UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT
GULF OF MEXICO OCS REGION

NTL No. 2024-G05 Effective Date: 11/18/2024

NOTICE TO LESSEES AND OPERATORS OF FEDERAL OIL, GAS, AND SULPHUR LEASES IN THE OUTER CONTINENTAL SHELF, GULF OF MEXICO OCS REGION

Managed Pressure Drilling Projects Using a Subsea Blow Out Preventer

This Notice to Lessees and Operators (NTL) provides guidance about your use and maintenance of the equipment and materials that are necessary to ensure the safety and protection of personnel, natural resources, and the environment in compliance with 30 CFR 250.703 when you conduct a managed pressure drilling (MPD) project in the Gulf of Mexico (GOM) outer continental shelf (OCS) for wells with subsea blowout preventers (BOPs). It also describes the information that should be included in an Application for Permit to Drill (APD) or Application for Permit to Modify (APM) so that BSEE can analyze a request for approval to use other circulating equipment for an MPD project pursuant to 30 CFR 250.738(m). If you are planning to use MPD with a surface BOP stack, please refer to NTL No. 2008-G07 (Managed Pressure Drilling Projects).

Intent

The intent of this NTL is to encourage proactive planning and provide a consistent approval process before you implement MPD operations. Be advised that any MPD implementation or contingency implementation of MPD requires prior BSEE review and approval pursuant to 30 CFR 250.738(m). This NTL addresses MPD as it applies to drilling with subsea BOPs. When using any form of MPD with a subsea BOP, you must maintain equivalent downhole mud weight greater than the estimated pore pressure at all times pursuant to 30 CFR 250.414(c)(1).

Definitions

Managed Pressure Drilling (MPD) is an adaptive well construction process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. Any flow incidental to the operation needs to be safely contained using an appropriate process. Aspects of MPD operations include:

1. MPD employs a collection of tools and techniques that may mitigate the risks associated with wells that have narrow downhole environmental limits by proactively managing the annular hydraulic pressure profile, and

2. MPD may include control of back pressure, fluid density, fluid rheology, annular fluid level, circulating friction, and hole geometry, or combinations thereof.

For the purpose of this NTL, MPD is limited to situations where the total well operation is performed:

1. Balanced or overbalanced, including hydrostatically overbalanced (no supplemental surface pressure needed to balance the formation pressure), or

2. Hydrostatically underbalanced (supplemental surface pressure required to balance the formation pressure).

BSEE parameters for safe drilling margin are stated under 30 CFR 250.414(c)(1). When you use managed pressure operations, you must provide for the ability to maintain and/or increase pressure at all times.

For MPD operations where the hydrostatic pressure[1] of the fluid is below formation pressure[2] and surface back pressure (SBP) is being used to maintain an overbalance pressure state to the formation, the allowable fluid underbalance should be limited to the amount of annulus friction pressure[3] expected in the current well section, not including the applied surface back pressure.

Example:

Expected formation pressure = 15.0 ppg
Expected annulus friction pressure due to pumps on circulating = 0.3 ppg
Allowable fluid underbalance = 0.3 ppg
Hydrostatic pressure of fluid (surface mud weight + fluid compressibility/cuttings load) = 14.7 ppg
Fluid compressibility/cuttings load = 0.1 ppg
Allowable surface mud weight = 14.6 ppg

Planning

You should contact the well operations engineers in the appropriate district office of the BSEE GOM Region Office (GOMR) as soon as you begin planning an MPD project using subsea BOPs. MPD projects, especially those proposed by lessees and operators that have not yet used

[1] Downhole static equivalent drilling fluid pressure comprised of the surface fluid weight with the additional factors from the fluid compressibility and the cuttings load. This does not include any surface back pressure that is imposed by the MPD equipment.
[2] Expected formation or fluid pressure.
[3] Additional pressure observed due to fluid friction in the annulus when circulation is established.

approved MPD techniques, require frequent interaction with the appropriate GOMR district while you conduct preliminary engineering assessments, develop plans and contingencies, plan hydraulics, assemble equipment, and conduct training exercises.

Necessary APD or APM Information

Under 30 CFR 250.738(m), BSEE can approve the use of other circulating or ancillary equipment if a request is made that includes a report from an independent third-party on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. Your APD or APM to conduct an MPD project should contain sufficient information for BSEE to review and assess the merits, operational safety, and environmental aspects of all proposed MPD operations. Accordingly, to enable BSEE to evaluate your request, we recommend that you include the following information in your APD or APM:

1. An analysis and discussion of all drilling concerns, including the rationale for using non-conventional drilling technology such as MPD. You should include details of the items that will be impacted by the pressure margins and a discussion of your plans to commence non-conventional circulation. We recommend that you provide the following:

   a. Pressure plots with pore pressures, fracture pressures, and surface/downhole mud weights (hydrostatic and surface back pressure) through each of the hole sections where you intend to use MPD. The most current and best technical estimate data should be used, including, but not limited to, depleted and abnormally pressured zones.
   b. Geologic data examining the risks of abnormalities or geologic uncertainties, and potential or known loss zones.
   c. If losses are possible, discuss the types of losses, detection methods and planned mitigations that will be implemented.
      i. If you experience losses while drilling, you must follow API Bulletin 92L as incorporated by 30 CFR 250.198.
   d. Casing design calculations with safety factors and proper explanation of assumptions used to generate the loads and how the use of MPD affects these loads.
   e. If the plan is to use MPD equipment for any other operations besides drilling (e.g., cementing, completions, decommissioning, casing or liner running), documentation for those operations should also be provided and discussed, including:
      i. Procedure(s) covering the specific operation being proposed, with record of independent third-party review and certification.
      ii. Full simulations for both conventional operations and proposed operations using the MPD equipment.
      iii. Well-specific, detailed justification as to why the proposed operation cannot be performed conventionally, including a discussion on how well control will be modified to provide a degree of protection, safety, or performance equal to or better than using conventional operations.
      iv. Signed risk assessment, providing risks and mitigations in place (with required signatures from operator and drilling contractor).

   v. For these operations, a downhole overbalanced state must be kept in the MPD system using mud density, surface back pressure, and/or annulus friction pressure at all times pursuant to 30 CFR 250.414(c)(1).

f. Schematics of all the Flow Control System (FCS) equipment, including footprints, piping and instrumentation diagrams, and design considerations.
g. Surface circulation system design specifications and redundancies, specifically for MPD implementation.
h. Your plans to install and operationally test the MPD equipment to the expected operational pressures, which includes all equipment that would be exposed to pressures such as riser, pressure relief valves, pressure control valves, riser pressure control devices (e.g., rotating control device, active control device, drill string isolation tool (DSIT), dual annulars), MPD buffer manifold, MPD choke manifold, and associated MPD flowlines on the drilling rig in a benign environment, such as within cased hole.
i. A description of the methods you will deploy to detect variations in flow rate during MPD operations. Include discussions of the well control, trip tank (or virtual trip tank), and pit system procedures; mud return flow trending; the monitoring and use of flow meters; logging tools including measurement while drilling, pressure while drilling, and logging while drilling; gas detection equipment installed; mud sampling procedures; and rheology monitoring.
   i. The coriolis meter(s) should be verified per manufacturing recommendations before beginning MPD operations on each well. BSEE may condition approval of the APD or APM on you documenting and making available coriolis meter readings onsite during BSEE inspections.
   ii. If coriolis meter(s) are not available for volume measurements into the well, the positive displacement pumps that are used for MPD operations should have the stroke (or variable frequency drive) efficiency verified with the coriolis meter(s) at least once before drilling each well section and every time the pumps have any work performed on them, or if the mud characteristics are changed significantly.
   iii. Pressure while drilling and coriolis meter information should always be available. BSEE may condition approval of the APD or APM on you notifying the appropriate GOMR district with a plan of action for proceeding with drilling if these sensing devices fail or have erratic readings. If you cannot demonstrate that your plan of action will protect health, safety, property, and the environment, as required under 250.107(a), BSEE may not approve the use of other circulating or ancillary equipment.
j. Identification of MPD well barrier elements and diagrams, with calculations and verification that these elements are rated to withstand anticipated loads (with safety factor) for planned operations. This should be provided for each hole section using MPD.

2. A description of your hydraulics model showing each individual hole section to be drilled with MPD and detailed schematics for all surface piping and downhole equipment configurations supporting the model, including the following:

    a. You should model downhole characteristics and the surface FCS using a range of anticipated fluid properties.
    b. For each individual hole section, you should provide calculations and methods used to determine annular friction pressure (AFP) values. We recommend that you discuss how you will manage AFP with the use of the MPD equipment.
    c. You should explain how you will compare your model against actual drilling data and make adjustments during operations. We recommend that you show how you will adjust the model if formation characteristics deviate from those expected during MPD operations.

3. MPD specifications, including the following:

    a. Documentation on how long it takes for the alternative riser isolation device (e.g., DSIT, quick closing annular) to fully close and isolate the riser pressure control devices.
    b. A discussion of the rig's fluid and gas separation capabilities.
    c. A description of how MPD use influences other safety systems (e.g., the emergency disconnect, watch circle, drift-off curves).
    d. For each MPD hole section, we recommend that you provide a simulation justifying what volume of gas influx can be handled safely if you plan to circulate an influx via MPD equipment. This simulation should identify the restricting equipment and all assumptions made.
    e. Pressure and volume rating for all MPD equipment, including changes in ratings for different operations (e.g., riser pressure control device rating if stripping, rotating, or static).

4. A discussion of the equipment and procedures that you will use during MPD operations, including the following:

    a. An operational matrix, such as that shown in the appendix of this NTL, specifying when you will adjust your drilling parameters and when you will implement conventional well control procedures. The operating limits described in the matrix (i.e., SBP and influx volumes) should be explained and justified with supporting documentation. BSEE may condition approval of the APD or APM on the following:
        i. If there is an increase in the approved influx volume, the appropriate GOMR district must be notified, and you must receive BSEE approval for the new matrix before commencing operations in the applicable hole section.
        ii. If there is an increase in the approved SBP values, the appropriate GOMR district must be notified, and you should test all MPD pressure control equipment to the increased values to ensure its continued

suitability for the conditions before commencing operations in the applicable hole section.

iii. Whenever the MPD operational matrix is updated (i.e., formation integrity test or leak off test values, mud weight values, SBP values) for any applicable hole section, it should be included in the next revised permit submittal.

iv. If influx removal is planned through the MPD system, such equipment is considered well control equipment, and you must adhere to the requirements of 30 CFR 250.738(m), notably, report submission from an independent third-party on the equipment's design and suitability for its intended use.

b. Any change in system mud volume may indicate the onset of an influx or a loss. Accordingly, BSEE may condition approval of the APD or APM on you documenting the actions taken to evaluate the potential existence of an influx or loss and retaining these records until the well is abandoned. Actual influxes or losses must also be reported to BSEE via Well Activity Report pursuant to 30 CFR 250.743(c).

c. Provide the calculations and simulations, along with graphical representation, outlining each hole section's maximum kick tolerance and intensity, including a discussion of the limiting factors. Additionally, you should discuss at what point the well will be swapped over to conventional well control and influx removed through the subsea BOP.

d. Provide a maintenance and testing schedule of all related pressure equipment that includes the initial installation and ongoing operations testing. The entire MPD system should be tested as part of the well control system (14-day, or 21-day frequency if you are approved for 21-day BOP testing) if the MPD matrix for the applicable section of hole includes an approved influx volume limit. This includes riser, pressure relief valves, pressure control valves, riser pressure control devices (e.g., rotating control device, active control device, DSIT, dual annulars), MPD buffer manifold, MPD choke manifold, and associated MPD flowlines. Adjustable pressure equipment should not be set at a pressure rating higher than tested values. The MPD system should be tested to the maximum surface back pressure value, as defined for the operation of the applicable hole section. BSEE may condition approval of the APD or APM on the following limitations:

i. You may not conduct operations on the well until a revised permit has been submitted that includes the independent third-party analysis report, per 30 CFR 250.738(m), which verifies the MPD system's design and suitability for its intended use.

ii. If any of the components of the MPD system do not hold the required pressure or incur a failure that prevents component(s) from meeting the functional specification, the equipment must be repaired/replaced immediately and retested to ensure continued protection of health, safety, property, and the environment, as required under 30 CFR 250.107(a). You must report any problems or irregularities, including any leaks, to the appropriate GOMR district. You must submit a revised permit under 30 CFR 250.738(m) and in compliance with 30 CFR

250.107(a)(4), with a written statement from an independent third-party documenting the repairs, replacement, or reconfiguration and certifying the equipment's design and suitability for its intended use. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.

e. A maintenance plan providing for consumable elements, such as the riser pressure control devices and information regarding available spares.
f. A description of the system that you will use to detect and monitor variations in flow rate or influx volume.
g. Instrumentation for measuring bottom hole pressure. We recommend that you include your plans to notify the appropriate GOMR district Manager, who must approve the forward plan, before you continue with MPD operations if the specified instrumentation malfunctions or fails pursuant to 30 CFR 250.738(b).
h. A description of the non-return valves (NRVs) that will be used to prevent flow up the drill string. At least two NRVs should be present in the bottom-hole assembly to prevent influx up the drill pipe. We recommend that you specify the type of valves and maintenance performed on those valves.
i. Include documentation that the mud-gas separator system (including upstream and downstream piping) has adequate capacity for the intended drilling program and can handle influx volumes approved in the MPD operations matrix, such as the expansion of gas at the surface, without increased risk. The piping should be routed so that no direct or uncontrolled discharges flow directly into the mud gas separator.
j. Describe the equipment and procedures you will employ to provide functional redundancy in the FCS. This should include the riser pressure control devices, mud pumps, chokes, flow meters, and flow detection instrumentation.
k. Describe the procedure(s) you will follow, with recommended record of independent third-party review, so that any potential influx will be safely handled once it has entered the riser should the riser pressure control devices fail to seal.
l. For each hole section, you should describe the maximum allowable pressure within the MPD system, so as not to exceed the weak point of formation or equipment, and describe the mitigating measures you propose to use to ensure that formation or equipment limits will not be exceeded.
m. For every well in which managed pressure operations are being proposed, we recommend that you attach the non-expired MPD class certification/notation for the mobile offshore drilling unit.

5. Plans for you and your contractors to develop and implement a hazards analysis for your MPD operations, as per the requirements in 30 CFR 250.1911.

6. Your plans to provide competency assurance for all involved personnel. We recommend that you describe the supplemental training you will provide for all identified relevant personnel engaged in MPD operations to ensure that they understand their role in MPD, are familiar with the equipment, and can properly perform their assigned duties. Training should also cover plans and procedures to address the transition between MPD operations and well control. BSEE may condition approval of the APD or APM on you maintaining a record of training and competency for key

personnel involved in MPD operations and making the record readily available on the rig.

7. The site-specific riser analysis, with the following considerations:

    a. The site-specific riser analysis should be performed by in independent third-party and not the drilling contractor.
    b. The site-specific riser analysis should be performed with the maximum planned surface back pressure and maximum surface mud weights. If the approved values are modified to reflect an increase in load case(s), you should submit a revised site-specific riser analysis to the appropriate GOMR district for approval.

8. Any other documentation requested by the appropriate GOMR district to assist in reviewing the MPD proposal.

Necessary Independent Third-Party Report Information

The following information should be included in the independent third-party report(s) required by 30 CFR 250.738(m) to demonstrate the equipment's design and suitability for its intended use:

1. All MPD procedures (Operational and Contingency).
2. All MPD equipment used for well control, per 30 CFR 250.738(m).
3. The non-expired MPD class certification and notation for the drilling rig (at a minimum, should include design review, inspection, testing, installation, and commissioning).
4. A site-specific riser analysis for the planned well location, with the following considerations:
    a. The site-specific riser analysis should be performed by in independent third-party, and not the drilling contractor.
    b. The site-specific riser analysis should be performed with the maximum planned surface back pressure and maximum surface mud weights. If the approved values are modified to reflect an increase in load case(s), you should submit a revised site-specific riser analysis to the appropriate GOMR district for approval.
5. Statement to document repairs, replacement, or reconfiguration of any MPD system components.

Note All independent third-party reports should be presented on official company letter head and include an executive summary, the name of reviewer(s), their findings, and a professional engineer signature and certification. If the independent third-party makes any recommendations, you should state if the recommendations have been accepted, and changes made, or if not, why the recommendations are not being addressed.

Requests for Trapping Pressure Using the Subsea BOP

If there is a technical circumstance that requires trapping pressure under the subsea BOP, you may request to do so. The appropriate GOMR district may approve the request if adequate justification is provided. The following documentation should be provided to support the request for trapping pressure below the subsea BOP:

1. A list of available options to maintain wellbore stability. This might include the following: closing one blind shear ram (BSR) to trap pressure, closing the other BSR, closing both BSRs, increasing mud weight in the well, using a riser cap, closing the BOP annular on the open hole, or any other options you may have.
2. Full simulations showing trapping pressure is a necessity. This should include a mud rollover (pre-cementing) if surface back pressure will be used during cementing. You should specify how the circulation rates used in the simulation were derived. This may include citing minimum required annular velocities for the scenario in question and the resulting minimum circulation rates.
3. Information about the condition of the BOP control system and rubber goods (e.g., current BOP control system leaks or issues, when the rubber goods were last changed, how often the rubber goods are changed, the number of activations since last changed, and has or will this BOP be hopped).
    a. If the trapped pressure request is approved, BSEE may not approve a subsea BOP stack hop request for a subsequent well.
4. A discussion on how trapping pressure using the BOP may affect its reliability if needed for a well control event.
5. A description of the range of expected pressures to be trapped beneath the BOP on the well.
6. A description of the well control procedures for possible scenarios that could occur while out of the hole with pressure trapped below the BOP (e.g., an increase in wellbore pressure, BSR(s) failure to hold pressure, dropped object on BSR(s)).
    a. Any referenced equipment or materials should be readily available on the rig.
7. A signed risk assessment, providing risks and mitigations in place (with signatures from operator and drilling contractor). The risk assessment should evaluate the risk of the proposed method in comparison to other possible options (e.g., riser margin, rolling over to kill weight mud).
8. A well-specific, detailed justification as to why trapping pressure must be used. This should include all available options, with a ranking of most preferred to least preferred for all options listed.
9. Procedure(s) describing how pressure below the BOP will be monitored and maintained, including plans for what will happen if the component trapping pressure begins to leak.
10. For hole sections where other managed pressure operations are proposed for a trapped pressure request (e.g., cementing, completions, decommissioning, casing or liner running), full simulations should be provided.
11. Procedure(s) covering the specific operation being proposed, with record of independent third-party review.
12. Independent third-party certification of the trapped pressure request, including

independent review of all the documentation listed in this subsection. The independent third-party should specify the technical circumstance required for trapping pressure using the BOP and provide a report on the equipment's design and suitability for its intended use.

13. If there is a possibility of evacuating a well location, such as inability to keep the rig on location, or impending storm or hurricane (either in pre-planning or ongoing trapped pressure operations), provide plans to bring the well to an overbalanced state without the use of trapped pressure.

Guidance Document Statement

BSEE issues NTLs as guidance documents in accordance with 30 CFR 250.103 to clarify, supplement, and provide more detail about certain BSEE regulatory requirements and to outline the information you provide in your various submittals. Under that authority, this NTL sets forth a policy on and an interpretation of 30 CFR 250.738(m) that provides a clear and consistent approach to submitting certain requests pursuant to that regulation. However, if you wish to use an alternative approach for compliance, you may do so, after you receive approval from the appropriate GOMR district per 30 CFR 250.408.

Paperwork Reduction Act of 1995 Statement:

The Office of Management and Budget (OMB) has approved the information collection requirements and assigned OMB Control Numbers 1014-0028 for the subpart G regulations, 1014-0018 for the subpart D regulations, and 1014-0017 for the subpart S regulations. This NTL does not impose any additional information collection requirements subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.).

Contact

If you have any questions regarding this NTL, you may contact the Well Operations Support Section in the BSEE GOM Region Office by telephone at (504) 731-7810, or by email at omm_dfo_woss@bsee.gov.

BRYAN DOMANGUE

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Bryan A. Domangue
Regional Director

Appendix

Managed Pressure Drilling Operations Matrix

The following matrix describes when you should proceed to corrective measures to bring any influx into control when performing MPD operations.

MPD Operations Matrix		**Surface Pressure**			
		At Planned Drilling Back-pressure	**At Planned Connection Back-pressure**	**> Planned Back-pressure and < Back-pressure Limit**	**≥ Back-pressure Limit**
Influx Volume	No influx	Continue drilling	Continue operation	Continue operation; adjust system to decrease WHP	Secure well; evaluate next planned action
	≤ Operating limit	Continue drilling; adjust system to increase BHP	Continue drilling; adjust system to increase BHP	Continue drilling; adjust system to decrease WHP and increase BHP	Secure well; evaluate next planned action
	< Planned limit	Cease drilling; adjust system to increase BHP	Adjust system to increase BHP	Secure well; evaluate next planned action	Secure well; evaluate next planned action
	≥ Planned limit	Secure well; evaluate next planned action	Secure well; evaluate next planned action	Secure well; evaluate next planned action	Secure well; evaluate next planned action

Definitions

Back-pressure limit: Back-pressure limit should be calculated and can be limited by riser limitations, casing design, surface equipment limitations, formation break down pressure, etc.

Operating limit: The limit at and below which drilling can continue.

Planned limit: The limit at and above which MPD ceases and a transition to well control operations is required.