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HPHT Production in the Gulf of Mexico

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ABBREVIATIONS AND ACRONYMS

APD	Application for a Permit to Drill
APM	Application for Permit to Modify
API	American Petroleum Institute
AMSE	American Society of Mechanical Engineers
BAVO	BSEE-approved verification organization
BOEM	Bureau of Ocean Energy Management
BOP	blowout preventer
BSEE	Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
DOCD	development operations coordination cocument
DPP	development and production plan
DWOP	Deepwater Operations Plan
EA	environmental assessment
EIS	environmental impact statement
EP	exploration plan
GOM	Gulf of Mexico
HP	high pressure
HPHT	high pressure, high temperature
HT	high temperature
I3P	independent third party
NTL	Notice to Lessees and Operators
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OEM	original equipment manufacturer
OOC	Offshore Operators Committee
psi	pounds per square inch
psia	pounds per square inch absolute
NEPA	National Environmental Policy Act
USDOI	U.S. Department of the Interior

1 HPHT RESERVOIRS IN THE GULF OF MEXICO

1.1 INTRODUCTION

There are several significant high pressure and/or high temperature (HPHT) projects at different stages of development in the Gulf of Mexico (GOM), and the Bureau of Ocean Energy Management (BOEM) recognizes unique challenges for production from HPHT wells in the GOM. There are engineering challenges for HPHT projects because special subsea equipment must be fabricated to withstand high pressures and/or temperatures to complete and produce HPHT wells. There are also significant costs associated with HPHT projects due to the research and development of HPHT equipment and fabrication, and the cost of research, design, and technology development. Due to the use of new technology, the Bureau of Safety and Environmental Enforcement (BSEE) conducts stepwise, detailed evaluations of HPHT applications according to BSEE's recently published guidelines for HPHT development. The information in this technical report explains what HPHT wells are, the current status of HPHT projects in the GOM, the potential risks associated with HPHT projects, the production safeguards in place, and the regulatory and permitting process for HPHT projects.

1.2 WHAT IS HPHT?

BSEE defines high pressure (HP) as an internal absolute pressure rating greater than 15,000 pounds per square inch absolute (psia) at the wellhead and high temperature (HT) as a temperature rating greater than 350 degrees Fahrenheit. Due to these high pressures and/or temperatures, special equipment that complies with BSEE's HPHT regulations and guidance is necessary for drilling, completing, and producing HPHT wells. BSEE considers HPHT equipment to be non-conventional technology, and production from HPHT wells requires a high level of scrutiny during the plan approval process. **Figure 1** shows the first project in the GOM to obtain BSEE approval to produce using HT technology.

Figure 1. Shell's Appomattox Platform. The first high-temperature project to produce in the Gulf of Mexico. Source: Shell, 2019.

1.3 WHERE IN THE GOM ARE FORMATIONS THAT MAY HAVE HPHT CHARACTERISTICS?

Reservoirs with HP or HT properties have been discovered in many areas of the GOM, but they are most prevalent in the Lower Tertiary and the Jurassic Norphlet formations. The Jurassic Norphlet Trend (shown in blue in **Figure 2**) is located in the Central and Eastern Planning Areas, and the Lower Tertiary Trend (shown in yellow in **Figure 2**) spans the Western and Central Planning Areas. The Jurassic Norphlet has some reservoirs characterized by HT, while the Lower Tertiary has some HP reservoirs. There are only a few reservoirs on the continental shelf that have both HP and HT properties. The western portion of the Lower Tertiary Trend, associated with the Perdido Fold Belt, is situated at shallower subsurface depths than the central area and is in a conventional pressure-temperature regime. The portion of the Lower Tertiary Trend in the central GOM is situated at much greater depths with higher attendant pressures. However, this region is also overlain by a thick salt canopy that adds to structural complexity, the difficulty of seismic imaging, and drilling difficulty, but it also has the effect of removing heat from the deeper formations. Because of the cooling effect of the salt, although still in an HPHT regime, the Lower Tertiary hydrocarbon system that would otherwise be overmature (low potential for farther hydrocarbon production) still exists in this region at greater depths than would otherwise be possible. Due to the greater subsurface depths, thickness of the overlying salt, and HPHT properties, the reservoirs in the central GOM Lower Tertiary are more complex and more expensive to develop.

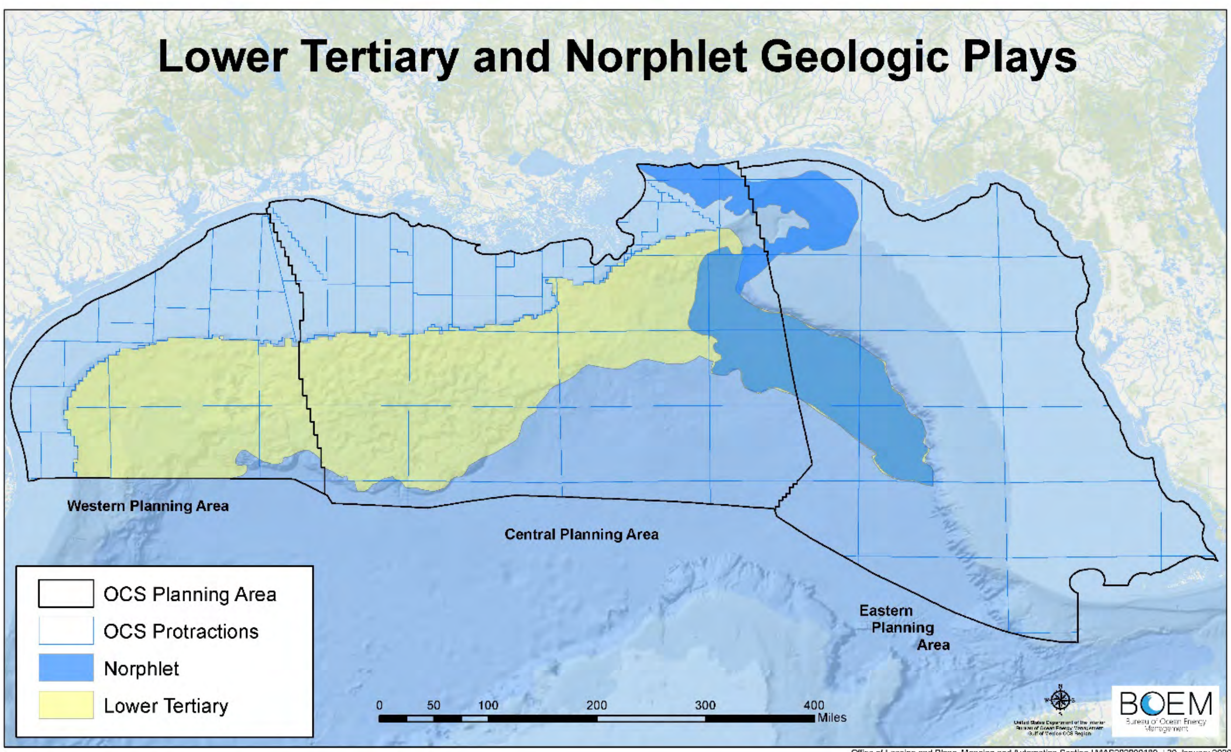

Figure 2. Lower Tertiary and Norphlet Formations in the Gulf of Mexico.

1.4 HAVE EXPLORATORY WELLS BEEN DRILLED INTO HPHT RESERVOIRS IN THE GOM?

Yes. Prior to the consideration of incentives for HPHT projects, many exploratory wells have already been drilled into HPHT reservoirs in the GOM (refer to **Figure 3**). Operators drill exploratory wells to specific subsurface targets in order to obtain information about a reservoir that can be used to identify the lateral and vertical extent of a hydrocarbon accumulation. Information collected during exploratory drilling is what provides data on pressures and temperatures of the reservoirs of interest.

Pressure and temperature in reservoirs generally increase with depth below the seafloor. **Figure 3** shows the bottom-hole pressures and temperatures of a set of 5,275 exploratory wells that were drilled in the GOM from 2000 to 2016. The study showed that, of 5,275 wells analyzed during that timeframe, 667 wells had reservoir pressure greater than 15,000 psia (Tetrahedron, Inc., 2017). In addition, temperature data were analyzed for 2,897 of the 5,275 wells. Twenty-five of those 2,897 wells had reservoir temperatures greater than 350 degrees Fahrenheit (Tetrahedron, Inc., 2017). A majority of HP wells currently being developed occur in water depths greater than 1,000 feet, whereas most HT wells occurr in water depths less than 1,000 feet (Tetrahedron, Inc., 2017).

It is important to understand that the pressures and temperatures shown in **Figure 3** were measured at the bottom-hole of the well, within the reservoir. However, BSEE classifies a well to be HP or HT based on the pressures and temperatures measured at the wellhead. The pressure and temperature measurements in the reservoir are not necessarily the same as the pressure and temperature measurements at the subsea wellhead, but they are important for calculating potential pressures and temperatures at the subsea wellhead. Pressures and temperatures can change between the reservoirs and the wellhead.

Pressure changes between the reservoir and the subsea wellhead are dependant on depth, reservoir pressure, and fluid gradient. For example, consider a subsea well that was drilled in 10,000 feet of water to a total depth of 30,000 feet and had a reservoir pressure of 23,000 psia. If the reservoir fluid gradient was 0.3 pounds per square inch (psi) per foot, then the pressure at the subsea wellhead would be 23,000 psi – (0.3 * 20,000) = 17,000 psia. This is considered an HP well by BSEE. However, if the reservoir pressure was 21,000 psia at the same depth and fluid gradient, then the wellhead pressure would only be 15,000 psia, and not a HP well by BSEE's definition.

Temperature changes between a reservoir and the wellhead can occur as a result of the Joule-Thomson Heating Effect. With this effect, reservoir fluids may increase or decrease in temperature as they flow from an area of high pressure to an area of low pressure without heat transfer (King, 2018). If a reservoir fluid were to increase in temperature as it flowed up the wellbore, where pressure is lower than in the reservoir, it is possible that the well could become a HT well, by BSEE definition, even if the temperature in the reservoir is not 350 degrees Fahrenheit or greater.

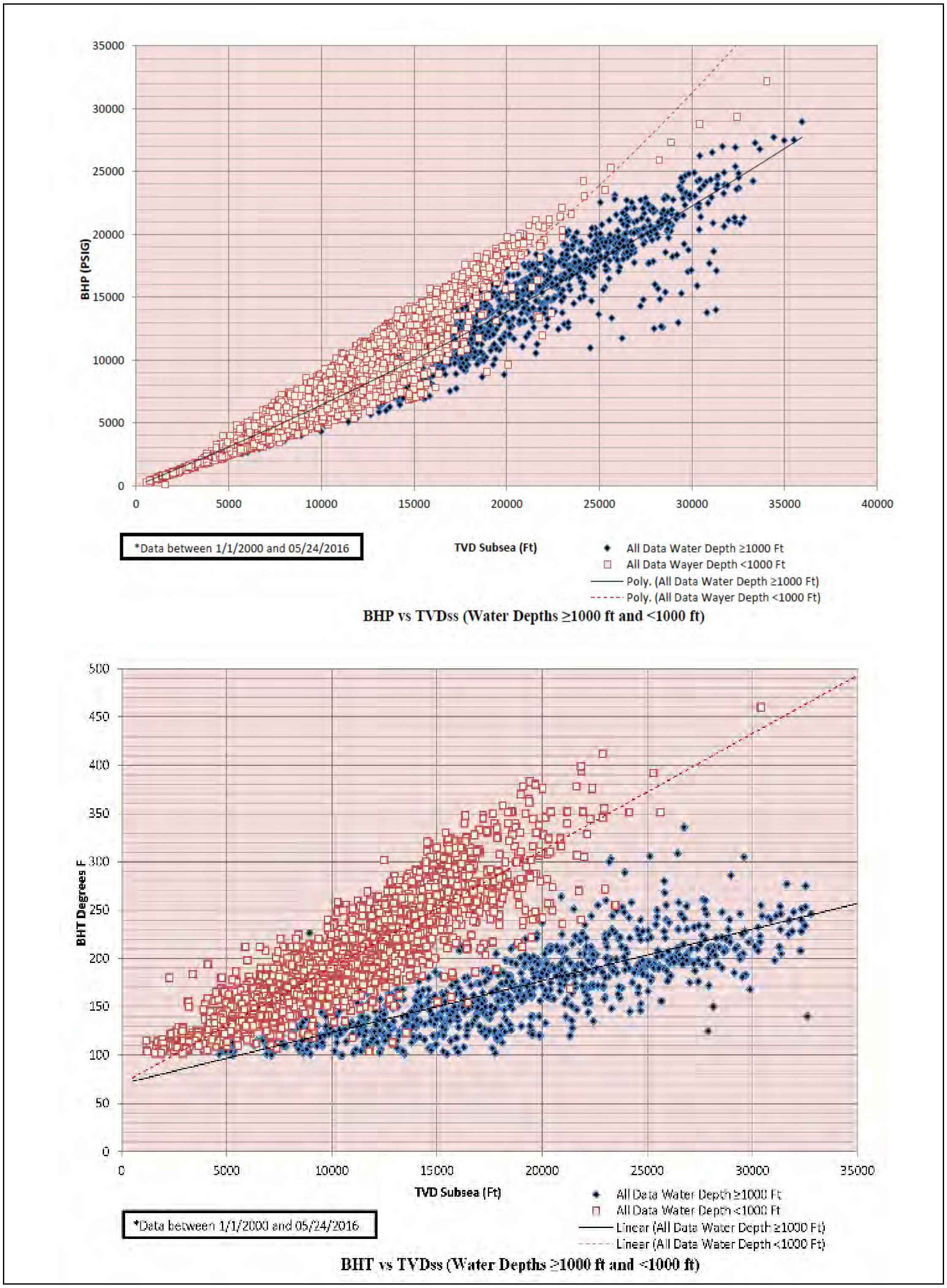

Figure 3. Bottom-hole Pressure and Temperature of Wells in the Gulf of Mexico Plotted against the Depth of the Well. Source: Tetrahedron, Inc., 2017.

1.5 What are the Challenges for Production from a Subsea HPHT Well?

HPHT wells have high pressure and/or high temperature properties at the wellhead. Industry has successfully drilled HPHT wells both onshore and in shallow water offshore since the 1970s (Offshore Operators Committee [OOC], 2018). These HPHT wells all had surface wellheads that were located onshore or on a shallow water platform with a dry tree (i.e., the production system is on the platform rather than subsea). Examples of early HP projects in the GOM, which had pressures above 15,000 psi at the surface wellhead include Shell Oil (1984) and Chevron Mobile Bay (1988). Both projects had surface wellhead equipment rated for pressures of 20,000 psi (Williams, 2017). It should be noted that equipment comes in increments of 5,000, so wellheads are rated for 5,000 psi, 10,000 psi, 15,000 psi, and 20,000 psi. If the pressure at a wellhead is 16,000 psi, then a 20,000-psi wellhead would be required to handle these pressures. Equipment and regulations exist for 20,000-psi wellheads onshore and for surface trees, but they are still being developed for subsea equipment.

The next challenge is the development of subsea equipment that can successfully handle HPHT conditions. Development and regulatory approval of subsea HPHT equipment is not as progressed as surface HPHT equipment and is the largest hurdle to producing from deepwater HPHT wells. Conventional subsea oil and gas equipment can be used to discover reservoirs that have HPHT properties, but those wells cannot be produced using conventional subsea equipment because the conventional equipment cannot replace the drilling mud to complete the well and conventional subsea equipment cannot withstand the pressures or temperatures of the HPHT environment. Due to the HPHT conditions, special subsea equipment must be fabricated to withstand high pressures and/or temperatures to complete and produce HPHT wells. BSEE is collaborating with industry to develop subsea HPHT equipment as the technology is developed and proven successful. Future standards for subsea HPHT designs will be based on proven technical advances and updated with technology development (OOC, 2018). For more detail on the development of standards for HPHT conditions, refer to **Section 1.9**.

1.6 Has BSEE Approved Production from Any Subsea HPHT Wells in the GOM?

Yes. Shell's Appomattox, located in the Gulf of Mexico about 80 miles south of New Orleans, is the first HT project to gain BSEE approval and begin production using BSEE's new HPHT guidance. Appomattox, which was completed in the Jurassic Norphlet formation, commenced oil production in May 2019. The Appomattox platform lies in 7,400 feet of water and is expected to produce 175,000 barrels of oil equivalent per day. The subsea wells of these projects have equipment rated for 15,000 psi and 400 degrees Fahrenheit. The reservoir temperature was measured at 350 degrees Fahrenheit or less. However, Shell designed subsea equipment for 400 degrees Fahrenheit due to the possibility of the Joule-Thomson Heating Effect, which could occurr in the early life of the reservoir. The use of equipment with higher temperature ratings was a safeguard implemented to handle temperatures in case the well were to become a HT environment during production. The Appomattox Project required special design for the new technology and equipment rated for completion and production from a HT well.

BSEE conducted detailed reviews of the new technology and equipment before approving its use. During the lengthy approval process, BSEE approved about 140 permits and plans covering different aspects of the Appomattox project, including the Conceptual Plan and the subsequent Deepwater Operations Plan (DWOP) (USDOI, BSEE, 2019a). Refer to **Sections 1.9 and 1.10** for more information on how BSEE reviews and approves new technology and **Section 1.14** for more detail on the full permitting process. Beginning in 2017, BSEE conducted several production safety system reviews and two pre-production inspections (refer to **Figure 4**) prior to approving Shell's production on the Appomattox platform. The permitting work for the Appomattox project ensured that the Appomattox Project adhered to the defined BSEE regulations and safety recommendations in BSEE's recently published HPHT-related guidance documents (USDOI, BSEE, 2019a). Refer to **Section 1.12** for more information on HPHT guidance documents.

Figure 4. Inspection of the Appomattox Platform in July 2018. Source: USDOI, BSEE, 2019a.

1.7 IS THERE POTENTIAL FOR ANY OTHER HPHT WELL PRODUCTION IN THE GOM?

Yes. Although, currently only one HT project has gained BSEE approval for production using the new BSEE guidance, there are additional HPHT projects working through BSEE's approval process, including HP projects. As of yet, BSEE has not approved any projects with subsea equipment rated for 20,000 psi. BSEE has received Conceptual Plans for the completion of several HPHT projects in the GOM. In addition to Appomattox, there are currently four HPHT projects at different stages of the Conceptual Plan approval process in the GOM:

Davy Jones: McMoRan's Davy Jones Project is targeting high-pressure gas in shallow water on the shelf. McMoRan completed the Davy Jones #1 and #2 wells on February 5, 2013, and May 25, 2014, after receiving approval of the Conceptual Plans from BSEE. These wells have surface wellheads rated for 25,000 psi and 450 degrees Fahrenheit and are considerered ultra high pressure. Both the Davy Jones #1 and #2 wells are currently not producing and are currently not economical.

Anchor: Chevron has submitted a Conceptual Plan to BSEE for the HP Anchor Project and BSEE is waiting for independent third party (I3P) testing results for the HP equipment and well designs to help inform its decision on approval of the Conceptual Plan. In December 2019, Chevron sanctioned the Anchor Project, making it the industry's first deepwater HP development to achieve a final investment decision. The Anchor Project subsea wells will be rated for 20,000 psi.

Shenandoah: Occidental (formerly Anadarko) and LLOG are working together on the Shenandoah Project, which is an HP project. Occidental is partnering with equipment manufacturers to develop the HP equipment and BSEE is reviewing the I3P testing results. LLOG will then submit a site-specific Conceptual Plan to BSEE for approval. Although not yet sanctioned, LLOG has ordered high-pressure subsea trees for their Shenandoah Project. The subsea wells for the Shenandoah Project will be rated for 20,000 psi.

North Platte: Total E&P USA, Inc. has submitted an initial Conceptual Plan to BSEE for the North Platte Project, which is an HP project with equipment rated for 20,000 psi. BSEE is waiting for the required I3P testing results for the HP equipment design to help inform its decision on approval of the Conceptual Plan. Total has moved forward and launched a front-end engineering and design process for North Platte. They have a 2021 target date for a final investment decision.

1.8 WHAT ARE THE POTENTIAL RISKS ASSOCIATED WITH HPHT PROJECTS?

Developing an HPHT oil and/or gas well comes with similar risks as those from a conventional well and also includes additional risk due to the extreme pressures and temperatures and the use of new and unique technology. Some new projects in the GOM will require subsea wellheads and trees rated for 20,000 psi or equipment to withstand 400 degrees Fahrenheit. Therefore, traditional subsea equipment cannot be used in the completion and production of HPHT wells because the equipment could fail structurally or due to fatigue.

1.9 WHAT ARE THE SAFEGUARDS IN PLACE TO MITIGATE THE RISKS ASSOCIATED WITH DRILLING AND PRODUCING HPHT WELLS?

Special equipment designed to withstand the pressures and temperatures of the HPHT environment is continuously being developed and tested. More than a decade's worth of research and development has gone into developing HPHT equipment. To better understand the equipment needs for the HPHT environment, BSEE has funded research to test equipment under HPHT conditions in order to inform guidelines for future standards (i.e., Aiken, 2016; Tims et al., 2016). Research included the potential for fatigue at high pressures and failure resulting from damage to elastomer seals at high temperatures (Pallanich, 2017). Pressure rating methods have also been evaluated and peer reviewed (Aiken, 2016).

Figure 5. Examples of Ruptured Test Bodies from High-Pressure Testing. Source: Aiken, 2016.

High-pressure laboratory testing has been done for non-traditional equipment to determine pressure limits. Refer to **Figure 5** for examples of ruptured equipment that has undergone laboratory testing for use in the HPHT environment. These are not examples of an accidental failure. The purpose of this trial was to pressure test the equipment to the point of structural failure to compare the calculated rupture pressure and the actual rupture pressure. Testing to structural failure is not routinely done. Structural tests determine the limits of the equipment, but the equipment would not be operated at those extreme pressures. For example, a piece of equipment designed to the American Society of Mechanical Engineers (ASME) Section VIII Division 3 for 20,000-psia working pressure would never be operated at a pressure greater than 20,000 psia. The rupture testing only determines the physical limits of the equipment to minimize the risk of structural or fatigue failure. It should be noted that equipment that has been tested in the laboratory would not be used in the field. A new piece of equipment would be manufactured for the field using the parameters that withstood laboratory testing.

The reports detailing the results of research are not the new standards, but they could be used to help inform the development of new standards for HPHT equipment. Risk assessments for new and emerging equipment have also been developed and provide a supplemental method for identifying and mitigating risks. The development of standards for design, manufacture, and testing of HPHT equipment will help to minimize the risk of structural failure or the fatigue failure of equipment that could result in undesirable events impacting safety and the environment, such as an oil spill due to loss of containment.

In addition to BSEE participating in the formation of industry-concensus HPHT standards, there are many requirements that must be met before an operator obtains a permit to drill, complete, and produce a subsea HPHT well. Both BOEM and BSEE conduct a rigorous permit review process that includes technical, safety, and environmental reviews. BSEE procedures currently require that every technology review includes an analysis of the mechanical barriers in place to keep oil and gas from escaping in the event of a failure. Comprehensive testing and approval processes for the deployment of non-conventional HPHT subsea technology substantially reduces the risk of potential accidents. Detailed steps and requirments of the permit review process can found in **Section 1.14**.

To ensure safety, BSEE also performs pre-production inspections of equipment before it is used. For example, as part of the approval process for production from Shell's Appomattox platform, BSEE conducted two pre-production inspections (refer to **Figure 6**). The first inspection occurred following the fabrication of the platform's topsides while it was still in the shipyard. Ten BSEE inspectors ensured that the topsides were constructed as

Figure 6. BSEE Inspectors Perform a Thorough Pre-production Inspection of Shell's Appomattox Platform. Source: USDOI, BSEE, 2018.

designed and approved, met industry and BSEE standards, and complied with Federal regulations. The second pre-production inspection took place after the platform was on location in the Gulf of Mexico (USDOI, BSEE, 2018).

1.10 How Does BSEE Review HPHT Project Permit Applications if there are Few Existing Engineering Standards for Subsea HPHT Equipment?

New technology and new equipment designs are necessary when drilling, completing a well, and producing from an environment with temperatures and pressures requiring the use of HPHT equipment. For example, the blowout preventer (BOP) shown in **Figure 7** meets the current engineering standards, American Petroleum Institute (API) Spec 16D, for use in the offshore environment; however, new subsea equipment or technology would be necessary to re-design this BOP for use in the HPHT environment. Current engineering standards are in place for subsea equipment rated up to pressures of 15,000 psi and temperatures of 350 degrees Fahrenheit (such as API Spec 17D for subsea wellheads and trees). Any subsea equipment rated for pressures and temperatures greater than 15,000 psi and 350 degrees Fahrenheit exceeds the limits of existing standards.

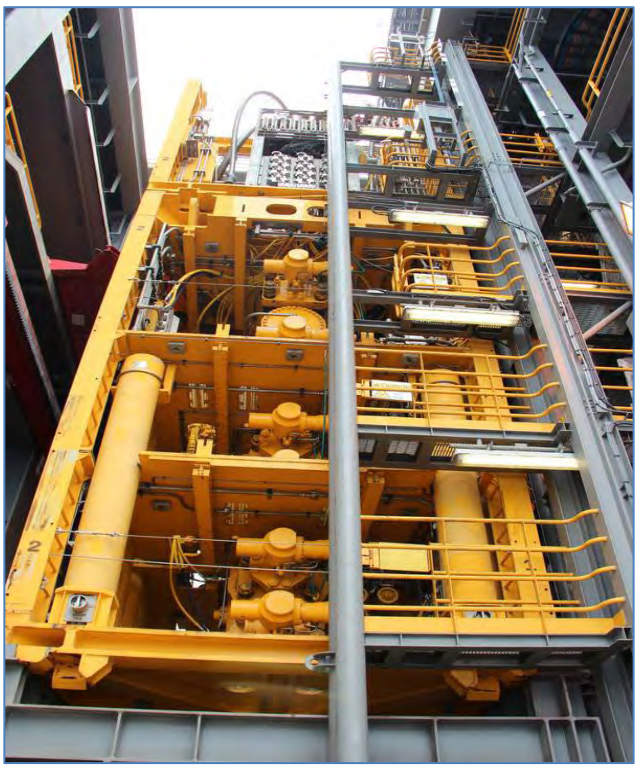

Figure 7. Example of a Typical 15,000-psi Subsea Blowout Preventer (BOP) Stack. New equipment has been developed with a rating of 20,000 psi. Source: USDOI, BSEE, pictured in Pallanich, 2017.

Although new equipment has been developed with higher pressure ratings, there are few existing standards for pressure ratings above 15,000 psi for subsea oil-field equipment. Industry has been working on subsea HPHT technology for many years; however, engineering standards take time to be created following the development of new technology. Therefore, the implementation of new technology, or non-conventional technology, has preceded the development of an engineering standard (Pallanich, 2017). Numerous HPHT engineering standards for subsea oil-field equipment are currently being developed to address these advancements in technology and will be published within the next 5 years. The challenge has been to understand how to adapt existing engineering design methods to the design of subsea oil-field equipment using materials that can withstand the HPHT environment. In order to implement the new technology before engineering standards for subsea oil-field equipment are fully developed and adopted, BSEE conducts stepwise, detailed evaluations of HPHT applications according to BSEE's recently published guidelines for HPHT development. Refer to **Section 1.12** for these guidelines.

All projects on the Outer Continental Shelf (OCS) in deep water (400 meters [1,312 feet] or greater), or using non-conventional production or completion technology, require a Conceptual Plan and a DWOP. The Conceptual Plan and DWOP provide for early dialogue between BSEE and industry before major capital expenditures on specific deepwater and subsea projects are committed. Because deepwater technology, like HPHT technology, has been evolving faster than BSEE's ability to revise OCS regulations, the Conceptual Plan and DWOP processes provide for a timely and flexible approach to providing guidance on regulatory requirements and keeping pace with the expanding deepwater operations and subsea technology.

Because there are few existing engineering standards for subsea HPHT equipment, HPHT equipment must be qualified and reviewed by BSEE before it can be manufactured and used for a site-specific project. The burden of proof to demonstrate the safety of the HPHT equipment rests with the operators. Operators must verify and validate HPHT components to ensure that they are fit-for-service for a site-specific project. They must be able to show that potential failures are mitigated before any designs are verified and validated to be fit-for-service. No equipment design can be used in the field until it has gone through design verification analysis and design validation testing for the protype.

In order for HPHT equipment to be verified, it must pass a design verification analysis, which determines if the equipment is able to withstand potential modes of failure. Equipment must be designed so that failure does not occur. The operator must show that the design of the equipment is based on sound science. During design verification analysis, several verification analytical checks occur, including plastic collapse (burst/rupture checks), local failure (strains exceed certain limits), ratcheting (deformation), bolting, and fatigue analysis using fracture mechanics or nominal stress (S/N) methods. Seal testing cannot be done analytically and must be done with a physical test.

In order for HPHT equipment to be validated, it must pass validation testing, which is defined by engineering standards. In validation testing, a prototype is tested to ensure that it performs in the HPHT environment. Validation typically follows design verification analysis and consists of the physical testing of prototypes that are equivalent to the production equipment in order to demonstrate compliance with specification requirements. Validation testing may include pressure testing, bending testing, compression testing, tension testing, and other tests as defined based on the potential modes of failure.

1.11 What is the Role of the Independent Third Party (I3P)?

The use of an independent third party (I3P) to review the design verification analysis and design validation testing helps BSEE during the approval process. In general, BSEE requires that an operator use an I3P review when equipment or technology requires a high degree of specialized engineering knowledge, exceeds the limits of existing engineering standards, or exhibits a risk potential or novelty that makes an additional level of review prudent. The job of the I3P is to review the work of the original equipment manufacturer (OEM) and operator. The operators oversee the new equipment produced by the OEM to ensure compliance with their functional design specifications. The

I3P determines if the work of the OEM and operator is performed as proposed using sound engineering judgment and recognized methods defined within existing science and standards. The I3P determines if the equipment is fit for its intended purpose by reviewing the design verification analysis and design validation testing, and documents through written reports, that all new HPHT equipment was designed and tested to the requirements established by both the OEM and operator.

After the equipment is qualified through design verification analysis and validation testing, the I3P must review, analyze, and summarize their findings of the process. The I3P and operator may both review the OEM's qualification documents separately and submit comments to the OEM. The OEM resolves all comments and then releases the documents to the I3P to prepare summary reports for submittal to BSEE. These reports are submitted to BSEE during the permit application process. Refer to **Figure 8** for a schematic of the interactions between the offshore industry and BSEE.

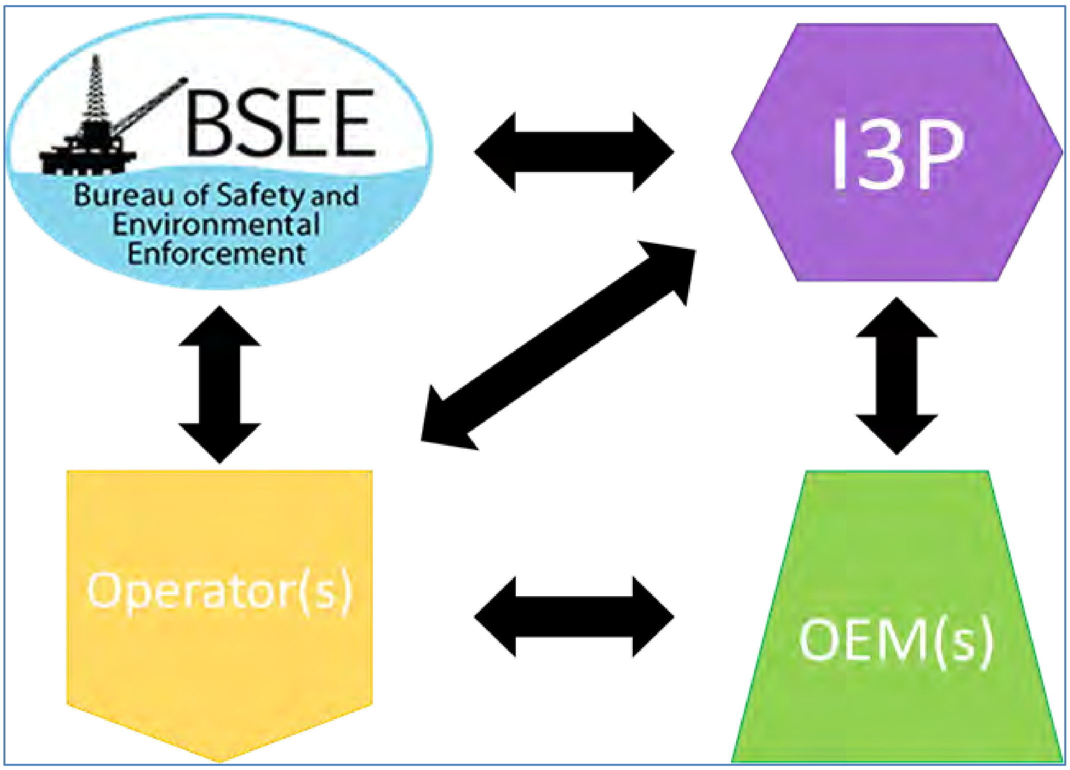

Figure 8. Cooperation between BSEE and Industry for New Technology Review and Standardization. Figure adapted from Patel, 2019. I3P = independent third party, OEM(s) = original equipment manufacturer(s).

The I3P has several reviews during the HPHT permitting process. At the component/assembly level, the I3P reviews the capacity in the expected service environment; at the project level, the I3P reviews that the equipment has the technical specifications listed at the project stated loads and are within the bounds of the previously verified component/assembly capacity (OOC, 2018). The I3P reviews to ensure that the outputs/results of the processes, methods, and designs meet or exceed the specified design targets. The I3P submits reports that clearly and concisely capture the results of their review of the various engineering analyses performed by the operator or OEM. These reports become part of the permanent BSEE record and are an integral part of the approval process (OOC, 2018).

Seven types of I3P summary reports (Reports 1A-1G) are submitted to BSEE for each piece or assembly of pieces of HPHT equipment under review. The I3P report format has been standardized to provide BSEE with a clear understanding of the new equipment design methodology and process (Patel, 2019). The information included in each summary report is listed below (Kluk, 2019):

- Report 1A – basis of design, technical specifications, and risk assessment.
- Report 1B – materials selection and qualification as well as environmental testing reports.
- Report 1C – summary of the verification design analysis, which includes the strength and fatigue analysis.
- Report 1D – validation testing for the equipment.
- Report 1E – the plan for field monitoring of loads to address fatigue loading and how fatigue will be monitored.
- Report 1F – fabrication, quality management system, and inspection and test plan that identifies the quality control process and inspections of the final products.
- Report 1G – all the previous reports are tied together and specifies that the equipment reviewed is fit for the purpose intended.

I3P reports (Reports 2A-2J) must also be submitted for well design. The information included in each of these reports is listed below (James, 2018):

- Report 2A – completion, intervention, and kill procedures. It must identify all of the necessary equipment to do this work and that the equipment is readily available and accessible and will remain so for the life of the well.
- Report 2B – force analysis for production tubing, casing, and liner.
- Report 2C – design analysis verification and validation testing for cementing materials in production casing and liner and associated cementing procedures.
- Report 2D – packer qualification analysis.
- Report 2E – qualification analysis for threaded connections for the production tubing, casing, and liner.
- Report 2F – trapped annular pressure and production casing pressure management plans.
- Report 2G – relief well capacity and HPHT capping stack analysis.
- Report 2H – justification for the estimated maximum anticipated surface pressure and shut-in tubing pressure.
- Report 2I – discussion of environmental conditions and material requirements.

Currently, the offshore industry is working together to thoroughly test and qualify new specialized equipment prior to its use in the HPHT environment. To help standardize the oversight process, as well as reduce replication and cost, operators have collaborated on materials qualification as well as sharing I3P verifications. In addition, BSEE has worked with industry organizations to create and clarify standards and regulatory requirements for new HPHT technology. Industry, I3Ps, and BSEE have worked together to clarify BSEE's requirements and review process. The operator, OEM, and I3P set responsibilities prior to project kick-off, and BSEE and the I3P keep all parties aligned through interaction, communication, and direct involvement during the review process (Patel, 2019).

One example of collaboration is where industry, operators, and I3Ps are working together to form a qualification team in order to qualify and approve all new equipment necessary for a 20,000-psi subsea BOP stack for the GOM (Kluk, 2019). The team engaged early and often with BSEE during the process. In this specific case, the goal was to use conventional BOP configuration and components but qualify each piece of equipment or subsystem that would be exposed to the HP environment for a 20,000-psi rating. Once the pieces are qualified, they can be manufactured and laboratory tested for a site-specific project. Communication between all parties is necessary to allow this process to work smoothly.

1.12 How do Recent Changes in the 2019 Well Control Rule Concerning Blowout Preventer (BOP) Regulations Apply to HPHT Projects?

The 2019 Well Control Rule replaces the use of a BSEE-approved verification organization (BAVO) with the use of an I3P for certain certifications and verifications of BOP systems and components, and removes the requirement to have a BAVO submit a Mechanical Integrity Assessment report for the BOP stack and system. This means that the I3P no longer needs to be a BAVO; however, I3P reviews are still required for BOPs. The use of an I3P is a long-standing industry practice for certifications and verifications similar to those that a BAVO would provide. BSEE has increased its interaction with I3Ps to better understand how they operate and carry out certifications and verifications. BSEE has determined that, since the majority of BAVOs were drawn from the existing I3P, they would continue to conduct the same verifications and, therefore, additional BSEE oversight and submittal to become a BAVO was unnecessary. BSEE determined that eliminating the BAVO system decreased procedural burdens and costs without decreasing meaningful improvements to safety or environmental protection (USDOI, BSEE, 2019b).

1.13 With Few Existing Engineering Standards for Subsea HPHT Equipment, What Guidance Does BSEE Provide to Lessees Applying for Permits for HPHT Projects?

An operator must submit several applications to BSEE in order to obtain approval to move forward with HPHT projects. Applications that must be approved by BSEE include a Conceptual Plan, Application for Permit to Drill (APD), Application for Permit to Modify (APM), and DWOP. Many of the applications also include I3P verification for new technology. As noted above, standards are still being developed for HPHT equipment, but BSEE has published guidance on requirements for HPHT projects based on research and collaboration with industry over the past decade.

In order to provide operators with guidance on BSEE requirements for HPHT projects, BSEE published a series of Notices to Lessees and Operators (NTLs). NTLs are formal documents that provide clarification, description, or interpretation of a regulation for the OCS, provide guidelines on the implementation of a special lease stipulation or regional requirement, provide a better understanding of the scope and meaning of a regulation by explaining BOEM or BSEE interpretation of a requirement, or transmit administrative information such as current telephone listings and a change in BOEM or BSEE personnel or office address. The NTLs for HPHT project guidance are available on BSEE's website at https://www.bsee.gov/guidance-and-regulations/guidance/notice-to-lessees.

NTL guidance for HPHT projects include the NTLs below:

NTL No. 2019-G02: "Guidance for Information Submissions Regarding Proposed High Pressure and/or High Temperature (HPHT) Well Design, Completion, and Intervention Operations" – This NTL provides guidance related to the process for requesting approval for well design, completion, and intervention operations for wells in an HP/HT environment.

NTL No. 2019-G03: "Guidance for Information Submissions Regarding Site Specific and Non-Site Specific HPHT Equipment Design Verification Analysis and Design Validation Testing" – This NTL provides guidance related to the process for requesting approval to install and use well completion equipment, well control equipment, well intervention equipment, trees, and production equipment designed for HPHT environments. This NTL also provides guidance regarding information submissions related to material selection, design verification analysis, and design validation and functional testing process and procedures. This NTL supersedes NTL No. 2007-G07.

NTL No. 2019-G04: "Requesting Approval to Consider External Hydrostatic Pressure Effects When Calculating Internal Pressure Containment Capability for Pressure Containing and Pressure Controlling Subsea Equipment" – This NTL provides guidance regarding the information that BSEE needs to analyze an operator's request for approval to consider external hydrostatic pressure in the design and calculation of internal pressure containment capability of subsea equipment.

1.14 How Does NEPA Fit into the Permitting Process?

The NEPA review is an important step in the permitting process and begins long before an operator submits an application to drill a well. BOEM conducts a NEPA analysis for each of the major stages of energy development planning. Due to the staged decisionmaking process in the Outer Continental Shelf Lands Act (OCSLA), BOEM does a staged or tiered process in which NEPA documents that cover potential impacts associated with the various stages of the OCSLA process are prepared. Programmatic NEPA review begins with the overarching Outer Continental Shelf Oil and Gas Leasing Program EIS. Pre-lease regional NEPA analyses occur prior to individual decisions to hold an oil and gas lease sale. These NEPA documents analyze the potential environmental impacts that could result if exploration, development, production, and decommissioning activities eventually occur. Once a lease is held by a lessee, post-lease site-specific NEPA reviews for the approval of specific activities on a lease occur. **Figure 9** shows the pre- and post-lease NEPA reviews that must occur before a permit is issued.

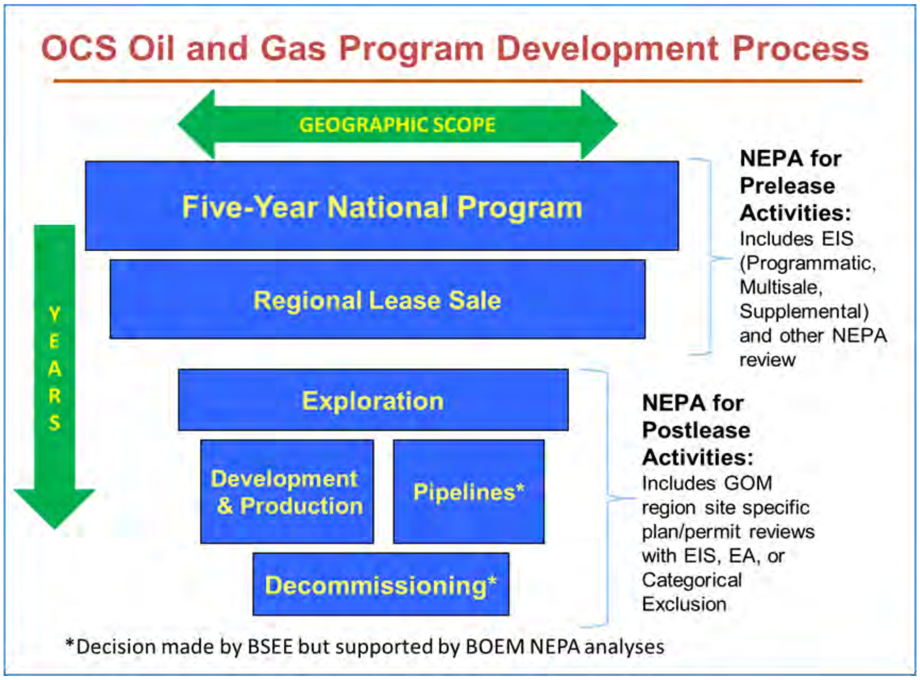

Figure 9. Pre- and Post-lease NEPA Reviews that Occur before a Permit is Issued.

NEPA review begins early in the process because thorough analysis of proposed activities can take longer than the regulatory timelines for plan reviews. Regulations allow BOEM 30 working days to review and make a decision on whether to approve, require modification, or disapprove an exploration plan (EP) and 60 working days to review and make a decision on whether to approve, require modification, or disapprove a development and production plan (DPP) or development operations coordination document (DOCD). More complex reviews, however, may take longer than the regulatory timeframes. In order to complete plan reviews within the regulatory timeframe, BOEM conducts large programmatic and regional NEPA reviews prior to holding a lease sale. Pre-lease NEPA documents consider a range of potential impacts that could occur as a result of an oil and gas lease sale, including activities that could be proposed in an EP, DPP, or DOCD. Post-lease NEPA review is site-specific and considers a specific activity that an operator proposes on a lease, such as drilling an exploratory or production well.

1.15 How Does an Operator Obtain a Permit to Drill and Complete an HPHT Project?

Prior to obtaining permits to drill a well, operators must submit plans to BOEM and BSEE for review and approval. BOEM conducts in-depth technical reviews of all lease EP, DPP (Eastern

Planning Area), and DOCD (Central and Western Planning Areas) and processes them for approval within mandated time frames, ensuring that plan activities are to be conducted in accordance with all applicable laws, regulations, and lease stipulations. BSEE conducts in-depth technical reviews and approval of all permit requests from offshore operators including Conceptual Plans, APDs, APMs, and DWOPs. The approval process involves review by both BOEM and BSEE. A plan is submitted to BOEM; the plan conducts the first set of reviews in the permit approval process, checking for consistency with regulations and laws, as well as conducting NEPA reviews. The plan is then transferred to BSEE who conducts the second set of reviews, focusing on the technical and safety aspects of the plan. Refer to **Figure 10** for the stepwise review process.

Operators submit an EP to BOEM when they propose to drill an exploratory well to investigate the potential oil and gas resource in a reservoir. BOEM's review evaluates the proposed activity for potential impacts and compliance with all applicable laws and regulations, including NEPA. Following BOEM's approval of the EP, the operator submits applications for specific activities to BSEE for approval. Prior to conducting any drilling operations, the operator is required to submit and obtain approval for an APD.

After the exploratory well is drilled, if the operator proposes to develop and produce that oil and gas resource from the reservoir, the operator submits a DPP or DOCD to BOEM for approval. BOEM again evaluates the proposed activity for potential impacts and compliance with all applicable laws and regulations, including NEPA. Following BOEM's approval of the DPP or DOCD, the operator submits a Conceptual Plan followed by an APD or APM to BSEE to complete the well. A well cannot be completed under the APD or APM until the Conceptual Plan approval is granted by BSEE. Following well completion, the operator submits a DWOP to BSEE to produce the well. All plans go through rigorous review to ensure compliance with established laws and regulations before any project-specific activities can begin on a lease.

For HPHT well completion and development, because many HPHT engineering standards have not yet been published for subsea equipment, HPHT Conceptual Designs and DWOPs follow a rigorous review process where equipment is qualified, verified, and validated, and an I3P reviews, analyzes, and summarizes their review of the HPHT plans for BSEE. Refer to **Sections 1.9 and 1.10** for more detail on the review process for new technology. **Figure 10** shows the permitting process for production from a HPHT reservoir.

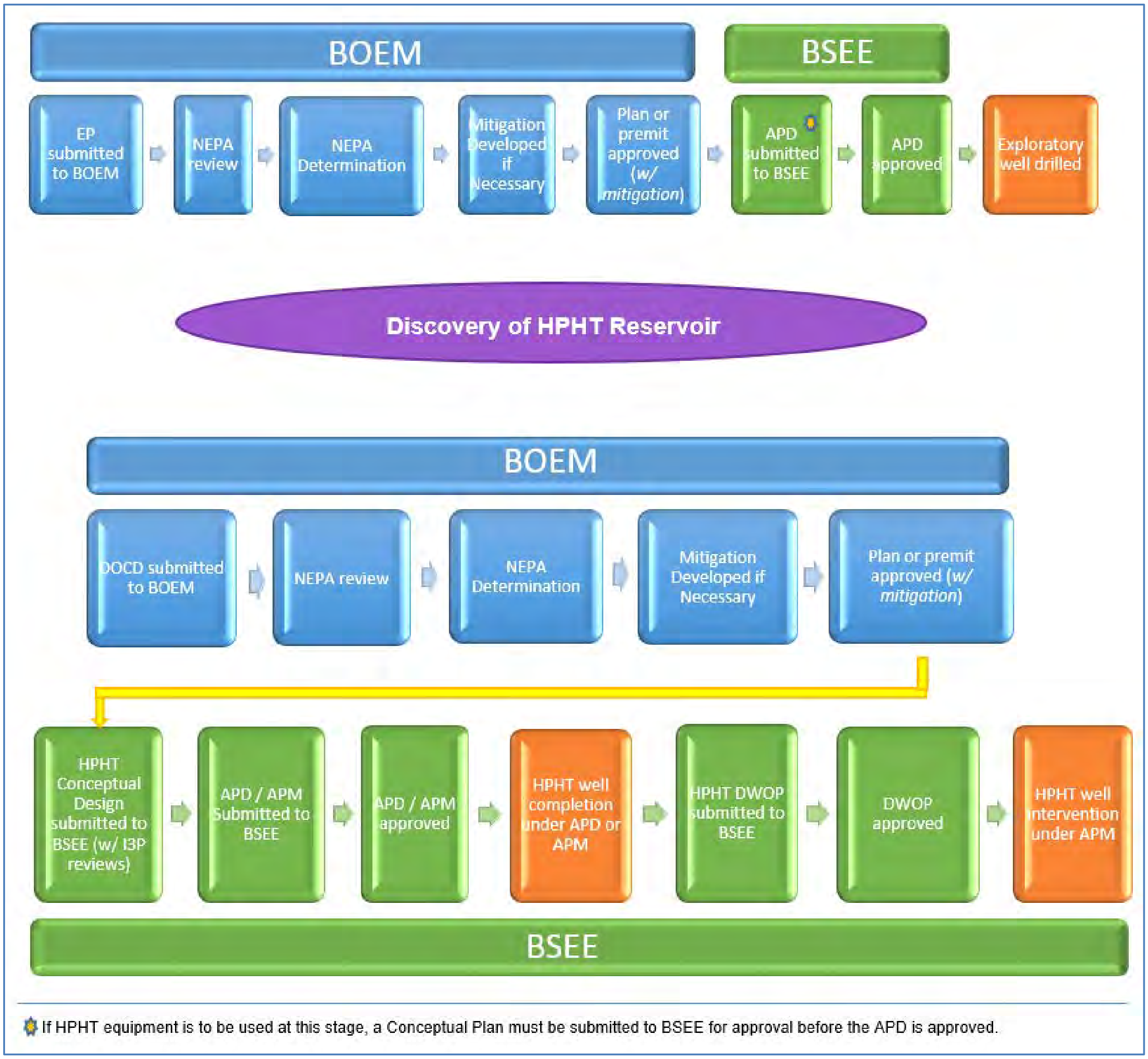

Figure 10. BOEM and BSEE's Approval Process to Drill and Produce an HPHT Well.

Note that this figure assumes the discovery or confirmation of the HPHT reservoir occurs after the exploration well is drilled. If the operator is drilling an exploratory well, expects to encounter an HPHT environment, and knows they want to complete and produce that well, then they must use HPHT equipment when drilling the exploratory well. For example, if the well is antcipated to be HP at the subsea wellhead, the exploratory well must be drilled with a 20,000-psia wellhead system if it is to be completed and developed. If the exploratory well were to be drilled with a 15,000-psia wellhead system, it would not gain approval for completion and development in the HP environment. In addition, because HPHT equipment will be used, the operator would need to submit a Conceptual Plan to BSEE for approval, along with the APD.

The following steps occur before an operator is approved to drill an exploratory well.

BOEM Review

Step 1: An operator must submit an EP to BOEM. The EP describes exploration activities, drilling rig or vessel, proposed drilling and well-testing operations, environmental monitoring plans, and other relevant information, and it includes a proposed schedule of the exploration activities.

Step 2: BOEM conducts an environmental review and evaluates the proposed exploration activities for potential impacts and compliance with all applicable laws and regulations, including NEPA. Supporting environmental information, archaeological reports, biological reports (monitoring and/or live bottom survey), and other environmental data determined necessary must be submitted with an OCS plan. The plan is reviewed by subject-matter experts that include, but are not limited to, geologists, geophysicists, engineers, biologists, archaeologists, air quality specialists, water quality specialists, oil-spill specialists, NEPA coordinators, and/or environmental/physical scientists. The plans and accompanying information are evaluated to determine whether any seafloor or drilling hazards are present; that air and water quality issues are addressed; that plans for hydrocarbon resource conservation, development, and drainage are adequate; that environmental issues and potential impacts are properly evaluated and mitigated; and that a proposed action is in compliance with NEPA, the Coastal Zone Management Act, BOEM's operating regulations, and other requirements. Refer to **Figures 11 and 12** for examples of site-specific deepwater benthic biological reviews and archaeological reviews. These reviews could result in mitigations that distance bottom-disturbing activity from sensitive seafloor benthic features and shipwrecks (refer to Step 4). Federal agencies, including the U.S. Fish and Wildlife Service, National Marine Fisheries

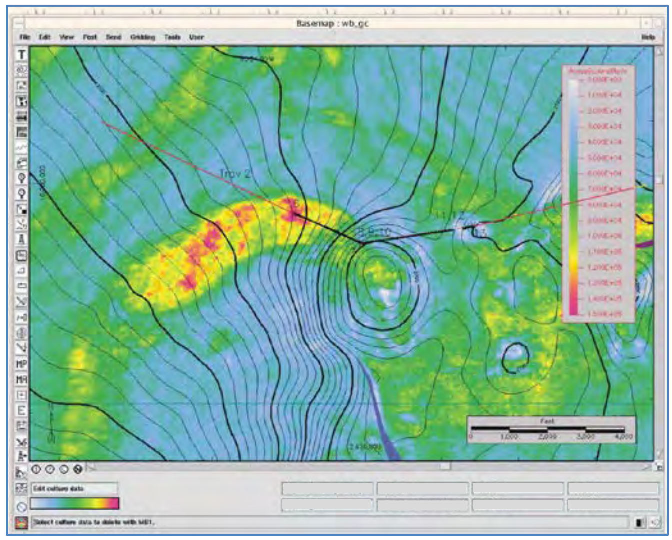

Figure 11. Example of a Site-specific Deepwater Benthic Biological Review for a Plan. Mitigations will distance bottom-disturbing activities from the sensitive benthic features.

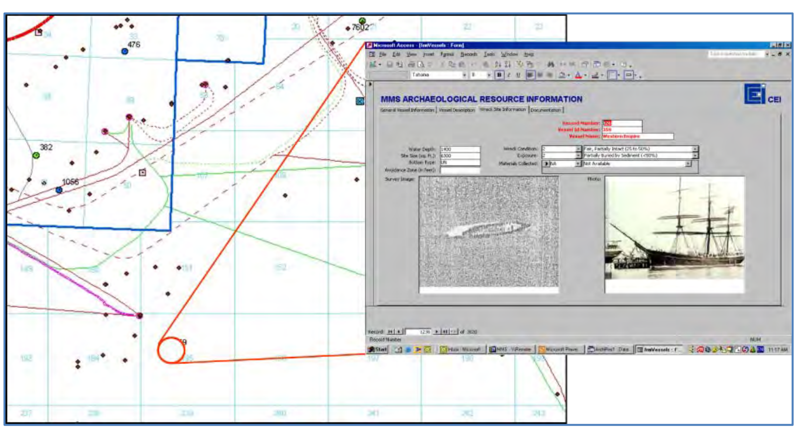

Figure 12. Example of a Site-specific Archaeological Review for a Plan. Mitigations will distance bottom-disturbing activities from the shipwreck.

Service, U.S. Environmental Protection Agency, U.S. Navy, U.S. Air Force, and U.S. Coast Guard, may be consulted if the proposal has the potential to impact areas under their jurisdiction. Each Gulf Coast State has a designated Coastal Zone Management agency that takes part in the review process. The OCS plans are also made available to the general public for comment through BOEM's Gulf of Mexico Office's Public Information Office.

Step 3: BOEM makes a NEPA determination of the proposal based on the environmental review. If the proposed action is determined to have minimal impacts, no futher NEPA review is necessary. If impacts are expected, a site-specific environmental assessment (EA) or environmental impact statement (EIS) is conducted.

Step 4: BOEM incorporates mitigating measures, as necessary, into plans. These measures may be implemented through, among other things, lease stipulations and project-specific requirements or conditions of approval. Conditions of approval are based on BOEM's and BSEE's technical and environmental evaluations of the proposed operations. Conditions may be applied to any OCS plan, permit, right-of-use and easement, or pipeline right-of-way grant.

Step 5: Following all NEPA review, the plan is approved by BOEM, with the conditional mitigations, as necessary.

BSEE Review

Step 1: An operator must submit to BSEE an APD, which contains information on the casing design, containment/capping stack, and blowout intervention. **Figure 13** shows some of the physical barriers put in place when drilling a well to prevent an oil spill. These barriers are reviewed before an APD is approved.

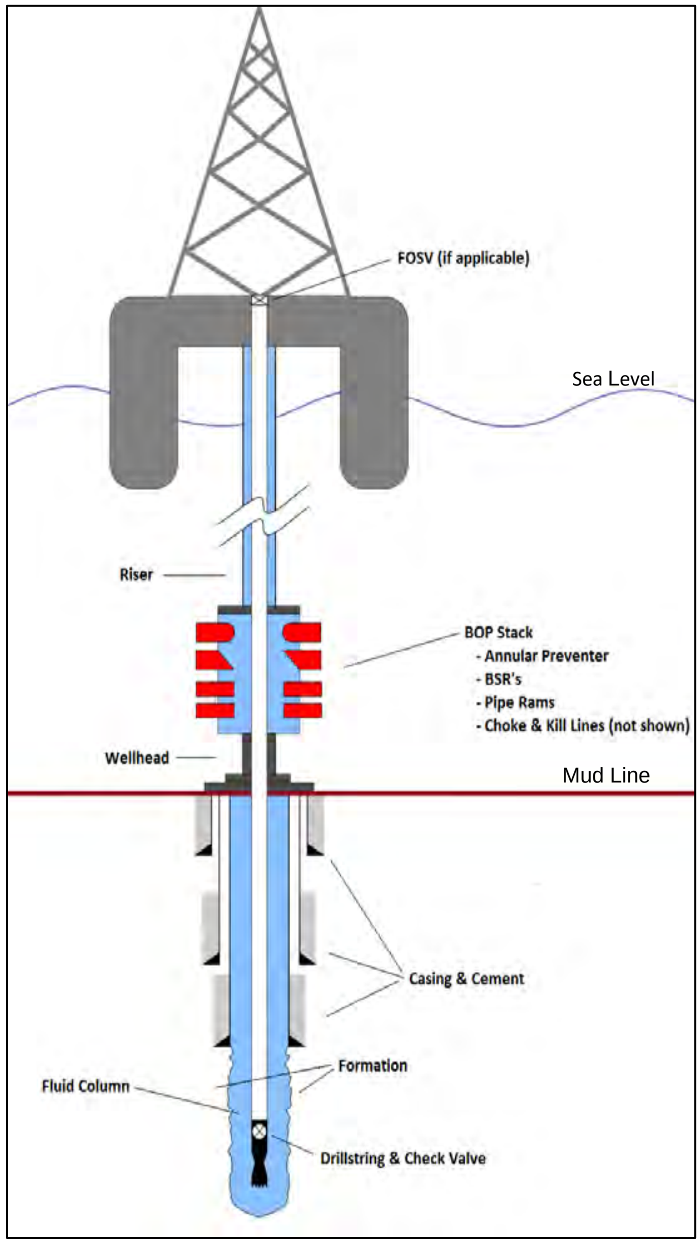

Figure 13. Diagram Showing a Well and Physical Barriers during the Drilling Process. Source: Hamilton et al., 2017.

Step 2: The APD is approved by BSEE.

Step 3: The operator drills the exploratory well.

After an exploratory well is drilled, an operator may choose to complete a development well and produce the resource. Well completion is a new stage of activity, beyond exploratory drilling, where a well is prepared for production. During well completion, final well casings are installed in the borehole to isolate hydrocarbons that will flow in the well. In addition, perforated sections of the casing are established to capture hydrocarbons from the reservoir into which the well is drilled.

If an operator has discovered a reservoir with HPHT characteristics and chooses to develop that reservoir, a rigorous permit review process occurs prior to obtaining approval to drill, complete, and produce the well. The process again starts with plan reviews and approvals by BOEM, but there are additional reviews by BSEE. BSEE must approve a Conceptual Plan before a well is completed and a DWOP before a well is produced. It should be noted that, if the operator wishes to complete and produce the exploratory well, rather than drill a new well after discovery, the exploratory well must be drilled with HPHT equipment, and a Conceptual Plan must be approved by BSEE before the APD is approved.

These steps occur before an operator is approved to complete and produce a HPHT well.

BOEM Review

Step 1: An operator must submit a DOCD or DPP to BOEM. The DOCD/DPP describes exploration activities, drilling rig or vessel, proposed drilling and well-testing operations, environmental monitoring plans, and other relevant information, and it includes a proposed schedule of the development and production activities.

Steps 2-5: For a DOCD/DPP, proceed the same as for an EP, which is described above.

BSEE Review

BSEE oversees seven major steps between applying for a permit to drill a HPHT well and producing from that well.

Step 1: The operator submits an HPHT Conceptual Plan to BSEE. The Conceptual Plan provides a proposed plan of the design and construction of the HPHT equipment, the design and procedures of the HPHT well completion (HPHT Well Design), an outline and specific expectations for the independent third party (I3P) review, and nomination of the I3P to perform the review. BSEE will then provide specific HPHT guidance to the operator. The final Conceptual Plan will not be approved until all of the I3P reports are received and reviewed by BSEE. No HPHT well may be completed until the Conceptual Plan is approved. Refer to **Section 1.10** for more detail on the use of an I3P during the Conceptual Plan review.

Step 2: An operator must submit an APD or APM to BSEE, which contains information on the casing design, the containment/capping stack, and blowout intervention. The APD or APM for an HPHT well completion cannot be approved until the Conceptual Plan is approved by BSEE.

Step 3: The APD or APM is approved by BSEE.

Step 4: HPHT well completion under the APD or APM.

Step 5: The operator then submits an HPHT Deepwater Operations Plan to BSEE, and project approval is required before a well can be placed on production. The DWOP is intended to address the different functional requirements of production equipment in deep water, particularly the technological requirements associated with subsea production systems, and the complexity of deepwater production facilities. The DWOP provides BSEE with information specific to deepwater equipment issues to demonstrate that a deepwater project is being developed in an acceptable manner as mandated in the OCSLA, as amended, and BSEE's operating regulations at 30 CFR part 250. BSEE reviews deepwater development activities from a total system perspective, emphasizing operational safety, environmental protection, and conservation of natural resources.

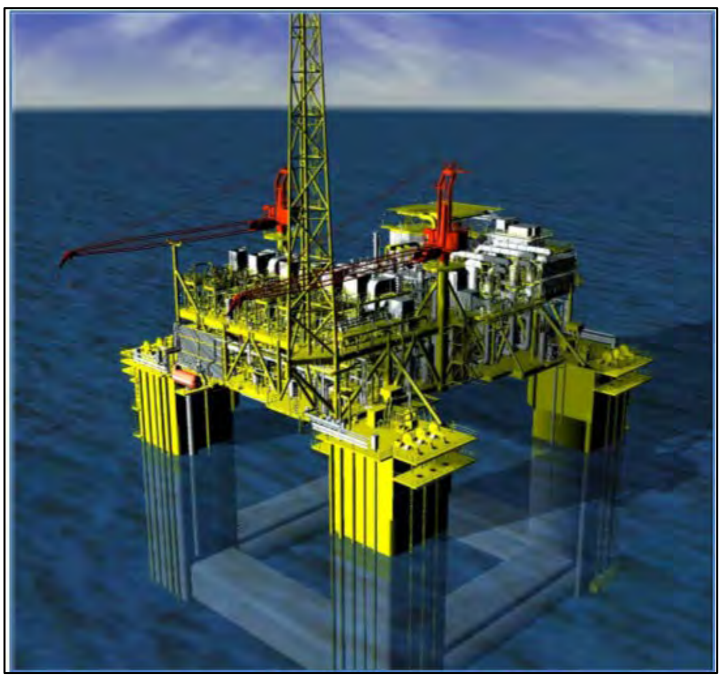

Figure 14. Example of a Graphic Representation of a Deepwater Platform to be Reviewed in a DWOP.

The DWOP process is a phased approach that parallels the operator's state of knowledge about how a field will be developed. A DWOP outlines the design, fabrication, and installation of the proposed development/production system and its components. A DWOP includes structural aspects of the facility (i.e., fixed, floating, or subsea); station-keeping (includes mooring system); wellbore, completion, and riser systems; safety systems; product removal or offtake systems; and hazards and operability of the production system. **Figure 14** shows a graphic representation of a deepwater platform to be reviewed in a DWOP. The DWOP provides BSEE with the information to determine that the operator has designed and built sufficient safeguards into the production system to prevent the occurrence of significant safety or environmental incidents. The DWOP, in conjunction with other permit applications, provides BSEE the opportunity to ensure that the production system is suitable for the conditions in which it will operate.

All DWOP approvals provide conditions of approval that may include using technologies that are not addressed in the regulations, such as HPHT technology. The Code of Federal Regulations for HPHT projects (30 CFR § 250.804) states that there are additional requirements for subsurface safety valves and related equipment (i.e., wellheads, tubing heads, tubulars, packers, threaded connections, seals, seal assemblies, production trees, chokes, well control equipment, and any other equipment that will be exposed to the HPHT environment) installed in HPHT environments. The additional requirements include a design verification analysis; design validation testing; and analyses, processes, and procedures that ensure that the equipment is fit-for-service in the HPHT environment.

Step 6: The DWOP is approved by BSEE.

Step 7: HPHT well intervention under the APM occurs.

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3 PREPARER AND CONTRIBUTING REVIEWERS

Preparer

Michelle Nannen, Environmental Scientist, BOEM

Contributing Reviewers

Christopher Bay, Economist, BOEM

Perry Boudreaux, Supervisory Environmental Scientist, BOEM

Sarah Coffman, Supervisory Economist, BOEM

Joan Hall, Supervisory Petroleum Engineer, BSEE

Russell Hoshman, Petroleum Engineer, BSEE

Hunter Jonsson, Petroleum Engineer, BOEM

Donald Maclay, Supervisory Petroleum Engineer, BOEM

Deborah Miller, Technical Publications Editor, BOEM

Kevin Nguyen, Petroleum Engineer, BOEM

Helen Rucker, Supervisory Environmental Scientist, BOEM

Bryan Stephens, Supervisory Geologist, BOEM

Toby Wraye, Senior Mission Analyst, BOEM

4 GLOSSARY

Bottom-hole – the bottom, or deepest point, of a well.

Blowout Preventer (BOP) – a set of specialized valves installed on the wellhead in stacks, which are used to control the flow of oil and gas from the well during drilling and production operations. This term is usually interchanged with blowout preventer stack and blowout preventer system, and it is abbreviated as BOP.

Dry Tree – A set of valves, spools, and fittings connected to the top of a well to direct and control the flow of formation fluids from the well. A dry tree is located on a platform rather than subsea (wet tree).

Gradient – an increase or decrease in the magnitude of a property (e.g., temperature, pressure, or concentration) observed in passing from one point or moment to another.

High pressure (HP) – an internal absolute pressure rating greater than 15,000 pounds per square inch absolute (psia) at the wellhead.

High temperature (HT) – a temperature rating greater than 350 degrees Fahrenheit at the wellhead.

Subsea wellhead – A wellhead that is used with a floating drilling rig that uses a subsea blowout preventer (BOP) stack for well control. The subsea wellhead is usually connected to the surface casing string, and all subsequent casing strings are installed, landed, and sealed inside the subsea wellhead’s high pressure housing, immediately below the BOP.

Wellbore – a borehole or a hole drilled into the seafloor to carry out exploration and extraction of oil and gas. It is the actual hole that forms the well and it is typically encased by cement and steel.

Wellhead – a structure that is installed at the top of an oil or gas well. Its main function is to ensure a safe operation and manage the flow of oil or gas from the well into the gathering-system. It is a system composed of valves, spools, and assorted adapters that control the pressure of the production well. It acts as an interface between the surface facilities and the casing strings in the wellbore.

The Department of the Interior Mission

The Department of the Interior protects and manages the Nation's natural resources and cultural heritage; provides scientific and other information about those resources; and honors the Nation's trust responsibilities or special commitments to American Indians, Alaska Natives, and affiliated island communities.

The Bureau of Ocean Energy Management Mission

The Bureau of Ocean Energy Management (BOEM) is responsible for managing development of U.S. Outer Continental Shelf energy and mineral resources in an environmentally and economically responsible way.