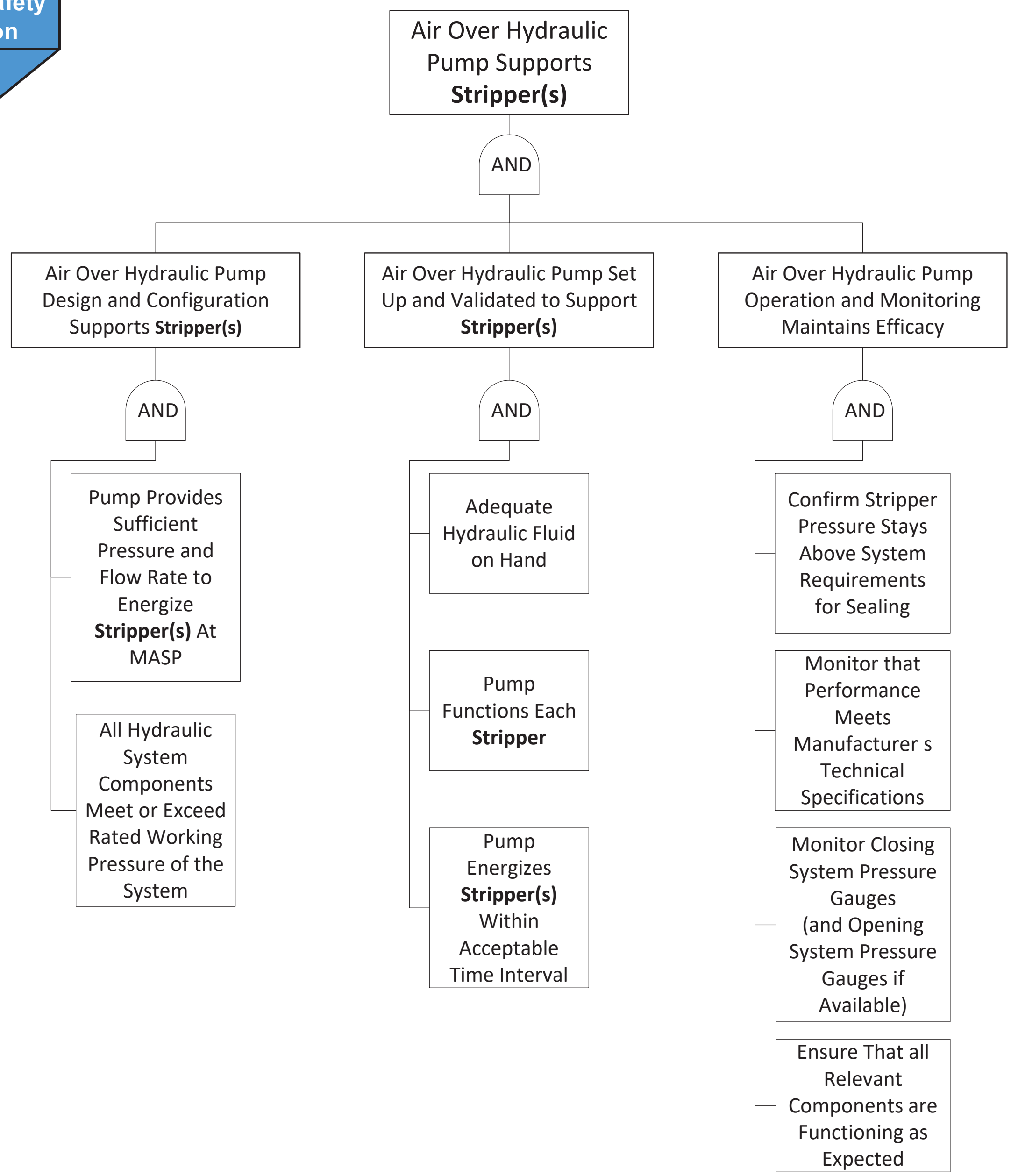
Alternate Success Path	**Blind Ram and Shear Ram; Flow Control Components; Primary Shear-Blind Ram**
Critical Support Systems	**Hydraulic power to rams; pipe-slip rams support CT string in post-shearing well control operations**
Threat Scenarios	**Shear blade sizing and sufficient hydraulic pressure must be confirmed.**

Critical Support Element: Hydraulic Pump

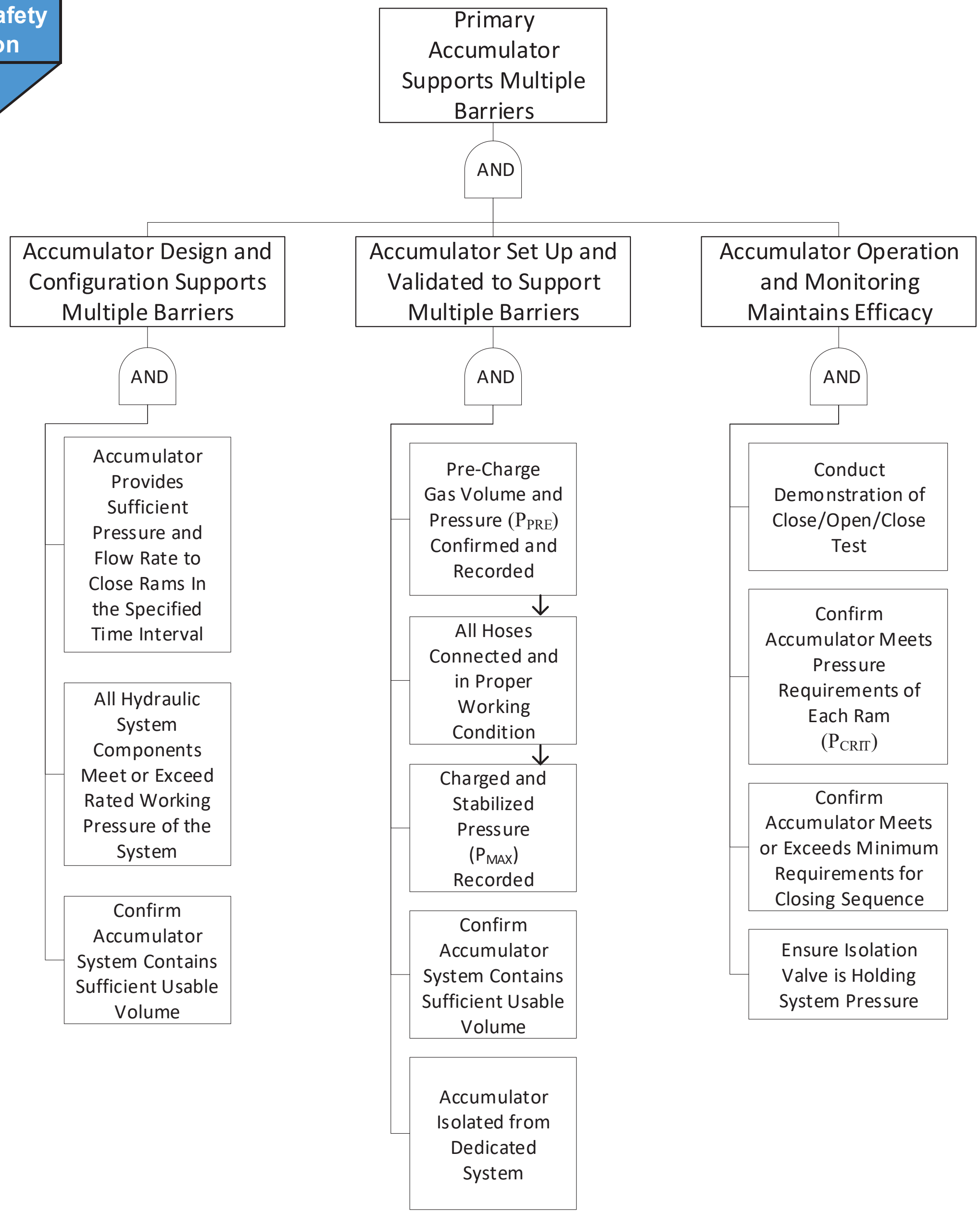
Applicability	**Coiled Tubing Operations**
Critical Safety Function / **Success Path**	
Alternate Success Path	**Accumulator Power**
Critical Support Systems	**Accumulator System**
Threat Scenarios	**Pump wear and reduced pressure/delivery are issues.**

Argonne NATIONAL LABORATORY Argonne Multiple Physical Barrier Approach

Critical Support Element: Air Over Hydraulic Pump for Stripper

Applicability	**Coiled Tubing Operations**
Critical Safety Function / **Success Path**	
Alternate Success Path	**Pipe Rams using Primary Accumulator power as source.**
Critical Support Systems	**Back-up Hydraulic Pressure Supply**
Threat Scenarios	**Loss of air pressure is a possible issue.**

Critical Support Element: Primary Accumulator System

Applicability	**Coiled Tubing Operations**
Critical Safety Function	
Success Path	
Alternate Success Path	**Hydraulic power from Power Pack**
Critical Support Systems	**Each accumulator system must have an isolation valve installed between the pressure source (primary accumulators) and the ram controls.**
Threat Scenarios	**Leakage within primary accumulator system or power fluid controls** **If unloader valve is included in the accumulator system, it may not provide adequate recharge pressure to system after cooling.**

Critical Support Element: Dedicated Accumulator System

Applicability	**Coiled Tubing Operations**

Critical Safety Function / Success Path

Dedicated Accumulator Supports Dedicated Shear-Blind Ram

AND

- Accumulator Design and Configuration Supports **Dedicated SBR**
  - AND
    - Dedicated Accumulator Provides Sufficient Pressure and Flow Rate to Close **Dedicated SBR** In the Specified Time Interval
    - All Hydraulic System Components Meet or Exceed Rated Working Pressure of the System
    - Confirm Accumulator System Contains Sufficient Usable Volume
- Accumulator Set Up and Validated to Support **Dedicated SBR**
  - AND
    - Pre-Charge Gas Volume and Pressure (P_{PRE}) Confirmed and Recorded
    - All Hoses Connected and in Proper Working Condition
    - Charged and Stabilized Pressure (P_{MAX}) Recorded
    - Confirm Accumulator System Contains Sufficient Usable Volume
    - Accumulator Isolated from Primary Accumulator System
- Accumulator Operation and Monitoring Maintains Efficacy
  - AND
    - Conduct Demonstration of Close/Open/Close Test
    - Confirm Accumulator Meets Pressure Requirements of **Dedicated SBR** (P_{CRIT})
    - Confirm Accumulator Meets or Exceeds Minimum Requirements for Closing Sequence
    - Ensure Isolation Valve is Holding System Pressure

Alternate Success Path	**Hydraulic power from Power Pack**
Critical Support Systems	**Each accumulator system must have an isolation valve installed between the pressure source (Dedicated accumulators) and the Dedicated SBR controls.**
Threat Scenarios	**Leakage within primary accumulator system or power fluid controls** **If unloader valve is included in the accumulator system, it may not provide adequate recharge pressure to system after cooling.**

Argonne Multiple Physical Barrier Approach

Critical Support Element: Injector

Applicability: **Coiled Tubing Operations**

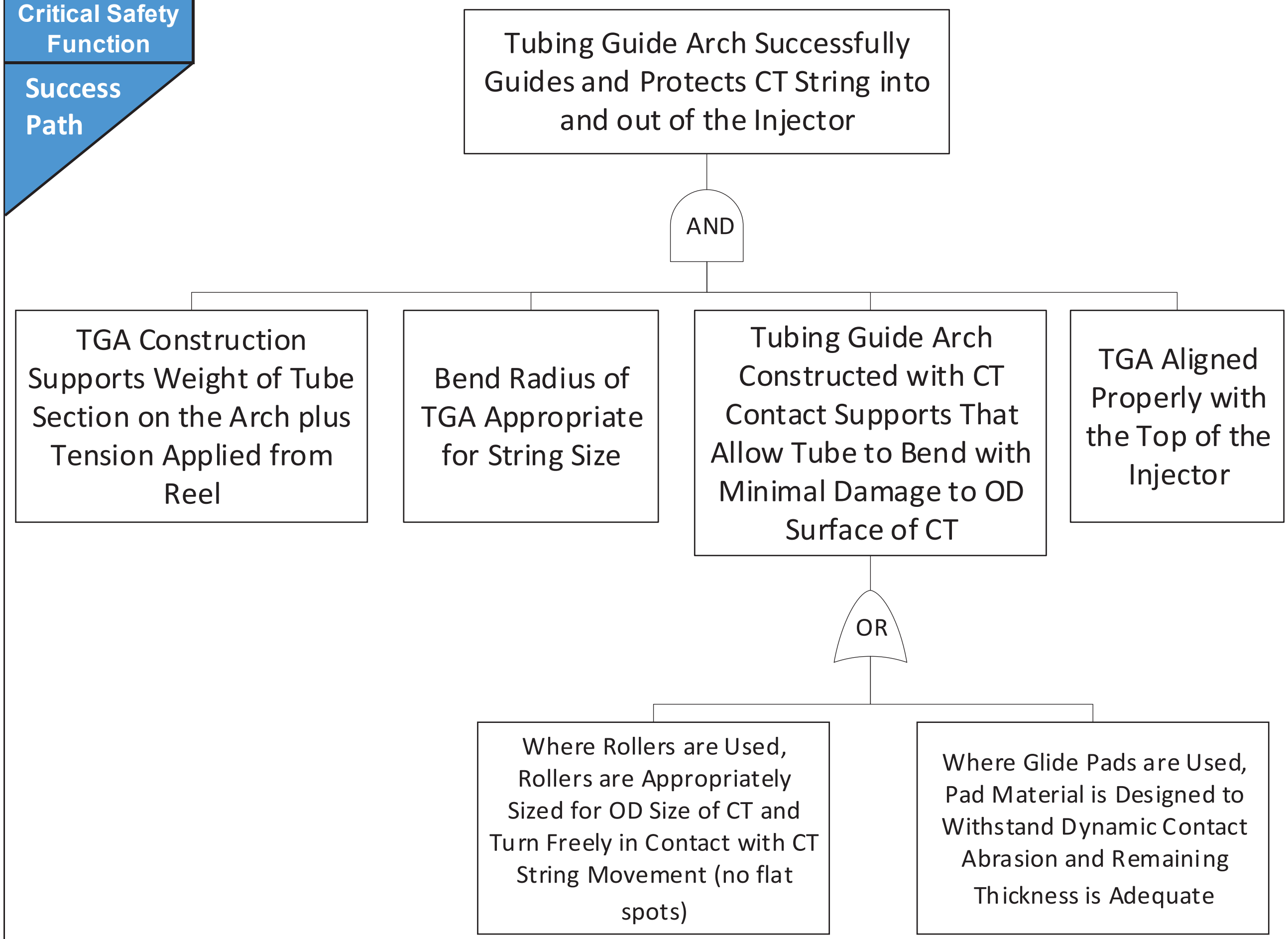
Critical Safety Function / Success Path:

- Injector Successfully Controls and Supports the CT String (AND)
  - Gripper Blocks Support the CT String without Damaging It (AND)
    - Gripper Blocks are Clean, Without Damage, and Free of Debris
    - Gripper Blocks are Sized Appropriately for OD Size of CT String
    - Traction Accumulator System Supports Skates (or Linear Beams)
    - Rollers Supporting Chain for Skates (or Linear Beams) Turn Freely and Have No Flat Spots
    - Skates (or Linear Beams) are Properly Aligned with Stripper Assembly and Anti Buckle Guide (where installed)
  - Chain and Skates (or Linear Beams) Support CT Loading (AND)
    - Drive Chain Designed to Support the Full Weight of CT String Without Imparting Damage or Excessive Wear
    - Drive Chain Tensioning System Adjusted Appropriately to Avoid Chain Buckling During CT Thrust Conditioning
    - Skates (or Linear Beams) are Designed to Load Chains and Support Full Weight of CT String
    - Skates (or Linear Beams) are Remotely Adjustable to Adequately Grip CT String
    - Skate (or Linear Beam) Force Applied to Gripper Blocks is adjusted to Secure CT String in Gripper Blocks within Structural Limits of CT String
  - Injector Motors Effectively Control Forces Applied to CT String (AND)
    - Motors Move CT String on Demand
    - Injector/ Motors Designed for Maximum Load
    - Pulling Force Adjusted to Keep CT String From Parting
    - Thrust Force Adjusted to Keep CT String from Catastrophic Buckling
    - Static Brake Controls Motor s Functions on Demand
  - Load Monitoring Devices Set Up and Calibrated Properly
  - Lift Point Pad Eyes and Slings Demonstrated to Support Maximum Rigging Load

Alternate Success Path: --

Critical Support Systems:
Injector Support/Stabilization Required (Crane, Support Stand, Lateral Guy Wires)
Power Pack Hydraulic System Required to Enable The Injector

Threat Scenarios: **The injector can cause damage to the CT string (e.g., grip/wear marks, scratches, gouges, misalignments) during operations, degrading its life/survivability.**

Critical Support Element: Tubing Guide Arch (TGA)	
Applicability	**Coiled Tubing Operations**
Critical Safety Function / **Success Path**	
Alternate Success Path	--
Critical Support Systems	**TGAs designed with hinges and hydraulic cylinders must maintain required hydraulic pressure to maintain TGA alignment.**
Threat Scenarios	**Bad rollers and/or glide pads can cause damage (e.g., scratches, gouges, adverse bending), degrading the life/survivability of the CT string.**

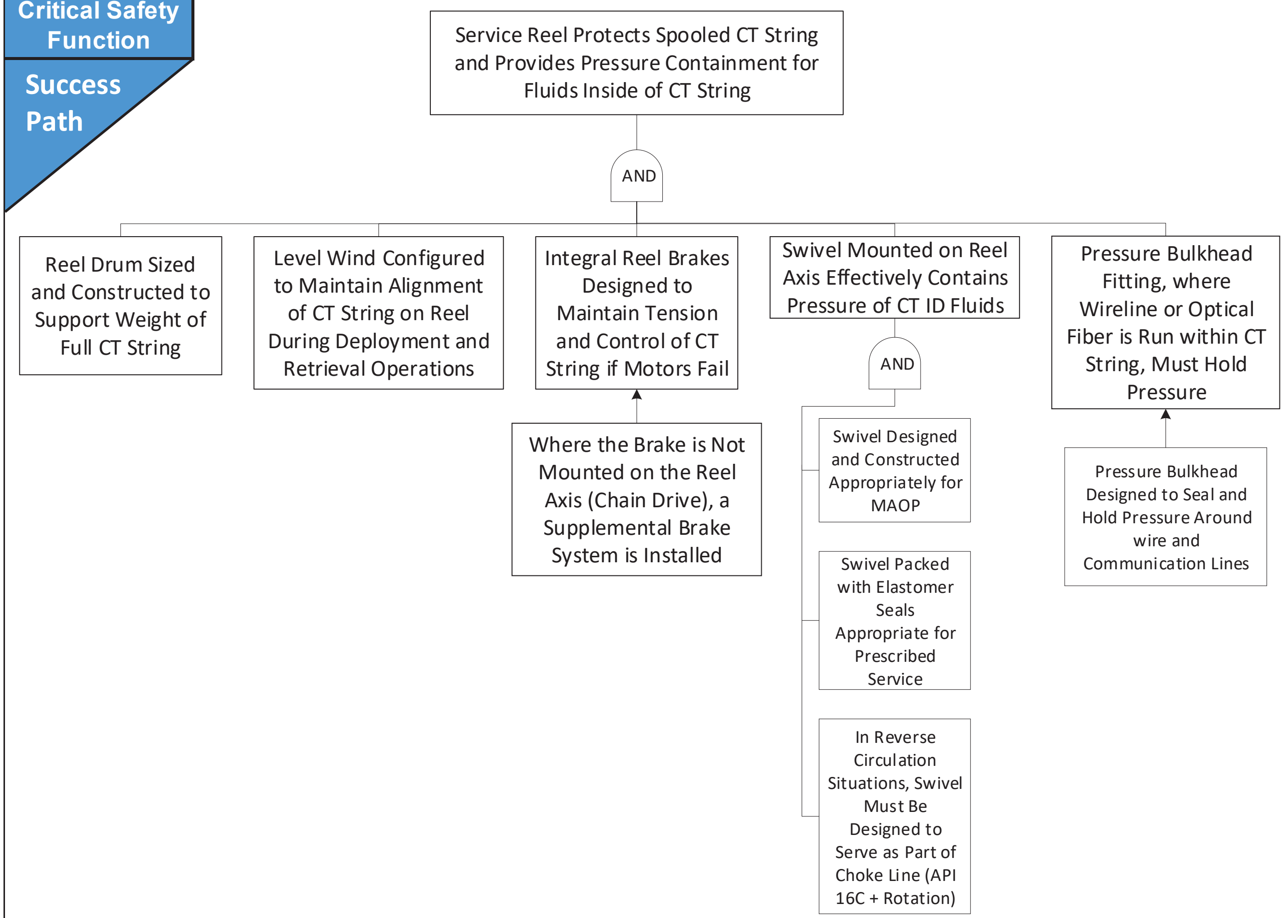
Critical Support Element: Service Reel

Applicability

Coiled Tubing Operations

Critical Safety Function

Success Path



Alternate Success Path

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Critical Support Systems

Power pack hydraulic system required to enable the reel.

Threat Scenarios

- **Loss of tension on CT string and poor alignment of string on the reel can cause damage (e.g., scratches, gouges, adverse bending), degrading its life/servieceability.**
- **Swivel and bulkhead leaks may lead to loss of pressure control.**

Appendix B

Coiled Tubing Equipment and Operations Checklist

SAS Industries Inc originally contributed a March 2018 checklist to this report. In January 2025, this checklist was replaced with a version released in March 2023. The new checklist contains cross-references to the latest API supporting documents and 30 CFR 250 regulations. - Added January 2025 by BSEE

SAS COILED TUBING WELL INTERVENTION AND EQUIPMENT CHECKLIST

Well Name: ______________________________________ Field: _________________________

Location: ____________________ Pressure Category: _______ MASP: __________ Psig

No.	ITEMS TO ADDRESS (Gray Field Items May Not Apply to Land Operations)	YES	NO
1.0	**Pre-Job: Well Intervention and Operations Information**		
1.1	Site inspection performed by Operator personnel prior to loadout.		
1.2	Hazards and response plan reviewed by Operator personnel.		
1.3	Equipment layout plan prepared and reviewed by Operator personnel.		
1.4	Piping and instrumentation drawing (P&ID) prepared and approved by Operator.		
1.5	For deepwater operations - CTLF and surface test tree spaceout prepared.		
1.6	For deepwater operations - choke line restraints upon emergency disconnect.		
1.7	For deepwater operations - kill line restraints upon emergency disconnect.		
1.8	Tree connection size: API __________ inch, ________ M psig flange rating		
1.9	Wellbore deviation survey (MD, TVD, azimuth, inclination and dogleg severity)		
1.10	Wellbore schematic (completion tubulars, lengths, tools and downhole hazards)		
1.11	Well bottomhole pressure: ____________ psig at _____°F		
1.12	Well shut-in tubing pressure: __________ psig at _____°F		
1.13	Projected kill weight density is ______ ppg and chemistry is _________________		
1.14	Proposed pumped fluid chemistry: _____________________________________		
1.15	Pumped fluid rheology: ______ ppg at _____°F (surface)		
1.16	Pumped fluid rheology: ______ ppg at _____°F (mudline)		
1.17	Pumped fluid rheology: ______ ppg at _____°F (bottomhole)		
1.18	Written job procedure reviewed and approved by Operator personnel.		
2.0	**Pre-Job: Information Provided to ________________(CT Vendor) by Operator**		
2.1	MASP of well and proposed Pressure Category for well control equipment.		
2.2	Operator hazards and response plan reviewed with CT Vendor personnel.		
2.3	Operator equipment layout and P&ID plans reviewed with CT Vendor personnel.		
2.4	Wellbore schematic and deviation survey provided to CT Vendor		
2.5	Proposed pumped fluid chemistry and rheology.		
2.6	Resident wellbore fluid types, chemistry and associated HSE hazards.		
2.7	Proposed pumping and rental pipe company to be used.		
2.8	Prescribed well intervention service to be performed.		
2.9	Desired CT string OD size and well control stack bore ID size.		
3.0	**Pre-Job: CT Workstring Design and Work History Provided to Operator by CT Vendor ____**		
3.1	CT workstring design (OD size, taper wall, grade) and length on service reel.		
3.2	CT workstring Material Test Report (MTR) and manufacturing certificate		
3.3	Most recent CT workstring weld map record and service history information.		
3.4	CT workstring bend-cycle fatigue life chart with predicted damage accumulation.		
3.5	Latest CT NDE inspection record of physical damage and dimensional changes.		
3.6	Axial load limits of CT workstring at maximum deployed depth and overpull limits.		
3.7	Predicted maximum allowable thrust load for CT outboard end.		
3.8	CT string collapse assessment performed for service at prescribed depth.		
3.9	CT workstring force analysis performed for the prescribed service.		
3.10	CT string capacity, “dry” weight and projected “wet” weight (full of prescribed fluid).		

No.	ITEMS TO ADDRESS (Gray Field Items May Not Apply to Land Operations)				YES	NO
4.0	Onsite: Well Control Stack Equipment Included in Rig-Up					
	Component	ID Bore	MAWP Rating	Connection		
4.1	Quad-Ram stack					
4.2	Dual Combi-Ram stack					
4.3	Shear-Blind Ram (single)					
4.4	Shear-Blind Ram (dedicated)					
4.5	Single Pipe Ram (below cross)					
4.6	Stripper Assembly (1st in service)					
4.7	Stripper Assembly (2nd in service)					
4.8	Rental gate valve					
4.9	Spacer spool segments					
4.10	Lubricator segments					
4.11	Flow cross outlet valves					
4.12	Returns line piping (integral)					
4.13	Choke manifold and valves					
4.14	Kill line inlet valves					
4.15	Kill line piping (integral)					
4.16	Pump line piping					
4.17	All valves immediately connected to well control stack are flanged connections.					
4.18	Flow cross valves equipped with remote-controlled hydraulic actuators.					
4.19	Kill line inlet equipped with remote, hydraulically-controlled valve or a check valve.					
4.20	Adjustable chokes equipped with remote-controlled hydraulic actuators.					
4.21	Choke manifold valves are equipped with remote-controlled hydraulic actuators.					
4.22	Sufficient hydraulic control lines are run to each well control stack component to eliminate the need to disconnect hoses for alternate function during operation.					
4.23	All well control stack ram bonnets torqued to manufacturer's specifications.					
4.24	All well control stack flange/hub bolts installed with appropriate makeup torque.					
4.25	Elastomeric seals in choke lines are appropriate for chemistry of returning fluids.					
4.26	Elastomeric seals in kill line(s) are appropriate for chemistry of fluids pumped.					
	Mechanical Performance of Barrier and Barrier - Assist Well Control Stack Rams					
4.27	Shear Ram Closing Ratio:_________ Shear-Blind Ram Closing Ratio:_________					
4.28	Shear Ram: ____________ psig hydraulic pressure to shear test tube.					
4.29	CT shear test sample: _________″ OD, _________″ wall thickness, _________ grade.					
4.30	Shear Ram "critical pressure" of ________ psig (accumulator circuit evaluation).					
4.31	Single Shear-Blind Ram: _________ psig hydraulic pressure to shear tube.					
4.32	CT shear test sample: _________″ OD, _________″ wall thickness, _________ grade.					
4.33	Single SBR "critical pressure" of ________ psig (accumulator circuit evaluation).					
4.34	Dedicated Shear-Blind Ram: _________ psig hydraulic pressure to shear tube.					
4.35	CT shear test sample: _________″ OD, _________″ wall thickness, _________ grade.					
4.36	Dedicated SBR "critical pressure" of _______ psig (accumulator circuit evaluation).					
4.37	Slip Ram Closing Ratio: __________ Pipe-Slip Ram Closing Ratio:__________					
4.38	Slip Ram: _________ psig hydraulic pressure to hold test tube to ____________ lbs.					
4.39	CT slip test sample: _________″ OD, _________″ wall thickness, _________ grade.					
4.40	Slip Ram "critical pressure" of __________ psig (accumulator circuit evaluation).					
4.41	Pipe-Slip Ram: _________ psig hydraulic pressure (hold test tube to _________ lbs).					
4.42	CT PSR test sample: _________″ OD, _________″ wall thickness, _________ grade.					
4.43	PSR "critical pressure" of ________ psig (accumulator circuit evaluation).					

No.	ITEMS TO ADDRESS (Gray Field Items May Not Apply to Land Operations)	YES	NO
5.0	**Onsite: CT Well Control Stack Accumulator Circuit – Closing Unit Design and Configuration**		
5.1	The “close-open-close” volume for CT well control stack rams is _______ gallons.		
5.2	**Option A**: All CT well control stack operations are sourced from a “Stand-Alone” Closing Unit configured to meet API Spec 16D		
5.3	Closing Unit designed with “primary” and “dedicated” accumulator circuits.		
5.4	“Primary” accumulator circuit properly configured to operate CT WC stack rams		
5.5	“Primary” accumulator circuit volume capable of “close-open-close” functions with 200 psig above precharge pressure remaining in system.		
5.6	Tests demonstrate that accumulator circuit pressure setting exceed Pcrit pressures at MASP for required Shear Ram and/or Shear-Blind Ram functions.		
5.7	“Dedicated” accumulator circuit properly configured to operate dedicated SBR		
5.8	“Dedicated” accumulator circuit volume capable of SBR “close-open-close” functions with 200 psig above precharge pressure remaining in system.		
5.9	Tests demonstrate that accumulator circuit pressure setting will exceed Pcrit pressures at MASP for required dedicated Shear-Blind Ram functions.		
5.10	**Option B**: “primary” well control stack operations from the CT Unit and the dedicated SBR operated from a “Stand-Alone” Closing Unit (Spec 16D)		
5.11	“Primary” accumulator circuit properly configured to operate CT WC stack rams		
5.12	“Primary” accumulator circuit volume capable of “close-open-close” functions with 200 psig above precharge pressure remaining in system.		
5.13	Tests demonstrate that CT accumulator circuit pressure setting will exceed Pcrit pressures at MASP for required Shear Ram and/or Shear-Blind Ram functions.		
5.14	“Dedicated” accumulator circuit properly configured to operate dedicated SBR		
5.15	“Dedicated” accumulator circuit volume capable of SBR “close-open-close” functions with 200 psig above precharge pressure remaining in system.		
5.16	Tests demonstrate that accumulator circuit pressure setting will exceed Pcrit pressures at MASP for required dedicated Shear-Blind Ram functions.		
5.17	**Option C**: All CT well control stack operations are sourced from the CT Unit accumulator “primary” and “dedicated” circuits.		
5.18	CT Unit designed with “primary” and “dedicated” accumulator circuits.		
5.19	“Primary” accumulator circuit properly configured to operate CT WC stack rams		
5.20	“Primary” accumulator circuit volume capable of “close-open-close” functions with 200 psig above precharge pressure remaining in system.		
5.21	Tests demonstrate that accumulator circuit pressure setting will exceed Pcrit pressures at MASP for required Shear Ram and/or Shear-Blind Ram functions.		
5.22	All well control stack rams functioned to confirm power from accumulator circuit.		
5.23	“Dedicated” accumulator circuit volume capable of SBR “close-open-close” functions with 200 psig above precharge pressure remaining in system.		
5.24	Tests demonstrate that accumulator circuit pressure setting will exceed Pcrit pressures at MASP for required dedicated Shear-Blind Ram functions.		
5.25	The “primary” and “dedicated” accumulator circuits are equipped with alarms to alert low pressure and low accumulator reservoir fluid level conditions.		
5.26	All well control stack rams functioned to confirm power from accumulator circuit.		
5.27	The close and open time for each well control stack ram is recorded in job log.		
5.28	Average accumulator precharge pressure observed at start-up: _________ psig (initial spike on accumulator circuit gauge when circuit is loaded)		
5.29	Maximum accumulator hydraulic charge pressure observed: _________ psig (maximum pressure observed on circuit gauge during loading)		
5.30	30-minute stabilized accumulator operating pressure observed: _________ psig (circuit gauge pressure 30 minutes after pressure loading)		
5.31	Minimum accumulator hydraulic circuit trip pressure observed: _________ psig (lower “trip” pressure of system recharge pressure from pump)		

No.	ITEMS TO ADDRESS (Gray Field Items May Not Apply to Land Operations)	YES	NO
6.0	**Onsite: CT Stripper Assembly ("First-in-Service" and "Second-in-Service")**		
6.1	Number and location of well control stack stripper assemblies identified in diagram.		
6.2	"1st in service" stripper is a ___________________ equipped with anti-buckle guide.		
6.3	"2nd in service" stripper is a __________________ equipped with anti-buckle guide.		
6.4	Top connection on upper stripper mechanically attaches to the injector		
6.5	Bottom connection on upper stripper meets API 6A (flanged / quick-union)		
6.6	New elastomeric element installed in "1st in service" stripper prior to RIH with CT.		
6.7	Elastomeric seals and element installed in "1st in service" stripper are appropriate for the chemistry of fluids to be encountered during the well intervention service.		
6.8	Top connection on lower stripper meets API 6A (flanged / quick-union)		
6.9	Bottom connection on lower stripper meets API 6A (flanged / quick-union)		
6.10	New elastomeric element installed in "2nd in service" stripper prior to RIH with CT.		
6.11	Elastomeric seals and element installed in "1st in service" stripper are appropriate for the chemistry of fluids to be encountered during the well intervention service.		
6.12	The spaceout of the strippers does not restrict the full closure of the well control stack rams when the CT BHA is located at surface.		
6.13	If wellhead pressure tap is on stripper assembly, hose connecting stripper body to Debooster/Transducer is approved for hydrocarbon service at RWP of stack.		
6.14	Sufficient hydraulic control lines are run to each stripper assembly component to eliminate the need to disconnect hoses for alternate function during operation.		
7.0	**Onsite: Coiled Tubing Bottomhole Assembly Components**		
7.1	The CT end connector identified as an "onsite installed" or "weld-on" device.		
7.2	The CT end connector has documentation and traceability to confirm that the body design and material chemistry is appropriate for the prescribed service.		
7.3	If "onsite installed" CT end connector, elastomers installed are appropriate for the fluid and temperature exposure during the well intervention operation.		
7.4	The "onsite installed" CT end connector has been load tested to __________ Lbs.		
7.5	If "weld-on" CT end connector, documentation and traceability are available to confirm material chemistry and welding procedure is approved by CT manufacturer for joining to the CT end OD, wall thickness and grade.		
7.6	If "weld-on" CT end connector, weld NDE record has been reviewed to confirm that the weld is structurally sound and capable of withstanding pressure/load.		
7.7	The "weld-on" CT end connector has been load tested to __________ Lbs.		
7.8	The CT end connector pressure tested to ________________ psig after installation.		
7.9	The CT "flow check sub" has documentation and traceability to confirm that the body design and material chemistry is appropriate for the prescribed service.		
7.10	Elastomers installed in the "flow check sub" are appropriate for the fluid and temperature exposure during the well intervention operation.		
7.11	The CT "flow check sub" has two valves installed identified as flapper / dart / ball.		
7.12	The CT BHA flow check valve sub has record of pressure tests conducted for each valve installed prior to installation onto the CT BHA end connector.		
7.13	The CT BHA flow check valve sub has been installed onto the end connector.		
7.14	The CT "Flow Check Assembly" has record of pressure tests conducted after installation on the CT BHA connector and prior to running into the well.		
7.15	All CT BHA component dimensions have been taken and a drawing prepared.		
7.16	A CT BHA fishing contingency plan is prepared and fishing tools identified.		

No.	ITEMS TO ADDRESS (Gray Field Items May Not Apply to Land Operations)	YES	NO
8.0	**Onsite: Coiled Tubing Injector**		
8.1	The injector design plate load rating (__________ Lbs.) is greater than the maximum anticipated pulling load for the prescribed service (__________ Lbs).		
8.2	The injector design is confirmed (fulcrum type/dual beam type/sheave drive).		
8.3	The injector skid frame is rigidly secured to the base plate of the injector and skates are properly aligned with the stripper assembly inlet brass.		
8.4	All lift point pad eyes have been load tested to confirm lift capability and NDE inspected to confirm no damage to the pad eyes as a result of the load test.		
8.5	The lift point pad eye inspections are within the annual NDE inspection period.		
8.6	The slings are within the annual inspection period and meet OSHA requirements (**29 CFR 1910.184**), **ASME B30.9**, **API RP 9B** and **API RP 2D**.		
8.7	All gauges are at proper zero and gauge faces are unobstructed.		
8.8	The drive motors have been function tested and chains turn properly.		
8.9	The injector brake has been function tested and works properly.		
8.10	Gripper blocks inspected for wear, debris and excessive oil / grease accumulation.		
8.11	Chain traction system equipped with a functioning accumulator system.		
8.12	The chain traction accumulator system is precharged to ________ psig.		
8.13	The coiled tubing is stabbed through the injector chains and stripper, with the recommended minimum chain traction pressure applied for starting in the well.		
8.14	The “pipe heavy” load cell type is identified (bladder type / strain gauge type).		
8.15	The “pipe heavy” load cell transport/restraining bolts are sufficiently backed off.		
8.16	If “pipe heavy” load cell is bladder type, hose to weight indicator gauge has been properly purged with clean ___________fluid (displace air/contaminated fluid).		
8.17	The “pipe heavy” bladder type load cell is properly pumped up and “zeroed”.		
8.18	The “pipe light” load cell type is identified (bladder type / strain gauge type)		
8.19	The “pipe light” load cell transport/restraining bolts are sufficiently backed off.		
8.20	If “pipe light” load cell is bladder type, hose to weight indicator gauge has been properly purged with clean ____________fluid (displace air/contaminated fluid).		
8.21	The “pipe light” bladder type load cell is properly pumped up and load cell setting has a weight indicator reading equal to the weight of the injector drive section.		
8.22	All hydraulic hoses are connected with no leaks observed at the quick connects.		
8.23	The injector is equipped with an “anti-fall” pole and fall arrest pulley mechanism.		
8.24	The injector “anti-fall” pole and fall arrest pulley have been confirmed to meet OSHA requirements (**29 CFR 1910.66**).		
8.25	The chain carrier rollers or skate rollers are round and turn freely (no flat spots).		
8.26	The injector has a pollution pan equipped with a drain valve and hose.		
9.0	**Onsite: Tubing Guide Arch (TGA)**		
9.1	The TGA rollers are appropriate for the size of CT to be run.		
9.2	The TGA rollers turn freely and are properly greased.		
9.3	The TGA is constructed with load support braces rigidly secured to the injector.		
9.4	The TGA structure is properly aligned with the injector drive section chains.		
9.5	All TGA lift point pad eyes have been load tested to confirm lift capability and NDE inspected to confirm no damage to the pad eyes as a result of the load test.		
9.6	TGA lift point pad eye inspections are within the annual NDE inspection period.		
9.7	The TGA slings are within the annual inspection period and meet OSHA requirements (**29 CFR 1910.184**), **ASME B30.9**, **API RP 9B** and **API RP 2D**.		

No.	ITEMS TO ADDRESS (Gray Field Items May Not Apply to Land Operations)	YES	NO
10.0	**Onsite: Prime Mover and Power Pack Hydraulic Circuits**		
10.1	All lift point pad eyes have been load tested to confirm lift capability and NDE inspected to confirm no damage to the pad eyes as a result of the load test.		
10.2	The lift point pad eye inspections are within the annual NDE inspection period.		
10.3	The slings are within the annual inspection period and meet OSHA requirements (**29 CFR 1910.184**), **ASME B30.9**, **API RP 9B** and **API RP 2D**.		
10.4	The prime mover/power pack skid is equipped with a pollution pan.		
10.5	All gauges are at proper zero and gauge faces are undamaged/unobstructed.		
10.6	The prime mover gauge panel is equipped with a functional engine tachometer.		
10.7	Engine radiator, oil level and transmission fluid level checked prior to start up.		
10.8	Engine radiator coolant protection adequate for service conditions.		
10.9	Engine mufflers are adequately insulated/wrapped as per **API RP 14C Para. 4.2** (also see **30 CFR 250.856 (a)** for offshore operations).		
10.10	Engine exhaust system equipped with spark arrester device(s) **(30 CFR 250.856 a)**.		
10.11	Diesel fuel and hydraulic oil tanks properly labeled for volume and contents.		
10.12	Diesel fuel tanks checked for fill level and have fire extinguishers placed nearby.		
10.13	Hydraulic oil tank level checked and volume adequate for intended service.		
10.14	If the power pack skid is equipped with components capable of generating electrical current, the power pack skid is grounded (6 AWG wire minimum).		
10.15	If the power pack skid is equipped with components capable of generating electrical current, the power pack conforms to **API RP 500** zone ratings.		
10.16	Prime mover skid equipped with a normal kill switch (______ seconds to kill).		
10.17	Prime mover skid equipped with an emergency kill switch (______ seconds to kill) which activates an air intake shut-off device (**30 CFR 250.856 b**) at a minimum.		
10.18	Hydraulic pump for injector is set to relieve injector motor pressure at 80% load limit for thrust or pull conditions. (see **MMS Safety Alert 187**). If **NO**, then the console pilot valve must be set to limit the injector thrust and pull loads to 80%.		
11.0	**Onsite: Service Reel Skid and Drum**		
11.1	All lift point pad eyes have been load tested to confirm lift capability and NDE inspected to confirm no damage to the pad eyes as a result of the load test.		
11.2	The lift point pad eye inspections are within the annual NDE inspection period.		
11.3	The slings and spreader bar are within annual inspection period and meet OSHA requirements (**29 CFR 1910.184**), **ASME B30.9**, **API RP 9B** and **API RP 2D**.		
11.4	The service reel swivel is properly greased. The swivel was last repacked on ________________ and has _____________ running feet since last repacking.		
11.5	Elastomeric seals in swivel and piping appropriate for chemistry of fluids pumped.		
11.6	All guards are installed on chain-drive mechanisms.		
11.7	The lubrication mechanism used to oil the tubing on the reel is **NOT ASPIRATED** and does not create a mist when applied onto the tubing.		
11.8	The service reel pump line piping manifold has at least one isolation valve dressed with appropriate seals installed between the pump line and the service reel swivel.		
11.9	The service reel plumbing has at least one isolation valve dressed with appropriate seals installed between the swivel and the connection to the coiled tubing string.		
11.10	The service reel plumbing has at least one gauge ball/pig launcher fixture between the swivel and the connection to the coiled tubing string.		
11.11	The coiled tubing connection to the service reel plumbing is with a Figure 1502 hammer union fitting welded onto the coiled tubing (reference end).		
11.12	The service reel skid is equipped with a pollution pan.		
11.13	If service reel drum equipped for chain drive, a friction-type brake is installed.		
11.14	Pressure bulkhead sealing material for E-line/Fiberoptic lines appropriate for fluids.		

No.	ITEMS TO ADDRESS (Gray Field Items May Not Apply to Land Operations)	YES	NO
12.0	**Onsite: Coiled Tubing Console**		
12.1	All lift point pad eyes have been load tested to confirm lift capability and NDE inspected to confirm no damage to the pad eyes as a result of the load test.		
12.2	The lift point pad eye inspections are within the annual NDE inspection period.		
12.3	The slings and spreader bar are within annual inspection period and meet OSHA requirements (**29 CFR 1910.184**), **ASME B30.9**, **API RP 9B** and **API RP 2D**.		
12.4	The control console skid is equipped with a pollution pan.		
	The control console is equipped with the critical monitoring devices shown below:		

	Display Component	Calibration Date	Operating Range		YES	NO
12.5	"Pipe heavy" Weight Indicator		Lbs.			
12.6	"Pipe light" Weight Indicator		Lbs.			
12.7	Well Head Pressure		Psig			
12.8	Circulating Pressure		Psig			
12.9	Weight Indicator Recorder		Lbs.			
12.10	Pressure Recorder		Psig			
12.11	Coiled Tubing Counter		Feet			
	The control console is equipped with equipment parameter devices shown below:					

	Display Component	Maximum Pressure	Operating Range	YES	NO
12.12	Stripper Hydraulic Pressure	Psig	Psig		
12.13	Accumulator Supply Pressure	Psig	Psig		
12.14	Well Control Stack Pressure	Psig	Psig		
12.15	Injector Pilot Pressure	Psig	Psig		
12.16	Chain Traction Pressure	Psig	Psig		
12.17	Chain Tension Pressure	Psig	Psig		

No.	ITEMS TO ADDRESS	YES	NO
12.18	The control console panel is equipped with a functional engine tachometer.		
12.19	All gauge faces and monitoring device displays are clean and view unobstructed.		
12.20	All gauges/monitoring demonstrated to be functional and zero properly.		
12.21	If the control console skid is equipped with components capable of generating electrical current, the console skid is grounded (6 AWG wire minimum).		
12.22	If the control console skid is equipped with components capable of generating electrical current, the control console conforms to **API RP 500** zone ratings.		
12.23	Control console is equipped with a normal kill switch (_______ seconds to kill).		
12.24	Control console is equipped with an emergency kill switch (______ seconds to kill).		
12.25	If the hydraulic pump for injector **does not** limit the injector motor pressure to 80% of thrust or pull load limit, injector pilot valve on console is set to limit the injector thrust and pull loads to 80% of maximum allowable loads.		
12.26	Console has chain traction pressure versus injector load chart displayed.		
12.27	Console has chain tension pressure versus injector load chart displayed.		
12.28	Console is equipped with fire extinguisher. (Size: _________Lb. Type: ________)		
12.29	Console doors and windows in good working order.		
12.30	If console is elevating, steps and landing used for entering and departing the console cab are configured with hand rails and are in compliance with OSHA.		
12.31	All electrical connections and extension power cords in good working order and comply with the classification requirements of **API RP 500**.		
12.32	Control console is equipped with manual hydraulic pump(s) for emergency stripper well control pressure applications.		

No.	ITEMS TO ADDRESS				YES	NO
13.0	**Onsite: Pressure Deboosters and Transducers**					
13.1	The Circulating Pressure Debooster is properly “pumped down” and hose to CP gauge purged with clean ________________ fluid (displace air/contaminated fluid).					
13.2	Elastomeric seals in contact with CP source appropriate for fluid chemistry.					
13.3	The Wellhead Pressure Debooster is properly “pumped down” and hose to WHP gauge purged with clean ________________ fluid (displace air/contaminated fluid).					
13.4	If installed on stack, Wellhead Debooster piping is high-pressure SS tubing.					
13.5	Elastomeric seals in contact with WHP source appropriate for fluid chemistry.					
13.6	Where used, pressure transducer electrical connections and cords in good working order and comply with the classification requirements of **API RP 500**.					
14.0	**Onsite: Service Pumping Equipment**					
14.1	All lift point pad eyes have been load tested to confirm lift capability and NDE inspected to confirm no damage to the pad eyes as a result of the load test.					
14.2	The lift point pad eye inspections are within the annual NDE inspection period.					
14.3	The slings are within the annual inspection period and meet OSHA requirements (**29 CFR 1910.184**), **ASME B30.9**, **API RP 9B** and **API RP 2D**.					
14.4	The pump skid is equipped with a pollution pan.					
14.5	All gauges are at proper zero and gauge faces are undamaged/unobstructed.					
14.6	Engine radiator, oil level and transmission fluid level checked prior to start up.					
14.7	Engine radiator coolant protection adequate for service conditions.					
14.8	Engine mufflers are adequately insulated/wrapped as per **API RP 14C Para. 4.2** (also see **30 CFR 250.856 (a)** for offshore operations).					
14.9	Engine exhaust system equipped with spark arrester device(s). **(30 CFR 250.856 a)**					
14.10	Diesel fuel and hydraulic oil tanks properly labeled for volume and contents.					
14.11	Diesel fuel tanks checked for fill level and have fire extinguishers placed nearby.					
14.12	Hydraulic oil tank level checked and volume adequate for intended service.					
14.13	If the pumping skid is equipped with components capable of generating electrical current, the power pack skid is grounded (6 AWG wire minimum).					
14.14	If the pumping skid is equipped with components capable of generating electrical current, the power pack conforms to **API RP 500** zone ratings.					
14.15	Pumping skid equipped with a normal kill switch (______ seconds to kill).					
14.16	Pumping skid equipped with an emergency kill switch (______ seconds to kill) which activates an air intake shut-off device (**30 CFR 250.856 b**) at a minimum.					
14.17	If the pumping unit is equipped with an automatic transmission, the transmission interlock engages at a speed of _________RPM.					
14.18	The predetermined pump rates anticipated for the prescribed service have been reviewed with the pump operator.					
14.19	Plunger Size: __________” OD Plunger Stroke Length: __________”					
14.20	Pump rate tests have been performed to confirm the following information:					
	Pump Rate	Engine Speed	Pump Gear	Plunger Speed	Pump Pressure	
	BPM	RPM		SPM	Psig	
	BPM	RPM		SPM	Psig	
	BPM	RPM		SPM	Psig	
14.21	Pump line pressure relief valve is installed (pressure setting of __________ Psig.					

Operator Representative Date

Service Vendor Representative Date

Appendix C

A Summary of the Coiled Tubing Equipment and Operation Training Materials

Learning Modules
Module 0: Introduction to Multiple Physical Barriers: A Risk-Informed Perspective

Module 1: Coiled Tubing Surface Handling Equipment and Performance Specifications

Module 2: Coiled Tubing Manufacturing, String Design, and Service Life Considerations

Module 3: Coiled Tubing Forces Encountered and Hydraulic Effects of Fluids Pumped Through CT Workstrings

Module 4: Coiled Tubing Well Control Equipment (WCE) Components

Module 5: Coiled Tubing Well Control Equipment (WCE) Assist Components

Module 6: Coiled Tubing Well Control Operating Systems

Module 7: Pressure Testing Equipment and Industry Best Practices[6]

Module 8: Introduction to Coiled Tubing Well Control Barrier Equipment Inspection Guidelines

Class Exercises

- Class Exercise A: Coiled Tubing Equipment and Operation Checklist Following Current BSEE Guidelines
- Class Exercise B: Coiled Tubing Well Control Equipment Rig-Up Assembly for Wells with Specified Conditions
- Class Exercise C: Coiled Tubing Well Control Equipment Operating Systems Design and Preparation
- Class Exercise D: Coiled Tubing Well Control Equipment Pressure Testing Systems and Preparation
- Class Exercise E: Coiled Tubing Well Control Equipment and Process Risk-Informed Checklist

Appendices

- Appendix 1A: Notes and clarification on coiled tubing equipment and specifications
- Appendix 1B: Additional information on coiled tubing critical monitoring devices
- Appendix 2: Well servicing grade coiled tubing tables
- Appendix 3: Coiled Tubing Well Control Barrier Success Paths
- Appendix 4: Coiled Tubing Well Intervention and Equipment Checklist

[6] This Module was added upon BSEE Inspection Team's request during the preliminary training course and was incorporated into the live training courses.

- Appendix 5: Preliminary Reading; Conversation Primer.[7]

[7] Source: https://www.catalyst.org