Formulating Guidance on Hydrotesting Deepwater Oil and Gas Pipelines

Final Report

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List of Acronyms

BASM	=	Best Available and Safest Methodology
BSDV	=	Boarding Shut-Down Valve
BSEE	=	Bureau of Safety and Environmental Enforcement
EASP	=	Elevation Adjusted Source Pressure
GOMR	=	Gulf of Mexico Region
MAOP	=	Maximum Allowable Operating Pressure
MESP	=	Maximum Expected (Internal) Surface Pressure
MSP	=	Maximum Source Pressure
PIP	=	Pipe in Pipe
RP	=	Recommended Practices
RWP	=	Rated Working Pressure
WHSITP	=	Wellhead Shut-in Tubing Pressure

1. Introduction

1.1 Background

As oilfield exploration has advanced into deeper waters, BSEE has encountered different approaches to hydrotesting deepwater pipelines and risers. Different pipeline designs [for example, pipe in pipe (PIP) and single pipe] introduce specific problems to BSEE pipeline engineers when considering hydrotest requirements. In shallow-water fixed-platform pipeline design, parameters such as product gradient, water depth, hydrotest pressures, and hydrotest location are well understood and accepted. However, as pipelines are being constructed for deeper water depths, environments are encountered that significantly alter the way pipelines are designed, hydrotested, and assigned regulatory specifics such as Maximum Allowable Operating Pressure (MAOP) and Maximum Source Pressure (MSP). As water depths increase to 10,000 feet and beyond, BSEE recognizes that several factors must be considered as they impact hydrotest methodology. These include:

1. BSEE design and hydrotest requirements as specified in 30CFR 250.1003(b)(1)and BSEE NTL 2009-G28, which allows the use of API RP 1111 [Ref 2] as an Alternative Compliance when approved

2. Pipeline design (i.e., PIP pipeline, single-pipe pipeline, etc.)

3. The difference between hydrotesting at the surface vs. at the mudline, and pipeline product fluid pressure gradient (i.e., gas, oil, or a combination of oil, water, and gas)

To address these issues relating to hydrotesting in deep water for BSEE and Industry, BSEE awarded to Stress Engineering Services, Inc. (Stress) a contract (BSEE Order No. E12PX00069) to help develop and evaluate the Best Available and Safest Methodology (BASM) to hydrotest deepwater pipelines and risers. Results and recommendations developed under this program are reported here.

1.2 Objective

The purpose of this report on hydrotesting deepwater pipelines is to provide industry-based BASM guidance to BSEE pertaining to certain alternate procedures and equipment (alternate-compliance) requests from the regulations in 30 CFR 250 Subpart J, specifically paragraphs 250.1002 and 250.1003. These guidelines pertain specifically to hydrotesting of deepwater pipeline system tiebacks from subsea wells to surface-based floating production systems and deepwater export pipeline and riser systems to downstream facilities under DOI jurisdiction. As described here, “pipelines” include flowlines, export pipelines, water-injection pipelines, gas-lift pipelines, and other pipeline systems. They include both manufactured pipe and fabricated elements in the pipeline system with maximum water depths to 10,000 feet.

1.3 Scope of Work

The Scope of Work that has been accomplished under this program includes the following tasks (albeit not necessarily in the sequence shown):

- *Task 1: Identify and define all critical deepwater pipeline terms such as Barrier Concept, MAOP, MSP, etc.*
- *Task 2: Compare critical differences between deepwater pipelines and shallow-water pipelines.*
- *Task 3: Discuss the regulatory hydrotest requirements for deepwater pipelines and alternative hydrotest methodologies used or proposed by industry.*
- *Task 4: Identify different methodologies for deepwater pipeline hydrotesting.*
- *Task 5: Based on sound engineering principles and detailed analyses, identify the BASM to hydrotest deepwater Gulf of Mexico oil and gas pipelines given the types of system components and testing locations.*
- *Task 6: Identify all pros and cons to consider when conducting a hydrotest of system components and testing locations.*

Based on BSEE requirements and sound engineering practices, the main drivers in developing these guidelines were as follows:

1. Recommendations are to be aligned with BASM.
2. The guidelines are to honor the physics of the deepwater pipeline environment, which requires consideration of local internal fluid hydrostatic pressure as well as local external hydrostatic pressure on pipes and components.
3. Driver #2 listed above requires that local pressure conditions along the pipeline and riser be considered, not only pressures at one of the pipeline ends.
4. The guidelines are to be consistent with API RP 1111, which is recognized by the industry as one of the most competent and up-to-date Recommended Practices (RP) for deepwater pipeline and flowline systems.
5. Where design of components falls outside the scope of API RP 1111, guidelines are to be in conformance with existing API or ASME industry standards. Where necessary, recommendations will be offered for consideration by API committees (in particular, API

17) to supplement relevant standards with guidance for deepwater design and hydrostatic test conditions.

1.4 Industry Workshops

To closely involve experts from the Oil and Gas Industry in the development of these Guidelines, Stress conducted two broad-based industry workshops for oil companies, suppliers, and BSEE. The primary objective was to discuss with key participants the pros and cons of regulations currently in place, and collect industry advice on currently used and/or recommended deepwater pipeline/riser hydrotesting practices.

- **Workshop 1** – Conducted on October 17, 2012 at Stress Engineering Services in Houston, Texas. Various representatives from Industry met with BSEE and the project technical team to discuss these issues and collect comments and advice on the regulatory hydrotest requirements for deepwater pipelines and alternative hydrotest methodologies used or proposed by industry. The day-long workshop format permitted participants from industry and BSEE to discuss hydrotest issues while Stress documented the discussions for use in preparing a first draft of improved guidelines.

- **Workshop 2** – Conducted on November 27, 2012, also at Stress. Industry representatives met again to review and revise a summary of potential guideline components based on discussions in the first Workshop, as well as receive and document discussions and feedback in this second Workshop.

- Results from these workshops were then documented in a working draft report that was written jointly by several key representatives from industry (listed on page ii).

Thus, the guidelines presented in this report are based on representative industry experience, and thus the Contractor provided primarily technical and administrative support to the industry representatives. So the following guidelines are broadly supported by Industry Participants from the two workshops conducted during this program.

1.5 Contents of Report

Section 2 of this report lays out the basic technical issues that have raised questions regarding hydrotesting pipelines in deeper waters. Various guidelines and recommendations are listed and described in Section 3. Attached to this report in Appendix A are examples of different pipeline systems configurations and test conditions with drawings and accompanying explanations.

It should be emphasized that the guidance provided here applies to DOI-regulated pipelines, flowlines, and risers to deepwater floating facilities. In this document, the terms “pipelines” and “flowlines” are used interchangeably. Some deepwater pipelines are regulated by DOT. The same guidelines are equally applicable to such pipelines, but there may be other regulations (e.g., 49 CFR 195, 192) that must be considered for DOT-regulated pipelines, and alternate compliance to those regulations may require interaction with other governmental entities.

2. Issues for Hydrotesting in Deep Water

Hydrotesting is one of the quality-control measures used to ensure that installed pipeline systems are fit for service. Qualification of the individual components of the pipeline for the intended service is an integral part of the design process. Hydrotest loads are one of the loads a pipeline system experiences in its service life, and these loads are also considered in the design process. For deepwater subsea systems, external pressure loadings must be considered in the design to be consistent with the fundamental physics. Hydrostatic conditions—both internal and external—are important for determining internal and external pressure loads at all locations.

It is very important that all guidelines, industry standards or RPs, and design documents (including permit applications) be explicit wherever practical about definitions of the word "pressure." Wherever "pressure" is described, the location needs to be defined (is it pressure at the wellhead, at the boarding valve, or at the deepest point in the flowline?) and whether the pressure is internal pressure, external pressure, or differential pressure (i.e., the difference between internal and external pressures). API RP 1111 is consistent in this terminology, and is based on use of differential pressure. However, it is recognized that some regulations at present do not use the term "differential" pressure but pipeline design codes do.

Confusion may also arise when the terms "absolute" and "gage" or "gauge" pressure are used in subsea applications. Gauge pressure, also spelled *gage* pressure, is the pressure relative to the local atmospheric or ambient pressure. So at sea level, the absolute pressure in air is 14.7 psia, and the gage pressure is 0 psig. These terms can also been adopted subsea, but one needs to then be careful with the nomenclature and application. Piezo-electric digital pressure transducers will provide an absolute pressure reading. Analog pressure gages are typically compensated and thus will provide a pressure reading relative to local hydrostatic pressure.

In the context of this report, the terms "absolute" and "gage" pressure are only relevant in the context of conducting a pressure test from a subsea location, and the following simplification is made: the small difference between gage pressure relative to 1 atm (psig) and absolute pressure (psia) is ignored and all units are simply expressed as "psi", except where expressly stated otherwise.

API RP 1111 defines a "design pressure" for each point along the pipeline. This design pressure is a differential pressure, and generally will vary by location. For subsea flowlines that tie back subsea wells to a floating platform, the maximum source pressure (MSP) is typically considered to be the SITP at the wellhead. However, the maximum internal pressure may be located somewhere other than the wellhead due to elevation differences along the flowline route as well as product density effects. The examples presented in Appendix A illustrate this point. For a production flowline with a riser connected to the surface facility and no isolation between the pipeline and riser, maximum internal pressure will generally be lowest at the surface because, even if the product is dry gas, product under pressure possesses a certain density. If the vertical distance between the wellhead and Boarding Shut-Down Valve (BSDV) is H (ft), average product density is γ_{prod} (lb/ft^3), and MSP at the wellhead is $P_{int\ WH}$ (psi) (or sometimes WellHead Shut In Tubing Pressure (WHSITP), the Maximum Expected (Internal) Surface Pressure (MESP) (psi) equals:

$$\text{MESP} = \text{MSP (or } P_{int\ WH}) - H \cdot \frac{\gamma_{prod}}{144} \tag{1}$$

The WHSITP is often defined in absolute terms (psia). If converted to psig units, referenced to pressure at sealevel, the WHSITP (and therefore in the context of the above, the MSP) would be reduced by 14.7 psig. To keep the "book keeping" in this report as simple as possible, and allow use of round numbers, it is assumed that the WHSTIP is expressed in psig relative to ambient pressure at sea level and as stated earlier, and simple units of "psi" are used. For each point along the pipeline, the internal pressure is calculated relative to the internal MSP. At each point (x) along the pipeline, the local external pressure $P_o(x)$ is also calculated. For a PIP flowline with the annulus at atmospheric pressure (and as indicated above, the atmospheric pressure is assumed equal to zero for convenience), $P_o(x)$ will be zero at all locations.

Equation (1) immediately illustrates the challenge that one faces with the current regulations, in particular, Paragraphs 250.1002 and 250.1003 in 30 CFR 250. These paragraphs assume a single MAOP for the entire pipeline. (And in most cases, unless (d) in Paragraph 250.1002 applies, the MAOP must be equal to or greater than the MSP.) Paragraph 250.1003 follows with the requirement that hydrotest pressure must be at least equal to 1.25 MAOP.

The challenge with the current regulations is further illustrated by Equation (2) below. If one assumes a single MAOP for a deepwater pipeline, the MAOP must be at least equal to MSP. Thus, the surface test pressure of the connected pipeline and riser system must be equal to 1.25 MAOP. At the wellhead, the internal test pressure then becomes at hydrotest:

$$P_{int\ test\ WH} = 1.25 \cdot \text{MSP (or MAOP)} + H \cdot \frac{\gamma_{sw}}{144} \tag{2}$$

where γ_{sw} = seawater density (lb/ft^3)

For a single-wall pipeline, the <u>differential test pressure</u> at the wellhead at hydrotest then becomes (for convenience, the BSDV is considered to be at the water line):

$$P_{dif\ test\ WH} = 1.25 \cdot \text{MSP} + H \cdot \frac{\gamma_{sw}}{144} - H \cdot \frac{\gamma_{sw}}{144} = 1.25 \cdot \text{MAOP} \tag{3}$$

Equation (3) can negate the benefit derived by allowing alternate compliance to 30 CFR 250 by allowing design of the pipe wall thickness using the concept of differential pressure design as per API RP 1111, because it is now apparent that the differential hydrotest pressure is as much as 1.25 MSP (because MSP is an internal pressure rather than a differential pressure).

To summarize these considerations, three different internal hydrotest pressures at the wellhead are possible for a surface-connected, single-wall pipeline with MSP at the wellhead:

1. Following API RP 1111 guidelines at the wellhead location, the minimum required differential hydrotest pressure equals:

$$P_{\text{differential test}} = 1.25 \cdot (MSP - H \cdot \frac{\gamma_{sw}}{144}) \tag{4}$$

   and thus the minimum required internal hydrotest pressure at the wellhead equals:

$$P_{\text{hydrotest internal}} = 1.25 \cdot (MSP - H \cdot \frac{\gamma_{sw}}{144}) + H \cdot \frac{\gamma_{sw}}{144} \text{ or:}$$

$$P_{\text{hydrotest internal}} = 1.25 \cdot MSP - 0.25 \cdot H \cdot \frac{\gamma_{sw}}{144} \tag{5}$$

   With a surface connected pipeline by riser, and without isolation of pipeline and riser, for example by disconnectable jumper, the actual internal hydrotest test pressure at the wellhead will always exceed this minimum required internal hydrotest pressure (i.e., this will become Case 3 below).

2. Following the existing regulation 30 CFR 250 at the wellhead location, the minimum required internal hydrotest pressure equals 1.25 MSP along the entire flowline and riser. Thus, for the same surface connected pipeline the internal hydrotest pressure at the wellhead equals:

$$P_{\text{hydrotest internal}} = 1.25 \cdot MSP + H \cdot \frac{\gamma_{sw}}{144} \tag{6}$$

3. Using the concept of MESP, the internal hydrotest pressure at the wellhead equals:

$$P_{\text{hydrotest internal}} = 1.25 \cdot MESP + H \cdot \frac{\gamma_{sw}}{144} \tag{7}$$

   or, substituting equation (1) into equation (7):

$$P_{\text{hydrotest internal}} = 1.25 \cdot (MSP - H \cdot \frac{\gamma_{prod}}{144}) + H \cdot \frac{\gamma_{sw}}{144} \tag{8}$$

Depending on water depth and product density, the internal hydrotest pressures in the flowline and riser derived by these three options can be significantly different. Recent designs have demonstrated that use of the second option may actually govern wall thickness selection of the pipeline, instead of internal design pressure during pipeline operation (and will also increase the required wall thickness of the riser).

It is therefore critically important that the different methods of calculating hydrotest pressures, as allowed by the regulations and supported by industry standards, be reconciled.

3. Proposed Guidelines and Recommendations

3.1 Deepwater Pipeline Design – Alternate Compliance

Alternate Compliance from the internal design pressure requirements in 30 CFR 250.1002 should use API RP 1111 4th Edition, ASME B31.8, ASME B31.4, or other BSEE-approved design codes for the design of deepwater pipeline system tiebacks from subsea wells to surface-based production systems and deepwater export pipeline and riser systems to shore-based facilities under the jurisdiction of DOI. (Note that Figure 1 in API RP1111 shows the pipeline systems covered by that standard.) Pipeline sections can be single-pipe or PIP. Pipeline risers can be steel catenary risers, lazy wave risers, free-standing hybrid risers, and are covered by API RP 1111 and API RP 2RD where applicable. Flexible pipe and risers are covered by API SPEC 17J and RP17B).

If a pipeline is designed in accordance with a code other than API RP 1111, the operator may still be able to hydrotest in accordance with API RP 1111. In these cases, the pipeline should be checked for the hydrotest load case in based on API RP 1111,

3.2 Deepwater Pipeline Hydrotesting – Alternate Compliance

Alternate compliance with the requirements for hydrostatic testing as per 30 CFR 250 Paragraph 250.1003(b)(1) should consider using API RP 1111 to define the minimum and actual test pressures at each location in the pipeline and riser under the following minimum conditions:

1. Minimum required offshore internal test pressure at the surface of a riser shall be at least 1.25 times MESP.

2. At each point along the riser and pipeline, the minimum offshore differential test pressure shall be equal to or greater than 1.25 times P_d , where P_d equals the Elevation-Adjusted Source Pressure (EASP) minus the local hydrostatic pressure for each point (as defined in API RP 1111).

3.3 Use of Differential Pressure in Design

Use of the concept of “differential” pressure for design of pipe or other round cylindrical shells has been validated, and forms the basis for the differential pressure design equations in API RP 1111. In general, qualification of pipeline components, other than pipe or round cylindrical shells, should be based on all anticipated loads and environments the components may experience during their service life to ensure that the component is fit for service. Qualification of pipeline components should include verification analysis and/or validation testing to ensure that the component is capable of meeting requirements for the specified application or intended use.

For some pipeline components (other than pipe or other round cylindrical shells), this approach may also result in validation that differential pressure can be used for design purposes. There are cases, however, where the simple use of differential pressure in design of more complex, multi-part components is not appropriate, not adequately validated, or not supported by Industry-recommended practices. One example is a subsea valve. While the cylindrical body of the valve and the ends (flanged or welded to pipe) may be designed using differential pressure, other parts of the valve require more careful consideration of the loads from internal and external pressure. The project team understands that the API subcommittee on Subsea Production Equipment is currently developing recommended methodologies for using differential pressure in the design of subsea components and directs readers to that source for further guidance.

3.4 System Design for Hydrotesting

Pipeline systems are frequently tested in sections. Systems contain manufactured components, valves, connectors, and fittings that are tested onshore and further tested as part of the complete system after installation. Systems also frequently contain fabricated assemblies - such as manifolds and jumpers - that are pre-tested onshore and only leak-tested after installation.

Early in the design process of a production system, the designer should evaluate the impact of a systems hydrostatic test on the design and pre-installation testing of the components of the system. As shown in the equations in Section 2, a systems test may impose larger **actual** hydrotest pressures than the **minimum required** test pressures. If this impact is not considered early in the design, it may lead to undesirable surprises during detailed design or, worse, during actual project execution.

The challenges imposed by this issue should not be underestimated. For example, a typical API 6A rated valve will undergo a body shell hydrostatic test of 1.5 times its rated working pressure (RWP). After the valve is fully assembled and incorporated into a subsea assembly, such as a PLET, it may be tested onshore to an internal pressure equal to 1.25 MAOP of the pipeline. This internal test pressure will not exceed 1.5 RWP, but may exceed the RWP. The owner/operator should verify with the valve manufacturer under which conditions such a test has been considered in qualification of the valve (typically, a valve used in a subsea tree will never experience an internal pressure exceeding its RWP after assembly). Additionally, once installed subsea, the valve may experience an internal pipeline system hydrotest pressure that far exceeds 1.25 MAOP (see the equations above), and in fact an internal test pressure that may approach 1.5 RWP. The valve may be subjected to this internal test pressure repeatedly (in case of problems during offshore hydrotesting). The valve manufacturer needs to be made aware of these possible load conditions at a time where proper consideration can be given to the impact on valve design. The manufacturer will likely need to run special engineering analysis and/or qualification testing to verify the valve will be unharmed by such test pressures well above 1.0xRWP.

This situation applies not only to API rated valves in production flowlines, but equally to deepwater valves in export pipelines. An ANSI 1500 rated valve (nominal internal design pressure of 3650 psi) in 8000 ft of seawater (for example) in an oil export pipeline, will experience an absolute internal hydrotest pressure of at least $1.25 \times 3650 + (64/144) \times 8000 = 8117$ psi, or 2.2 times its RWP. Clearly, the valve manufacturer needs to be fully aware of these loadings.

Where a systems hydrostatic test governs design, consideration should be given to isolating pipeline sections to minimize the difference between minimum required internal hydrotest pressure of a section and actual internal hydrotest pressure.

3.5 Maximum Expected (Internal) Surface Pressure (MESP)

For a production flowline, MESP is calculated based on the lowest appropriate fluid weight in the pipeline and riser, the MSP, and the difference in elevation between the pressure source and point of reference. In Barrier Concept applications (subsea pipelines from subsea wells), the MESP point of reference is the BSDV. Barrier concepts are covered in API RP 14C. For convenience in this guideline, the BSDV is located at the water line, so that when the guideline addresses “depth” or “water depth,” the effect of the height of the boarding valve above the water line can be ignored. In detailed design, however, all elevations of relevant points in pipeline and riser shall be appropriately considered.

In a request for alternate compliance to the BSEE GOMR, the pipeline designer should:

- Calculate the MESP using API RP 1111 employing the lowest appropriate fluid density for life-of-field conditions.

- Demonstrate that differential design pressure of all line pipe and riser pipe at each point along pipeline and riser is equal to or greater than P_d , which equals the Elevation-Adjusted Source Pressure (EASP) minus the local hydrostatic pressure for each point. The use of P_d is consistent with API RP 1111. EASP is the local internal pressure. For a PIP flowline with the annulus at atmospheric pressure, the local external pressure would thus be zero.

- Ensure that for a production pipeline all subsea non-pipe equipment and components are capable of containing and operating at P_d if differential-pressure design is appropriate for the specific component, or can withstand the loads of actual local internal and external pressure if differential-pressure design is not appropriate.

- Ensure that the BSDV on incoming flowlines is certified according to API Spec 6A, API Spec 6AV1, and fire-rated for 30 minutes, and has a pressure rating equal to or greater than the MESP. Ensure that valves on export pipelines are certified to either API Spec 6A or API Spec 6D and has a pressure rating equal to greater than MESP.

There are other production scenarios where the MSP will not be present at the wellhead. Examples are export pipelines, where the MSP is at the discharge point of the pump, and gas or water injection pipelines, where the MSP may also be defined at the surface. In all such cases, the designer should carefully consider the maximum internal and external pressures along the pipeline and riser and identify where the internal design pressure may actually exceed the MSP. This is often determined conveniently by using the concept of $P_{d.}$ There may be scenarios where the internal pressure in the pipeline exceeds the MSP at the wellhead (see examples in Appendix A).

3.6 Pipeline Pre-Testing

Pressure testing a pipeline section with water requires a stabilized pressure of at least 1.25 times P_d for at least 8 hours when installed, relocated, up-rated, or reactivated after being out of service for more than 1 year. A pre-test is a pressure test on a pipeline assembly or section of pipeline conducted prior to installation. A request to pre-test a pipeline assembly or section is an alternate compliance from the requirements of 30 CFR 250.1003(b)(1).

In such an alternative compliance request to the BSEE GOMR, provisions must be included to:

- Conduct the pre-test with water at a stabilized pressure of at least 1.25 times the maximum P_d of the pipeline for at least 4 hours.
- Maintain all sides of the pipe clear and accessible at all times during the pre-test to accommodate visual inspection.
- Inspect the pipe visually from a safe position during the pre-test to verify that no leaks occur in the system.

- After installation, conduct a leak test of the installed pipeline assembly or section for at least 2 hours at a stabilized pressure sufficiently high to allow leak detection. For jumpers an internal test of the jumper after installation may be problematic because it requires testing against closed valves and the required test pressure may exceed the Rated Working Pressure of the isolation valves. An alternative test method for jumpers is an external seal test of the mechanical connectors for 15 minutes at an internal annulus test pressure (between internal pressure seal and test seal) of at least 1.25 times the local external pressure. Because the annulus fluid content is very small, a 15 minute test is more than sufficient to assess leak integrity. Pressures applied should not exceed connector manufacturer's recommendations.

3.7 Subsea Tie-Ins to Legacy Pipelines

When a new pipeline system is connected to an existing pipeline system, the designer must verify that operating conditions imposed by the connection of the new pipeline do not result in an overpressure of the existing pipeline system, or conversely, that the operating conditions of the existing pipeline system cannot cause an overpressure of the newly tied-in system.

3.8 Minimum Differential Hydrostatic Test Pressure

There may be instances in deep water where the absolute value of the local external pressure is close to or exceeds the local MESP. Equation (4) may then imply that the minimum required hydrotest pressure may be close to zero. If the pipeline is tested as a system with the riser from the surface, equation (8) will show that it is extremely unlikely that the actual internal test pressure would be close to zero. If the pipeline segment is isolated from the riser for the hydrotest, however, then equation (4) may cause the differential test pressure to be so low as to result in a meaningless test. The operator should, however, recognize that a future retest of the entire system may be necessary and that isolation at such time of pipeline and riser may be impractical. It would thus be advisable for the operator to recognize the maximum value of either the present minimum required test pressure or a future retest pressure. In addition, it is recommended that API be advised to discuss with the API RP 1111 Committee the need to add guidance to a future revision of API RP 1111 to state that the minimum differential test pressure at any location in the pipeline should exceed 25% of the local external pressure of the pressure containing pipe.

3.9 References

1. 30 CFR PART 250 — OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF, in particular, Subpart J, Paragraphs 250.1002: "Design Requirements for DOI Pipelines," and 250.1003: "Installation, Testing and Repair Requirements for DOI Pipelines."

2. API RP 1111: "Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)," Fourth Edition, 2009.

Appendix A: Example Hydrotesting Options for Deepwater Developments

General

Three potential development options for deepwater flowline and riser systems were considered and analyzed by the project team to demonstrate how a possible hydrotest program can be implemented based on the use of API RP 1111, 4th edition (2009). These three options are illustrated schematically in Appendix A-1. Reference is made to Sections 4.1.2.1, 4.2.2 and 8.2.4.1 of RP 1111, which sets the hydrostatic pressure test limits to ≥125% of flowline design pressure (where the defined flowline design pressure ≥ maximum differential pressure in the system), or 111% of shut-in pressure, whichever is greater.

Other than the terms MSP (Maximum Source Pressure), WHSIP (Wellhead Shut-In Pressure), EASP (Elevation Adjusted Source Pressure), TVD (Total Vertical Depth), and BSDV (Boarding Shutdown Valve), the terminology used in the illustrations has been purposefully kept basic to convey the interrelationship between pressures at different locations of the flowline/riser system. It is emphasized that MSP is the reservoir pressure. EASP is defined as the local internal shut-in pressure, which is based on the density (pressure gradient) of the produced fluid and elevation difference from the reservoir.

The field physical conditions are assumed to be identical for these three options, and are summarized as follows:

- Reservoir TVD: 25,000 ft
- Max. Reservoir Pressure: 16,000 psi
- Max. Reservoir Temperature: 275°F
- Produced Fluid Density: 28.8 lb/ft^3
- Elevation at Wellhead: (-)10,000 ft
- Max. Wellhead Temperature: 250°F
- Max. Wellhead Shut-In Pressure: 13,000 psi

Note: For simplicity, elevation of the BSDV is at sea level.

Option 1 – Single Section Hydrotest for a Single Pipe (Non-PIP) Flowline/Riser System

Option 1 describes a single pipe (non-PIP) flowline/riser system that extends from a flowline PLET located near the wellhead to a BSDV located on a floating production unit (FPU). For this option, the system is subjected to a single hydrotest from the temporary pressure cap on the flowline PLET connection hub to the BSDV.

Table A-1 presents the design and hydrotest pressures for Option 1 at each defined location along the flowline:

Table A-1: Hydrotest Pressures for Option 1

LOCATION					DESIGN API RP 1111, 4TH Ed.	HYDROTEST				
ID	Component	Elevation ft. vs MSL	Elevated Adjusted Source Pressure (EASP) (psi)	External Pressure (psi)	Minimum Design Pressure (Differential)[1] (psi)	Minimum Required Differential Pressure @ Location (psi)	Selected[2] Minimum Surface Pressure (psi)	Resulting Internal Pressure @ Location (psi)	Resulting Differential Pressure @ Location (psi)	Hydrotest Factor
A	BSDV	0	11,000	0	11,000	13,750	13,750	13,750	13,750	1.25
B	Riser TD	-5,000	12,000	2,250	9,750	12,188	13,750	16,000	13,750	1.41
C	Flowline Low Point	-11,000	13,200	4,950	8,250	10,313	13,750	18,700	13,750	1.67
D	Flowline PLET	-10,000	13,000	4,500	8,500	10,625	13,750	18,250	13,750	1.62

[1]Internal Pressure – External Pressure
[2]Can be rounded for convenience

Hydrotest Governing Case
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The internal maximum shut-in pressure is calculated for each location based on the MSP (reservoir pressure) and the head of the produced fluid inside the flowline.

$$EASP = MSP - Head_{produced\text{-}fluid} \text{ (elevation difference between location and MSP)}$$

<u>Example</u>:

$$EASP \text{ for wellhead (WHSIP)} = MSP - Head_{produced\text{-}fluid}$$

$$= 16{,}000 \text{ psi} - [28.8 \text{ lb/ft}^3 \times (25{,}000 \text{ ft} - 10{,}000 \text{ ft})/144 \text{ in}^2/\text{ft}^2]$$

$$= \underline{13{,}000 \text{ psi}}$$

The external pressure at each location is calculated based on the elevation of the flowline at that location and the density of the seawater.

$$P_{external} = Elevation \times \frac{\gamma_{sw}}{144}$$

Per API RP 1111, the design pressure at each location is equal to the differential pressure at that point.

$$P_{design} = EASP - P_{external}$$

The governing hydrotest pressure for the flowline system is based on the location with the highest differential pressure and is defined as:

$$P_{hydrotest} = 1.25 \times P_{design\text{-}max}$$

For Option 1, the location with the highest differential pressure is at the BSDV (11,000 psi – 0 psi = 11,000 psi). Therefore, the hydrotest pressure for this case is equal to 1.25 times the differential pressure at the BSDV (1.25 × 11,000 psi = 13,750 psi).

Due to the head of hydrotest water at the riser touchdown (Point B), the internal hydrotest pressure at that point is 16,000 psi (13,750 psi test pressure + 2,250 psi hydrostatic head of test water). The differential pressure at Point B is 13,750 psi due to the application of external seawater pressure (16,000 psi – 2,250 psi). Similarly, the internal pressure at the flowline low point (Point C) is 18,700 psi (13,750 psi test pressure + 4,950 psi hydrostatic head of test water). The differential pressure at Point C is 13,750 psi due to the application of external seawater pressure (18,700 psi – 4,950 psi). Finally, at the flowline PLET (Point D), the internal pressure in the flowline is 18,250 psi (13,750 psi test pressure + 4,500 psi hydrostatic head of test water), and the differential pressure is 13,750 psi (18,250 psi – 4,500 psi).

Option 2 – Multi-Section Hydrotest of Single Pipe (Non-PIP) Flowline/Riser System

In applying the design methodology from API RP 1111, the hydrotest pressure of a pipeline or flowline system must be considered during the design of the system. In cases where a flowline/riser system is designed for a single system hydrotest, as demonstrated in Option 1 above, maximum differential pressure occurs at the BSDV (maximum elevation). In certain cases, it may be advantageous to divide the flowline/riser system into multiple sections to lower the design pressure and thus the hydrotest pressure of some of the sections. For instance, the on-bottom portion of the flowline may be separated from the riser through the use of PLETs or other suitable means for isolation, which would enable two separate hydrotests to be conducted—one hydrotest for the riser section and a second hydrotest for the on-bottom section of the flowline. This division enables a lower design pressure and hydrotest pressure to be applied to the flowline section of the system. The lower design and hydrotest pressures could result in lower material costs. However, the cost of the two additional PLETs and jumpers must be considered, and total system cost may not be lower. However, other factors such as installation costs and welding issues may result in sectioning adding value overall.

Option 2 presents such a case where the flowline/riser system is divided into two distinct sections (riser section, flowline section) through the use of PLETs. The riser/flowline system is subjected to the same internal shut-in pressures and external pressures as defined in Option 1.

However, division of the system into two distinct sections allows different design and hydrotest pressures to be defined for the two sections.

Table A-2 presents the design and hydrotest pressures for Option 2 at each defined location along the flowline:

Table A-2: Hydrotest Pressures for Option 2

LOCATION					DESIGN API RP 1111, 4TH Ed.	HYDROTEST				
ID	Component	Elevation ft. vs MSL	Elevated Adjusted Source Pressure (EASP) (psi)	External Pressure (psi)	Minimum Design Pressure (Differential)[1] (psi)	Required Differential Pressure @ Location (psi)	Selected[2] Minimum Surface Pressure (psi)	Resulting Internal Pressure @ Location (psi)	Resulting Differential Pressure @ Location (psi)	Hydrotest Factor
A	BSDV	0	11,000	0	11,000	13,750	13,750	13,750	13,750	1.25
B	Riser PLET	-5,000	12,000	2,250	9,750	12,188	13,750	16,000	13,750	1.41
C	Flowline PLET #1	-5,000	12,000	2,250	9,750	12,188	12,200	14,450	12,200	1.25
D	Flowline Low Point	-11,000	13,200	4,950	8,250	10,313	12,200	17,150	12,200	1.48
E	Flowline PLET #2	-10,000	13,000	4,500	8,500	10,625	12,200	16,700	12,200	1.44

[1]Internal Pressure – External Pressure
[2]Can be rounded for convenience

Hydrotest Governing Case
Hydrotest Group #1
Hydrotest Group #2

In Option 2, the maximum pressure differential in the riser section occurs at the BSDV (Point A). As with Option 1, the riser portion of Option 2 is designed for 11,000 psi at the top of the riser with a test pressure of 13,750 psi. While holding the test pressure differential of 13,750 psi, the internal test pressure at the riser PLET (Point B) is 16,000 psi considering the head of the test water (13,750 test pressure differential + 2,250 test water head).

The design and hydrotest pressures for the flowline section of the system are lower since the riser section is no longer considered. The maximum pressure differential in the flowline section (Point C to Point E) occurs at Flowline PLET #1 (Point C), which is the shallowest point for the flowline section. At this point, the maximum pressure differential at Point C is 9,750 psi (12,000 psi max internal shut-in pressure – 2,250 psi external pressure). The corresponding required hydrotest differential pressure is 12,188 psi (1.25 × 9,750 psi). For convenience, this value has been rounded up to 12,200 psi. Accounting for the head of test water, the flowline internal hydrotest pressure at Point C is 14,450 psi (12,200 psi hydrotest surface pressure + 2,250 psi test water head pressure).

From Table A-2, for applying the hydrotest surface pressure of 12,200 psi, the resulting hydrotest pressures at Locations D and E and all locations in between are above the minimum required hydrotest pressures.

Option 3 – Multi-Section Hydrotest of PIP Flowline/Riser System

Similar to Option 2, the Option 3 flowline/riser system shown in Appendix A-1 depicts a deepwater system divided into two sections, but with the flowline section as a PIP flowline. For this case, the need for the two sections becomes more compelling since there is no external pressure acting on the inner pipe of the flowline. Consequently, for the design of the PIP, both the design differential pressure and hydrotest differential pressures are equal to the internal pressures at each point of the flowline. For that reason, it is advantageous for the hydrotest surface pressure to be as low as possible.

Table A-3 summarizes the design and hydrotest pressures for Option 3 at the defined locations:

Table A-3: Hydrotest Pressures for Option 3

LOCATION					DESIGN API RP 1111, 4TH Ed.	HYDROTEST				
ID	Component	Elevation ft. vs MSL	Elevated Adjusted Source Pressure (EASP) (psi)	External Pressure (psi)	Minimum Design Pressure (Differential)[1] (psi)	Required Differential Pressure @ Location (psi)	Selected[2] Minimum Surface Pressure (psi)	Resulting Internal Pressure @ Location (psi)	Resulting Differential Pressure @ Location (psi)	Hydrotest Factor
A	BSDV	0	11,000	0	11,000	13,750	13,750	13,750	13,750	1.25
B	Riser PLET	-5,000	12,000	2,250	9,750	12,188	13,750	16,000	13,750	1.41
C	Flowline PLET #1	-5,000	12,000	2,250	9,750	12,188	12,750	15,000	12,750	1.31
D	PIP @ Flowline PLET #1	-5,000	12,000	0	12,000	15,000	12,750	15,000	15,000	1.25
E	PIP Low Point	-11,000	13,200	0	13,200	16,500	12,750	17,700	17,700	1.34
F	PIP @ Flowline PLET #2	-10,000	13,000	0	13,000	16,250	12,750	17,250	17,250	1.33
G	Flowline PLET #2	-10,000	13,000	4,500	8,500	10,625	12,750	17,250	12,750	1.50

[1]Internal Pressure – External Pressure
[2]Can be rounded for convenience

Hydrotest Governing Case
Hydrotest Group #1
Hydrotest Group #2

In Option 3, as for Options 1 and 2, the maximum pressure differential occurs in the riser section at the BSDV (Point A). The riser section of Option 3 is designed for 11,000 psi at the top of the riser with a test pressure of 13,750 psi. While holding the test pressure differential of 13,750 psi, the internal test pressure at the riser PLET (Point B) is 16,000 psi considering the head of the test water (13,750 test pressure differential + 2,250 test water head).

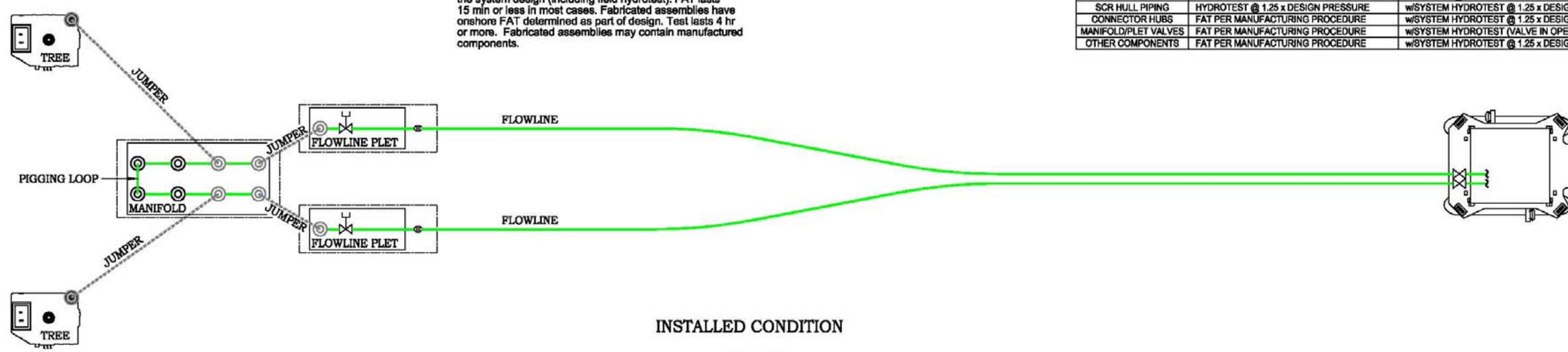
Again, as in Option 2, the design and hydrotest pressures for the flowline section of the system are lower since it is not necessary to consider the riser section. However, due to the PIP design, no external pressure can be subtracted from the internal pressure, and the governing pressure differential in the flowline section (Point C to Point G) occurs at Flowline PIP @ PLET #1 (Point D). The required design pressure differential at Point D is 12,000 psi (12,000 psi max internal shut-in pressure – 0 psi external pressure). The required hydrotest pressure at Point D is 15,000 psi (1.25 $\times$ 12,000 psi). With a hydrotest surface pressure of 12,750 psi, adding the test water head of 2,250 psi results in 15,000 psi pressure at Point D.

Appendix A-1: Sketches of Hydrotest Options

NOTE:
Manufactured components have FAT as part of quality control in the manufacturing procedure.
Fabricated assemblies are pressure tested based on the system design (including field hydrotest). FAT lasts 15 min or less in most cases. Fabricated assemblies have onshore FAT determined as part of design. Test lasts 4 hr or more. Fabricated assemblies may contain manufactured components.

COMPONENT TEST TABLE

COMPONENT	ONSHORE	OFFSHORE
MANIFOLD	HYDROTEST @ 1.25 x DESIGN PRESSURE	LEAK TEST @ 1.0 x DESIGN PRESSURE
F/L PLET	HYDROTEST @ 1.25 x DESIGN PRESSURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
JUMPERS	HYDROTEST @ 1.25 x DESIGN PRESSURE	SEAL TEST (AFTER JUMPER INSTALLATION) LEAK TEST @ 1.0 x DESIGN PRESSURE
SCR HULL PIPING	HYDROTEST @ 1.25 x DESIGN PRESSURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
CONNECTOR HUBS	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
MANIFOLD/PLET VALVES	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST (VALVE IN OPEN POSITION)
OTHER COMPONENTS	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE



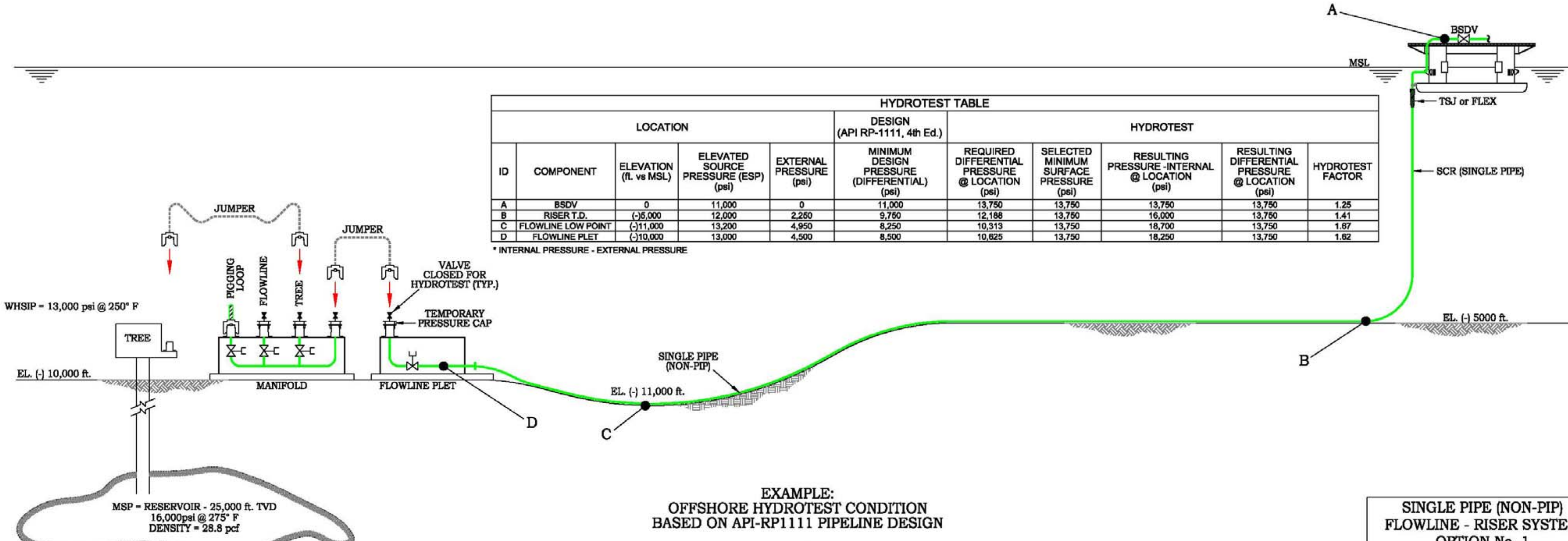
INSTALLED CONDITION

PLAN VIEW

HYDROTEST TABLE

LOCATION					DESIGN (API RP-1111, 4th Ed.)	HYDROTEST				
ID	COMPONENT	ELEVATION (ft. vs MSL)	ELEVATED SOURCE PRESSURE (ESP) (psi)	EXTERNAL PRESSURE (psi)	MINIMUM DESIGN PRESSURE (DIFFERENTIAL) (psi)	REQUIRED DIFFERENTIAL PRESSURE @ LOCATION (psi)	SELECTED MINIMUM SURFACE PRESSURE (psi)	RESULTING PRESSURE -INTERNAL @ LOCATION (psi)	RESULTING DIFFERENTIAL PRESSURE @ LOCATION (psi)	HYDROTEST FACTOR
A	BSDV	0	11,000	0	11,000	13,750	13,750	13,750	13,750	1.25
B	RISER T.D.	(-)5,000	12,000	2,250	9,750	12,188	13,750	16,000	13,750	1.41
C	FLOWLINE LOW POINT	(-)11,000	13,200	4,950	8,250	10,313	13,750	18,700	13,750	1.67
D	FLOWLINE PLET	(-)10,000	13,000	4,500	8,500	10,625	13,750	18,250	13,750	1.62

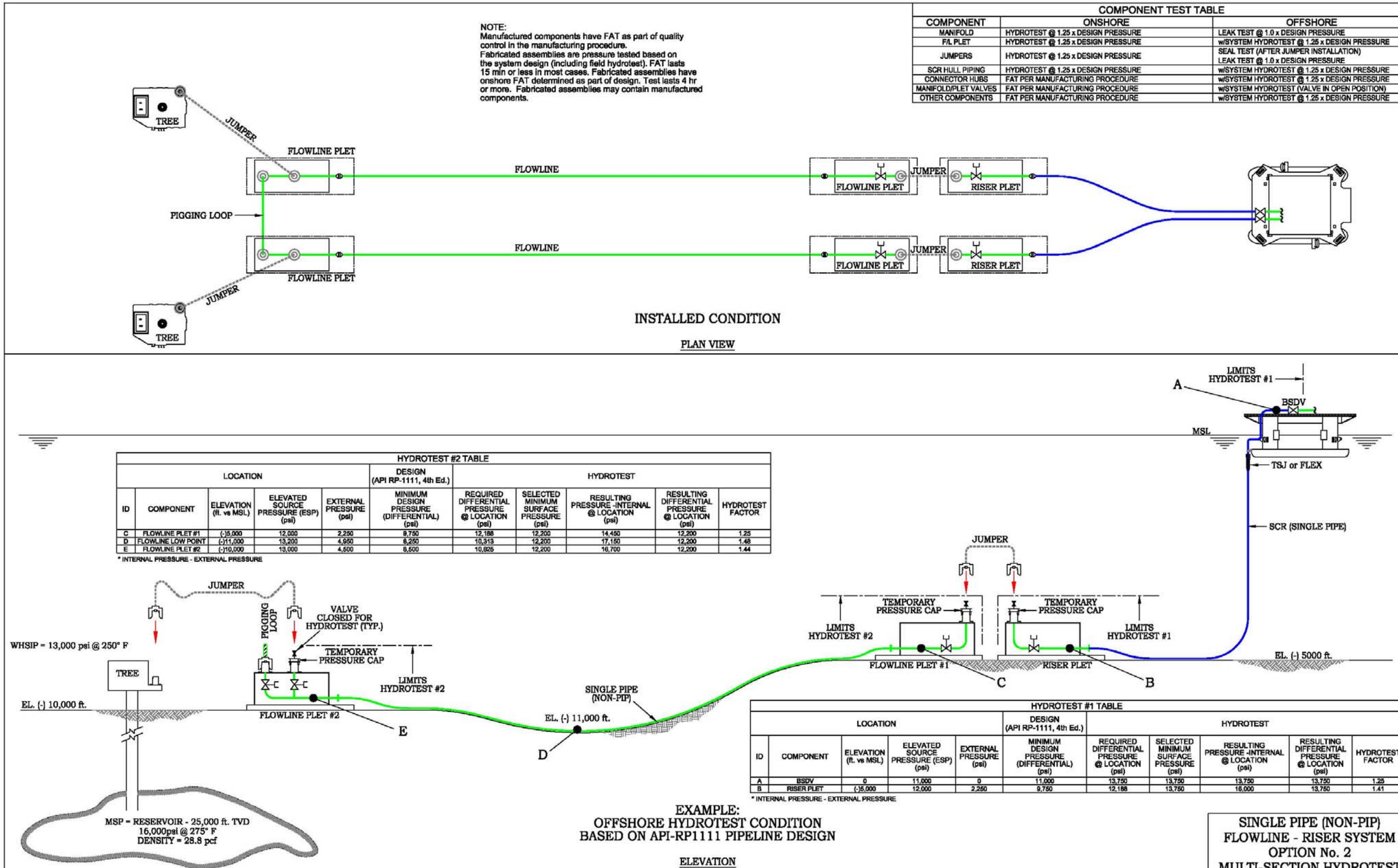
* INTERNAL PRESSURE - EXTERNAL PRESSURE



EXAMPLE:
OFFSHORE HYDROTEST CONDITION
BASED ON API-RP1111 PIPELINE DESIGN

ELEVATION

SINGLE PIPE (NON-PIP)
FLOWLINE - RISER SYSTEM
OPTION No. 1
SINGLE SECTION HYDROTEST



NOTE:
Manufactured components have FAT as part of quality control in the manufacturing procedure.
Fabricated assemblies are pressure tested based on the system design (including field hydrotest). FAT lasts 15 min or less in most cases. Fabricated assemblies have onshore FAT determined as part of design. Test lasts 4 hr or more. Fabricated assemblies may contain manufactured components.

COMPONENT TEST TABLE

COMPONENT	ONSHORE	OFFSHORE
MANIFOLD	HYDROTEST @ 1.25 x DESIGN PRESSURE	LEAK TEST @ 1.0 x DESIGN PRESSURE
F/L PLET	HYDROTEST @ 1.25 x DESIGN PRESSURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
JUMPERS	HYDROTEST @ 1.25 x DESIGN PRESSURE	SEAL TEST (AFTER JUMPER INSTALLATION) LEAK TEST @ 1.0 x DESIGN PRESSURE
SCR HULL PIPING	HYDROTEST @ 1.25 x DESIGN PRESSURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
CONNECTOR HUBS	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
MANIFOLD/PLET VALVES	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST (VALVE IN OPEN POSITION)
OTHER COMPONENTS	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE

HYDROTEST #2 TABLE

LOCATION					DESIGN (API RP-1111, 4th Ed.)	HYDROTEST				
ID	COMPONENT	ELEVATION (ft. vs MSL)	ELEVATED SOURCE PRESSURE (ESP) (psi)	EXTERNAL PRESSURE (psi)	MINIMUM DESIGN PRESSURE (DIFFERENTIAL) (psi)	REQUIRED DIFFERENTIAL PRESSURE @ LOCATION (psi)	SELECTED MINIMUM SURFACE PRESSURE (psi)	RESULTING PRESSURE -INTERNAL @ LOCATION (psi)	RESULTING DIFFERENTIAL PRESSURE @ LOCATION (psi)	HYDROTEST FACTOR
C	FLOWLINE PLET #1	(-)5,000	12,000	2,250	9,750	12,188	12,200	14,450	12,200	1.25
D	FLOWLINE LOW POINT	(-)11,000	13,200	4,950	8,250	10,313	12,200	17,150	12,200	1.48
E	FLOWLINE PLET #2	(-)10,000	13,000	4,500	8,500	10,625	12,200	16,700	12,200	1.44

* INTERNAL PRESSURE - EXTERNAL PRESSURE

HYDROTEST #1 TABLE

LOCATION					DESIGN (API RP-1111, 4th Ed.)	HYDROTEST				
ID	COMPONENT	ELEVATION (ft. vs MSL)	ELEVATED SOURCE PRESSURE (ESP) (psi)	EXTERNAL PRESSURE (psi)	MINIMUM DESIGN PRESSURE (DIFFERENTIAL) (psi)	REQUIRED DIFFERENTIAL PRESSURE @ LOCATION (psi)	SELECTED MINIMUM SURFACE PRESSURE (psi)	RESULTING PRESSURE -INTERNAL @ LOCATION (psi)	RESULTING DIFFERENTIAL PRESSURE @ LOCATION (psi)	HYDROTEST FACTOR
A	BSDV	0	11,000	0	11,000	13,750	13,750	13,750	13,750	1.25
B	RISER PLET	(-)5,000	12,000	2,250	9,750	12,188	13,750	16,000	13,750	1.41

* INTERNAL PRESSURE - EXTERNAL PRESSURE

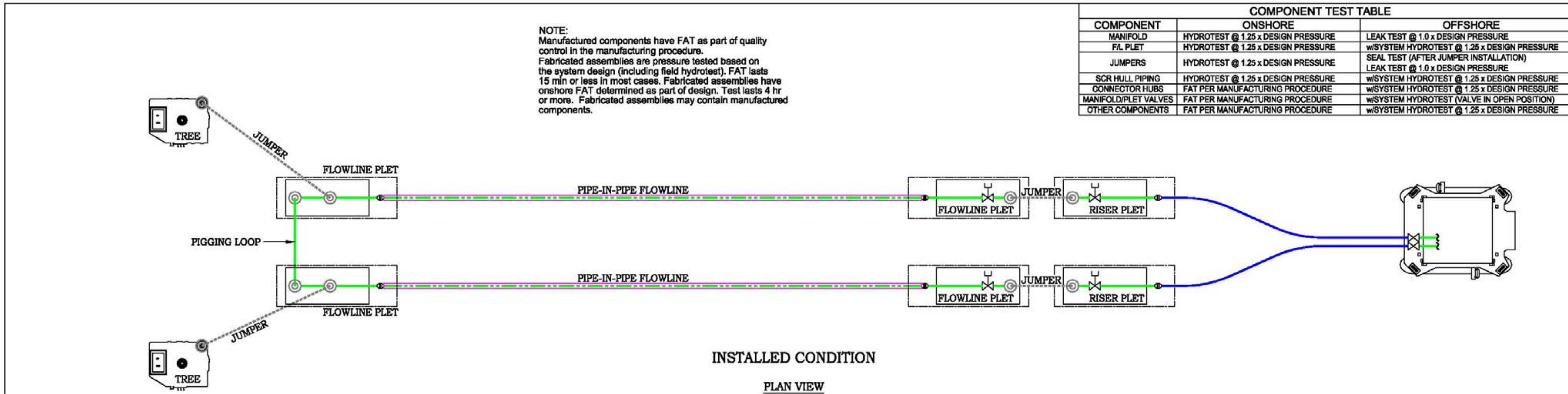
EXAMPLE:
OFFSHORE HYDROTEST CONDITION
BASED ON API-RP1111 PIPELINE DESIGN

ELEVATION

SINGLE PIPE (NON-PIP)
FLOWLINE - RISER SYSTEM
OPTION No. 2
MULTI-SECTION HYDROTEST

NOTE:
Manufactured components have FAT as part of quality control in the manufacturing procedure.
Fabricated assemblies are pressure tested based on the system design (including field hydrotest). FAT lasts 15 min or less in most cases. Fabricated assemblies have onshore FAT determined as part of design. Test lasts 4 hr or more. Fabricated assemblies may contain manufactured components.

COMPONENT TEST TABLE		
COMPONENT	ONSHORE	OFFSHORE
MANIFOLD	HYDROTEST @ 1.25 x DESIGN PRESSURE	LEAK TEST @ 1.0 x DESIGN PRESSURE
F/L PLET	HYDROTEST @ 1.25 x DESIGN PRESSURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
JUMPERS	HYDROTEST @ 1.25 x DESIGN PRESSURE	SEAL TEST (AFTER JUMPER INSTALLATION) LEAK TEST @ 1.0 x DESIGN PRESSURE
SCR HULL PIPING	HYDROTEST @ 1.25 x DESIGN PRESSURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
CONNECTOR HUBS	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE
MANIFOLD/PLET VALVES	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST (VALVE IN OPEN POSITION)
OTHER COMPONENTS	FAT PER MANUFACTURING PROCEDURE	w/SYSTEM HYDROTEST @ 1.25 x DESIGN PRESSURE

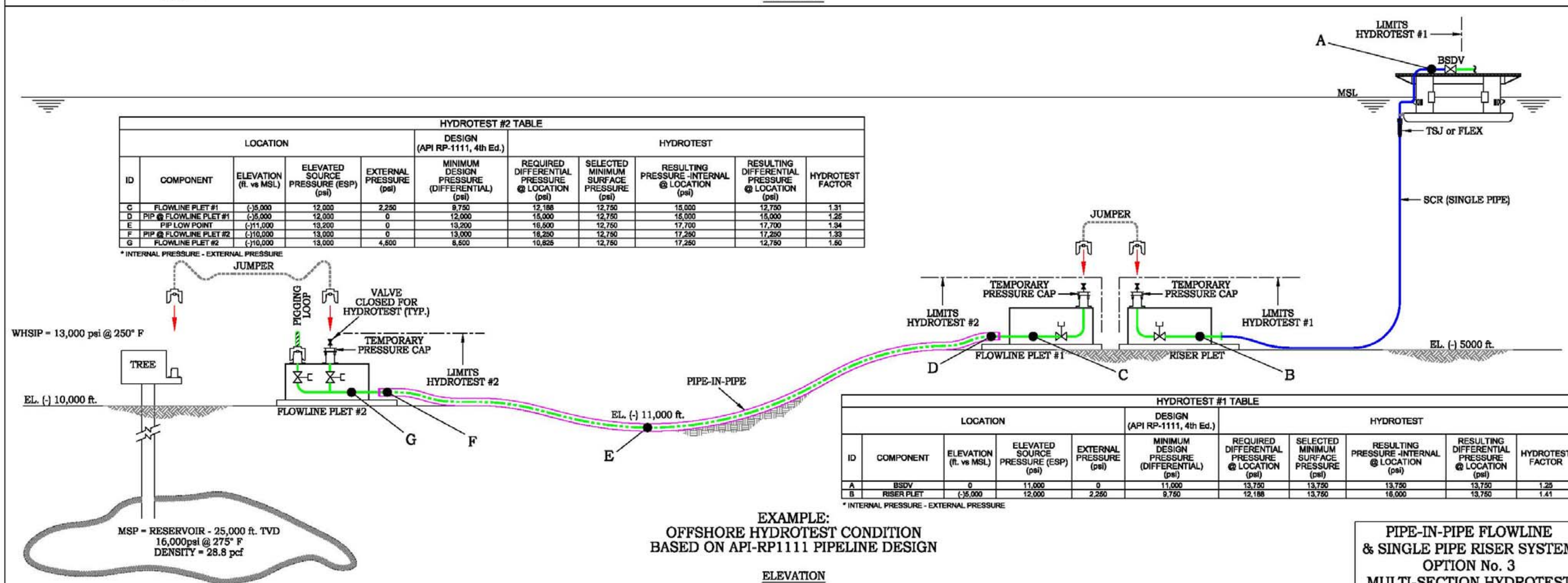


INSTALLED CONDITION

PLAN VIEW

HYDROTEST #2 TABLE											
LOCATION					DESIGN (API RP-1111, 4th Ed.)	HYDROTEST					
ID	COMPONENT	ELEVATION (ft. vs MSL)	ELEVATED SOURCE PRESSURE (ESP) (psi)	EXTERNAL PRESSURE (psi)	MINIMUM DESIGN PRESSURE (DIFFERENTIAL) (psi)	REQUIRED DIFFERENTIAL PRESSURE @ LOCATION (psi)	SELECTED MINIMUM SURFACE PRESSURE (psi)	RESULTING PRESSURE -INTERNAL @ LOCATION (psi)	RESULTING DIFFERENTIAL PRESSURE @ LOCATION (psi)	HYDROTEST FACTOR
C	FLOWLINE PLET #1	(-)5,000	12,000	2,250	9,750	12,188	12,750	15,000	12,750	1.31
D	PIP @ FLOWLINE PLET #1	(-)5,000	12,000	0	12,000	15,000	12,750	15,000	15,000	1.25
E	PIP LOW POINT	(-)11,000	13,200	0	13,200	16,500	12,750	17,700	17,700	1.34
F	PIP @ FLOWLINE PLET #2	(-)10,000	13,000	0	13,000	16,250	12,750	17,250	17,250	1.33
G	FLOWLINE PLET #2	(-)10,000	13,000	4,500	8,500	10,625	12,750	17,250	12,750	1.50

* INTERNAL PRESSURE - EXTERNAL PRESSURE



HYDROTEST #1 TABLE											
LOCATION					DESIGN (API RP-1111, 4th Ed.)	HYDROTEST					
ID	COMPONENT	ELEVATION (ft. vs MSL)	ELEVATED SOURCE PRESSURE (ESP) (psi)	EXTERNAL PRESSURE (psi)	MINIMUM DESIGN PRESSURE (DIFFERENTIAL) (psi)	REQUIRED DIFFERENTIAL PRESSURE @ LOCATION (psi)	SELECTED MINIMUM SURFACE PRESSURE (psi)	RESULTING PRESSURE -INTERNAL @ LOCATION (psi)	RESULTING DIFFERENTIAL PRESSURE @ LOCATION (psi)	HYDROTEST FACTOR
A	BSDV	0	11,000	0	11,000	13,750	13,750	13,750	13,750	1.25
B	RISER PLET	(-)5,000	12,000	2,250	9,750	12,188	13,750	16,000	13,750	1.41

* INTERNAL PRESSURE - EXTERNAL PRESSURE

EXAMPLE:
OFFSHORE HYDROTEST CONDITION
BASED ON API-RP1111 PIPELINE DESIGN

ELEVATION

PIPE-IN-PIPE FLOWLINE
& SINGLE PIPE RISER SYSTEM
OPTION No. 3
MULTI-SECTION HYDROTEST