March 12, 2008

Department of the Interior
Minerals Management Service (MS 4024)
Attn: Rules Processing Team (Comments)
381 Elden Street
Herndon, VA 20170-4817

Re: RIN 1010-AD 11; Sub Part J-Pipelines and Pipelines Rights-of-Way
FR Vol. 72, No. 191 10-3-07

Ladies and Gentlemen:

The Offshore Operators Committee (OOC) appreciates this opportunity to provide written comments on the subject proposed rule to amend regulations regarding pipelines and pipeline rights of way associated with Outer Continental Shelf oil and gas and other mineral operations as published in the October 3, 2007 Federal Register. OOC is an organization of some 124 producing and service companies who conduct essentially all of the OCS oil and gas exploration and production activities in the Gulf of Mexico. Comments made on behalf of OOC are submitted without prejudice to any member's right to have or express different or opposing views.

OOC understands that MMS conducted a complete rewrite of Subpart J using plain language and restructured the rule to improve readability and clearly outline requirements in tabular form in many places. While OOC is encouraged that MMS has chosen to provide more guidance and consolidate its requirements in the many NTL's associated with Sub Part J, we were surprised at the magnitude and direction that the rule making chose to take. Unlike recent rule making efforts, this effort clearly attempts to more rigidly prescribe new reporting, documentation and record keeping requirements far above current levels. With our current experience furnishing permitting and operating information and the long cycle times associated with an overwhelmed group in the GOM OCS Region, it is surprising that the MMS has chosen to actually expand requirements, while cutting response time for submittal of information. Our experience with cycle time necessary to get work carried out has been very disappointing and the new rule has the potential to multiply the amount of information the already swamped group with more data of questionable value as required for regulatory oversight. The rule takes the position of being more interactive to the point of requiring information on a time line that

could prove impractical or slow down the development process such that permitting is the critical path in lieu of actual design, construction, installation and operation. OOC appreciates that MMS rewrote the proposed rule to consolidate and streamline, but the many authors of the new rule also added significant new requirements that we must challenge the value of in light of our current safe operating record.

While the new version eliminates some requirements that are no longer deemed necessary and incorporates into the proposed rule the numerous Notices to Lessees and Operators (NTLs) that clarify the current regulation, the MMS's additions to Sub Part J will not reduce the burden on industry to provide a significant amount of new technical and operational information. The draft rule will significantly increase the amount of data necessary to provide and shorten the time frame normally associated with the process.

The NOPR is broadly targeted at three critical areas: safety, reliability, and environmental. OOC agrees these areas are important to the industry, customers, general public, and regulators. With this in mind, OOC would like to know specifically where MMS believes the industry is falling short of expectations in these areas. If this is the case, OOC is requesting the MMS to share its data it has indicating offshore pipelines issues, or lack of performance, in these three areas. NOPR does not outline specifics in this area.

The NOPR would create numerous conflicting and duplicative requirements between the Department of Transportation (DOT) and the Department of Interior (DOI). Consequently, OOC believes the NOPR creates confusion, inconsistencies, and redundancy for the offshore pipeline operators. Additionally, the conflicting and duplicative requirements will create jurisdictional overlaps and conflicts among the two agencies. OOC believes the NOPR contradicts the 1996 Memorandum of Understanding (MOU) between DOT and DOI governing their respective responsibilities on the OCS. The intention was expressed in the Federal Register notice of February 14, 1997:

> *The MOU places, to the greatest extent practicable, producer Operated pipelines under DOI responsibility and transporter operated pipelines under DOT responsibility. Producers are companies which are engaged in the extraction and processing of hydrocarbons on the OCS. Transporters are companies which are engaged in the transportation of those hydrocarbons. As a result of this revision, some pipelines, predominantly producer operated pipelines, currently under DOT responsibility, will be under DOI responsibility……the changes described in the MOU will substantially reduce the burden of overlapping Federal jurisdictions and inconsistencies between agency requirements This will substantially increase the efficiency of governmental resources on the OCS without compromising safety.*

The NOPR is clearly in disagreement with the 1996 Memorandum of Understanding between DOI and DOT. OOC's review of the MOU, statutes and regulations leads to the conclusion that DOI and DOT have Federal Authority over pipeline safety of their respective designated facilities. The 1996 MOU between DOT and DOI clearly

recognizes this fact, such that the potential overlapping or conflicting regulations of OPS and MMS is the underlying reason for establishing the MOU. There is no indication that the agreements made in the MOU have been abrogated as provided for in the language of the MOU.

The proposed rule as issued October 3, 2007 seeks to re-write 30 CFR Part 250 which is directed at pipelines offshore. In the process it has retained parts of MMS' previous rules and added many new ones, some of which were contained in non-rulemaking form such as Notice to Lessee (NTL). MMS is also proposing changes to 30 CFR Part 253, Oil Spill Responsibility, Part 254, Oil Spill Response Requirements and Part 256, Leasing of Sulphur or Oil and Gas. The authority for these regulations is based upon the OPA, the OCSLA and the FWPCA. We believe MMS is not however, authorized to impose regulations inconsistent with or duplicative of DOT's regulations. Likewise, we believe it does not have authority, like the explicit congressional authority for States in the PSA, to exceed DOT requirements.

The MMS Notice of Proposed Rule (NOPR) asserts that the proposed rule is not a significant rule as determined by OMB and is not subject to review under EO 12866. OOC disagrees with this assertion.

The proposed rule has the potential of an annual effect of $100 million or more to the economy. OOC is developing preliminary estimated costs to implement the rule but does not have these figures at this time. OOC preliminary estimates show a potential annual compliance of over $1. billion per year over the next ten years and a one time cost of $185 million to develop the required program, plans and procedures.

The MMS has not provided any information in the NOPR that states the benefit of the new regulations. For the years 2006 and 2007, as reported to DOT for OCS pipeline incidents there was approximately $600 thousand of gas loss per year, $11.3 million of company costs to affect repairs per year and no cost to the public. This is for the approximately 14,000 miles of DOT jurisdictional pipe. The costs for E&P systems is similar in scope and are slightly higher since there are more segments of smaller diameter E&P lines in the GOM. The costs for 2005 for both DOT and E&P lines were significantly higher due to two major hurricanes in the Gulf of Mexico. The gas loss cost that year was $11.4 million for transmission lines and lower for the E&P segment of the industry with the transmission company costs of repairs being $74.6 million and no costs to the public. A four year average (2004 to 2007) of natural gas transmission systems shows an average per year gas loss cost of $4.3 million, an average per year for company repair and any clean up cost of $29.5 million with no costs to the public. During this period there were no fatalities or injuries reported to DOT or to the MMS.

OOC's response has been grouped into this cover letter with general information, a General Comments Section and an attachment with detail comments on the elements of the rule making. Also enclosed are copies of OOC's presentations from the February 22, 2008 to be included in the record. If the MMS desires a meeting to better review the

comments or suggestions, a cross functional Industry team can be provided to meet with MMS representatives.

If you have any questions, please contact me at 504-934-2159.

Very truly yours,

Original Signed

Allen J. Verret
Executive Director, Offshore Operators Committee

RIN 1010-AD 11; Sub Part J-Pipelines and Pipelines Rights-of-Way
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General Comments:

Consistency with Other MMS Regulations

We encourage MMS to look at other similar regulations such as Subpart B for Plans and provide consistency with those regulations whenever possible. This would include the number of copies of an application provided and type, paper or digital, format of environmental information, the establishment of processing time limits, etc. We also encourage MMS to look at the notification requirements in the proposed rule versus existing rules. For example, we have far more safety devices under Subpart H than Subpart J, yet the notification requirement for Subpart J greatly exceed those for Subpart H. MMS should build upon these practices that are working for both industry and MMS whenever possible.

Pipeline Application Process

Although MMS has done a good job of outlining application requirements, the information is somewhat jumbled and not in good order. If you use the tables in 250.014-1030 as a "checklist" or "table of contents" for a pipeline application, the sequence of information is not entirely logical. We suggest that MMS restyle these tables so that the information is in the order they would like to see it in a pipeline application. We don't believe that industry should be mandated to provide the information in this sequence, but many operators will use it in that fashion to ensure they cover all of the required items. This could lead to more consistent pipeline applications which surely would be easier for MMS to process if the information was provided in a logical and consistent manner.

Subsea Production System

It appears that the proposed regulation was written for traditional pipeline systems and the various subsea components were inserted into the regulation. This is confusing and in many cases simply does not work. We suggest that subsea systems be given their own section in the regulation and that issues unique to the these systems be addressed. Issues such as "major" versus "minor manifolds, the difference (if any) between a manifold and PLET or PLEM to the regulatory process should be clearly identified. Trying to place these components within the confines of terminology like "appurtenance" simply does not work because the components are too different. We caution MMS to clearly think through how segment numbers and ROWs are issued. Given the flexibility of these systems, the components may be rearranged in the future and with some forethought, segments and ROWs can be set up to simply these future changes. We caution against making these regulations overly prescriptive or they will be out of date before they are made final since this is an area of technology evolution and advances.

Riser CVA

The riser CVA program as proposed goes far beyond the CVA for structures in Subpart I. The riser CVA program is predicated primarily on independent analysis not verification. We do not understand the benefit of having a separate engineering firm conduct a

complete independent design of the risers. This is an extremely expensive and time consuming process. We do not do this for structures, why do we do it for risers? Since riser CVAs have been required, have actual modifications to the design been required due to the CVA program? The proposed rule requires that the design CVA must be completed prior to fabrication of the riser commencing. This requirement will impede development in the GOM as it does not fit our project economic models. We do not understand why we need to return to the CVA program each and every time we add a riser to a structure. We do not return to the CVA program each and every time we modify a structure. What is the benefit of this requirement? MMS should establish reasonable CVA requirements for the addition of new risers on existing structures.

Operation and Maintenance Plans

It should be recognized that operation and maintenance plans for pipelines is only a subset of plans covering our structures, wells, process equipment, etc. These regulations should be harmonized and made consistent with plans for the rest of our facilities. Duplication in efforts should be avoided whenever possible. MMS should expect a wide range and style of plans.

Repair Applications

We are concerned that the repair application cycle time will lead to longer shut in times and more pollution than necessary. In many cases we utilize standard repair procedures. These procedures could be pre-approved and utilized when necessary with follow up reporting. This would eliminate burden on industry, MMS and get pipeline repaired in the shortest amount of time. Attention could then be focused on those circumstances where standard procedures are not applicable.

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
Subpart A—General			
250.105	Remove the definitions of "lease term Pipelines", Pipelines" and "Right-of-way pipelines" and adds: *Chemosynthetic communities* means assemblages of tubeworms, clams, mussels, bacterial mats, and a variety of associated organisms that obtain their energy from the oxidation of various organic compounds rather than from light (photosynthesis) and the sun dependent photosynthetic food chain that supports all other life on earth. *Lease term pipeline* means a pipeline that is applied for by a lessee or designated lease operator, and that is completely contained within the boundaries of a single lease, unitized leases, or contiguous (not cornering) leases held by that lessee or operated by that designated lease operator. *Pipeline* means the horizontal components, risers, and appurtenances installed for transporting oil, gas, sulphur, and produced water. Piping confined to a production platform or structure, commonly referred to as a flowline, is regulated under subpart H of this part, Oil and Gas Production Safety Systems, and is excluded from this subpart. *Pipeline right-of-way (ROW)* means an authorization issued by MMS under the authority of section 5(e) of the OCSLA (43 U.S.C. 1334(e)) and section 8 of the OCSLA (43 U.S.C. 1337(p)(1)(B)) that allows for the construction and use of an associated ROW pipeline for the purpose of transporting oil, natural gas, or sulphur. The term also means the area covered by that authorization.	1. The definition of "Pipeline" should include the transportation of seawater and chemicals. For example, water injection pipelines may carry seawater. Methanol or other chemicals used in bulk on a platform may be transported by pipeline. 2. We recommend that "Umbilical" be defined to distinguish it from "Pipeline". The proposed definition is based on API Spec 17E.	*Pipeline* means the horizontal components, risers, and appurtenances installed for transporting oil, gas, sulphur, produced water, chemicals or seawater. Piping confined to a production platform or structure, commonly referred to as a flowline, is regulated under subpart H of this part, Oil and Gas Production Safety Systems, and is excluded from this subpart. *Umbilical* means a group of electric cables, optical fiber cables, hoses, tubes, either on their own or in combination with each other, cabled together for flexibility and over sheathed and/or armored for mechanical strength complete with end terminations and other ancillary equipment, installed between a fixed platform, a floating production facility or a land-based station, and a fixed platform, a floating production system or a subsea system, providing control, data communication and transportation of production system service fluids and/or utility supplies.

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	Pipeline ROW holder means a person, association, or corporation that has been granted a pipeline ROW on the OCS by MMS under the authority of section 5(e) of the OCSLA (43 U.S.C 1334(e)) and section 8 of the OCSLA (43 U.S.C. 1337(p)(1)(b)). *ROW pipeline* means a pipeline that is within: (1) An unleased OCS block(s), or which crosses any portion of an unleased OCS block; (2) An OCS lease or unit, or which crosses any portion of an OCS lease or unit, and the applicant is not a lessee or the designated lease operator of that lease, or the unit operator of that unit.		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
250.105	**Amend the definition of "Affected State" to** *Affected State* means with respect to any program, plan, lease sale, or other activity proposed, conducted, or approved under the provisions of the Act, any State: (1) The laws of which are declared, under section 4(a)(2) of the Act, to be the law of the United States for the portion of the OCS on which such activity is, or is proposed to be, conducted; (2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or installation or other device permanently or temporarily attached to the seabed; (3) Which is receiving, or according to the proposed activity, will receive oil for processing, refining, or transshipment that was extracted from the OCS and transported directly to such State by means of vessels or by a combination of means including vessels; (4) Which is designated by the Secretary as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the OCS; and (5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents to the marine or coastal environment in the event of any oil spill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities; (6) Which is directly adjacent to the proposed route of a ROW pipeline; or (7) Which contains the onshore base you will use to provide supply and service support for ROW pipeline operations.		
250.125 (a)	**Service Fee Table Updated with the following:** (20) New Pipeline Application (Lease Term Pipeline) $3,100 (21) Pipeline Application-Modification (Lease Term Pipeline) $1,800 (22) Pipeline Application-Modification (ROW Pipeline) (includes the application to modify the associated Pipeline ROW Grant, if applicable). $3,650		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(23) Pipeline Repair Application $340 (24) Application to Decommission a Pipeline (Lease Term Pipeline) $1,000 (25) Application for a New Pipeline ROW Grant (includes the application for the associated ROW pipeline and any application to install or establish an associated accessory). $2,350 (26) Application for a Pipeline ROW Grant (to convert a Lease Term Pipeline to an ROW Pipeline) $200 (27) Request to Assign a Pipeline ROW Grant $170 (28) Application to Relinquish a Pipeline ROW Grant (includes the decommissioning application for the associated ROW pipeline and any application to decommission an associated accessory). $1,900		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
250.198	**Documents Incorporated by reference** API RP 1111, Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design), Third Edition, July 1999, Sections 4.1.6.2, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.2.1, 4.3.2.2, and 4.5.4 only, API Stock No. D11113. DNV RP B401, Recommended Practice for Cathodic Protection Design, 1993, Table 6.9.1 only.	1. The 1993 edition of DNV RP B401 has been rescinded. We recommend incorporating Table 10-8 from the 1995 edition.	DNV RP B401, Recommended Practice for Cathodic Protection Design, 2005, Table 10-8 only.
250.199(e)(9)	Add Forms MMS-153, MMS-2030, MMS-149 to Paperwork Reduction Act Statements		
253	**Oil Spill Financial Responsibility for Offshore Facilities**		
253.3	**How are the terms used in this regulation defined?** *Designated applicant* means the responsible party or, if there is more than one responsible party, a person that the responsible parties designate to demonstrate OSFR for a COF on a lease, permit, pipeline right-of-way (ROW), or right-of-use and easement (RUE). *Pipeline* means the horizontal component, risers, and appurtenances installed for the purpose of transporting oil, gas, sulphur, and produced water. *Responsible Party* has the following meanings: (1) For a COF that is an ROW pipeline, responsible party means the pipeline ROW holder. (2) For a COF that is not an ROW pipeline, responsible party means either a lessee or permittee of the area on which the COF is located; or the holder of an RUE granted under applicable State law, or under the OCSLA (43 U.S.C. 1331 *et seq.*) for the area in which the COF is located (if the holder is a different person than the lessee or	The definition of "Pipeline" needs to match that in 30 CFR 250.105.	*Pipeline* means the horizontal components, risers, and appurtenances installed for transporting oil, gas, sulphur, produced water, chemicals or seawater. Piping confined to a production platform or structure, commonly referred to as a flowline, is regulated under subpart H of this part, Oil and Gas Production Safety Systems, and is excluded from this subpart.

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	permittee). A Federal agency, State, municipality, commission, or political subdivision of a State, or any interstate body that as owner transfers possession and right to use the property to another person by lease, assignment, or permit is not a responsible party. (3) For a decommissioned COF, responsible party means any person who would have been a responsible party for the COF immediately before decommissioning. *Right-of-use and easement (RUE)* means an authorization granted by MMS to use the OCS to construct and maintain platforms, artificial islands, and installations and other devices at an OCS site other than an OCS lease you own. This does not include pipeline ROWs.		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
253.10	**What facilities does this part cover?** (a) This part applies to any COF that is on any lease or permit issued, any ROW pipeline (see definition at § 250.105 of this chapter), or on any RUE granted under the OCSLA (43 U.S.C. 1331, *et seq.*) or applicable State law. (b) For a COF that is an ROW pipeline which extends onto land, this part applies to the portion of the pipeline lying seaward of the first accessible flow shut-off device on land.		
253.11	**Who must demonstrate OSFR?** (d) The designated applicant for a ROW pipeline must be the pipeline ROW holder. (e) The designated applicant for a COF on a RUE must be the holder of the RUE. (f) MMS may require the designated applicant for a lease, permit, pipeline ROW, or RUE to be a person other than the person identified in paragraphs (b) through (e) of this section if MMS determines that the person identified in paragraphs (b) through (e) of this section cannot adequately demonstrate OSFR.		
253.15	**What are my general OSFR compliance responsibilities?** (a) You must maintain continuous coverage for all your leases, permits, pipeline ROWs, and RUEs with COFs for which you are the designated applicant.		
254	**OIL SPILL RESPONSE REQUIREMENTS FOR FACILITIES LOCATED SEAWARD OF THE COASTLINE**		
254.6	*Owner or operator* means, in the case of an offshore facility, any person owning or operating such a facility. If the facility is a right-of-way (ROW) pipeline (see definition at § 250.105), the owner or operator is the pipeline ROW holder. In the case of a decommissioned offshore facility, it means the person who owned such facility immediately prior to such decommissioning.		
256	**LEASING OF SULPHUR OR OIL AND GAS IN**		

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	THE OUTER CONTINENTAL SHELF		
256.62	**Assignment of lease or interest in lease.** (g) Within 30 calendar days after MMS approves an assignment of a lease, or approves a new designation of operator for a lease under § 250.143 or § 250.144, you (the new lessee or designated lease operator) must submit a report to the Regional Supervisor that: (1) Lists every lease term pipeline (see definition at § 250.105), including decommissioned pipelines on the lease; and (2) Indicates which pipelines remained as lease term pipelines after the lease assignment was approved by MMS.	MMS already has in it files the pipelines that are located on a lease. Therefore, the value of this requirement to provide a report that lists every lease term pipeline, including decommissioned pipelines, on the lease is not apparent. If the issue is that MMS wants the operator to determine if any pipelines that were formally lease term pipelines should now be redesignated as ROW lines or ROW lines should be redesignated as lease term lines, then an application to redesignate the lines is appropriate.	(g) Within 30 calendar days after MMS approves an assignment of a lease, or approves a new designation of operator for a lease under § 250.143 or § 250.144, you (the new lessee or designated lease operator) must: (a) submit an application in accordance with § 250.1125 for a ROW grant for any pipelines which were formally lease term pipelines and are now ROW pipelines; and (b) submit an application in accordance with § 250.1136 to relinquish a pipeline ROW grant for any pipelines which were formally ROW pipelines and are now lease term pipelines.
Subpart J—Pipelines and Right-of-Ways			
General			
250.1000	**Definitions**		
	Terms used in this subpart have the following meanings: ***Accessory*** means a platform, a major subsea manifold, or similar subsea structures attached to a ROW pipeline to support pump stations, compressors, manifolds, etc. The site used for an accessory is part of the pipeline ROW grant. ***Appurtenance*** means equipment, device, apparatus, or other object attached to or associated with a horizontal component or riser. Examples include anodes, valves, flanges, fittings, umbilicals, vortex-induced vibration (VIV) devices, subsea manifolds, templates, pipeline end modules (PLEM's), pipeline end terminals (PLET's), anode sleds, other sleds, and jumpers (other than jumpers connecting subsea wells to manifolds). ***Failure*****,** when applied to a pipeline or safety system, means any condition of the pipeline or a safety system component that prevents the	1. We agree that a table or listing of common acronyms would be useful and provide clarity and we encourage MMS to include such a listing in the final rule. 2. The definition of “Accessory” includes the term “major subsea manifold” while the definition of “Appurtenance” includes the term “subsea manifolds”. It is not clear what the difference is between these terms. It appears that a subsea manifold that is attached to a ROW pipeline is an “accessory” while a subsea manifold that is attached to a lease term pipeline is an “appurtenance”. 3. The definition of “Appurtenance” refers to pipeline end modules (PLEMs). The common usage (as in API RP 17A) is pipeline end manifold (PLEMs)	***Accessory*** means a platform, a subsea manifold, or similar subsea structures attached to a ROW pipeline to support pump stations, compressors, manifolds, etc. The site used for an accessory is part of the pipeline ROW grant. ***Appurtenance*** means equipment, device, apparatus, or other object attached to or associated with a horizontal component or riser. Examples include anodes, valves, flanges, fittings, umbilicals, vortex-induced vibration (VIV) devices, subsea manifolds (except those attached to ROW pipelines), templates, pipeline end manifolds(PLEM's), pipeline end terminals (PLET's), anode sleds, other sleds, anchor piles used as foundations for PLEMs, PLETs and other sleds, and jumpers. ***Failure*** when applied to a pipeline or safety system, means any condition of the pipeline or a

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	complete performance of its design and function. ***Horizontal component*** means a horizontal pipe that connects a pipeline riser, subsea wellhead or template, or pipeline to a pipeline riser, subsea wellhead or template, or pipeline (synonymous with the term "linepipe"). ***Leak*** means the release of product from a pipeline. ***Live bottoms (low relief features)*** means sea grass communities; areas that contain biological assemblages consisting of sessile invertebrates and/or algae living upon and attached to naturally occurring hard or rocky formations with rough, broken, or smooth topography; and areas where a hard substrate and vertical relief may favor the accumulation of turtles, fishes, or other fauna. These features occur throughout the POCSR, in the Eastern Planning Area of the Gulf of Mexico, and in the Beaufort Sea in Alaska. ***Live bottoms (pinnacle trend features or seamounts)*** means small, isolated, low to moderate relief carbonate reef features; outcrops of unknown origin; or hard substrates exposed by erosion that provide surface area for the growth of sessile invertebrates and/or algae, and attract large numbers of fish. These features occur in an area of topographic relief throughout the POCSR and AKOCSR, and in the northeastern portion of the western GOMR. In the POCSR and AKOCSR, these features include rocky reefs, rock outcrops, pinnacles or seamounts. In the GOMR, these features include pinnacle trend features. ***Maximum allowable operating pressure*** *(MAOP)* means the highest operating pressure allowable at any point in a pipeline. ***Military warning or water test area*** means an area on the OCS that is used by the U.S. Department of Defense for conducting various mission operations, including air-to-air gunnery, rocket and missile research and testing, sonar buoy operations, pilot training, and aircraft carrier	4. The definition of "Appurtenance" refers to "jumpers" (other than jumpers connecting subsea wells to manifolds). It is not clear why these jumpers have been excluded from the definition of appurtenance and what these jumpers should be considered to be. What about jumpers that connect subsea wells to PLEMS, PLETS or Inline Sleds? Are these also excluded from the definition of appurtenances? We further note that no definition of jumper has been proposed, so we have provided one. Alternatively, jumpers could be included in the definition of horizontal components by just adding a sentence in the definition that says. "Also includes jumpers". 5. We also note that anchor piles used as foundations for subsea manifolds and sleds have not been included in the rulemaking. We propose including them in the definition of appurtenance. 6. The definition of "Failure" is too broad and the term "complete" can be too broadly interpreted. 7. The definition of a "leak" should exclude the planned, controlled release from a pipeline, generally for maintenance reasons. A leak is commonly referred to as a consequence of a failure. 8. Military warning or water test areas. We encourage MMS to provide up-to-date DOD sites lists, with viable addresses, phone numbers and contacts on a regular basis and to identify the ones that must be notified in the pipeline application letter. Many times industry attempts to notify DOD but either gets no response or has inadequate contact information. MMS should work with DOD to identify those groups that actually want the notification. 9. It is not clear to us why MMS defines "Live	safety system component that prevents the intended performance of its design and function. ***Leak*** means the uncontrolled release of product from a pipeline. ***Jumper*** means a short piece of either rigid or flexible pipe with a connector half at either end used to connect pipelines and/or subsea facilities together or to connect a subsea well to a subsea manifold, PLEM, PLET or other sled. ***OCS Pipeline*** means a lease term or ROW pipeline located on the OCS under the jurisdiction of either DOI or DOT. ***Riser*** means a vertical or sloped conducting pipe section that connects the pipeline to equipment on a platform. ***Splash zone*** means that portion of a pipeline riser that is located between 20 feet above the mean water line and 10 feet below the mean water line.

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	operations. ***New or unusual technology*** means equipment or procedures that have: (1) Not been used previously or extensively in an MMS OCS Region; (2) Not been used previously under the anticipated operating conditions; or (3) Operating characteristics that are outside the performance parameters established by this subpart. ***Potentially sensitive biological features*** means those features not protected by an MMS biological lease stipulation that are of moderate to high relief (about 8 feet or higher), provide surface area for the growth of sessile invertebrates, and attract large numbers of fish. These features would be located outside any "No Activity Zone" of any of the named topographic features and would not be located on any live-bottom (pinnacle trend) stipulated blocks. ***Production platform*** means a platform on the OCS that receives hydrocarbon or sulphur production either directly from wells or from other platforms that produce hydrocarbons or sulphur from wells. It may include processing equipment for treating the production or separating it into its various liquid and gaseous components. ***Riser*** means a vertical conducting pipe that connects a horizontal component of a pipeline to equipment on a platform. ***Splash zone*** means that portion of a pipeline riser that is located between 20 feet above the maximum tide and 20 feet below the minimum tide. ***Topographic features*** means identified isolated areas of moderate to high relief that provide habitat for hard-bottom communities and numerous plant and animal species, and support, either as shelter or food, large numbers of commercially and recreationally important fishes.	bottoms (low relief features)", "Live bottoms (pinnacle trend features or seamounts)", "New or unusual technology", "Potentially sensitive biological features", "Production Platform" and "Topographical features" in Subpart J in lieu of Subpart A since these terms are used elsewhere in the regulations and it is important for the definitions to be identical. We recommend that these definitions either be deleted or moved to Subpart A. 10. "New or Unusual Technology" This is the same definition as in § 250.200. Since it is utilized in several parts of the regulations, perhaps it should be moved to Subpart A. 11. The definition of splash zone is too broad in the proposed definition. While "minimum and maximum tides" are often used in design, for operation, we normally refer to mean water lines. We believe our proposed definition will adequately cover the zone of interest on the riser. 12. The "vertical" portion of a riser may be "vertical" or sloped. We propose that the definition of a riser be modified. 13. We note that the term "OCS Pipelines" is not actually defined yet a definition can be inferred in § 250.1002 and 1003. We propose that it be defined for clarity.	
250.1001	**What general performance and recordkeeping requirements apply to OCS pipelines?**		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(a) *Performance*. You must design, construct, operate, maintain, inspect, and decommission all OCS pipelines, appurtenances, accessories, and safety system components in a manner that: (1) Conforms to the OCSLA (43 U.S.C. 1331, *et seq.*), as amended, applicable implementing regulations, other applicable laws, approved applications, approved Development Operations Coordination Documents (DOCD) and Development and Production Plans (DPP), and lease provisions and stipulations; (2) Is safe; (3) Prevents unauthorized discharges; (4) Does not unreasonably interfere with other uses of the OCS, including those involved with national security or defense; and (5) Does not cause undue or serious harm or damage to the human, marine, or coastal environment.	1. (a)(5) is overly broad and vague. We recommend that this provision be removed.	(a)(5) remove from regulation
	(b) *Records*. You must retain all records related to the design, construction, operation, maintenance, testing, inspections, repairs, failures, and decommissioning of an OCS pipeline for as long as the pipeline remains in place, unless otherwise specified by the Regional Supervisor or in these regulations, and make them available to MMS upon request.	1. Retaining **ALL** records related to the design, construction, operations, maintenance, testing, inspections, repairs and decommissioning of all OCS pipelines is overly broad is not warranted. We recommend that MMS model the record retention requirements in § 250.903.	(b) Records. As of the effective date of this regulation, you must compile, retain, and make available to MMS representatives for the functional life of all OCS pipelines, unless otherwise specified by the Regional Supervisor or in these regulations: (1) The as-built drawings; (2) The design assumptions and analyses; (3) A summary of the fabrication and installation nondestructive examination records; (4) Hydrotest records (5) The inspection results from the inspections required by § 250.1102 and 1103 of this subpart; and (6) Records of repairs (7) Decommissioning records (c) You must provide MMS with the location of these records in your pipeline application. (d) If you sell, transfer or designate another

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
			operator of the pipeline, you must transfer all records required by (b) to the new operator who must retain the records from that point forward.
250.1002	**What are the types of OCS pipelines?**		
	An OCS pipeline is either a lease term pipeline or an ROW pipeline.		
250.1003	**Which departments have jurisdiction over OCS pipelines?**		
	An OCS pipeline is under the jurisdiction of either the Department of the Interior (DOI) or the Department of Transportation (DOT).	The proposed rulemaking is very confusing and misleading since the DOI and DOT regulations are not the same for design, operation, inspection and maintenance for OCS Pipelines. By reading the proposed regulation, an operator could come to the conclusion that so long as he follows these regulations his DOI or DOT pipeline would be compliance with the regulatory requirements. The MOU between DOI and DOT calls for the avoidance of duplication of regulatory efforts regarding OCS pipelines, the coordination and consultation during the development and implementation of regulatory requirements, compatible regulatory requirements for all OCS pipelines whether under DOI or DOT jurisdiction and the promotion of safety and environmental protection on the OCS. This rulemaking does not achieve those goals. We recommend that one or more of the following actions be taken: 1. Delay this rulemaking until DOI and DOT can develop compatible regulatory requirements for all OCS pipelines; or 2. Clearly identify in the regulation where DOT has different regulations from those in Subpart J; or 3. Make this proposed regulation applicable to only DOI pipelines.	
250.1004	**What are the criteria for determining jurisdiction?**		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(a) *DOI jurisdiction criteria.* An OCS pipeline is under DOI jurisdiction if it is: (1) A lease term pipeline that is not subject to regulation under 49 CFR, parts 192 and 195, and does not cross into State waters; or (2) An ROW pipeline that is operated by an identified pipeline operator (the person or entity identified by the pipeline ROW holder as authorized to control or manage the pipeline's operations), and that is either: (i) A producing pipeline operator (the identified pipeline operator of an ROW pipeline that is a lessee or designated lease operator of one or more OCS leases), unless it is subject to regulation under 49 CFR, parts 192 and 195, and crosses into State waters; or (ii) A transporting pipeline operator (the identified pipeline operator of an ROW pipeline that is not a lessee or a designated lease operator of an OCS lease), and the pipeline is not subject to regulation under 49 CFR, parts 192 and 195.	This language is very confusing. We recommend that the current definitions of a DOI pipeline and DOT pipelines in § 250.1001 be retained until such time as DOI and DOT agree on mutually acceptable definitions. It is very confusing to have one set of definitions in Subpart J and different definitions in 49 CFR 192 and 195.	
	(b) *DOT jurisdiction criteria.* An OCS pipeline that is not under DOI jurisdiction (see paragraph (a) of this section) is under DOT jurisdiction.		
	(c) *Jurisdiction transfer.* You may request that a pipeline under DOI jurisdiction be transferred to DOT jurisdiction, or that a pipeline under DOT jurisdiction be transferred to DOI jurisdiction, by submitting a written petition for approval to the Regional Supervisor and the DOT Office of Pipeline Safety (OPS) Regional Director. In the petition, you must provide sufficient justification for the transfer. The Regional Supervisor and the DOT OPS Regional Director will decide jointly whether to approve the petition.	We recommend that a timeframe be established for the approval of the petition.	(c)….The Regional Supervisor and the DOT OPS Regional Director will decide jointly whether to approve the petition within 90 days of receiving the petition.
250.1005	**What are the requirements regarding jurisdiction transfer points?**		
	(a) *Jurisdiction transfer point.* For each applicable pipeline, you must meet the requirements of this paragraph (a).	The nearest OCS facility may not be associated with the pipeline. It may also be an unmanned facility without any record retention capability.	(2) You must keep the schematics referenced in paragraph (a)(1) of this section at the pipeline operator's field office nearest the transfer point or

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(1) You must identify the specific point at which regulatory jurisdiction transfers from DOI to DOT, or from DOT to DOI, by:
(i) Durably marking an above-water jurisdiction transfer point or, if that is not practical, identifying the transfer point on a schematic; or
(ii) Identifying an underwater jurisdiction transfer point on a schematic.
(2) You must keep the schematics referenced in paragraph (a)(1) of this section at the nearest OCS facility and make them available to MMS upon request.</td><td>Therefore, we recommend keeping the schematic at the pipeline operator's field office nearest the transfer point or other locations conveniently available to the District Supervisor.</td><td>other locations conveniently available to the District Supervisor and make them available to MMS upon request.</td></tr>
<tr><td></td><td>(b) Jurisdiction transfer point disagreement. If the lessee(s), designated lease operator(s), or pipeline ROW holder(s) of connecting pipelines cannot agree upon a transfer point, the Regional Supervisor and the DOT OPS Regional Director will jointly determine the jurisdiction transfer point.</td><td></td><td></td></tr>
<tr><td>250.1006</td><td>When must I submit the applications, requests, plans and reports, and make the notifications required by this subpart?</td><td></td><td></td></tr>
<tr><td></td><td>(a) Applications and requests. For all OCS pipelines you must submit applications to MMS, and receive approvals, according to the following table:
<table>
<tr><th>Application or request</th><th>Required by</th><th>When to submit</th><th>Total number of copies</th></tr>
<tr><td>(1) Transfer jurisdiction</td><td>§ 250.1004(c)</td><td>Before jurisdiction can be transferred from DOI to DOT, or from DOT to DOI</td><td>1 to MMS. 1 to OPS.</td></tr>
<tr><td>(2) New pipeline</td><td>§ 250.1007(a)</td><td>Before you install, maintain, or operate a new pipeline</td><td>3</td></tr>
<tr><td>(3) Modify a pipeline</td><td>§ 250.1093(a), (b)</td><td>Before you conduct operations</td><td>3</td></tr>
</table></td><td>1. The table, and other similar tables in the rulemakings, provided is a very helpful and effective way of communicating the various applications, notifications, etc that are required.

2. We encourage MMS to limit the number of paper copies that are required to be submitted for plans, applications and reports. For DOCDs in the GOM region, we note that we are allowed to submit one paper copy and one copy on CD. We recommend that this also be the submittal practice for pipeline applications, plans and reports where more than one copy is required to be submitted. We further encourage MMS to continue developing their electronic submittal system similar to eWell for plans, applications and reports.</td><td></td></tr>
</table>

Proposed Section Number	Proposed Text				Summary of Comments and Rationale	Proposed Language
			to modify a pipeline			
	(4) Repair a pipeline	§ 250.1095(a)	Before you conduct any repair work on a pipeline	1		
	(5) Decommission a pipeline in place	§ 250.1109(a)(1)	Before you conduct operations to decommission a pipeline in place	3		
	(6) Decommission a pipeline by removal	§ 250.1109(a)(2)	Before you conduct operations to decommission a pipeline by removal	3		
	(7) Re-commission a decommissioned pipeline	§ 250.1113(a)(1)	Before you re-commission a decommissioned pipeline	1		
	(8) Accessory	§ 250.1141(a)	Before you install, operate, and maintain an accessory to an ROW pipeline	3		
	(9) Modify an accessory	§ 250.1146	Before you conduct operations to modify an accessory	3		
	(10) Decommission an accessory-Initial	§ 250.1147 (see § 250.1726)	In the POCSR and AKOCSR, at least 2 years before you decommission an accessory	1		
	(11)	§ 250.1147	Before you	2		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	Decommission an accessory-Final | (see § 250.1727) | decommission an accessory |		
	(b) ***Pipeline ROW grant applications and requests.*** For ROW pipelines, you must submit the following applications and requests to MMS, and receive approvals, in addition to those listed in paragraph (a) of this section: Application or request | Required by | When to submit | Total number of copies (1) Obtain a pipeline ROW grant | § 250.1125(a) | Before you install, maintain, or operate an ROW pipeline | 1 original and 2 copies. (2) Modify a pipeline ROW grant | § 250.1132(a) | Before you can modify a pipeline ROW grant | 1 original and 2 copies. (3) Assign a pipeline ROW grant | § 250.1134(a) | Before you can assign a pipeline ROW grant | 2 executed originals. (4) Relinquish a pipeline ROW grant | § 250.1136(a) | Before you can relinquish a pipeline ROW grant | 1 original and 2 copies.	1. We encourage MMS to limit the number of paper copies that are required to be submitted. For DOCDs in the GOM region, we note that we are allowed to submit one paper copy and one copy on CD. We recommend that this also be the submittal practice for pipeline applications where more than one copy is required to be submitted. We further encourage MMS to continue developing their electronic submittal system similar to eWell for plans and applications.	
	(c) ***Notifications.*** You must make notifications to MMS according to the following table: Notification | Under section | When to notify (1) Pipeline construction | § 250.1041(a), using Form MMS-153 | At least 48 hours before you commence pipeline construction. (2) Discovery of archaeologi | § 250.1049(d) | Immediately.	1. Form MMS-153 provides a standard format for the required information. However, we would like to see MMS develop this form as an eWell type notification that can be submitted electronically. Until that can be done, we would like the option of submitting it by fax or as an attachment to an e-mail. 2. (c)(2) Proposed § 250.1049(d) requires notification within 72 hours of discovery	(c)(2) Within 72 hours of discovery

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language

cal resource		
(3) Hydrostatic pressure test	§ 250.1058(b), using Form MMS-153	At least 48 hours before you conduct a hydrostatic pressure test on a pipeline.
(4) Safety equipment failure or removal	§ 250.1069(b) and 250.1085(a)	In the GOMR, when the safety equipment remains out of service for 12 hours. Immediately in the POCSR and AKOCSR.
(5) Corrective action	§ 250.1069(d)	Immediately when you repair or replace safety equipment and resume operating the pipeline, or when you have provided an equivalent degree of protection and resume operating the pipeline.
(6) Return safety equipment to service	§ 250.1085(c)	Immediately when you return out-of-service safety equipment to service or when you provide an equivalent degree of protection.
(7) Pipeline leak	§ 250.1088(b)	Immediately or as soon as practicable after you discover that a pipeline has leaked.
(8) Pipeline relocation	§ 250.1093(e), using Form MMS-153	At least 48 hours before you begin the work to relocate a pipeline.
(9) Lapse of financial security for a pipeline ROW grant	§ 250.1121(b)	Within 72 hours after the security lapses.
(10) Sabotage or subversive activity	§ 250.1131(k)	Immediately upon discovery.

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(d) ***Plans and Reports***. You or the Certified Verification Agent (CVA), as appropriate, must submit plans and reports to MMS according to the following table:		

Plan/Report	Under section	When to submit	Total number of copies
(1) Pipeline construction, including pressure test results	§ 250.1051(a)	Within 45 calendar days after you complete pipeline construction	3
(2) Design verification plans for pipeline risers connected to floating platforms	§ 250.1053(a)	At least 30 calendar days before you submit the associated pipeline application	1
(3) Fabrication verification plans for pipeline risers connected to floating platforms	§ 250.1053(b)	At least 30 calendar days before you submit the associated pipeline application	1
(4) Installation verification plans for pipeline risers connected to floating platforms	§ 250.1053(c)	At least 30 calendar days before you submit the associated pipeline application	1
(5) Interim CVA reports for pipeline risers connected to floating platforms	§ 250.1054(c); § 250.1055(d); § 250.1056(d)	CVA submits during each verification phase	1
(6) Final CVA	§	CVA submits	1

Proposed Section Number	Proposed Text				Summary of Comments and Rationale	Proposed Language
	design reports for pipeline risers connected to floating platforms	250.1054(d)	within 90 calendar days of receipt of the design data, or within 90 calendar days after MMS approval to act as a CVA, whichever is latest, and before fabrication begins			
	(7) Final CVA fabrication reports for pipeline risers connected to floating platforms	§ 250.1055(e)	CVA submits within 90 calendar days after completion of fabrication, and before riser installation	1		
	(8) Final CVA installation reports for pipeline risers connected to floating platforms	§ 250.1056(e)	CVA submits within 45 calendar days after pipeline riser installation	1		
	(9) Directed pressure test	§ 250.1060(d)	As directed by the Regional Supervisor	As directed by the Regional Supervisor.		
	(10) Out-of-service pipeline	§ 250.1086(d)	Within 48 hours after a pipeline is deemed to be out of service	1		
	(11) Out-of-service pipeline reactivation,	§ 250.1086(g	Within 30 calendar days after you	1		

Proposed Section Number	Proposed Text				Summary of Comments and Rationale	Proposed Language
	including pressure test results	)	reactivate a pipeline that has been out of service			
	(12) Flaring/venting operations	§ 250.1089(b)	Within 72 hours after completing flaring or venting operations	1		
	(13) Pipeline modification, including pressure test results	§ 250.1093(f)	Within 30 calendar days after you complete the pipeline modification	1		
	(14) Pipeline repair, including pressure test results	§ 250.1095(e)	Within 30 calendar days after you complete a repair	1		
	(15) Flexible joint inspections	§ 250.1102(b)	Within 30 calendar days after you complete the inspection	1		
	(16) Pipe-to-electrolyte potential measurements	§ 250.1102(d)	No later than October 31 of the same year, or within 60 calendar days of the measurements, whichever is earlier	1		
	(17) Additional inspections and surveys	§ 250.1103(a) through (f)	As directed by the Regional Supervisor	1		
	(18) Pipeline decommissioning	§ 250.1111	Within 30 calendar days after you complete the decommissioning	1		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(19) Decommissioned pipeline re-commissioning, including pressure test results | § 250.1113(b) | Within 30 calendar days after you complete the re-commissioning | 1 (20) Accessory installation | § 250.1144 | Within 45 calendar days after you complete accessory installation | 3 (21) Accessory inspections | § 250.1145(a)(2) | By November 1 of each year | 1 (22) Accessory decommissioning | § 250.1147 (see § 250.1729) | Within 30 calendar days after you decommission an accessory | 2 (23) Accessory site clearance | § 250.1147 (see § 250.1743(b)) | Within 30 calendar days after you conduct site clearance verification operations | 2		
Applications for New Pipelines			
250.1007	**How do I apply for approval for a new pipeline?**		
	Before you install, maintain, or operate a new pipeline (including a jumper), or a pipeline you create with a combination of new pipe and existing pipe, you must submit three copies of a pipeline application to the Regional Supervisor for approval. If you prefer to submit all or part of your pipeline application electronically (see § 250.186(a)(3)), you should consult with the Regional Supervisor for further guidance.	1. The proposed language is confusing with its reference to "jumpers" since "jumpers" were previously defined as "appurtenances" and are included in the definition of a pipeline. We recommend this reference be removed. 2. The reference to "maintain" is confusing for a new pipeline and we don't know what that means for a new pipeline. We recommend that	Before you install or operate a new pipeline, or a pipeline….

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td></td><td>“maintain” be deleted.</td><td></td></tr>
<tr><td></td><td>(a) Application contents. (1) Your application must include the information described in § 250.1014 through 250.1030.
(2) The Regional Supervisor may require you to include additional information, if necessary, to assist in evaluating your pipeline application.
(3) The Regional Director may require less information or analysis than you otherwise must provide in your pipeline application when:
(i) Sufficient information or analysis is readily available to MMS;
(ii) Other coastal or marine resources are not present or affected; or
(iii) Other factors, such as technological advances, affect information needs.</td><td>1. The use of new or unusual technology includes the use of proprietary information in many cases. If new or unusual technology is proposed, the applicant should be allowed to also submit a “Public Information” copy of the application in which the proprietary information is excluded and includes a brief discussion of the general subject matter of the omitted information. This is the way new and unusual technology is treated in Subpart B for EPs and DOCDS.</td><td>(4) If new or unusual technology is proposed to be utilized, a public information copy of the application may also be submitted in which any proprietary information is excluded and includes a brief discussion of the general subject matter of the omitted information.</td></tr>
<tr><td></td><td>(b) Where to submit the application. You must submit a pipeline application to one of the MMS Regional offices shown in the following table.
<table>
<tr><th>For OCS areas adjacent to the . . .</th><th>Submit your application to . . .</th></tr>
<tr><td>(1) State of Alaska</td><td>Minerals Management Service, Alaska OCS Region (AKOCSR), Regional Supervisor, Field Operations.</td></tr>
<tr><td>(2) Atlantic Coast States and in the Gulf of Mexico</td><td>Minerals Management Service, Gulf of Mexico OCS Region (GOMR), Regional Supervisor, Field Operations.</td></tr>
<tr><td>(3) States of California, Oregon, Washington, or Hawaii</td><td>Minerals Management Service, Pacific OCS Region (POCSR), Chief, Office of Facilities, Safety & Enforcement.</td></tr>
</table></td><td></td><td></td></tr>
<tr><td></td><td>(c) Withdrawal after submission. You may withdraw your pipeline application at any time, and for any reason, by notifying the Regional Supervisor in writing.</td><td></td><td></td></tr>
<tr><td>250.1008</td><td>Where must I send copies of my pipeline application?</td><td></td><td></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(a) *Impacted leases and pipeline ROW grants.* When you submit a pipeline application to MMS, you must provide a copy of the pipeline application to each lessee or designated lease operator of an existing lease, and to each holder of a pipeline ROW grant (active or terminated) that could be impacted by your proposed pipeline construction or towing operations.	1. The use of the term "impacted" is very vague and could be interpreted in many ways. For example, is a lease impacted if a drilling rig anchor spread from an adjacent lease crosses over to a lease where a pipeline is proposed? We recommend that MMS retain the current terminology of leases and pipelines "intersected". 2. We disagree that providing a copy of the entire pipeline application to each lease and pipeline ROW grant intersected is beneficial. At a minimum, the operator should provide a summary of the design and construction or towing operation, a copy of the plat where the pipeline intersects the lease or ROW grant and a copy of the proposed crossing arrangement if a pipeline or appurtenance is being crossed.	**(a) Leases and pipeline ROW grants intersected.** When you submit a pipeline application to MMS, you must provide a copy of the pipeline application (or public information copy if new or unusual technology is proposed) to each lessee or designated lease operator of an existing lease, and to each holder of a pipeline ROW grant (active or terminated) that is intersected by your proposed pipeline construction or towing operations. In lieu of providing a copy of the application, a summary of the pipeline design and construction or towing information along with a plat when the pipeline intersects the lease or ROW grant and a copy of the proposed crossing arrangement if a pipeline or appurtenance is being crossed.
	(b) *Affected States.* Unless the proposed operations described in your pipeline application are under a general concurrence from the affected State, when you submit a new ROW pipeline application to MMS you must provide each affected State with all of the following: (1) A copy of the pipeline application. Pursuant to 43 CFR part 2, Appendix E, MMS has determined that none of the information included in an ROW pipeline application is proprietary. Therefore, you must not exclude any information from the copies of the application you submit to affected States. (2) A consistency certification (see 15 CFR 930.57). (3) All necessary data and information (see 15 CFR 930.58).	1. We disagree that none of the information included in an ROW pipeline application is proprietary. If new or unusual technology is proposed, the application may have proprietary information. We suggest that the applicant provide the state with a "public information copy" of the application as described above under (a).	(1) (1) A copy of the pipeline application. If new or unusual technology is proposed, a public information copy of the application can be provided.
250.1009	**How does MMS process a pipeline application?**		
	The Regional Supervisor determines whether the application is complete, accurate, and fulfills the requirements of this subpart. If the Regional Supervisor determines that your application does not meet these conditions, the Regional Supervisor will notify you of the problem or	1. We request that MMS establishes timeframes for the various processing steps proposed in the regulation. We note that MMS has established timeframes in Subpart B that could be used as a model.	*(a)Determine whether deemed submitted.* Within 15 working days after receiving your proposed pipeline application and its accompanying information, the Regional Supervisor will review your submission and deem your application submitted if:

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	deficiency. The Regional Supervisor will not begin final review of your application until it is complete.	2. We agree with MMS conducting a completeness review of the application. However, the "complete" is not defined. We suggest that MMS model the completeness review after the regulations in Subpart B for EPs and DOCDs	(1) The submitted information, fulfills requirements and is sufficiently accurate; and (2) You have provided the required number of copies. (b) Identify problems and deficiencies. If the Regional Supervisor determines that you have not met one or more of the conditions in paragraph (a) of this section, the Regional Supervisor will notify you of the problem or deficiency within 15 working days after the Regional Supervisor receives your pipeline application and its accompanying information. The Regional Supervisor will not deem your pipeline submitted until you have corrected all problems or deficiencies identified in the notice. (c) Deemed submitted notification. The Regional Supervisor will notify you when the pipeline is deemed submitted.
	(a) *Compliance review.* The Regional Supervisor will ensure that your proposed operations conform to the OCSLA (43 U.S.C.1331, *et seq.*), as amended; other applicable laws; and applicable MMS regulations.	1. We believe the model established for EPs and DOCDs in Subpart B is a good basis for pipeline applications. We encourage MMS to follow this model as applicable.	**What actions will MMS take after the pipeline application is deemed submitted?** (a) *MMS compliance review.* The Regional Supervisor will review the pipeline activities described in your proposed application to ensure that they conform to the performance standards in § 250.202. (b) *MMS environmental impact evaluation. For ROW pipelines, t*he Regional Supervisor will evaluate the environmental impacts of the activities described in your proposed application and prepare environmental documentation under the National Environmental Policy Act (NEPA) (42 U.S.C. 4321 *et seq.*) and the implementing regulations (40 CFR parts 1500 through 1508). (c) *Amendments.* During the review of your proposed application, the Regional Supervisor may require you, or you may elect, to change your application.

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(b) *Environmental impact evaluation*. The Regional Supervisor will evaluate the environmental impacts of your proposed operations, and prepare environmental documentation under NEPA (42 U.S.C. 4321, *et seq.*) and its implementing regulations (40 CFR parts 1500 through 1508).	2. It is our understanding that the environmental impact evaluation for lease term pipelines is conducted in the DOCD process which is why they are included in the DOCD. If this is true, then environment impact evaluation should only be conducted on ROW pipelines. For lease term pipelines, MMS should only be conducting environmental impact evaluations once, either through the DOCD process or through the pipeline application process, not both.	
	(c) *Amendments*. During the review of your pipeline application, the Regional Supervisor may require you, or you may elect, to change your pipeline application.		
250.1010	**What conditions must my pipeline application meet?**		
	The Regional Supervisor will approve your pipeline application only if you satisfy all of the criteria in this section.		
	(a) You must obtain the Regional Supervisor's approval of either a DOCD or DPP that covers the structure at the originating end of the pipeline (e.g., platform, well, subsea skid), if the proposed pipeline is a lease term pipeline (see § 250.1015(b)).		
	(b) You must provide the Regional Supervisor with a copy of your approved State permit (see § 250.1016(c)), if the proposed pipeline will enter or cross any State submerged lands.	1. A state permit (when required) and the MMS application are concurrent activities. The state permit should be required to be submitted prior to MMS approval, but should not be required prior to MMS deeming the application submitted. MMS review of the application should not be delayed while the state permit is being secured.	(b) You must provide the Regional Supervisor with a copy of your approved State permit (see § 250.1016(c)), if the proposed pipeline will enter or cross any State submerged lands prior to MMS approving the application.
	(c) If the proposed pipeline will enter or cross any safety fairway or anchorage area, you must provide the Regional Supervisor with a copy of your approved U.S. Army Corps of Engineers permit (see § 250.1016(d)).	1. A COE permit (when required) and the MMS application are concurrent activities. The COE should be required to be submitted prior to MMS approval, but should not be required prior to MMS deeming the application submitted. MMS review of the application should not be delayed while the COE permit is being secured.	(c) If the proposed pipeline will enter or cross any safety fairway or anchorage area, you must provide the Regional Supervisor with a copy of your approved U.S. Army Corps of Engineers permit (see § 250.1016(d)) prior to MMS approving the application.
	(d) If an OCS lease or pipeline ROW grant could be impacted by your proposed pipeline	1. Please see comments above on “impacted”	(d) If an OCS lease or pipeline ROW grant is intersected by your proposed pipeline

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	construction or towing operations (see § 250.1016(e) and (f)), you must: (1) Provide the Regional Supervisor with a return receipt or letter of no objection from the lessee or designated lease operator of each impacted lease, or the holder of each impacted pipeline ROW grant (active or terminated); and (2) Ensure that each entity you notified under paragraph (d)(1) of this section had at least 30 days from the date they received the pipeline application from you to submit comments to the Regional Supervisor.	2. (2) was reworded to provide clarity.	construction or towing operations (see § 250.1016(e) and (f)), you must: (1) Provide the Regional Supervisor with a return receipt or letter of no objection from the lessee or designated lease operator of each intersected lease, or the holder of each intersected pipeline ROW grant (active or terminated); and (2) Each entity that you notified under paragraph (d)(1) has 30 days from the date they received the pipeline application from you to submit comments to the Regional Supervisor.
	(e) If the proposed pipeline will terminate or originate at a new hot tap or other connection on the OCS, the lessee, designated lease operator, or pipeline ROW holder of the receiving or delivering pipeline must first obtain approval from the Regional Supervisor to modify their pipeline.	1. In some cases, the receiving pipeline may be permitting their pipeline modification concurrently with the proposed pipeline application. While it is reasonable that the modification be approved prior to MMS approving the proposed pipeline application, it should not prevent MMS from deeming the proposed application complete nor should it delay MMS review of the proposed application.	(e) If the proposed pipeline will terminate or originate at a new hot tap or other connection on the OCS, the lessee, designated lease operator, or pipeline ROW holder of the receiving or delivering pipeline must first obtain approval from the Regional Supervisor to modify their pipeline before your application can be approved.
	(f) For ROW pipeline and new accessory installation applications, either: (1) All affected States with approved CZMA programs have concurred, or have been conclusively presumed to concur, with your coastal zone consistency certification in your pipeline application under section 307(c)(3)(A) of the Coastal Zone Management Act (CZMA) (16 U.S.C. 1456(c)(3)(A)); or (2) The Secretary of Commerce finds, under section 307(c)(3)(A) of the CZMA (16 U.S.C.1456(c)(3)(A)), that the proposed ROW pipeline operations or new accessory installation are consistent with the objectives of CZMA, or are otherwise necessary in the interest of national security.	1. The CZM determination should be obtained prior to the final approval of the pipeline and new accessory installation application, however, MMS should not delay deeming the application complete or review of the application.	
	(g) For ROW pipeline applications, you must demonstrate oil spill financial responsibility (OSFR) as required by 30 CFR 253.13, if applicable (see § 250.1029).	1. We disagree that oil spill financial responsibility has to be demonstrated prior to MMS approving the application. According to 30 CFR 153.15(b) …coverage for your new COF is submitted before the COF goes into operation.	

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		Meeting the requirements in § 250.1029. Therefore, this provision should be deleted.	
250.1011	**What can I do if an affected State objects to my ROW pipeline application?**		
	For ROW pipeline and new accessory installation applications, if an affected State objects to the coastal zone consistency certification in your application, you may follow the procedures in either paragraph (a) or (b) of this section.		
	(a) You may amend your application to accommodate the State's objection, and submit the amendment to the Regional Supervisor for approval and to the affected State for its consistency determination. The amendment need only address information related to the State's objection.		
	(b) You may appeal the State's objection to the Secretary of Commerce using the procedures in 15 CFR part 930, subpart H. The Secretary of Commerce will either: (1) Grant your appeal by finding, under section 307(c)(3)(B)(iii) of CZMA (16 U.S.C. 1456(c)(3)(B)(iii)) that the proposed operations are consistent with the objectives of CZMA, or are otherwise necessary in the interest of national security; or (2) Deny your appeal, in which case you may either amend your application under paragraph (a) of this section or withdraw your application and not conduct the proposed operations.		
250.1012	**How will the Regional Supervisor notify me of the decision on my pipeline application?**		**What decisions will MMS make on the pipeline application and within what timeframe?**
	After review and evaluation, the Regional Supervisor will notify you in writing whether your pipeline application is approved or disapproved.		(a) *Timeframe.* The Regional Supervisor will make a decision within 30 calendar days on your deemed submitted pipeline application after the latest day that: (I) the last amendment to your proposed application is received by the Regional Supervisor (II) the conditions in 250.1010 (a-f) have been

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
			satisfied.
	(a) The Regional Supervisor will approve your pipeline application if it complies with all applicable requirements; and will inform you of any conditions that you may be required to meet. In the approval letter, the Regional Supervisor will assign a unique MMS pipeline segment number that you must use in all subsequent correspondence regarding the pipeline.		
	(b) The Regional Supervisor will disapprove your pipeline application if the proposed operations would probably cause serious harm or damage (and you cannot amend the proposed pipeline operations to avoid such conditions) to life (including fish or other aquatic life), property, any mineral (in areas leased or not leased), the national security or defense, or the marine, coastal, or human environment. The Regional Supervisor will provide the reason(s) for disapproving your pipeline application in writing.		
250.1013	**When may the Secretary cancel approval of a pipeline application?**		
	The Secretary may cancel approval of your pipeline application upon your request, or if pipeline operations under the application are in suspension or temporary prohibition (see § 250.1091) for at least 5 years (see section 5(a)(2) of the OCSLA (43 U.S.C. 1334(a)(2)). To cancel approval under this section, the Secretary must determine after a hearing that all of the following conditions are met:		
	(a) Continued operation under the approved pipeline application would probably cause serious harm or damage to life (including fish and other aquatic life), property, mineral resources (in areas leased or not leased); the national security or defense, or the marine, coastal, or human environment;		
	(b) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(c) The advantages of cancellation outweigh the advantages of continuing the pipeline application in force.</td><td></td><td></td></tr>
<tr><td colspan="2">Pipeline Application Contents</td><td></td><td></td></tr>
<tr><td>250.1014</td><td>General information</td><td></td><td></td></tr>
<tr><td></td><td>You must provide the following general information:
<table>
<tr><th>You must provide a(n). . .</th><th>That includes. . .</th><th>and. . .</th></tr>
<tr><td>(a) Cover letter</td><td>(1) The name of the company and the name, title, and signature of the company representative filing the application; and (2) A statement that you are applying for approval of the pipeline in accordance with § 250.1007</td><td></td></tr>
<tr><td>(b) List of contacts</td><td>The name and MMS operator number of the company filing the application, and the company's managerial, regulatory, and technical representatives who the Regional Supervisor can contact while processing the application</td><td>For each contact, you must include the: (1) Company name; (2) Business and postal address; (3) Telephone number; (4) Telefax number; and (5) E-mail address.</td></tr>
<tr><td>(c) Indication of the pipeline</td><td>An indication whether the proposed pipeline will be a lease</td><td></td></tr>
</table></td><td>1. (b) we do not understand MMS rationale for requiring up to 4 contact persons. A single contact should suffice which is similar to the way MMS works. We are given one MMS contact persons and he or she works within the MMS organization to process the application. The applicant should be able to do the same.</td><td>(b) The name and MMS operator number of the company filing the application, and the company's managerial, regulatory, and technical representatives who the Regional Supervisor can contact while processing the application. Contact information for a single representation can be provided, if preferred.</td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	type | term pipeline type or an ROW pipeline | (d) Indication of the pipeline jurisdiction | An indication whether the proposed pipeline will be under the jurisdiction of DOI or DOT | If you wish petition to transfer jurisdiction from DOI to DOT or to transfer jurisdiction from DOT to DOI (see § 250.1004(b)), you may include the request in your pipeline application. (e) Tentative schedule for conducting pipeline operations | The date your installation operations will begin and end | The date you will place the pipeline into service. (f) New or unusual technology statement | A statement whether you will or will not use a new or unusual technology to carry out your proposed pipeline operations | If you will use new or unusual technology, provide a narrative description of the technology and the rationale for its selection. (g) Payment | Payment of a nonrefundable service fee (see § 250.125 for amount) | If the application is for a lease term pipeline.		
250.1015	**Other general information.**		
	If your proposed pipeline operations meet any of the criteria in the following table, you must provide the indicated information: If. . . | You must provide. . . (a) You are applying for an ROW pipeline | A statement that certifies that you have an	1.(a) We do not understand the rationale for MMS requesting certification that a ROW pipeline has obtained coverage under the NPDES permit. It is up to the ROW pipeline operator to determine if coverage under the NPDES permit is needed. In many cases, ROW pipeline operator	(a) delete from regulation (b) The MMS assigned control number for the DOCD or DPP that a covers or will cover your proposed pipeline operations. If you have not submitted the DOCD or DPP, you must provide

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	approved National Pollutant Discharge Elimination System (NPDES) permit, or that you have applied for an NPDES permit that covers your proposed pipeline operations. (b) You are applying for lease term pipeline in the GOMR — The MMS assigned control number for the DOCD or DPP that a covers or will cover your proposed pipeline operations. If you have not submitted the DOCD or DPP, you must provide the date you intend to submit the document or plan to the GOMR. (c) You are applying for an ROW pipeline and you propose to use measures beyond those required by this part to minimize or mitigate environmental impacts — A description of the additional measures you will use. (d) Your pipeline will operate in a sour environment — A certification that the pipeline is designed in accordance with the requirements in § 250.1035. (e) You will install a supervisory control and data acquisition(SCADA) system — A brief description of the system.	will obtain coverage under the permit when they have a planned discharge from the pipeline, but will not maintain continuous coverage over the operational life of the pipeline. We recommend that this condition be removed. (b) If the DOCD or DPP has not yet been filed when the pipeline application is filed, the exact date it will be filed is probably unknown. We suggest that MMS be notified and provided this information when the DOCD or DPP has been filed and MMS has assigned the control number.	this information when it is available.
250.1016	**Information regarding other agencies and entities.**		
	If your proposed pipeline operations meet any of the criteria in the following table, you must provide the indicated information: For each . . . — You must provide . . . (a) ROW pipeline and new accessory installation — (1) Coastal zone consistency certification according to 15 CFR	1. (a)(2) Evidence that you sent the coastal zone certification will not be available to submit with the pipeline application. It should be clarified that this can be provided when available. We suggest adding a reference to footnote 1.	(a)(2) Evidence that you sent your pipeline or accessory application, consistency certification (see 15 CFR 930.57), and all necessary data and information (see 15 CFR 930.58) to each affected State for their CZMA consistency[1]

Proposed Section Number	Proposed Text		Summary of Comments and Rationale	Proposed Language
		930.57 for each affected State; and (2) Evidence that you sent your pipeline or accessory application, consistency certification (see 15 CFR 930.57), and all necessary data and information (see 15 CFR 930.58) to each affected State for their CZMA consistency determination.	(b)(1) We encourage the MMS to provide up-to-date lists of military and water test areas along with contact information that want to be contacted concerning our activities. Many times, we contact them and they don't respond. It could be that these are inactive areas that just aren't interested. (e) Please see our comments on "impacted" above. It appears that the intention is to notify the lease operator where construction vessels anchors will be placed on their lease; however, the term "impacted is very broad and could be interpreted in many ways. Also, there is no mention of towing or dragging installation activities. All leases and ROW pipelines crossed by the tow route should receive notification. (f) Comments above for (e) are generally applicable for ROW pipelines. We also note that it is sometimes difficult to identify pipelines that have been proposed, but not installed or operational at the time a pipeline application is prepared. We encourage MMS to keep their pipeline records as up to date as possible. We also note that during the application stage, construction vessels may not be contracted; therefore, accurately knowing construction anchor placement is difficult.	(e) Proposed pipeline that will enter into an existing OCS lease, or whose construction operations could intersect a lease (e.g., placing anchors on the lease or dragging across a lease) (f) Proposed pipeline that will cross an existing ROW pipeline or decommissioned pipeline, or where construction anchors will be placed or construction towing or dragging operations occur within 500 feet of an existing ROW pipeline or decommissioned pipeline.
	(b) ROW pipeline, if the routes of the vessels and aircraft you will use to support your proposed pipeline operations are located in or could traverse established military warning or water test areas	(1) An identification of the warning and water test area(s); and (2) A certification that, before you begin pipeline construction operations, you will contact the military installation with jurisdiction over the area concerning the control of electromagnetic emissions and the use of vessels and aircraft in the area.		
	(c) Proposed pipeline that will enter into or cross State offshore waters	A copy of the approved permit from that State.[1]		
	(d) Proposed pipeline that will enter into or cross any safety fairway or anchorage area	A copy of the approved U.S. Army Corps of Engineers permit.[1]		
	(e) Proposed pipeline that will enter into an existing OCS lease, or whose construction operations could impact lease operations (e.g., placing anchors on the lease)	OCS area and block designations, OCS lease number, and name of the lessee or designated lease operator for each impacted lease.		
		OCS area and block designations of the crossing or impact point, and name of the pipeline ROW holder.		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	decommissioned pipeline (i.e., placing anchors or routing the pipeline across or within 500 feet of an existing ROW pipeline) |		
	(g) Proposed pipeline that will originate or terminate at an existing valve or hot tap assembly | (1) OCS area and block designations of the tie-in point(s); and (2) Name of the lessee or designated lease operator if a connecting pipeline is a lease term pipeline; or the name of the pipeline ROW holder if a connecting pipeline is an ROW pipeline.		
	(h) Proposed pipeline you identified pursuant to paragraphs (e), (f), and (g) of this section | A photocopy of a return receipt or a letter of no objection that indicates the date that the lessee, designated lease operator, or pipeline ROW holder received a copy of your pipeline application by registered or certified mail (or equivalent).[1]		
	[1] If this document is not available when you submit your application, you may submit the document later.		
250.1017	**Location information.**		
	(a) You must provide the following location information: You must provide . . . | That must . . . (1) A location plat based on the North American Datum of 1927 (NAD 27) for the GOMR (Gulf) and POCSR, and the North American Datum of 1983 (NAD 83) for the AKOCSR and GOMR (Atlantic), with a minimum scale of 1 inch = 2,000 feet | Include the information listed in paragraph (b) of this section.	1. (a)(1) We assume that a minimum scale of 1 inch = 2,000 ft means that we could use a scale such as 1 inch = 20 ft for something like a jumper. (a)(2) the proposed language is not clear. (a)(4) At what point does the pipeline end and the riser begin for SCRs? Should this be the touchdown point? The transition point between riser and pipeline? The operator defined point between pipeline and riser? For SCRs there is a	(2) An Electronic file of the digital coordinates of a sufficient number of points to provide an accurate representation of the entire route of the proposed pipeline or umbilical, including turns (4) The total length (feet) of the horizontal component of the proposed pipeline including any horizontal component of the riser, the length in Federal waters (feet), and the length in State waters (feet), if applicable

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(2) An Electronic file of the digital coordinates of a sufficient number of points to provide an accurate representation of the entire route of the proposed pipeline, including turns and umbilicals — Be in decimal degree latitude and longitude and based on NAD 27 for the GOMR (Gulf) and POCSR, and NAD 83 for the AKOCSR and GOMR (Atlantic). The Regional Supervisor will specify the file format for providing this information. (3) Information on the proposed locations of the origin, termination, and inclusive OCS blocks traversed by the pipeline route — Include, if applicable, the OCS area, block number, and lease number. (4) The total length (feet) of the proposed pipeline excluding risers, the length in Federal waters (feet), and the length in State waters (feet), if applicable	horizontal component of the riser that is located on the seabed and for ROW pipeline's this should be included in the ROW; therefore, the length of the pipeline excluding risers would be shorter than the ROW length. We request that MMS clarify what information they are looking for in this requirement.	
	(b) The location plat required by paragraph (a)(1) of this section must do all of the following: (1) Identify the lessee, designated lease operator, or pipeline ROW holder. (2) Show OCS area, block, and lease designations. (3) Show the pipeline route from origination to termination, including the plant or refinery, if applicable. It must also show flow direction and, if an ROW pipeline, the 200-foot pipeline ROW and any site for an accessory. (4) Show the routes and flow directions of all umbilicals. (5) Identify all platforms (including accessories) and pipelines (MMS-assigned segment numbers) that your proposed pipeline will connect to, cross, or otherwise impact. (6) Identify all safety fairways, anchorage areas, and military warning or water test areas that are	(b)(4) Why does the flow direction of the umbilical need to be shown. In many cases the flow could be in either direction depending on the service of the individual tubes in the umbilical? We recommend that this be eliminated. (b)(5) how would a platform or pipeline be impacted if the proposed pipeline does not connect to or cross it? We recommend that "or otherwise impact" be eliminated. (b)(6) Why do safety fairways, anchorage areas, and military warning or water test areas within 500 feet of the center line of the proposed pipeline need to be identified? We believe that just those intersected by the pipeline need to be identified.	(b)(4) Show the routes of all umbilicals. (b)(5) Identify all platforms (including accessories) and pipelines (MMS-assigned segment numbers) that your proposed pipeline will connect to or cross. (b)(6) Identify all safety fairways, anchorage areas, and military warning or water test areas that intersected by the proposed pipeline, the 200-foot pipeline ROW or any site for an accessory.

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	within 500 feet of the center line of the proposed pipeline. (7) Show the burial depth (feet) of the pipeline along its entire length. (8) Show the water depth (feet) along the entire length of the pipeline. (9) Depict the water depth (feet), X-Y coordinates, and decimal degree latitude and longitude of each of the following key points: (i) Locations of the originating and terminating structures; (ii) Points where the proposed pipeline crosses a fairway, an anchorage area, or a lease or block boundary; (iii) Locations of subsea valves, flanges, hot taps, tie-ins, anode sleds, connecting sleds (including PLEM's and PLET's), manifolds (including those that are accessories), and other appurtenances; (iv) Locations of pipeline crossings; (v) Points throughout the curvature of a turn; and (vi) Point where the pipeline enters into State jurisdiction, if applicable. (10) Include a certification by a registered engineer or land surveyor that the information on the plat is accurately represented.		
	(c) For each ROW pipeline, you must provide a map at an appropriate scale that shows the: (1) Proposed pipeline route relative to the shoreline, the onshore support base you will use, and the proposed primary transportation routes for your support vessels and aircraft; and (2) Distance to shore (miles) of the pipeline route origination and termination points.	1. We assume that the onshore support base referenced here is the one used during the operational life of the pipelines for inspections, maintenance, testing of the safety system and not for the initial construction activities. In many cases, multiple onshore support bases will be utilized during the initial construction phase and in many cases, only one trip from the onshore base will occur. These bases have not normally been identified when the application has been filed and may change during the construction activities.	
250.1018	**Origination and termination information.**		
	You must provide origination and termination information as indicated in the following table: Type of information | When required | Contents (a) General | In all cases | (1) The type of structure	(a)(7) We do not understand why this information is being requested and what MMS will use it for. The manned or unmanned status of a platform may change over the life of a	(a)(7)_delete from regulation (e)(1) Design fatigue life (years) of the riser

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
	information on the facilities where the proposed pipeline will originate and terminate		(i.e., platform, well jacket or caisson, subsea well, manifold, tie-in, or blind flange); (2) MMS-assigned name of the structure (if applicable); (3) OCS area and block designations; (4) OCS lease number (if applicable); (5) Distance to shore (miles); (6) Water depth (feet); (7) Whether the structure is manned or unmanned; and (8) If the facility is equipped with a pig launcher/receiver, a description of its major features and rating.	pipeline. We recommend that this requirement be eliminated. (e) It is not clear what is considered a "traditional riser" vs a "non traditional riser" . Is a traditional riser a "fixed" riser and a non traditional riser anything other "fixed"? (e) (1) During the application phase, we can not determined the fatigue point at which we would replace a riser. The remaining fatigue life of a riser is evaluated at various times during the riser's life based on operational and environment conditions the riser has been subjected to and the results of in-service inspection and its remaining service life. We recommend that this requirement be eliminated.	
	(b) Riser design information for each pipe diameter	If the pipeline will connect at a platform, well jacket, or caisson	(1) Design life (years); (2) Outside diameter (inches); (3) Wall thickness (inches); (4) Pipe grade; (5) Hydrostatic test pressure (psi) and duration (hours); (6) Type and thickness (mils) of the external corrosion coating; (7) Type and thickness (mils) of the external corrosion coating in the splash zone; (8) Type and thickness (mils) of the internal corrosion coating; (9) Type of riser, e.g., fixed, catenary, top tension, flexible; (10) Type, pressure rating (psi), and, if applicable, the de-rated pressure rating (psi) of the insulating flange; and (11)		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
			Whether the riser can be inspected using in-line inspection tools (e.g., smart pigs).		
	(c) Non-traditional pipe	If you plan to use any non-traditional pipe (e.g., flexible pipe) to construct the riser	(1) The name and a description of the non-traditional pipe; (2) The manufacturer's design specification sheet; (3) The design pressure (psi); (4) An identification of the design standards you used; and (5) A review by a third-party verification agent (specified in API Spec 17J (incorporated by reference as specified in § 250.198), where applicable) if you intend to use any unbonded flexible pipe.		
	(d) Riser guard design	In all cases	A drawing that shows how you will protect the riser(s) from physical damage that could result from contact with floating vessels.		
	(e) Catenary and other non-traditional riser	If the riser will be a catenary or other non-traditional design	(1) Design fatigue life (years) of the riser and the fatigue point at which you would replace the riser; (2) Identification of the design standards you used; and (3) Type and rating of the connecting device you will use;		
	(f) Subsea manifold	If the proposed pipeline will originate or terminate at a subsea	A diagram of the facility showing its major features including: (1) Pressure rating (psi) of the pressure limiting component; (2) Type of exterior protective coating; and (3)		

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		manifold	Description of the cathodic protection system.		
	(g) Subsea tie-in	If the proposed pipeline will originate or terminate at a subsea tie-in	Information about the tie-in that includes: (1) Type of tie-in assembly (existing valve or new hot tap); (2) MMS-assigned pipeline segment number of the delivering or receiving pipeline; (3) MAOP (psi) of the delivering or receiving pipeline; and (4) Schematic drawing of the tie- in assembly.		
	(h) Subsea blind flange	If the pipeline will originate or terminate at a subsea blind flange	Information about the blind flange that includes the: (1) Type; (2) Pressure rating (psi); and (3) If applicable, the de-rated pressure rating (psi).		
	(i) Other appurtenances and other accessories	If the pipeline will include any equipment, device, apparatus, or other object not described in paragraphs (e) through (h) of this section	Information about the appurtenance that includes: (1) Description of the appurtenance; (2) Schematic drawings showing the arrangement and orientation of the appurtenances; and (3) For subsea manifolds, pipeline end modules (PLEM's), and pipeline end terminals (PLET's), a diagram of the appurtenance showing its major features and dimensions, pressure rating (psi), and type of exterior protective coating, and a description of the		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td><table><tr><td></td><td></td><td>cathodic protection system.</td></tr></table></td><td></td><td></td></tr>
<tr><td>250.1019</td><td>Horizontal component and appurtenances information.</td><td></td><td></td></tr>
<tr><td></td><td>You must provide horizontal component and appurtenances information as indicated in the following table:<table><tr><th>Type of information</th><th>When required</th><th>Required data elements</th></tr><tr><td>(a) Pipeline internal design pressure</td><td>For all pipelines</td><td>(1) Internal design pressure (psi) you calculated; (2) Formula you used to calculate the internal design pressure; (3) Design factors you used in calculating the internal design pressure; and (4) Calculations you performed to derive the internal design pressure for each pipe diameter and wall thickness.</td></tr><tr><td>(b) Pipeline collapse design pressure</td><td>For all pipelines to be installed in water depths greater than 1000 feet</td><td>(1) External pressure on the pipe in (psi); (2) Collapse design pressure (psi) you calculated; (3) Formula you used to calculate the external design pressure; (4) Collapse factor you used in calculating the external design pressure; (5) Calculations you performed to derive the external design pressure for each pipe diameter and wall thickness; and (6) Description of any collapse arrestors you intend to install or other mitigation you intend to use.</td></tr></table></td><td>(a), (b) and (c) don’t appear to be applicable all appurtenances. Please clarify

(d) we assume that traditional pipe is pipe in accordance with API Spec 5L. If not, please clarify.

(j) for crossings of communication and power cables, is there a database that identifies these facilities? Otherwise, how will we determine in advance that they will be crossed by the proposed pipeline until a pre lay survey is conducted?

(j)(5) Will using the information shown in the MMS pipeline data base satisfy this requirement? It is very difficult to actually determine the presence or absence of H2S.

(h)(4) it is not clear what needs to be shown on a drawing for umbilical termination assemblies. Please clarify.
(i) (3) does all of this information have to be shown on the drawing or can it be a combination of drawing and text?</td><td>You must provide horizontal component and appurtenances (as applicable) information as indicated in the following table:</td></tr>
</table>

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
	(c) Horizontal component design	For all pipelines, for each pipe diameter incorporated in the horizontal component of the pipeline	(1) Design life (years); (2) Pipe outside diameter (inches); (3) Pipe wall thickness (inches); (4) Pipe grade; (5) Bare pipe and weighted pipe specific gravities, and a statement (based on stability analysis) that the pipeline will remain stable following installation; (6) Type of welds (e.g., longitudinal, electrical resistance welded (ERW), submerged arc welded (SAW), seamless); (7) Hydrostatic test pressure (psi) and test duration (hours); (8) Type and thickness (mils) of the external corrosion coating; (9) Type and thickness (mils) of the internal corrosion coating; (10) Density (pounds/cubic foot) and thickness (inches) of the concrete weight coating; and (11) Statement indicating whether or not the pipe can be inspected using in-line inspection tools (e.g., smart pigs).		
	(d) Non-traditional pipe	If you plan to use any non-traditional pipe (e.g., coiled tubing, flexible pipe,	(1) Name and a description of the non-traditional pipe; (2) Manufacturer's design specification sheet; (3) Design pressure (psi); (4) Identification of the design standards you used; and (5) Review		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		unbonded flexible pipe) to construct the horizontal componen t	by a third-party independent verification agent (specified in API Spec 17J (incorporated by reference as specified in § 250.198), where applicable) if you intend to use any unbonded flexible pipe.		
	(e) Pipeline cathodic protection system	If you plan to install a cathodic protection system that uses bracelet anodes	(1) Anode composition; (2) Design anode life expectancy (years); (3) Formula and calculations you used to determine the design life of your anodes; (4) Anode consumption rate (pounds/amp/year); (5) Net weight per anode (pounds); (6) Anode interval (feet); and (7) Number of anodes.		
	(f) Non-traditional cathodic protection system	If you plan to install a cathodic protection system that does not use bracelet anodes	(1) Specify and describe the system; and (2) Provide the applicable information from paragraph (e) of this section, and the information and calculations you used to show that your pipeline is cathodically protected.		
	(g) Pipeline valves and flanges	If you plan to install a valve or flange on the horizontal componen t (not at the originatin g or terminatin g points)	Information about each valve or flange that includes the: (1) Type; (2) Pressure rating (psi); and (3) If applicable, the de-rated pressure rating (psi).		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		as an appurtenance to the pipeline			
	(h) Umbilicals	If you plan to install umbilicals as appurtenances to the pipeline	A drawing that shows: (1) Types of umbilicals (e.g., electrical, hydraulic, chemical) you plan to install; (2) Configuration of the umbilicals in the bundle; (3) Length (feet) and outside diameter (inches) of the bundle; and (4) Any associated umbilical termination assemblies.		
	(i) Other appurtenances	If you plan to install any equipment, device, apparatus, or other object not described in paragraphs (e) through (h) of section	Information about each appurtenance that includes: (1) Description of the appurtenance; (2) Schematic drawings showing the arrangement and orientation of the appurtenances; and (3) For subsea manifolds, pipeline end modules (PLEM's), and pipeline end terminals (PLET's), a diagram of the appurtenance showing its major features and dimensions, pressure rating (psi), type of exterior protective coating, and a description of the cathodic protection system.		
	(j) Pipeline crossings	If the pipeline will cross any existing	(1) MMS-assigned segment number of the pipeline or umbilical (if applicable) to be crossed; (2) OCS area and block		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	pipeline, umbilical, power or communication cable, or other structure or object | designations of the crossing location; (3) Description of the method you will use to separate the pipeline from the existing structure or object and the separation distance (inches); (4) Water depth (feet) at the pipeline crossing; (5) Indication of the presence or absence of $H_{2G4}S$ in the crossed pipeline; and (6) Diagram that shows a profile of the crossing that includes the depth of cover (feet).		
250.1020	**Schematic flow diagram.**		
	You must provide a schematic flow diagram of the proposed pipeline that is consistent with the diagram(s) required by § 250.802(e)(1) through (3), as appropriate, and that shows:	1. Although the proposed rule suggests that Simplified Safety Flow Diagrams per API RP 14 C can be submitted to evaluate new or modified facilities, we point out that MMS currently is requiring operators to create new simpler drawings. The MMS Pipeline Section should use the API RP 14 C drawings as they provide the required information and accurately depict the facility and all inputs to the pipelines.	
	(a) All pressure sensing devices and associated control lines;		
	(b) All pressure safety valves (PSVs) and settings;		
	(c) All shutdown valves (SDVs), flow safety valves (FSVs), and block valves;		
	(d) All pressure-regulating devices (including back-pressure regulators);		
	(e) Any subsea manifolds, PLEMs and PLETs, and other appurtenances;		
	(f) Input source(s) (e.g., wells, pumps, compressors, and vessels) and the maximum source pressure (MSP) (psi) of each;		
	(g) Flow direction (or predominate direction for bi-directional flow);		
	(h) Safety equipment for the input source;		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(i) Rated working pressure (psi) of all valves and flanges;</td><td></td><td></td></tr>
<tr><td></td><td>(j) Any specification (spec) breaks;</td><td></td><td></td></tr>
<tr><td></td><td>(k) Initial receiving equipment, vessel, or pipeline, and its rated working pressure (psi) or MAOP (psi);</td><td></td><td></td></tr>
<tr><td></td><td>(l) Pig launchers and receivers;</td><td></td><td></td></tr>
<tr><td></td><td>(m) Calculated MAOP (psi) of the proposed pipeline;</td><td></td><td></td></tr>
<tr><td></td><td>(n) MMS-assigned segment number and approved MAOP (psi) of any connecting pipeline; and</td><td></td><td></td></tr>
<tr><td></td><td>(o) The transfer point where jurisdiction changes between DOI and DOT, if applicable.</td><td></td><td></td></tr>
<tr><td>250.1021</td><td>Shallow hazards information.</td><td></td><td></td></tr>
<tr><td></td><td>You must provide information on shallow hazards as indicated in the following table:
<table>
<tr><th>Type of information</th><th>When required</th><th>Contents</th></tr>
<tr><td>(a) Shallow hazards survey report</td><td>For ROW pipelines in the GOMR, and for all pipelines in the POCSR and AKOCSR</td><td>Shallow hazards survey report of the proposed pipeline route based on information obtained from the shallow hazards survey (see § 250.1032(a)). The Regional Supervisor will specify requirements for preparing the report.</td></tr>
<tr><td>(b) Shallow hazards analysis of any seafloor and subsurface geologic</td><td>In all cases</td><td>(1) Description of the hazards along the pipeline route; (2) Discussion of any special safety measures you will take to minimize the adverse</td></tr>
</table></td><td>1.(a) If a shallow hazard report has been previously submitted to MMS, we should not have to resubmit it with a pipeline application. MMS should be able to retrieve it from their files. If the pipeline route needs to be updated or added, then just submitted maps with the proposed route should be sufficient.

2. (b)(1) if this analysis is already included in the body of the shallow hazard report for the proposed pipeline route, it should not have to be either repeated or re-summarized with the application.</td><td>(a) Shallow hazards survey report (if not previously provided)</td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	features, and any manmade features or conditions, which may have an adverse effect on the proposed pipeline | | effects of shallow hazards on the proposed pipeline; and (3) Discussion of how you will comply with the hazard mitigation requirements specified in § 250.1042.		
250.1022	**Construction information.**		
	You must provide pipeline construction information as indicated in the following table: Type of information | When required | Contents (a) Installation method | In all cases | A brief description of the method you will use to install the proposed pipeline (e.g., S-lay, J-lay, reeled lay, towed lay). (b) General information on the vessel/equipment you will use to construct the proposed pipeline | In all cases | (1) Type of vessel (e.g., anchor supported, dynamic positioning) or equipment (e.g., trucks, bulldozers); (2) Name of the vessel (if known); (3) Maximum anchor radius (feet); (4) Capacity of fuel tanks (barrels); and (5) Proposed anchor location for operations in the POCSR. (c) Tow route | If you plan to install the pipeline by towing or dragging it to the installatio | (1) Plat that depicts the entire tow route and indicates where the pipeline will be dragged on the seafloor, if applicable. (2) Electronic file containing the the digital coordinates of	(b)(2) why does the vessel name need to be submitted? What will it be used for? Many times this is not known when the application is submitted and the installation vessel may change at the last minute. We recommend that this be deleted. (b)(4) if the vessel has not been identified, how is the capacity of the fuel tanks going to be determined? We recommend that an estimate be provided. What will this information be used for? This information is already provided in the DOCD for lease term pipelines; therefore, it should be limited to ROW pipelines. (c) Each lease or ROW pipeline that is crossed by the tow route should be notified and given an opportunity to comment. See comments for 250. 1016(e). (d) We recommend that the air emission requirements be based on the requirements in 250.249. Especially specifying the projected emissions noted in 250.249(a) in lieu of the generic statement currently in (d)(5). The air emissions related to the construction of lease term pipelines are calculated based on this requirement. We also note that you are requesting emissions on an hourly and daily	(b)(2) delete from regulation (b)(4) For ROW pipelines, estimate of the storage of capacity of its fuel tanks.

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		n site	sufficient points to provide an accurate representation of the proposed tow route. In preparing this file, you must: (i) Use the file format specified by the Regional Supervisor; (ii) Include the data for the entire tow route; and (iii) Present the data in decimal degree latitude and longitude, based on NAD 27 for the GOMR (Gulf) and the POCSR, and NAD 83 for AKOCSR and GOMR (Atlantic). (3) Shallow hazards survey report for the tow route (see § 250.1032(a)). (4) Analysis of any seafloor and subsurface geologic features, and any manmade features or conditions, which may have an adverse effect on the pipeline if towed or dragged. The analysis must include a: (i) Discussion of the hazards along the pipeline tow route; (ii) Description of any special safety measures you will take to minimize the adverse effects of shallow hazards on the towing operations; and (iii) Discussion of how you will comply with the hazard mitigation requirements specified in § 250.1042.	basis instead of peak hourly emissions and total annual emissions. It would appear to us that it would be more useful to MMS and to Industry for the air emissions to be calculated on the same basis. Further, the air emission spreadsheets currently utilized for EPs and DOCDs in the GOM region could also be utilized for calculating these emissions which again would lead to consistency. (e) We suggest that discharge information requirements be modeled after 250.248. For the GOM Region, we suggest that this information be provided to MMS in the same format as it is for EPs and DOCDs. This is the format that the information is currently provided to MMS for lease term pipelines. It will lead to consistency in providing the information.	
	(d) Air emissions	For ROW pipelines	(1) Total rated output (horsepower) of each		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		in the GOMR, and for all pipelines in the POCSR and AKOCSR, you must provide air emissions information for all combustion sources used in pipeline construction operations	vessel/equipment; (2) Rated output (horsepower) of each combustion emission source on the vessel(s) and a description of its use (e.g., crane, compressor, generator, dehydrator); (3) Run time (hours/day and days/year) for each emission source; (4) Documentation of any emission control technologies you will employ; and (5) Maximum hourly, daily, and total projected emissions for all pipeline installation-related emission sources.		
	(e) Vessel discharges	For ROW pipelines in the GOMR, and for all pipelines in the POCSR and AKOCSR, you must provide information on discharges for all vessels associated with your pipeline installation	(1) Types and general characteristics of the wastes that will be generated and discharged into the ocean during construction operations; (2) Volume (gallons) of waste that will be discharged; (3) Average and maximum discharge rates (gallons/hour); (4) Description of any treatment or storage; and (5) Discharge location and method for each type of discharge.		
	(f) Pipeline burial	If you plan to bury the pipeline	(1) Method you will use to bury the pipeline (e.g., jet, plow); and (2)		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		(see § 250.1044(c))	Depth of burial (feet), including the depths in safety fairways and anchorage areas.		
	(g) Pipeline self burial	If you expect that the pipeline will bury itself naturally in the sediment, you must provide a request to use an alternative procedure under § 250.141	(1) Appropriate site-specific geotechnical data (e.g., sediment compaction, shear strength) and other information to verify sediment conditions; and (2) Information specified in § 250.1027(a).		
	(h) Obstruction protection	In all cases	Information concerning any covering (e.g., dome, cage, sandbags, concrete mats) you will use to protect a manifold, tie-in, or blind flange at the pipeline origination and termination points, and all valves, flanges, other appurtenances, and pipeline crossings along the horizontal component of the pipeline (see § 250.1046(a)). The information you provide must include: (1) A drawing that shows the specifications of the protective covering and the equipment it will protect; (2) A drawing and a description of the relationship of the protective covering to		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language

		the seafloor (e.g., mat edges buried); (3) A discussion of any anchor pins or sandbags you will use to hold the protective covering in place, if applicable; (4) A description of the cathodic protection system for the protective covering, if appropriate; and (5) A discussion of your plans for maintaining the protective covering.
(i) Underwater vent pipelines	If you plan to install an underwater vent pipeline	A description of the provisions you will make for anchoring the end of the underwater vent pipeline.

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250.1023	**Onshore support base, terminal, support vessels, and aircraft information.**		
	You must provide information on each onshore base you will use to provide supply and service support for your proposed pipeline operations as indicated in the following table:	1. (a) We assume that the onshore support base referenced here is for our ongoing operation support, not our one time construction support. Construction support can come from many onshore bases that may not even be identified at the time the application is filed and may change multiple times. In many cases an onshore base may only be used for one activity during construction. This information is already provided for lease term pipelines in the DOCD; therefore it should only be required for ROW pipelines	(a) When required… For ROW pipelines in the GOMR, and all pipelines in the POCSR and AKOCSR

Type of information	When required	Contents
(a) Onshore support base	In all cases	(1) Name and location of the onshore support base, and whether it will be a new or existing facility; (2) Description of the necessary work, if you plan to construct a new onshore support base or make major additions to an existing one; and (3) Timetable for land acquisition (including rights-of-way and easements) and construction or

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language

		expansion if you plan to acquire land to construct a new facility or expand an existing one.
(b) Onshore terminal	For pipelines that will transport product to shore	The name, description, and location of the primary onshore terminal (including any refinery, gas plant, or compressor station) that will be built or undergo expansion or major modification as the result of your proposed pipeline operations.
(c) Support vessels and aircraft (general)	For ROW pipelines in the GOMR, and all pipelines in the POCSR and AKOCSR	Information for each type of vessel/equipment (e.g., anchor-handling boats, tug boats, supply boats, service boats, crew boats) and aircraft you will use to support your proposed pipeline operations that includes: (1) Fuel tank storage capacity (barrels); (2) Maximum number of vessels/equipment that will be in the area of operations at any one time; and (3) Trip frequency or duration.
(d) Diesel oil supply vessel/equipment	For ROW pipelines in the GOMR, and all pipelines in the POCSR and AKOCSR	Information on the vessels you will use to supply diesel oil to your pipeline installation vessels/equipment that includes: (1) Vessel length (feet); (2) Diesel oil storage capacity (barrels); and (3) Frequency of fuel transfers.

250.1024	**Operation information.**		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>You must provide the following pipeline operation information:</td><td></td><td></td></tr>
<tr><td></td><td>(a) Pipeline operating temperature. The anticipated maximum and minimum operating temperatures ([deg]F) of the proposed pipeline.</td><td></td><td></td></tr>
<tr><td></td><td>(b) Proposed MAOP. Your proposed MAOP (psi) for the pipeline, and the method you used to determine the MAOP (see § 250.1081).</td><td></td><td></td></tr>
<tr><td>250.1025</td><td>Service and products information.</td><td></td><td></td></tr>
<tr><td></td><td>You must indicate the primary service and, if applicable, the secondary service of the proposed pipeline (e.g., oil, bulk oil, natural gas, bulk gas, condensate, gas and condensate, gas lift, instrument, flare/vent, water, methanol, glycol, sulphur, or other chemicals). If the pipeline will be bidirectional, you must provide the service for each direction and indicate which one will predominate.
<table>
<tr><th>If you will be primarily transporting . . .</th><th>Then you must provide . . .</th><th>The Regional Supervisor may also require . . .</th></tr>
<tr><td>(a) Natural gas</td><td>(1) The anticipated maximum flow rate (MMCFD); (2) The maximum design flow rate (MMCFD); (3) The specific gravity of the gas; (4) The carbon dioxide (CO_2) and hydrogen sulfide (H_2S) concentrations (ppm); (5) Your provisions for controlling</td><td>The chemical and physical characteristics of the gas.</td></tr>
</table></td><td>(d) Can we determine from the MMS data base if the third party pipelines we are crossing transport a product with an H2S concentration greater than 20 ppm? Otherwise, we may not know this until the pipeline application notifications are sent and the operator informs us of this condition. We assume this is requirement is only applicable to new crossings since it references a H2S Contingency Plan for construction operations.</td><td></td></tr>
</table>

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		internal corrosion; and (6) Your provisions for flow assurance			
	(b) Liquid hydrocarbons	(1) The anticipated maximum flow rate (BPD); and (2) The maximum design flow rate (BPD); (3) The API[deg] gravity of the liquid; (4) The anticipated CO_2 and H_2S concentrations (ppm); (5) Your provisions for controlling internal corrosion; and (6) Your provisions for flow assurance	The chemical and physical characteristics of the oils (see definition under 30 CFR 254.6).		
	(c) Chemicals	(1) The anticipated maximum flow rate (BPD); (2) The maximum design flow rate (BPD); (3) Your provisions for controlling internal corrosion	The chemical and physical characteristics of each chemical.		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
	(d) A product with an H_2S concentration greater than 20 ppm, or will cross a pipeline that transports a product with an H_2S concentration greater than 20 ppm	(1) An H_2S Contingency Plan prepared according to § 250.490(f); (2) A reference to an approved or submitted H_2S Contingency Plan that covers the operation of the proposed pipeline and/or the construction operations at the pipeline crossing; or (3) A statement that you will submit for approval to the appropriate District Manager either an H_2S Contingency Plan(s) or an amendment to an approved H_2S Contingency Plan(s) before you install the proposed pipeline.			
	(e) A product with an H_2S concentration greater than 500 ppm	Two (2) copies of an H_2S dispersion modeling report or the			

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>
<table>
<tr><td></td><td>modeling results (see § 250.1082(b)), or a reference to such report or results if already submitted to the Regional Supervisor.</td><td></td></tr>
</table>
</td><td></td><td></td></tr>
<tr><td>250.1026</td><td>Biological and archaeological information.</td><td></td><td></td></tr>
<tr><td></td><td>You must provide the biological and archaeological information indicated in the following table:
<table>
<tr><th>Type of information</th><th>When required</th><th>Contents</th></tr>
<tr><td>(a) Chemosynthetic communities report</td><td>If the proposed pipeline, or the associated anchors or chains of the pipeline construction vessel (or a proposed accessory, or the associated anchors or chains of the construction barge) will be placed in water depths 1,312 feet or greater</td><td>Three copies of a high-density chemosynthetic communities report. The Regional Supervisor will specify the contents of this report.</td></tr>
<tr><td>(b) Sensitive</td><td>If the proposed</td><td>Plats, a photo documentation survey</td></tr>
</table>
</td><td>1. This information is already provided in DOCDs for lease term pipelines; therefore, it should be limited to ROW pipelines.</td><td>You must provide the biological and archaeological information indicated in the following table for ROW pipelines in the GOMR, and all pipelines in the POCSR and AKOCSR.</td></tr>
</table>

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
	biological features reports or documentation	pipeline, or the associated anchors or chains of the pipeline construction vessel (or a proposed accessory platform, or the associated anchors or chains of the construction barge) will be placed in the vicinity of any biologically-sensitive features, including but not limited to topographic features, live bottoms (low-relief features), live bottoms (pinnacle trend features or seamounts), and potentially sensitive biological	report, and/or a high-resolution geophysical data survey report to identify and locate the features. The Regional Supervisor will specify when you must provide these plats and reports, and their contents.		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	features		
	(c) Archaeological report	If you propose bottom-disturbing operations in areas that are identified as high probability shipwreck blocks or prehistoric areas	Three copies of an archaeological report, or a reference to such a report if it was already provided to the Regional Supervisor. The Regional Supervisor will specify the contents of the archaeological report.
250.1027	**Requests for alternative compliance or departure.**		
	You must provide any request for alternative compliance or departure as indicated in the following table:		
	Type of request: (a) Alternative compliance When required: You must request approval from the Regional Supervisor if you plan to use any alternate procedures or equipment (see § 250.141) What your request must do: (1) Identify the MMS regulation for which you are seeking alternative compliance; (2) Describe the procedure, method, or equipment you plan to use; (3) Explain the reason you want to use the procedure, method, or equipment; and (4) Explain how you will achieve a level of safety and environmental protection that is equal to or greater than that		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	<table><tr><td></td><td></td><td>prescribed by the MMS regulation.</td></tr><tr><td>(b) Departure</td><td>You must request approval from the Regional Supervisor if you plan to depart from any current MMS regulatory requirements (see § 250.142) concerning the proposed pipeline</td><td>(1) Identify the MMS regulation for which you are seeking to forego or delay compliance; (2) Describe the procedure, method, or equipment you plan to use, if applicable; and (3) Explain the reason you wish to forego or delay compliance with the identified MMS regulation.</td></tr></table>		
250.1028	**Oil and hazardous substance spill response information.**		
	You must provide the following oil and hazardous substance spill response information:		
	(a) *Oil spill response planning.* For ROW pipelines, you must provide either: (1) An Oil Spill Response Plan (OSRP) for the pipeline prepared according to the requirements of 30 CFR part 254; or (2) A reference to your approved regional or subregional OSRP (see 30 CFR 254.3) that includes: (i) A discussion of your regional or subregional OSRP, and a statement that your proposed ROW pipeline operations will be covered by that OSRP; (ii) The locations of your primary oil spill equipment base and any preplanned equipment staging areas; (iii) The names of your oil spill removal organizations for both spill response equipment and personnel;		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(iv) The calculated volume (barrels) of your worst case discharge scenario (see 30 CFR 254.26(a)) for your proposed ROW pipeline; (v) A comparison of the above worst case discharge scenario with the applicable worst case discharge scenario in your approved regional or subregional OSRP; and (vi) A discussion of your worst case discharge scenario and your response in adverse weather conditions for your proposed operations (see 30 CFR 254.26(b), (c), (d) and (e)).		
	(b) *Modeling report.* If you model a potential oil or hazardous substance spill, a modeling report, the modeling results, or a reference to such report or results if you already submitted it to the Regional Supervisor.		
	(c) *Flower Garden Banks National Marine Sanctuary (FGBNMS).* If you propose to conduct operations within the protective zones of the FGBNMS, a description of your provisions for monitoring the impacts of an oil spill on the environmentally sensitive resources at the FGBNMS.		
250.1029	**Oil Spill Financial Responsibility (OSFR) demonstration information.**		
	For ROW pipelines that will transport oil (see definition at 30 CFR 253.3), you must provide a statement that you have demonstrated or will demonstrate OSFR coverage in the amount specified in 30 CFR 253.13(b) unless the static volume of the pipeline is 1,000 barrels, or less, or the calculated volume of your worst case discharge scenario is 1,000 barrels or less.	1. Please note that OSFR coverage has to be in place before the pipeline becomes operational, not before the pipeline application is approved.	For ROW pipelines that will transport oil (see definition at 30 CFR 253.3), you must provide a statement that you have demonstrated or will demonstrate OSFR coverage in the amount specified in 30 CFR 253.13(b) prior to the operation of the pipeline unless the static volume of the pipeline is 1,000 barrels, or less, or the calculated volume of your worst case discharge scenario is 1,000 barrels or less.
250.1030	**Environmental Impact Analysis (EIA) information.**		
	For ROW pipelines, you must provide a project-specific EIA that identifies and analyzes the potential direct and indirect environmental impacts of your proposed ROW pipeline operations (including the installation and operation of any accessory) to assist the	1. We suggest that this requirement be modeled after 250.261 and that the information be provided in the same manner and format as for DOCDs in the GOM region. This will provide consistency in providing the information which will benefit both MMS and industry.	

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language

Regional Supervisor in complying with NEPA (42 U.S.C. 4321, *et seq.*) and other relevant Federal laws. Your EIA must include:

Type of information	What must be included
(a) Resources, conditions, and activities that could affect or be affected by your proposed ROW pipeline operations	(1) Meteorology, oceanography, geology, and geological and/or manmade hazards; (2) Air and water quality; (3) Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, and algal or plant life;
	(4) Threatened or endangered species, and their critical habitat, as defined by the Endangered Species Act (ESA) of 1973 (16 U.S.C. 1531, *et seq.*);
	(5) Sensitive biological resources or habitats such as essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, coastal monuments, national natural landmarks, rookeries, and calving grounds;
	(6) Archaeological resources;
	(7) Socio-economic resources, as specified in paragraph (b) of this section;
	(8) Coastal and marine uses, such as military or commercial operations, shipping, and mineral exploration or development; and
	(9) Other resources, conditions, and operations identified by the Regional Supervisor.
(b) Socio-economic resources	(1) The approximate number, timing, and duration of employment of persons engaged in onshore support and construction operations; (2) Population (including the approximate number of people and families added to local onshore areas);

Proposed Section Number	Proposed Text		Summary of Comments and Rationale	Proposed Language
		(3) Existing offshore and onshore infrastructure (including major sources of supplies, services, energy, and water);		
		(4) Types of contractors or vendors that may place a demand on local goods and services;		
		(5) Land use;		
		(6) Subsistence resources and harvest practices;		
		(7) Recreation and recreational and commercial fishing (including seasons, location, and type);		
		(8) Minority and lower income groups;		
		(9) Federally-recognized tribes in the AKOCSR; and		
		(10) Coastal zone management programs.		
	(c) Impact producing factors (IPF) that can cause impacts to the environmental resources you identified in paragraph (a) of this section	(1) Air emissions; (2) Seafloor disturbance from anchoring and structure emplacement; (3) Discharges; (4) Emissions of light and noise; (5) Water intakes and discharges; (6) Use of service vessels and helicopters;		
		(7) Construction or expansion of onshore support facilities;		
		(8) Onshore waste disposal; and		
		(9) Accidental events, including oil or chemical spills and hydrogen sulfide ($H_{2G4}S$) releases.		
	(d) Environmental impact analysis (EIA)	(1) Analysis of the direct and indirect impacts (including those from accidents) of the IPFs you identified in paragraph (c) of this section on the environmental resources, conditions, and activities you identified in paragraph (a) of this section;		
		(2) Analysis of the potential cumulative impacts from other activities to those environmental		

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	resources, conditions, and activities you identified in paragraph (a) of this section; (3) Description of the type, severity, and duration of the potential impacts, and their biological, physical, and other consequences and implications; (4) Description of the potential measures to minimize or mitigate the potential impacts; and (5) Description of the alternatives to your proposed ROW pipeline operations that you considered while developing your pipeline application, and a comparison of the potential environmental impacts. (e) Consultation: A list of agencies and persons that you consulted or you will consult, regarding potential impacts associated with your proposed pipeline operations. (f) References cited: A list of the references that you cite in the EIA.		
Pipeline Design			
250.1031	**What are the general requirements for designing a pipeline?**		
	You must design a pipeline, including the horizontal component, risers, valves, flanges, fittings, umbilicals, and all other appurtenances to do all of the following:		
	(a) Mitigate any reasonably anticipated detrimental effects of water currents, storm or ice scouring, soft or hard bottoms, mud slides, earthquakes, hurricanes, subfreezing temperatures, and other environmental factors;		
	(b) Withstand the anticipated maximum differential pressure to prevent both burst and collapse;		
	(c) Withstand the static and dynamic loads that will be imposed on the pipe during construction		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>and under operating conditions;</td><td></td><td></td></tr>
<tr><td></td><td>(d) Mitigate the effects of thermal expansion and contraction; and</td><td></td><td></td></tr>
<tr><td></td><td>(e) Mitigate the effects of internal and external corrosion.</td><td></td><td></td></tr>
<tr><td>250.1032</td><td>What must I do to avoid or mitigate hazards?</td><td></td><td></td></tr>
<tr><td></td><td>(a) Shallow hazards survey. You must conduct a shallow hazards survey using appropriate high-resolution geophysical survey techniques and other tools to locate potential hazards. The Regional Supervisor will specify the survey area, instrumentation, and methodology.</td><td></td><td></td></tr>
<tr><td></td><td>(b) Route selection. You must use the results of the shallow hazards survey required by paragraph (a) of this section, charts, maps, and other sources of relevant information to:
(1) Select a route that avoids surface and subsurface hazards as much as possible (e.g., in anchorage areas, existing pipelines, other manmade objects, active faults, rock outcrops, mudslide areas); and
(2) Identify hazards that you cannot avoid, and design the pipeline to mitigate the effects of these hazards.</td><td>1. We recommend changing from possible to practical. Some of the route modifications that might be possible will not be practical in terms of the length of the routes, bends and turns required.</td><td>(1) Select a route that avoids surface and subsurface hazards as much as practical (e.g., in anchorage areas, existing pipelines, other manmade objects, active faults, rock outcrops, mudslide areas); and</td></tr>
<tr><td>250.1033</td><td>What are the design requirements for horizontal components and risers?</td><td></td><td></td></tr>
<tr><td></td><td>(a) Internal design pressure. (1) You must determine the internal design pressure for steel horizontal components and risers using the following formula or the equations in section 4.3.1 of API RP 1111 and, if applicable, sections 4.3.1.1 and 4.3.1.2 of API RP 1111 (incorporated by reference as specified in § 250.198):
$P = \frac{2 \times S \times t}{D}(F \times E \times T)$
<table><tr><th>Variable</th><th>Description</th></tr><tr><td>P</td><td>Internal design pressure (psi).</td></tr><tr><td>S</td><td>Specified minimum yield strength (psi), stipulated in the specification under which the pipe was purchased from the manufacturer or determined in accordance with section 811.253(h) of</td></tr></table></td><td>1. The requirements of (a) (1) are misleading since DOT does not recognize API RP 1111. DOT references in 49 CFR 192 and 195 should be provided for pipelines under the jurisdiction of DOT until such time that MMS and DOT agree on requirement that are applicable to both DOI and DOT pipelines.

2. (a)(1) Nominal wall thickness variable is “t” not “T”

3. (a)(1) Variable E description references Table 841.1B of ANSI/ASME B31.8. This should be Table 841.115A. Variable E description references section 811.253(d) of this standard. This should be 817.13(d)</td><td>(a)(Internal design pressure. (1) You must determine the internal design pressure for steel horizontal components and risers under the jurisdiction of DOI using the following formula or the equations in section 4.3.1 of API RP 1111 and, if applicable, sections 4.3.1.1 and 4.3.1.2 of API RP 1111 (incorporated by reference as specified in § 250.198). The internal design pressure for steel horizontal components and risers under the jurisdiction of DOT must be determined using the applicable regulations found in 49 CFR 192 and 195.
<table><tr><th>Variable</th><th>Description</th></tr><tr><td>P</td><td>Internal design pressure (psi).</td></tr><tr><td>S</td><td>Specified minimum yield strength (psi),</td></tr></table></td></tr>
</table>

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr>
<td></td>
<td>
<table>
<tr><td></td><td>ANSI/ASME B31.8 (incorporated by reference as specified in § 250.198).</td></tr>
<tr><td>T</td><td>Nominal wall thickness (inches).</td></tr>
<tr><td>D</td><td>Nominal outside diameter of pipe (inches).</td></tr>
<tr><td>F</td><td>Construction design factor (0.72 for the horizontal component and 0.60 for risers).</td></tr>
<tr><td>E</td><td>Longitudinal joint factor from Table 841.1B of ANSI/ASME B31.8 (incorporated by reference as specified in § 250.198) (See also section 811.253(d) of this standard).</td></tr>
<tr><td>T</td><td>Temperature derating factor obtained from Table 841.1C of ANSI/ASME B31.8 (incorporated by reference as specified in § 250.198).</td></tr>
</table>

(2) For limitations, see section 841.121 of ANSI/ASME B.31.8 (incorporated by reference as specified in § 250.198). When calculating the internal design pressure for steel pipe, you may account for the effects of external hydrostatic pressure as shown in ANSI/ASME B.31.8, Chapter 8 (incorporated by reference as specified in § 250.198).
</td>
<td>4. (a)(1) a)(1) Variable S description references Section 811.253(h) of ANSI/ASME B31.8. Should be Sections 817.13(h) & 841.112

5. (a)(1) Variable T description references Table 841.1C of ANSI/ASME B31.8. Should be Table 841.116A

6. (a)(2) Reference for limitations should be Section 841.111

7. MMS currently has a problem properly documenting the approved MAOP in their data base when it is calculated accounting for the effects of external hydrostatic pressure. We recommend that MMS update their system so these MAOPs are properly documented.

8. It should be recognized that for deepwater pipelines, the design pressure may vary substantially along its length. MMS needs to be able to understand and accept a variable design pressure.</td>
<td>
<table>
<tr><td></td><td>stipulated in the specification under which the pipe was purchased from the manufacturer or determined in accordance with section 817.13(h) of ANSI/ASME B31.8 (incorporated by reference as specified in § 250.198).</td></tr>
<tr><td>t</td><td>Nominal wall thickness (inches).</td></tr>
<tr><td>D</td><td>Nominal outside diameter of pipe (inches).</td></tr>
<tr><td>F</td><td>Construction design factor (0.72 for the horizontal component and 0.60 for risers).</td></tr>
<tr><td>E</td><td>Longitudinal joint factor from Table 841.115A of ANSI/ASME B31.8 (incorporated by reference as specified in § 250.198) (See also section 817.13(d) of this standard).</td></tr>
<tr><td>T</td><td>Temperature derating factor obtained from Table 841.116A of ANSI/ASME B31.8 (incorporated by reference as specified in § 250.198).</td></tr>
</table>

(2) For limitations, see section 841.111 of ANSI/ASME B.31.8 (incorporated by reference as specified in § 250.198). When calculating the internal design pressure for steel pipe, you may account for the effects of external hydrostatic pressure as shown in ANSI/ASME B.31.8, Chapter 8 (incorporated by reference as specified in § 250.198).
</td>
</tr>
<tr>
<td></td>
<td>(b) External design pressure. You must predict the external (collapse) design pressure for steel pipe for pipelines to be installed in water depths greater than 1000 feet using the equations in sections 4.3.2.1 and 4.3.2.2 of API RP 1111 (incorporated by reference as specified in § 250.198).</td>
<td>1. Do the DOT regulations in 49 CFR 192 and 195 have requirements for collapse pressure? Should this be limited to DOI lines?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(c) Catenary riser for a fixed structure. You must design a catenary riser for a fixed structure according to sections 4.5.4 and 4.1.6.2 of API RP 1111 (incorporated by reference as specified in § 250.198).</td>
<td>2. Do the DOT regulations in 49 CFR 192 and 195 have similar requirements for catenary risers? Should this be limited to DOI lines?</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(d) Riser for tension leg platform or a floating</td>
<td>3. Do the DOT regulations in 49 CFR 192 and</td>
<td></td>
</tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	system. You must design a pipeline riser for a tension leg platform or a floating system according to API RP 2RD (incorporated by reference as specified in § 250.198).	195 have requirements for catenary risers? Should this be limited to DOI lines?	
	(e) *Unbonded flexible pipe.* If you plan to install a pipeline using unbonded flexible pipe, you must design the pipeline according to the specifications and the review standards for a third-party independent verification agent specified in API Spec 17J (incorporated by reference as specified in § 250.198).	4. Do the DOT regulations in 49 CFR 192 and 195 have requirements for unbonded flexible pipe? Should this be limited to DOI lines?	
	(f) *External protective coating*. You must design a pipeline to provide the: (1) Horizontal component and appurtenances with an external protective coating to minimize external corrosion; (2) Risers with an additional external coating to resist the detrimental effects of corrosion, sunlight, and wave action in the splash zone; and (3) Pipe and appurtenances exposed to the atmosphere with a suitable coating.	1. we suggest rewording to clarify the language.	(2) Risers with an external coating capable of resisting the detrimental effects of corrosion, sunlight, and wave action in the splash zone; and
	(g) *Internal corrosion control.* You must design a pipeline to mitigate internal corrosion (e.g., the use of internal coatings, corrosion-resistant alloys) over its design life.	1. for clarity, we suggest adding to the examples of internal corrosion control measures.	**(g) *Internal corrosion control.*** You must design a pipeline to mitigate internal corrosion (e.g., the use of internal coatings, corrosion-resistant alloys, pigging on a set frequency, injection of corrosion inhibitors) over its design life.
	(h) *Flow assurance*. You must design a pipeline to ensure that adequate flow can be sustained throughout its design life (e.g., using pipe-in-pipe, insulated pipe, electrically heated pipe, piggable pipe).	1. for clarity, we suggest adding to the example of flow assurance.	**(h) *Flow assurance***. You must design a pipeline to ensure that adequate flow can be sustained throughout its design life (e.g., using pipe-in-pipe, insulated pipe, electrically heated pipe, piggable pipe, provisions to inject flow assurance chemicals).
	(i) *Pipeline on-bottom stability*. You must design a pipeline so that it will be stable in the geologic and weather conditions for the area. (1) Your pipeline must remain stable during a storm. The stability must be determined using appropriate backfill rates and storm data for the area. If the pipeline is in a water depth less than 200 feet and is jetted at least 3 feet below the natural seabed, it must be stable during a 2-year storm (minimum). If you expect that the pipeline	1. We assume that these requirements do not pertain to pipelines that are still in the construction phase and have not been fluid filled yet. If this assumption is not correct, please clarify. 2. The proposed regulation goes well beyond the current requirements in 250.1002 (f). There is no reference information on the criteria for a 2-year or 100-year storm. It is also not clear on what is	**(i) *Pipeline on-bottom stability***. (1)You must design a pipeline so that it will be stable in the geologic and weather conditions for the area. (2) The Regional Supervisor may require additional stability design measures based on the geologic or weather conditions for the area.

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	will bury itself naturally in the sediment in a water depth less than 200 feet, it must remain stable during a 100-year storm (minimum). If the pipeline is in a water depth 200 feet or greater and is not buried, it must be stable during a 100-year storm (minimum). (2) The Regional Supervisor may require additional stability design measures based on the geologic or weather conditions for the area.	considered stable. We also point out that it is impossible to ensure on bottom stability in the event of a mudslide. We understand and share MMS' concern on movement of pipelines during storm conditions. However, we believe that MMS and industry need to invest in some R&D efforts on this subject prior to issuing a prescriptive rule that needs clarity. We propose using general language in the rule and work towards developing appropriate methodology to evaluate stability.	
	(j) *Underwater vent pipeline*. You must design an underwater vent pipeline (any pipeline that transports natural gas that has been vented during upset or abnormal conditions or bleed down operations to a location where the gas is discharged underwater or flared at a flare pile) to ensure that the discharge point is: (1) A minimum of 250 feet from the delivering structure; and (2) Anchored to the sea floor, unless the gas is flared at a flare pile.		
	(k) *Riser supports*. When designing riser supports, you must consider the: (1) Loads induced by riser operations; (2) Environmental loads, taking into account 100-year return period storm criteria as set out in API RP 2A-WSD (incorporated by reference as specified in § 250.198); and (3) Installation loads on risers that are pre-installed.		
250.1034	**What are the design requirements for appurtenances?**		
	You must design pipeline appurtenances as set forth below:		
	(a) *Pipeline valve.* You must design a pipeline valve to meet the minimum design requirements of API Spec 6A (incorporated by reference as specified in § 250.198), API Spec 6D/ISO 14313 (incorporated by reference as specified in § 250.198), or the equivalent. You may not use a		

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	valve under any operating conditions that exceed the applicable pressure or temperature ratings in those standards. The material of the valve must be compatible with the product being transported.		
	(b) *Pipeline flange.* You must design a pipeline flange: (1) To meet the minimum design requirements of ANSI B16.5 (incorporated by reference as specified in § 250.198), API Spec 6A (incorporated by reference as specified in § 250.198), or the equivalent; (2) To withstand the MAOP of the pipeline; (3) To maintain its physical and chemical properties at the maximum and minimum anticipated operating temperatures; and (4) Using material that is compatible with the product being transported.		
	(c) *Pipeline fittings*. You must use pipeline fittings (couplings, elbows, unions, tees, swage nipples, buckle arrestors, gaskets, etc.) that: (1) Have pressure-temperature ratings based on stresses for pipe of the same or equivalent material; (2) Have a bursting strength greater than the computed bursting strength of the pipe; and (3) Use material that is compatible with the product being transported.	1. We do not understand the rationale for requiring fittings to have a higher burst pressure than the connecting pipes. We also point out that this is another one of the areas where the DOT regulations are different than those proposed in this rulemaking. We recommend being consist with the DOT language in 49 CFR 192.149	(2) Have a bursting strength greater than or equal to the computed bursting strength of the pipe; and
	(d) *Anode cathodic protection system*. You must: (1) Design your anode cathodic protection system to have a life expectancy of 30 years or for the design life of the pipeline, whichever is longer; and (2) Use the following equation, or another equation and/or method acceptable to the Regional Supervisor in accordance with the provisions of § 250.141, to calculate anode design life: $T = \frac{M \times U \times v}{(I \times 8760)}$ Variable / Description T — Time (years).	1. We do not agree with MMS mandating a fixed life expectancy for cathodic protection systems for all pipelines. Some pipelines have a short life and others a long life. The requirement should be to design a cathodic protection system for at least the design life of the pipeline which is required to be stated in the pipeline application in 250.1019 (c) along with design anode life expectancy. If the pipeline remains operational for longer than the design life of the CP system, then the CP system should be evaluated and retrofitted if required. Section 250.1102 (d) requires that we measure the pipe-to-electrolyte potential for anode systems annually and report it MMS. Therefore, if MMS believes that the CP is	(1) Design your anode cathodic protection system to have a life expectancy for at least the design life of the pipeline and state the life expectancy for CP system in the application required in 250.1019. (3) You can obtain values for the utilization factor (U) from DNV RP B401, Table 10-8 (incorporated by reference as specified in § 250.198). You can obtain values for electrochemical efficiency (v) from the anode manufacturer. (4) If the pipeline is proposed to remain operational beyond the design life of the CP, the

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	M — Total net anode mass (pounds). U — Utilization factor. v — Electrochemical efficiency (amp x hour/pound). I — Current demand (amp). (3) You can obtain values for the utilization factor (U) from DNV RP B401, Table 6.9.1 (incorporated by reference as specified in § 250.198). You can obtain values for electrochemical efficiency (v) from the anode manufacturer.	insufficient to protect the pipeline, MMS can require that the system be evaluated and retrofitted, if appropriate. Otherwise, we do not know why MMS would want to collect the data in 250.1102(d) 2. If the current version of DNV RP B401 is used as recommended in 250.198, the proper reference is Table 10-8.	operator must evaluated the CP system and retrofit, if required.
250.1035	**What are the design requirements for sour service?**		
	If your pipeline will operate in a sour environment (fluids containing water as liquid and H_2S exceeding the limits defined in paragraphs 1.3.1.1 and 1.3.1.2 of NACE Standard MR0175 (incorporated by reference as specified in § 250.198)), you must design your pipeline in accordance with section 10.5 of NACE Standard MR0175.		
250.1036	**When must I sectionalize a pipeline?**		
	The Regional Supervisor may require you to design your pipeline in sections to reduce the volume of your worst case discharge (see 30 CFR 254.47).		
Pipeline Fabrication			
250.1038	**What are the general requirements for fabricating a pipeline?**		
	You must fabricate each pipeline in a manner that:		
	(a) Adheres to a suitable quality control program that includes inspection, testing, spot checks, and evaluation by qualified personnel;		
	(b) Adheres to the specified design tolerances;		
	(c) Conforms to recognized engineering practices; and		
	(d) Complies with applicable regulations, codes, guides, standards, and recommended practices.		
Pipeline Construction			

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td>250.1040</td><td>What are the general requirements for constructing a pipeline?</td><td></td><td></td></tr>
<tr><td></td><td>You must construct each pipeline in accordance with your approved application, and in a manner that:</td><td></td><td></td></tr>
<tr><td></td><td>(a) Minimizes construction stresses and strains;</td><td>1. We believe the goal is to keep stresses and strains to within acceptable limits so that the pipeline can be successfully installed and operated.</td><td>(a) Keeps construction stresses and strains to within acceptable limits;</td></tr>
<tr><td></td><td>(b) Ensures that the pipeline is constructed on the approved route;</td><td></td><td></td></tr>
<tr><td></td><td>(c) Avoids or mitigates geologic and manmade hazards, artificial reefs, archaeological resources, and biologically sensitive features;</td><td></td><td></td></tr>
<tr><td></td><td>(d) Minimizes the length of unsupported spans; and</td><td></td><td></td></tr>
<tr><td></td><td>(e) Protects the pipeline from damage.</td><td></td><td></td></tr>
<tr><td>250.1041</td><td>Who must I notify before I begin construction?</td><td></td><td></td></tr>
<tr><td></td><td>Before you begin pipeline construction, you must make the notifications in the following table:
<table>
<tr><th>Who you must notify</th><th>When you must make notification</th><th>Other requirements</th></tr>
<tr><td>(a) U.S. Coast Guard (USCG)</td><td>At least 30 calendar days before you conduct pipeline construction operations</td><td>You are encouraged to notify the applicable USCG Marine Safety Office so that a Notice to Mariners can be prepared.</td></tr>
<tr><td>(b) Military installations</td><td>Before you conduct pipeline construction operations in an established military warning or water</td><td>You must notify the commander of the military installation that exercises jurisdiction of the area concerning the control of electromagnetic emissions and the use of vessels, equipment, and aircraft in the area.</td></tr>
</table></td><td>1. (a) Industry has not received any guidance from USCG indicating that they want to be notified prior to pipeline construction activities commencing for all pipelines. If this is desired then USCG needs to issue guidance on the notification they need including timing, office to notify since the pipeline may cross more than one Marine Safety Office and the information that is to be provided. While we appreciate MMS trying to be complete and helpful, we question if this notification belongs in MMS regulations and recommend that it be omitted.

2. (b) as commented earlier, we request that MMS maintain up to date notification information for military installations that actually want to be notified prior to pipeline construction. Many times we attempt to make a notification and do not receive any response. It is helpful if MMS identifies the installations that need to be notified as a condition of approval of the pipeline application.</td><td>1. (a) delete from regulation</td></tr>
</table>

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	test area	3. (c) We encourage MMS to develop MMS-153 as an electronic submittal through the eWell system. We note that you state that it can be submitted by telefax or e-mail. We request that you provide a version of the form that can be filled in on the computer and attached to an e-mail. Please provide an e-mail address that the form can be sent. 4. We are unclear as to the benefit that is derived by these notifications. If the notification to MMS is so that the construction activities can be inspected by MMS personnel, we question how many inspections are actually performed by MMS on an annual basis and if it would make more sense for MMS to identify activities they want to inspect and then work with the operator to ensure that adequate notice is provided in lieu of making everyone provide notice.	
	(c) MMS, Regional Supervisor | At least 48 hours before you commence construction operations | You must make this notification by telefax or email, using Form MMS-153 (Notification of Pipeline Installation/Relocation/ Hydrotest).		
250.1042	**What must I do to avoid or mitigate hazards during construction?**		
	To avoid or mitigate hazards during pipeline construction, you must comply with the requirements in the following table: Requirement | What you must do | Details (a) Buoying hazards | Before you perform pipeline construction operations or other bottom-disturbing activities (2) In areas congested with pipelines or debris, use buoys to outline a safe	1. (c) we question the value of preparing a plat to a minimum scale of 1:12,000 oriented to true north. In most cases the anchor plots will be developed in the field on the surveyor's screen once specific wind/wave conditions are known.	
	You must: (1) Buoy all existing pipelines and other potential hazards located within 500 feet of the operation (including anchor patterns); or		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		working area large enough to accommodate your proposed pipeline construction operations.			
	(b) Navigation system	In lieu of complying with paragraph (a) of this section	You may use a state-of-the-art, real-time primary navigational positioning equipment (e.g., DGPS) on all vessels (e.g., pipeline construction vessels, derrick barges, anchor-handling vessels) associated with your pipeline construction operations to depict existing pipelines and other potential hazards.		
	(c) Location plat	Before you perform pipeline construction operations	You must: (1) Prepare a plat with a minimum scale of 1:12,000 oriented to true north depicting the location of proposed pipeline construction operations, all associated anchor patterns, existing pipelines (both active and inactive), debris fields, or other potential hazards in the area. The plat must be dated, accurate, and indicative of current conditions (including post-hurricane conditions and recent construction or modification activities0; and		
			(2) Provide copies of the		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language

		plat to key personnel on all vessels (e.g., pipeline construction vessels, derrick barges, and anchor-handling vessels) associated with your pipeline construction operations.

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250.1043	**What must I do to install a hot tap?**		

To install a hot tap, you must comply with the requirements in the following table:

Requirement	What you must do	Details
(a) Area inspection	If you plan to install a hot tap on an existing pipeline located in a water depth less than 200 feet, you must first determine whether proper cover is being maintained on the portion of the pipeline in the vicinity of the proposed work. If you determine that environmental or other factors have detrimentally affected the burial depth of the pipeline	(1) Notify the Regional Supervisor within 48 hours after you first observe the problem; and (2) Submit a plan of corrective action under § 250.1097 to the Regional Supervisor within 30 calendar days after you first observe the problem.
(b) Cathodic protection system measurements	If your pipeline is located in: (1) The AKOCSR; or (2) The GOMR or POCSR, and (i) The pipeline is composed of any pipe that is more than 20 years old; or (ii) The life expectancy of the	Take measurements of the pipe-to-electrolyte potential at locations along submerged sections of a pipeline when you conduct hot tap operations on a pipeline.

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	cathodic protection system cannot be calculated		
250.1044	**What must I do to protect a horizontal component?**		
	To protect the horizontal component during construction, you must comply with the requirements in the following table:		

Component or activity	Requirement
(a) External coating	You must protect the external coating of the horizontal component during construction.
(b) Cathodic protection system	You must locate and install the components of the cathodic protection system in a manner that will minimize the possibility of damage.
(c) Burial	You must bury each pipeline you install in water depths less than 200 feet to a depth of at least three feet below the mud line. On a case-by-case basis, the Regional Supervisor may:
	(1) Grant you approval to allow a pipeline to self bury, or allow you to use an alternative method of compliance in accordance with the provisions of § 250.141; or
	(2) Require you to increase the burial depth of a pipeline that will transport a product containing H_2S in highly congested or active areas.
(d) Other protective measures	The Regional Supervisor may require burial or other protection of the pipeline in any water depth if the Regional Supervisor determines that such measures will reduce the likelihood of environmental degradation, or mitigate a potential hazard to trawling operations or other uses of the OCS.
(e) Burial in fairways and anchorage	You must consult with the U.S. Army Corps of Engineers as they may have more stringent burial requirements for pipelines that enter or cross safety

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	areas: fairways or anchorage areas. (f) Spanning: You must provide sufficient supports, or use other mitigation measures (e.g., installing strakes), to avoid excessive loads or deformations and fatigue damage that could result from spanning.		
250.1045	**What must I do to protect a riser?**		
	To protect a riser during construction, you must comply with the requirements in the following table: (a) External coating: Protect the external coating of the riser during construction. (b) Cathodic protection system: Locate and install the components of the cathodic protection system in a manner that will minimize the possibility of damage. (c) Vortex induced vibration (VIV) suppression devices: Protect any preinstalled VIV suppression devices during construction. (d) Impact protection: (1) Protect a pipeline riser from physical damage that could result from contact with floating vessels by using riser guards or other protection measures that are capable of transferring impact loads to the platform structure; and (2) Not use pipe-in-pipe configurations as riser impact protection.		
250.1046	**What must I do to protect an appurtenance and crossing?**		
	(a) *Protection methods*. You must protect all pipeline valves, taps, tie-in assemblies, capped pipelines, flanges, crossings, and repaired sections installed in water depths less than 500 feet with at least 3 feet of cover or with a protective device (e.g., cement mats, cages)	1. We question the benefit of requiring all pipeline sections which have been repaired in water depths less than 500 ft to be buried and covered by protective devices. Repaired sections may entail a significant quantity of pipe. We believe this should be on a case-by –case	**(a) *Protection methods***. You must protect all pipeline valves, taps, tie-in assemblies, capped pipelines, flanges, crossings, installed mats, cages) unless an alternate procedure is otherwise approved by the Regional Supervisor in accordance with the provisions of § 250.141.

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	unless an alternate procedure is otherwise approved by the Regional Supervisor in accordance with the provisions of § 250.141. <table><tr><th>If you . . .</th><th>You must . . .</th></tr><tr><td>(1) Bury the appurtenance or crossing</td><td>Maintain the three-foot burial depth throughout the life of the pipeline, including after the pipeline has been decommissioned in place.</td></tr><tr><td>(2) Use a protective device</td><td>Design it to be compatible with other uses of the OCS. The height and the slope of the device must allow for a smooth transition over the appurtenance or crossing.</td></tr></table>	basis depending upon the type of repair, etc.	(b) The Regional Supervisor may require repaired pipeline sections located in water depths less than 500 feet to be protected as in (a) above when warranted.
	(b) *Separation.* You must install the pipeline in a manner that: (1) Provides for a separation of at least 12 inches for the life of the pipeline at pipeline crossings, power cable crossings, etc.; and (2) Prevents physical contact with existing umbilicals and communication cables.		
	(c) *Existing pipelines*. If you plan to install a pipeline that will tie into or cross an existing pipeline, you must examine the portion of the existing pipeline in the vicinity of the proposed tie-in or crossing. If you determine that environmental or other factors have detrimentally affected the burial depth of the pipe or any appurtenance, any protective cover of the pipe (in water depths less than 200 feet), or any protective cover for any appurtenance (in water depths less than 500 feet), you must notify the Regional Supervisor. The Regional Supervisor may require the responsible party to submit a plan of corrective action (under § 250.1097) to remedy the problem.		
	(d) *Atmospheric zone.* You must protect valves and fittings exposed to the atmosphere with a suitable coating.		
250.1047	**What must I do to construct a pipeline in or near a designated use area?**		
	If you construct a pipeline in or near a designated use area, you must follow the requirements in the	1. (a) (4) We recognize that the requirement to enter into an agreement with the commander of	(b) Will be in a designated lightering zone (see 33 CFR 156.300)

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	following table. Pipeline construction operations include the use of anchors, chains, and wire ropes.	the individual command headquarters is an existing requirement. However, in many cases when we try to contact and enter into such agreements, the military warning area or test area either doesn't respond doesn't want to enter into an agreement. MMS should work with these groups to find out who still wants to be notified and what agreement they want to enter into or remove the requirement from MMS regulations. 2. (b) We recommend that this notification be limited to designated lightering zones. If it is to be extended to "traditional lightering zones" please define those areas. 3. We assume that the required notification is for good communication and is not a shared use issue. If this is a shared use area, then MMS needs to identify the steps to be taken to adequately protect the right of operators for crossing or using the area for installation of systems vital for the nations energy infrastructure. 4. MMS should provide current contact information for the appropriate representatives of the Industry Taskforce on Offshore Lightering we are required to contact.	

If your pipeline construction operations . . .	Then . . .
(a) Are conducted in or near a designated military warning or water test area	You must: (1) Assume all risks of damage to property, or injury to persons you employ or who are otherwise connected with your pipeline construction operations, that is caused by any act or omission, regardless of negligence or fault, resulting from the programs or activities of the military installation exercising jurisdiction over the military warning or water test area;
	(2) Indemnify and hold harmless the United States against all claims for loss, damage, or injury sustained by persons you employ, or who are otherwise connected with your pipeline construction operations, that are caused by any act or omission, regardless of negligence or fault, resulting from the programs or activities of the military installation exercising jurisdiction over the military warning or water test area;
	(3) Control your electromagnetic emissions in accordance with the requirements specified by the commander of the military installation that has jurisdiction over the military warning or water test area to the degree necessary to prevent damage to, or interference with, Department of Defense flight, testing, or operations; and
	(4) Enter into an agreement with the commander of the individual command headquarters when you

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		operate, or cause to be operated on your behalf, a boat, ship, or aircraft in a military warning or water test area. Such an agreement must provide for the positive control of boats, ships, and aircraft operating in the military warning or water test area at all times.		
	(b) Will be in a designated lightering zone (see 33 CFR 156.300) or traditional lightering area in the Gulf of Mexico	You must contact representatives of the Industry Taskforce on Offshore Lightering to discuss potential conflicts between your pipeline construction operations and the lightering activities in these zones and areas.		
	(c) Could be in a designated safety fairway or anchorage area, in a safety or security zone, or near a deepwater port	The operations are subject to the prohibitions, restrictions, procedures, and other requirements contained in applicable U.S. Coast Guard regulations (see 33 CFR part 166 for fairways and anchorage areas, 33 CFR part 165 for safety and security zones, and 33 CFR part 150 for deepwater ports).		
	(d) Are in the vicinity of a State-established artificial reef	You must: (1) Contact the appropriate State natural resource agency or artificial reef coordinator; and		
		(2) Ensure that the pipeline route is not within 1000 feet, or other distance specified by the Regional Supervisor, from the perimeter of the artificial reef area.		
	(e) Could disturb the sea floor in or near an area that was used until 1970 by the Department of Defense as an ordnance dumping area	You must consider the area as potentially hazardous and take appropriate and necessary precautions.		

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	(f) Are in the vicinity of any U.S. Air Force communication towers in the Gulf of Mexico — You must ensure that: (1) The construction vessel and any support vessels do not move within: (i) A 500-foot radius of the center of a tower site; and (ii) 100 feet of the centerline of a line of sight between a master tower and a remote tower; and (2) Your electromagnetic transmissions do not interfere with the operation of the towers.		
250.1048	**What must I do to construct a pipeline in or near a sensitive biological feature or area?**		
	If you construct a pipeline in or near a biological feature or area, you must follow the requirements in the following table. Pipeline construction operations include the use of anchors, chains, and wire ropes.		
	If your pipeline construction operations could . . . — Then . . .		
	(a) Disturb seafloor areas in water depths greater than 1,312 feet — You must: (1) If required by the Regional Supervisor, obtain appropriate high-resolution geophysical data of chemosynthetic communities in the area of pipeline construction operations to accurately identify and locate the features to prepare the required submittals (e.g., bathymetry map, survey report);		
	(2) Locate all seafloor disturbances (including those caused by anchors, anchor chains, wire ropes, appurtenance installation, and the pipeline) at least 250 feet from any identified features or areas that could support high-density chemosynthetic communities; and		
	(3) Use a state-of-the-art primary navigation system (e.g., DGPS) on your pipeline construction vessel and anchor-handling		

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		vessels to ensure that any seafloor disturbances do not occur within 250 feet of such features of areas.		
	(b) Disturb the sensitive biological habitats (e.g., coral reefs) associated with an identified topographic feature	You must: (1) Locate all seafloor disturbances (including those caused by anchors, anchor chains, wire ropes, appurtenance installation, and the pipeline) at least 500 feet outside the boundary of the designated "No Activity Zone" of such a feature; and (2) Use a state-of-the-art primary navigation system (e.g., DGPS) on your pipeline construction vessel and anchor-handling vessels to ensure that any seafloor disturbances do not occur within 500 feet of the boundary of the designated "No Activity Zone" of such a feature.		
	(c) Disturb live bottoms (pinnacle trend features or seamounts) that likely provide habitat for high-density biological assemblages	You must: (1) If required by the Regional Supervisor, obtain appropriate high-resolution geophysical data or photo-documentation of live bottoms (pinnacle trend features or seamounts) in the area of pipeline construction operations to accurately identify and locate the features and to prepare the required submittals (e.g., bathymetry map, survey report);		
		(2) Locate all seafloor disturbances (including those caused by anchors, anchor chains, wire ropes, appurtenance installation, and the pipeline) at least 100 feet from the identified live bottoms; and		
		(3) Use a state-of-the-art primary navigation system (e.g., DGPS) on your pipeline construction vessel and anchor-handling vessels to ensure that any seafloor disturbances do not occur within 100 feet of the live		

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		bottoms.		
	(d) Disturb live bottoms (low relief features) that likely provides habitat for sea grasses; aggregated fishes, turtles, or other fauna; or coral community organisms	You must: (1) If required by the Regional Supervisor, obtain appropriate high-resolution geophysical data or photo documentation of live bottoms (low relief features) in the area of operations to accurately identify and locate the features to prepare the required submittals (e.g., bathymetry map, survey report);		
		(2) Locate all seafloor disturbances (including those caused by anchors, anchor chains, wire ropes, appurtenance installation, and the pipeline) to avoid impacting the identified live bottoms; and		
		(3) Use a state-of-the-art primary navigation system (e.g., DGPS) on your pipeline construction vessel and anchor-handling vessels to ensure that you do not adversely impact the live bottoms.		
	(e) Disturb potentially sensitive biological features, as determined from your analysis or review of survey information	You must: (1) Locate all seafloor disturbances (including those caused by anchors, anchor chains, wire ropes, appurtenance installation, and the pipeline) to avoid impacting the potentially biological sensitive features; and		
		(2) Use a state-of-the-art primary navigation system (e.g., DGPS) on your pipeline construction vessel and anchor-handling vessels to ensure that you do not adversely impact the potentially sensitive biological features.		
	(f) Adversely affect a marine sanctuary established by the Secretary of	Marine sanctuaries are subject to the prohibitions, restrictions, procedures, and other requirements contained in 15 CFR part 922.		

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	Commerce under the authority of section 302 of the Marine Protection, Research and Sanctuaries Act of 1972, as amended (16 U.S.C. 1432)		
250.1049	**What must I do to construct a pipeline in or near an archaeological resource?**		
	If you construct a pipeline in or near an archaeological resource, you must follow the requirements in the following table. Pipeline construction operations include the use of anchors, chains, and wire ropes.		

If . . .	You must . . .
(a) An archaeological resource is known to exist, or the Regional Director has reason to believe that an archaeological resource may exist, in the area of the proposed pipeline construction operations	Obtain appropriate high-resolution geophysical data in the area of operations to accurately identity and locate the existing or potential archaeological resources to prepare a survey report. The Regional Supervisor will specify the survey area, instrumentation, and methodology.
(b) The review by the Regional Supervisor of the archaeological report included with your pipeline application (see § 250.1026(c)) concludes that an archaeological resource may be present	Either: (1) Locate the site of your pipeline construction operations to avoid the potential archaeological resource by at least the distance specified by the Regional Supervisor; or (2) Establish to the satisfaction of the Regional Director that an archaeological resource either does not exist or will not be

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		adversely affected by your pipeline construction operations. In making this determination, the Regional Director may require you to conduct further archaeological investigations, using personnel, equipment, and techniques the Regional Director considers appropriate. You must submit the investigation report to the Regional Director for review.		
	(c) Based on further archaeological investigations, the Regional Director will notify you immediately if it's determined that the archaeological resource exists and may be adversely affected by your pipeline construction operations	Not take any action that may adversely affect the archaeological resource until the Regional Director has told you how to protect it.		
	(d) You discover a potential archaeological resource while conducting your pipeline surveys, pipeline construction operations, or any other activity related to the pipeline	Immediately halt all seafloor disturbing operations within the area of the discovery and notify the Regional Director of the discovery within 72 hours. If the site was impacted by your operations, or if impacts to the site or to the area cannot be avoided, the Regional Director will specify the additional investigations you must conduct to determine if the resource is potentially eligible for listing to the National		

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	Register of Historic Places under criteria established by 36 CFR 60.4. If these investigations determine that the resource is potentially eligible for listing in the National Register of Historic Places, the Regional Director will tell you how to protect the resource, or how to mitigate adverse impacts to the site.		
250.1050	**When must I prepare and implement an H_2S contingency plan for construction?**		
	You must prepare an H_2S Contingency Plan before you construct a pipeline (using an anchor-supported construction vessel) that crosses a pipeline which transports a product with an H_2S concentration that, if released, could result in atmospheric concentrations of 20 ppm or more. The H_2S Contingency Plan must be in accordance with § 250.490(f) and cover your pipeline construction operations. You must:	1. How do we determine which third party pipelines have high H2S concentrations that would require the contingency plan? Is the pipeline operator whose pipeline is being crossed required to provide that information? Is this information available in the MMS database? Will MMS state this as a condition of approval in the pipeline application approval?	
	(a) Implement this H_2S Contingency Plan before the leading construction vessel anchors are placed within 3,000 feet of the crossed pipeline, and maintain it in effect until no trailing construction vessel anchors are within 3,000 feet of the crossed pipeline; and		
	(b) Keep a copy of the H_2S Contingency Plan on the pipeline construction vessel.		
250.1051	**What information must I submit after construction is completed?**		
	(a) *Construction report.* You must submit three copies of a pipeline construction report to the Regional Supervisor within 45 calendar days after you complete pipeline construction. The construction report must include: (1) The MMS-assigned pipeline segment	1. (a) We don't agree with MMS assessment that the post construction report can be provided in 45 days. We recommend keeping the current 90 days. Further, we see no benefit in providing the reports in a shorter time period.	**(a) *Construction report.*** You must submit three copies of a pipeline construction report to the Regional Supervisor within 90 calendar days after you complete pipeline construction which is considered to be when a successful hydrotest has been concluded. The construction report

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	number. (2) The dates you started and concluded pipeline construction operations. (3) An "as built" location plat, based on NAD 27 for the GOMR (Gulf) and POCSR, or NAD 83 for the AKOCSR and GOMR (Atlantic), drawn at a minimum scale of 1 inch = 2,000 feet that: (i) Depicts the same information you included with your pipeline application (see § 250.1017(a) and (b)); (ii) Includes a list of the latitude and longitude coordinates in both NAD 27 and NAD 83, and the X-Y coordinates in NAD 27 for the GOMR (Gulf) and POCSR, or NAD 83 for AKOCSR and GOMR (Atlantic), of all key points; (iii) Depicts the boundaries of the pipeline ROW, as granted, if applicable; and (iv) Includes a certification by a registered engineer or land surveyor that attests to the accuracy of the "as-built" locations of the pipeline and appurtenances. (4) An electronic file containing the digital coordinates of the key points of the "as-built" pipeline and umbilical routes, including turns, and, if required by the Regional Supervisor, the position of lay barge anchors, chains, and cables. The digital data must be in decimal degrees latitude and longitude and based on NAD 83. (5) Discussion of the reasons for deviation if the pipeline route deviates from the route in your approved application by more than 200 feet. (6) The type, size, weight, number, and spacing of any anodes that were installed on the pipeline, if the information differs substantially from the information you provided in your approved pipeline application. (7) A description of the protective covering, anchor pins, or sand bags you used to install or protect a valve, tap, subsea tie-in, capped line, or other appurtenance, if the installation differs substantially from the design you provided in your approved pipeline application.	2. (a) The completion of pipeline construction is not defined. We suggest that construction be considered complete after the hydrotest has been completed. (3)(a)(iv) We note a new requirement that the “as built” location plat is required to be certified by a registered engineer or land surveyor. This requirement is problematic since in may cases the installation contractor is utilizing non US personnel who do not meet these requirements. We suggest a signed certification is sufficient. 4. (a) We note that a times the pipeline is laid but there is a lengthy time prior to hydrotesting. In those cases it may be beneficial to split the report into two submittals, the survey data in one report and the hydrotest data in a separate report so that the survey data can be updated in the MMS system in a timely manner.	must include: (iv) Includes a certification that attests to the accuracy of the "as-built" locations of the pipeline and appurtenances. (11) The operator may submit items (1)-(8) and (10) within 90 days after the pipeline has been laid and item (9) within 90 days after a successful hydrotest on the pipeline has been concluded.

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	(8) The pipe-to-electrolyte potential readings for hot taps required by § 250.1043(b). (9) A report of the hydrostatic pressure test (see § 250.1061) required by § 250.1060(a)(1). (10) A plat at a scale of 1 inch = 1,000 feet (or other scale required by the Regional Supervisor) that depicts bathymetry, any biologically-sensitive or archaeological feature (if applicable), and the position of all anchors, chains, and cables, if the pipeline or the associated anchors, chains, or cables are: (i) Located in the POCSR or AKOCSR; or (ii) Located in the GOMR, and if they are within: (A) 500 feet of the "No Activity Zone" of an identified topographic feature or other biologically-sensitive feature; (B) 100 feet of any live bottom (pinnacle trend feature or seamount) with a vertical relief of eight feet or more; (C) 100 feet of any live bottom (low relief feature); or (D) A distance specified by the Regional Supervisor of any potential archaeological resource.		
	(b) *MMS actions.* The Regional Supervisor will review your pipeline construction report and inform you in writing of any deficiencies if the report is unacceptable.	1. We assume that this means that MMS will not inform you that the construction report has been received and accepted. Previously, MMS used this mechanism to inform the operator of the MAOP that has been assigned to the pipeline since in many cases it is based on the hydrotest data. We request that MMS inform us in writing that that pipeline construction report is accepted and the MAOP that has been assigned. We also believe that MMS should establish a timeframe in which they will process these reports. Since we request 90 days to submit the report, we suggest MMS should process them in 90 days.	**(b) *MMS actions.*** The Regional Supervisor will review your pipeline construction report and inform you in writing within 90 days of receiving the construction report that the report is either accepted or of any deficiencies if the report is unacceptable. The assigned MAOP for the pipeline will also be provided.
	(c) *National Ocean Service (NOS).* You must submit a copy of the "as-built" location plat required by paragraph (a)(3) of this section to the NOS within 45 calendar days after you complete pipeline construction.	1. The regulatory requirement to provide this information to another agency should be referenced in the rule. This information could easily be shared within the framework of the two agencies and not be a burden on the operator to	**(c) *National Ocean Service (NOS).*** You must submit a copy of the "as-built" location plat required by paragraph (a)(3) of this section to the NOS within 90 calendar days after you complete pipeline construction.

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		furnish yet another piece of information to a federal agency with overlapping requirements. 2. The timeframe for this submittal should also be 90 days. 3. MMS should provide and maintain the address for the NOS.	
Pipeline Risers Connected to Floating Platforms			
250.1052	**What are the requirements for pipeline risers connected to floating platforms?**		
	(a) *General*. New pipeline risers and major modifications of, or repairs to, existing risers connected to floating platforms are subject to the Pipeline Riser Verification Program. A major modification or major repair to a pipeline riser means: (1) The replacement, removal, or repair of any material, component, or appurtenance; (2) Any reconfiguration or external event that could affect the design life of the riser; or (3) Any operation on the riser that involves welding.	1. We fail to understand the benefit of subjecting new risers to be installed on existing facilities that predate the inclusion of risers in the CVA program that have exactly the same design as existing risers on platforms must be subjected to the riser CVA program. 2. We fail to understand why risers that don't carry hydrocarbons (i.e. water injection) are subjected to the riser CVA program. Please explain the benefit. 3. Any effects of the risers on the structure they are to be installed on are covered under the CVA program under Subpart I. 4. General note: We note there is nothing in the rulemaking on what MMS will do with the CVA information. There is no information on when and in what form MMS will approve the CVA plan and CVA nomination although we note they have to be submitted for approval along with modifications. Can we proceed without approval? After MMS receives the final CVA reports, what action will be taken and when?	
	(b) *Verification requirements*. All pipeline risers subject to the Pipeline Riser Verification Program must undergo design verification, fabrication verification, and installation verification.	(b)	
	(c) *Certified Verification Agent (CVA)*. All pipeline risers subject to the Pipeline Riser		

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	Verification Program require separate verification that necessitates the use of a CVA specifically for the pipeline riser.		
	(d) *CVA qualifications.* (1) Your design verification must be conducted by, or be under the direct supervision of, a registered professional civil or structural engineer or equivalent with previous experience in directing the design of similar risers. (2) Your fabrication verification must be conducted by qualified personnel with previous experience in third-party fabrication verification or experience in the fabrication of similar risers. (3) Your installation verification must be conducted by qualified personnel with previous experience in third-party installation verification or experience in the installation of similar risers.		
	(e) *CVA responsibilities*. (1) The CVA must conduct the activities specified in § 250.1054, 250.1055, and 250.1056. (2) The CVA must consider the provisions of applicable regulations, codes, guides, standards, recommended practices, approved plans, and the requirements of this subpart when performing riser verification. (3) Individuals or organizations acting as CVA's must not function in any capacity that would create a conflict of interest, or the appearance of a conflict of interest. (4) The CVA is the contact with the Regional Supervisor regarding all riser verification and reporting. The CVA is directly responsible for providing immediate reports to the Regional Supervisor of all incidents that affect the design, fabrication, and installation of pipeline risers.		
250.1053	**What are the requirements for pipeline riser verification plans?**	1. If the operator is proposing one CVA firm to perform more than one of the CVA plans (for example Design and Fabrication), a single document covering both plans could be submitted. We see no need to submit separate Design and Fabrication plans in this case.	
	(a) *Design verification plan.* You must submit a	1. The requirement to submit design plans at	**(a) *Design verification plan.*** You must submit a

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	design verification plan to the Regional Supervisor for approval before the design work is completed, before you start fabrication and installation, and at least 30 calendar days before you submit the associated pipeline application. You must submit a separate design verification plan for each pipeline riser. Your design verification plan must include: (1) Riser diameter, service, type, and designer(s); (2) A project management timeline (Gantt Chart) that depicts key design activities and when the CVA will submit the interim and final reports required by § 250.1054(c) and (d); (3) Abstracts of the computer programs that will be used in design verification; (4) A summary of major design considerations and the approach that will be used to verify the validity of these design considerations; and (5) The CVA nomination information specified in paragraph (d) of this section.	least 30 calendar days before you submit the associated pipeline application is too prescriptive. We do not plan out to the day when the submittals will be made. Since the CVA Plan requirements are thoroughly spelled out in the NTL, the is no need for a lengthy review of the CVA plan. 2. Submitting the design verification plan prior to the design work being completed may be possible for new designs, but in many cases, we will be installing risers on existing platforms where the riser design work was previously conducted. 3. In many cases long lead items and materials are ordered well in advance of fabrication. If this is considered in the "start of fabrication", this requirement cannot be met. 4. We recommend that the design verification plan be submitted no later than with the pipeline application. 5. We understand that the rationale behind submitting a separate design verification plan for each pipeline riser is for your internal documentation requirements. If we are proposing 8 risers of the same design, we don't understand why we can't develop one plan to cover all 8 risers. We could submit 8 copies if desired for filing purposes. Please clarify. 6. We question the value in submitting a Gantt Chart since we have not been good at estimating these dates. What value does this serve MMS? The CVA must submit the required reports based on the progress of the project. Further, why does it need to be in Gantt Chart format? A table showing the report schedule should suffice.	design verification plan to the Regional Supervisor for approval no later than with the associated pipeline application.
	(b) ***Fabrication verification plan.*** You must submit a fabrication verification plan to the	1. Please see comments above on the timing of the submittal and the submittal of separate plans	You must submit a fabrication verification plan to the Regional Supervisor for approval before you

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	Regional Supervisor for approval before you start fabrication and at least 30 days before you submit the associated pipeline application. You must submit a separate fabrication verification plan for each pipeline riser. Your fabrication verification plan must include the following: (1) Riser diameter, service, and type; (2) A project management timeline (Gantt Chart) that depicts key fabrication activities and when the CVA will submit the interim and final reports required by § 250.1055(d) and (e); (3) A summary of major fabrication considerations and the approach that will be used to verify the validity of these fabrication considerations; and (4) The CVA nomination information specified in paragraph (d) of this section.	and Gantt Charts.	start fabrication and no later than with associated pipeline application.
	(c) *Installation verification plan.* You must submit an installation verification plan to the Regional Supervisor at least 30 days before you submit the associated pipeline application. You must submit a separate installation verification plan for each pipeline riser. Your installation verification plan must include the following: (1) Riser diameter, service, and type; (2) A project management timeline (Gantt Chart) that depicts key installation activities and when the CVA will submit the interim and final reports required by § 250.1056(d) and (e); (3) Abstracts of the computer programs that will be used in installation verification; (4) A summary of major installation considerations and the approach to be used to verify the validity of these installation considerations; and (5) The CVA nomination information specified in paragraph (d) of this section.	1. Although the CVA firm may have been selected, the actual individuals performing the CVA work may not be identified until shortly before going offshore. The CVA Plan requirements are thoroughly spelled out in the regulation so there is no need for a lengthy review period. 2. Please see comments above on the submittal of separate plans and Gantt Charts.	(c) You must submit an installation verification plan to the Regional Supervisor at least 30 days before installation commences.
	(d) *CVA nomination information.* (1) As part of your design verification, fabrication verification, and installation verification plans, you must include nominations for your proposed CVA's for the Regional Supervisor's approval.		

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	(2) For each nomination, you must provide a qualifications statement that includes the following information: (i) Whether the nomination is for the design, fabrication, or installation phase of verification, or for any combination of these phases; (ii) Experience in the design, fabrication, or installation of similar risers; (iii) Experience in third-party verification, inspection, or auditing of similar risers; (iv) Resumes of key personnel and their responsibilities; (v) Size and type of organization or corporation; (vi) In-house availability of, or access to, appropriate technology, including computer programs, hardware, and testing materials and equipment; (vii) Ability to perform the CVA functions for the specific project considering current commitments; and (viii) Previous experience with MMS requirements and procedures.		
	(e) *Modifications.* Submit modifications to your verification plans, including changes in the CVA and key personnel, to the Regional Supervisor for approval.	1. Changes to the Gantt chart should not have to be submitted as a modification to the CVA plan. This is overly burdensome and serves no purpose.	
250.1054	**What must the CVA do to verify pipeline riser design?**		
	The riser design CVA must use good engineering judgment and practices while conducting an independent verification of the design of the riser. The CVA must ensure that the riser is designed to withstand the environmental and functional load conditions appropriate for the intended design life of the riser at the proposed location. The pipeline riser design CVA must verify information, conduct analyses, and submit design reports as required by paragraphs (a) through (d) of this section.		
	(a) The CVA must verify the following: (1) Planning criteria, including the design basis; (2) Operational requirements;	1. It is the role of the CVA to verify the submitted design, not to make recommendations for cleaning of marine growth and in-service	(13) Provisions to account for marine growth (14) delete (15) delete

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	(3) Environmental loading data; (4) Soil conditions; (5) Safety factors; (6) Material and component specifications; (7) Cathodic protection design and riser coating; (8) Interference analysis; (9) Input for the design of vendor components, such as specialty joints and connectors; (10) Vortex-induced vibration (VIV) suppression system to ensure that specifications for installation and design meet required suppression efficiency; (11) Welding specifications to ensure that they are appropriate and adequate for the design and inspection of the riser; (12) Preliminary installation analysis; (13) Provisions to account for marine growth and associated cleaning recommendations; (14) Recommendations on in-service inspection frequency; and (15) Other pertinent parameters of the proposed design.	inspection. If MMS wants this information verified by the CVA, then MMS should include it in a rulemaking to include it in the information to be submitted to the CVA. We note that there is no similar requirements in the CVA program in Subpart I. If the MMS desires to get suggestions on this type of information, it is within the agency rights to procure this type of information from contractors but not burden the operator with payment of this service. 2. (15) This is a vague requirement. Recommend removing it to remove the "blank check" from the CVA.	
	(b) The CVA must perform independent analyses of the following: (1) Riser design cases with appropriate load conditions, as specified in API RP 2RD (incorporated by reference as specified in § 250.198), including, but not limited to, operation, shut-in, and extreme; (2) Riser stresses, including extreme storm response for critical design conditions; and (3) Riser fatigue of selected cases that consider VIV, wave frequency fatigue analysis, vortex-induced motion (VIM), thermal and pressure cycles, riser interaction with seabed (touchdown zone), fatigue due to internal corrosion (if sour service), and other applicable concerns and issues.		
	(c) The CVA must submit interim design reports to the Regional Supervisor at intervals approved in your design verification plan. The CVA must include the following in each interim	1. We fail to understand why or how the CVA will update the Gantt chart since he may not know the project schedule. At most he should update his report submittal schedule.	

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	design report: (1) Details of how, by whom, and when the design verification activities were conducted to date; (2) Description of the CVA's activities during design verification to date; (3) Summary of the CVA's findings to date; (4) Description of any outstanding or notable issues found on the riser design to date; and (5) A Gantt chart showing project progress.		
	(d) The CVA must submit a final design report to the Regional Supervisor before fabrication begins and either within 90 calendar days after receipt of the design data, or within 90 calendar days after MMS approves the design verification plan, whichever is later. The CVA must submit a separate final design report for each pipeline riser. The CVA must include the following in the final design report: (1) Riser diameter, service, type, and designer(s); (2) Details of how, by whom, and when the design verification activities; (3) Description of the CVA's activities during design verification; (4) Summary of the CVA's findings; (5) Confirmation of compliance with the design specifications; (6) Recommendation to accept or reject the riser design; and (7) Any additional information and comments that the CVA deems necessary including, but not limited to: (i) Design basis; (ii) Summary of design CVA scope; (iii) Key drawings; (iv) Summary of input and output from the independent analyses performed; (v) Comparison between results of the original design analyses and the CVA design analyses; (vi) In-service inspection frequency and inspection method recommendations; and	1. (d) The timeframe for the submittal of the final design report is totally unrealistic. This requirement can and will adversely effect cycle time and prevent the operator from taking those scheduling risks that our industry has taken on projects that are fast tracked to allow quick development of OCS reserves. Our experience to date indicates that the design verification cannot be completed within 90 days. Many times the questions and answers and reanalysis drag on for many months. We understand that MMS will not approve the pipeline application associated with the riser prior to the CVA submitting the final design report. If we choose to commence fabrication prior to receiving approval, that should be our risk. 2. (vi) and (vii) The requirement for the CVA to recommend specific in service frequency and inspection method is beyond the normal function of CVA agencies and if the MMS desires this type of contracted service, it is suggested that the MMS contract the services but not burden the operator with the added expense and potentially little value information except for documentation of files for recording purposes. While we understand the MMS desire to learn more about this aspect, it is not the operators responsibility to educate or train the MMS pipeline group on industry efforts and operating practices.	**d) The CVA must submit a final design report** to the Regional Supervisor prior to the approval of the pipeline application associated with the riser. (vi) delete (vii) delete

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(vii) Cleaning recommendations.		
250.1055	**What must the CVA do to verify pipeline riser fabrication?**		
	The riser fabrication CVA must use good engineering judgment and practices while conducting an independent verification of the fabrication activities. The CVA must monitor the fabrication of the riser to ensure that it has been built according to the approved design and fabrication plans. If the CVA finds that fabrication procedures are changed or design specifications are modified, the CVA must inform you. If you accept the modifications, then the CVA must notify the Regional Supervisor. The pipeline riser fabrication CVA must make inspections, witness activities, perform spot checks and submit fabrication reports as required by paragraphs (a) through (e) of this section.		
	(a) The CVA must make periodic onsite inspections while fabrication is in progress and verify the following fabrication items, as appropriate: (1) Quality assurance and quality control programs; (2) Adequacy of fabrication site facilities; (3) Material quality and identification methods; (4) Fabrication procedures specified in the approved plan, and adherence to such procedures; (5) Welder and welding procedures qualification and identification; (6) Dimensional tolerances specified, and adherence to those tolerances; (7) Nondestructive examination (NDE) requirements, and evaluation results of the specific examinations; (8) Destructive testing requirements and results; (9) Repair procedures; (10) Installation of corrosion protection systems and splash-zone protection; and (11) Status of quality assurance and quality control records at various stages of fabrication.		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(b) The CVA must witness: (1) Factory Acceptance Testing (FAT) of vendor components; and (2) Welding of specialty joint to riser material.		
	(c) The CVA must perform spot checks as necessary to determine compliance with applicable regulations, codes, guides, standards, recommended practices, and approved plans.		
	(d) The CVA must submit interim fabrication reports to the Regional Supervisor at intervals approved in your verification plan. The CVA must include the following in each interim fabrication report: (1) Details of how, by whom, when, and where the fabrication verification activities were conducted to date; (2) Description of the CVA's activities during fabrication verification to date; (3) Summary of the CVA's findings to date; (4) Description of any outstanding or notable riser design issues found to date; and (5) A Gantt chart showing project progress.	1. See comments above on reports.	
	(e) The CVA must submit a final fabrication report to the Regional Supervisor within 90 calendar days after completion fabrication, but before the beginning of pipeline installation. The CVA must submit a separate final fabrication report for each pipeline riser. The CVA must include the following in the final fabrication report; (1) Riser diameter, service, and type; (2) Details of how, by whom, when, and where the fabrication verification activities were conducted; (3) A description of the CVA's activities during fabrication verification; (4) A summary of the CVA's findings; (5) Confirmation of compliance with the design specifications and the approved fabrication plan; (6) Recommendations to accept or reject the fabrication; and (7) Any additional information and comments that the CVA deems necessary, including:	1. We suggest 30 days to put pressure on the CVA to get the report finalized.	**(e) The CVA must submit a final fabrication report** to the Regional Supervisor within 30 calendar days after completion of fabrication, but before the beginning of pipeline installation.

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(i) Summary of fabrication scope; (ii) Welding program details; (iii) NDE program details, including acceptance criteria and evaluation results; (i) Dimensional control adherence; (v) The inspection report of the FAT of vendor components; and (vi) Quality assurance and quality control program details.		
250.1056	**What must the CVA do to verify pipeline riser installation?**		
	The pipeline riser CVA must use good engineering judgment and practice in conducting an independent verification of the installation activities. The CVA must monitor the installation of the riser to ensure that it has been built according to the approved design and installation plans. If the CVA finds that installation procedures are changed or design specifications are modified, the CVA must inform you. If you accept the modifications, the CVA must notify the Regional Supervisor. The pipeline riser installation CVA must verify compliance, perform spot checks, and submit fabrication reports as required by paragraphs (a) through (e) of this section.		
	(a) The CVA must verify the: (1) Quality assurance and quality control program; (2) Adequacy of installation vessel(s) and equipment; (3) Material quality and identification methods; (4) Installation procedures specified in the approved installation plan, and adherence to such procedures; (5) Welder and welding procedures qualification and identification; (6) Dimensional tolerances specified, and adherence to those tolerances; (7) NDE requirements, and evaluation results of the specified examinations; (8) Repair procedures;		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(9) Installation test data; (10) Installation of corrosion protection systems and splash-zone protection; (11) Installation of VIV suppression devices as specified in the approved design, and adherence to such design; and (12) Status of quality assurance and quality control records at various stages of installation.		
	(b) The CVA must perform spot checks as necessary to determine compliance with applicable regulations, codes, guides, standards, recommended practices, and approved plans.		
	(c) The CVA must witness the: (1) Pipe load-out at the shore base; and (2) Riser installation operations.		
	(d) The CVA must submit interim installation reports to the Regional Supervisor at intervals approved in your verification plan. The CVA must include the following in each interim installation report: (1) Details of how, by whom, when, and where the installation verification activities were conducted to date; (2) Description of the CVA's activities during installation verification to date; (3) Summary of the CVA's findings to date; (4) Description of any outstanding or notable riser design issues found to date; and (5) A Gantt chart showing project progress.		
	(e) The CVA must submit a final installation report to the Regional Supervisor within 45 calendar days after installation of the pipeline. The CVA must submit a separate installation report for each pipeline riser. The CVA must include the following in the final installation report: (1) Riser diameter, service, and type; (2) Details of how, by whom, when, and where the installation verification activities were conducted; (3) A description of the CVA's activities during installation verification;	1. We believe it is more realistic to give the CVA 120 days to submit the final report.	**e) The CVA must submit a final installation report** to the Regional Supervisor within 120 calendar days after installation of the pipeline.

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(4) Summary of the CVA's findings; (5) Confirmation of compliance with the design specifications and the approved installation plan; (6) A recommendation to accept or reject the installation; and (7) Any additional information and comments that the CVA deems necessary, including: (i) Summary of installation scope; (ii) Welding program details, including weld maps; (iii) NDE program details, including acceptance criteria and evaluation results; (iv) Dimensional control adherence; (v) Quality assurance and quality control program details; (vi) Incidents that occurred during installation; and (vii) As-built drawings.		
Pipeline Pressure Testing			
250.1057	**What are the general requirements for pressure testing a pipeline?**		
	You must pressure test a pipeline in a manner that:		
	(a) Verifies that the pipeline has the requisite structural integrity to withstand normal and maximum operating pressures, and is capable of product containment;		
	(b) Ensures that the test equipment is properly selected and in good working order; and		
	(c) Uses work practices and procedures that reduce hazards to personnel and equipment, and protect the environment.		
250.1058	**What are the requirements for conducting a hydrostatic pressure test for a pipeline?**	1. This is an area where the proposed regulations and DOT regulations are not the same. DOT regulations allow for the use of substances other than water to pressure test pipelines and in some cases to different pressures than in the proposed regulation as examples of differences. Until MMS and DOT agree on common regulations for OCS pipelines, we recommend that the differences be highlighted.	**What are the requirements for conducting a hydrostatic pressure test for a pipeline under DOI jurisdiction (see 49 CFR 192 and 195 for requirements for pipelines under DOT jurisdiction)?**

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(a) *Purpose.* A hydrostatic pressure test must test the tensile strength of a pipeline by pressuring up the pipeline with water.	1 (a). We recommend removing the words "tensile strength" and replacing it with "structural and product containment integrity. The only way to verify the tensile strength is to take the pipeline up to tensile, which we do not want to do. The test is limited to 95% of SMYS.	**(a) *Purpose.*** A hydrostatic pressure test must test the structural and product containment integrity of a pipeline by pressuring up the pipeline with water.
	(b) *Notification.* You must notify the Regional Supervisor, using Form MMS-153 (Notification of Pipeline Installation/Relocation/Hydrotest), at least 48 hours before you conduct a hydrostatic pressure test on a pipeline.	1. As discussed previously, we question the benefit of this requirement. We assume it is so MMS can witness the hydrotest. How many hydrotests does MMS witness annually? We have no problem with MMS witnessing hydrotests, but we believe it would be better for MMS to identify tests they want to witness and work with the operator to provide the appropriate notice instead of giving notice for all hydrotests.	
	(c) *Equipment.* During a hydrostatic pressure test, you must: (1) Measure the test fluid temperature and the test fluid pressure using synchronized temperature and pressure recorders; and (2) Use pressure gauges and recorders that are sufficiently accurate to determine whether the pipeline is leaking during the test.		
	(d) *Procedures*. When you conduct a hydrostatic pressure test, you must: (1) Test the pipeline (including the riser(s)) at a minimum stabilized pressure of at least 125 percent of the MAOP for the length of time specified in § 250.1060(a), (b), or (c); (2) Take deadweight test readings and record the reading, time, and reason for any pressure fluctuations at intervals no greater than 30 minutes; and (3) Use a test pressure that will not produce a stress in the pipeline in excess of 95 percent of the specified minimum-yield strength of the pipe.	1.(d) This requirement is very misleading for gas pipeline risers under DOT jurisdiction which must test to 1.5 times the MAOP. An operator could easily get a lower MAOP assigned than he designed for by following this regulation. 2.(d)(2) references readings from specific equipment while (c) above does not specify the same equipment. We believe there are many acceptable ways of accurately measuring pressure such as deadweight testers (DWT), mechanical or digital gauges calibrated to a DWT, etc. We also recommend that readings be taken hourly vs 30 minutes if a continual chart recorder is utilized.	(1) Test the pipeline (including the riser(s)) at a minimum stabilized pressure of at least 125 percent of the MAOP for the length of time specified in § 250.1060(a), (b), or (c) for pipelines under DOI jurisdiction or in accordance with 49 CFR 192 and 195 for pipelines under DOT jurisdiction; (2) Take pressure readings and record the readings, time, and reason for any pressure fluctuations at intervals no greater than 30 minutes or 60 minutes if a continual chart recorder is utilized.
	(e) *Successful test*. A successful hydrostatic pressure test means that there was no observable leakage, and a stabilized pressure was maintained for the last 2 hours of the test.		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(f) *Discharging test medium.* You must dispose of the test medium in accordance with applicable laws and regulations.		
250.1059	**What are the requirements for leak testing a pipeline?**		
	(a) *Conducting a leak test*. When you conduct a leak test, you must: (1) Use a stabilized pressure that is capable of detecting all leaks; (2) Use pressure gauges and recorders that are sufficiently accurate to determine whether the pipeline is leaking during the test; and (3) Conduct the test for at least two hours during daylight.	1. (a)(3) The requirement for daylight testing is not necessary with the technological advancements and is punitive and will drive up costs and delay action to secure action on leaks. In some cases, ROVs are used to observe for leaks and it doesn't matter if the test is performed in daylight or not. We recommend that this requirement be eliminated. 2. Since water is not specified, we assume that any appropriate fluid (water, natural gas, methanol, etc) can be utilized for a leak test so long as the objectives of the test can be achieved. In many cases for subsea production systems, a leak test for a jumper connection needs to be performed using methanol or some other substance or chemical that is injected into the system via the umbilical.	(3) Conduct the test for at least two hours during daylight unless alternative leak observation measures are utilized other than the surface expression of a leak
	(b) *Successful leak test*. A leak test must successfully test the integrity of a pipeline. A successful leak test means no observable leakage during the test period.		
250.1060	**When must I perform a pressure test on a pipeline?**		
	(a) *Hydrostatic pressure test.* After you install the pipeline, you must successfully perform an 8-hour hydrostatic pressure test of a pipeline (including the riser(s)) before you: (1) Put a new pipeline into service; (2) Put a relocated pipeline into service; (3) Put a pipeline with an increased MAOP into service; (4) Reactivate a pipeline that was out of service for more than one year; (5) Re-commission a pipeline that was decommissioned; or (6) Re-activate a pipeline that was modified by	1.(a)(4) For subsea production systems, hydrotesting in place may not always be feasible on lines that have been Out of Service. We encourage MMS to allow alternative tests that address subsea production systems. 2. In some cases, a combination of scenarios occur such as a pipeline being dragged by an anchor out of the right of way and repaired with a spool piece. Does this require an 8-hr hydrotest for a relocated pipeline or is it a repair using a spool piece and tested in accordance with paragraph (c)? Are these just handled on a	(7) Short segments of pipe, spool pieces, appurtenances such as jumpers and subsea manifolds may be hydrotested for 4-hours if the piece is visable during the test prior to installation in lieu of hydrotesting as part of the pipeline. After installation, non destructive tests of the final tie-in welds and external leak tests on mechanical end connections must be conducted.

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	adding new pipe (except in the case of a pipeline repair using a spool piece that complies with paragraph (c) of this section).	case-by-case basis? 3. We note that in many cases MMS will waive the requirement to perform a hydrotest on a pipeline that has been out of service for more than one year. We recommend that MMS continue that practice where appropriate. 4. Short segments of pipe, spool pieces, appurtenances such as jumpers and subsea manifolds may be tested onshore or where they can be visibly observed during the test. These tests are typically 4-hour hydrotests. After installation, non destructive tests of the final tie-in welds or external leak tests on mechanical end connections are performed. We recommend that this be added to the regulation For instance, the tie-in jumper connecting one export gas pipeline into a downstream gas trunkline will not be internally tested due to problem of introducing water into a dry system, and need to avoid any possibility of introducing water into downstream trunkline. Similarly, the final tie-in jumper between a producing well and a manifold or pipeline may not be internally tested in place due to difficulty of isolating w/ sufficient integrity (only valve isolation possible) to perform a rigorous internal leak test. In this case, the jumper is hydrotested onshore, and the mechanical connectors are externally leak tested after jumper installation. 5. The propose regulation appear to preclude the riser from being pre-tested separately from the pipeline. Please clarify. 6. We note that “relocated pipeline” has not be defined. Please clarify what is meant by this term.	

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td>(b) Pressure test after repair using a clamp. Before you return a pipeline to service following a repair using a clamp:<table><tr><th>If you completed the repair using a . . .</th><th>You must successfully perform . . .</th></tr><tr><td>(1) Mechanical clamp</td><td>A leak-test of the pipeline (including riser(s)) or, if required by the Regional Supervisor, an 8-hour hydrostatic pressure test of the pipeline (including riser(s)).</td></tr><tr><td>(2) Welded clamp</td><td>An 8-hour hydrostatic pressure test of the pipeline (including riser(s)).</td></tr></table></td><td>1. We do not understand the rationale of requiring an 8-hour hydrotest when a welded clamp has been utilized for a repair vs a leak test if a mechanical clamp is utilized. We recommend that they be treated the same.

2.</td><td>(b) Pressure test after repair using a clamp. Before you return a pipeline to service following a repair using either a mechanical or welded clamp:
(1) You must successfully perform a leak test of the pipeline (including riser(s); or
(2) if required by the Regional Supervisor, successfully perform an 8-hour hydrostatic pressure test of the pipeline (including riser(s)).</td></tr>
<tr><td></td><td>(c) Pressure test after repair using a spool piece. Before you return a pipeline to service following a repair using a spool piece you must meet the requirements in the following table:<table><tr><th>After you install the spool piece, if . . .</th><th>You must successfully perform . . .</th></tr><tr><td>(1) You connected the spool piece using flanges</td><td>A 4-hour hydrostatic pressure bench test of the spool piece, and a leak test of the pipeline (including riser(s).</td></tr><tr><td>(2) The spool piece is visible during the test and is not connected using flanges</td><td>A 4-hour hydrostatic pressure test of the pipeline (including riser(s)), and a non-destructive test (i.e. x-rays) of the connections</td></tr><tr><td>(3) The spool piece is not visible during the test</td><td>An 8-hour hydrostatic pressure test of the pipeline (including riser(s)).</td></tr></table></td><td>1. (3) We assume that this requirement is for a spool piece welded in place and recommend that it be clarified.

2. In some cases, a repair may be made with a spool piece that has couplings that incorporate an external leak test of the primary seal(s). These connectors should be treated as flange connectors.

BP's Mardi Gras repair system and the DW RUPE repair system employ grip & seal connectors to connect the spool piece to the existing pipe ends. In general, deep water repairs will not use flanges and we shouldn't endow flanges w/ some unjustified preference. Grip & Seal connectors have been extensively qualified and tested and are arguably a more reliable means of connection than a flange, primarily because they incorporate external leak tests on the connectors which allows pre-knowledge that the primary seal has been correctly actuated before internal testing is implemented, whereas flanges do not incorporate such tests as a normal part of their use.</td><td><table><tr><th>After you install the spool piece, if…</th><th>You must successfully perform…</th></tr><tr><td>(1) You connected the spool piece using flanges or other spool piece couplings incorporating an external leak test of the primary seal(s)</td><td>A 4-hour hydrostatic pressure bench test of the spool piece, and a leak test of the pipeline (including riser(s)).</td></tr><tr><td>(2) The spool piece is visible during the test and is not connected using flanges or other spool piece couplings incorporating an external</td><td>A 4-hour hydrostatic pressure test of the pipeline (including riser(s)), and a non-destructive test (i.e., x-rays) of the connections.</td></tr></table></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
			leak test of the primary seal(s). | (3) The spool piece is welded in place and not visible during the test | An 8-hour hydrostatic pressure test of the pipeline (including riser(s)).
	(d) *Directed pressure test.* The Regional Supervisor may require you to pressure test a pipeline to verify its integrity whenever the Regional Supervisor determines that there is a reasonable likelihood that the pipeline was damaged or weakened by external or internal conditions. When so directed, you must submit the results of these tests to the Regional Supervisor (see § 250.1061).		
250.1061	**What information must I include in a pressure test report?**		
	(a) *Hydrostatic pressure test*. You must submit the results of the hydrostatic pressure test in conjunction with the reports required by § 250.1051(a)(9), 250.1060(d), 250.1086(g)(5), 250.1093(g)(5), 250.1095(e)(6), and 250.1113(b)(5). The pressure test report must include: (1) Test description; (2) Pressure and temperature charts; (3) Instrument calibration data; (4) Minimum and maximum pressure calculations; (5) Deadweight pressure test readings and temperature log; (6) Record of problems encountered during the test including their causes and corrective actions taken; and (7) Documentation of any factors that affected pressures or temperatures.	1. (a)(5) 250.1058(c)(2) does not require the use of deadweight pressure testers. Therefore, this requirement needs to be modified.	(a)(5) Pressure gauge readings and temperature log.
	(b) *Leak test*. You must submit the pressure and temperature charts of any required leak test in conjunction with the report required by §	1. We question the rationale of providing temperature charts for a leak test that is performed subsea since the temperature will be	Remove the requirement for temperature charts for a subsea leak test.

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>250.1095(e)(7).</td><td>static. We recommend this requirement be removed.</td><td></td></tr>
<tr><td colspan="2">Pipeline Safety Equipment</td><td></td><td></td></tr>
<tr><td>250.1062</td><td>What are the general requirements for pipeline safety equipment?</td><td></td><td></td></tr>
<tr><td></td><td>You must provide each pipeline with safety equipment that:</td><td></td><td></td></tr>
<tr><td></td><td>(a) Prevents or minimizes the consequences of overpressure, leaks, and failures;</td><td></td><td></td></tr>
<tr><td></td><td>(b) Protects personnel and the environment;</td><td></td><td></td></tr>
<tr><td></td><td>(c) Considers the need to limit surge pressures and other deviations from normal operations; and</td><td></td><td></td></tr>
<tr><td></td><td>(d) Is properly installed, operated, and maintained.</td><td></td><td></td></tr>
<tr><td>250.1063</td><td>What are the safety equipment requirements for a departing pipeline?</td><td></td><td></td></tr>
<tr><td></td><td>(a) Departing pipeline means a pipeline that receives:
(1) Production from a production, boosting, compressor, or manifold platform; a subsea well, manifold, or other facility; or an incoming pipeline;
(2) Gas-lift gas;
(3) Supply gas; or
(4) Water, fuel, or chemicals.</td><td>1. This is an area where DOI and DOT requirements are not the same. Until MMS and DOT agree on consistent requirements, the differences should be highlighted in the regulation. Pipelines under DOT jurisdiction should meet DOT requirements.</td><td></td></tr>
<tr><td></td><td>(b) You must comply with the safety requirements for a departing pipeline in the following table:
<table>
<tr><th>Safety equipment</th><th>Requirements</th></tr>
<tr><td>(1) Pressure safety high and low (PSHL) sensors</td><td>You must protect a departing pipeline with PSHL sensors that directly or indirectly shut in all delivering sources.</td></tr>
<tr><td>(2) PSHL sensor settings</td><td>(i) You must set the PSHL sensors required by paragraph (a) of this section to activate at pressures that are no more than 15 percent above and below the limits of the normal operating pressure range of the pipeline. (ii) For pipelines that transport a product containing H_2S, you must set the pressure safety low</td></tr>
</table></td><td>1.(b) The PSHL's for DOT lines aren't typically set at +/-15% of operating pressure at midline booster stations where there is such a wide range of operating pressures. Platforms that have multiple outlets will have wide swings in pressure that vary monthly. No charts are ran to determine these settings on a DOT line.

2. (b)(3) In lieu of retaining the actual pressure charts and well test records on the platform, we recommend that scanned copies of the charts and records be available electronically at the facility.

3. (b)(4) Although FSVs and SDVs are installed on some departing pipelines, they are also an</td><td>(b) You must comply with the safety requirements for a departing pipeline in the following table for a pipeline under DOI jurisdiction or the requirements in 49 CFR 192 and 195 for pipelines under DOT jurisdiction.

(b)(3)(i) You must keep the most current pressure recorder charts at the nearest OCS facility, or alternatively have scanned copies available electronically, and make them available for inspection by MMS upon request.

(b)(3)(ii) You must keep the most recent well test records at the nearest OCS facility, or alternatively have scanned copies available electronically, and make them available for</td></tr>
</table>

Proposed Section Number	Proposed Text		Summary of Comments and Rationale	Proposed Language
		(PSL) sensor to activate at a pressure that is no more than 10 percent below the lower limit of the normal operating pressure range of the pipeline. (iii) For a departing pipeline that receives production from a subsea well, you may set the pressure safety high (PSH) sensor to activate at a pressure that is up to 5 percent above the latest recorded wellhead shut-in tubing pressure. (iv) You must not set the PSH sensor to activate at a pressure greater than the MAOP of the pipeline. (v) You must not set the PSH sensor to activate at a pressure within 5 percent of the pressure safety valve (PSV) set point.	added source for potential hydrocarbon leaks. These should only be required to be installed if justified after a risk assessment.	inspection by MMS upon request.
	(3) PSHL sensor settings determination	(i) You must determine the sensor settings required by paragraph (b) of this section by using a pressure recorder to establish the current normal operating pressure range. You must keep the most current pressure recorder charts at the nearest OCS facility, and make them available for inspection by MMS upon request. (ii) For a departing pipeline that receives production from a subsea well, you must use well test records to determine the sensor settings. You must keep the most recent well test records at the nearest OCS facility, and make them available for inspection by MMS upon request.		
	(4) Flow safety valve (FSV) and shutdown valve (SDV)	The Regional Supervisor may require you to equip or otherwise protect a departing pipeline with an FSV and/or an automatic SDV.		
	(5) Subsea tie-in	You must equip the originating end of all departing pipelines that receive production from a connecting pipeline at a subsea tie-in with a block valve and an FSV.		
250.1064	**What are the safety equipment requirements for an incoming pipeline?**			

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(a) Incoming pipeline means a pipeline that delivers:
(1) Production to a production, booster, or compressor platform;
(2) Gas-lift gas to a well, manifold platform, or to another pipeline at a subsea tie-in;
(3) Supply gas; or
(4) Water, fuel, or chemicals.</td><td></td><td></td></tr>
<tr><td></td><td>(b) You must comply with the safety equipment requirements for an incoming pipeline in the following table:<table><tr><th>Safety equipment</th><th>Requirements</th></tr><tr><td>(1) FSV</td><td>You must protect an incoming pipeline with an FSV to prevent backflow.</td></tr><tr><td>(2) SDV</td><td>You must equip an incoming pipeline, except a water pipeline, that boards a production platform or manned platform (a platform that has personnel on board 24 hours per day, or on which personnel are quartered overnight) with an automatic SDV that: (i) Is actuated by the platform's automatic- and remote-emergency shut-in systems; (ii) Is located immediately upon boarding the platform. If the SDV is on a horizontal section, you must locate it in an unclassified area (classified area is defined in API RP 500 and API RP 505; both documents are incorporated by reference in § 250.198) and no more than 10 feet from the boarding pipeline riser. This requirement applies only to pipelines installed or modified after [INSERT THE EFFECTIVE DATE OF THE RULE]; and (iii) Closes within 45 seconds after it is actuated.</td></tr><tr><td>(3) Gas-lift pipeline</td><td>This paragraph applies to an existing incoming gas-lift pipeline installed before [INSERT THE DATE SIX MONTHS AFTER THE EFFECTIVE DATE OF THE RULE] to an unmanned minor platform. (A minor platform is one that contains fewer</td></tr></table></td><td>1. We do not believe that it is appropriate to define a manned platform in this Subpart. Unmanned platforms may quarter personnel overnight from time to time. We do not believe it is MMS intent to require these platforms to install SDVs.

2 (2) We understand that within no more than 10 feet from the boarding pipeline riser is from the point where the piping system turns back to a horizontal orientation. We recommend that this be clarified.

3. It may not always be possible to locate a SDV in an unclassified area. If it is located in a classified area, then the device must be rated for classification it will be located in.

4. We assume that remote emergency shut-in systems refers to a SCADA or similar system that can close the SDV that is remote to the platform. If this is not correct, please clarify.</td><td>(2) You must equip an incoming pipeline, except a water pipeline, that boards a production platform or manned platform with an automatic SDV that: (i) Is actuated by the platform's automatic- and remote-emergency shut-in systems; (ii) Is located immediately upon boarding the platform. that If the SDV is on a horizontal section, you must locate it in an unclassified area (classified area is defined in API RP 500 and API RP 505; both documents are incorporated by reference in § 250.198), or provide a device rated for the classification area it is located in, and no more than 10 feet after the piping turns back to a horizontal orientation.</td></tr>
</table>

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	than six well completions or fewer than two pieces of production equipment). In lieu of complying with paragraphs (b)(1) and (b)(2) of this section, you may protect the pipeline with an FSV located either: (i) Immediately upstream of each casing annulus; or (ii) Immediately upstream of the first inlet valve on the wellhead.		
	(4) Subsea tie-in: You must equip the terminating end of an incoming pipeline that delivers production to a connecting pipeline at a subsea tie-in with a block valve and an FSV.		
250.1065	**What are the safety equipment requirements for a crossing pipeline?**		
	(a) A crossing pipeline means a pipeline that crosses a platform but does not receive or deliver production to that platform. A crossing pipeline includes both the incoming and departing pipeline segments.		
	(b) You must comply with the safety requirements for a crossing pipeline in the following table: Safety equipment / Requirements (1) FSV: You must protect a crossing pipeline installed after [INSERT THE EFFECTIVE DATE OF THE RULE] that crosses an unmanned or non-production platform with an FSV to prevent backflow. (2) SDV: You must equip the terminating end of the incoming segment(s) of a crossing pipeline (except a water pipeline) that crosses a production platform or manned platform (a platform that has personnel on board 24 hours per day, or on which personnel are quartered overnight) with an automatic SDV that: (i) Is operated by a PSHL sensor to protect the departing segment(s) of the crossing pipeline; (ii) Is actuated by the platform's automatic- and	1. (2) SDV same comments and recommendations as for 250.1064.	

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	remote-emergency shut-in systems; (iii) Is located immediately upon boarding the platform. If the SDV is on a horizontal section, you must locate it in an unclassified area (a classified area is defined in API RP 500 and API RP 505; both documents are incorporated by reference in § 250.198) and no more than 10 feet from the boarding pipeline riser. This requirement applies only to pipelines installed or modified after [INSERT THE EFFECTIVE DATE OF THE RULE]; and (iv) Closes within 45 seconds after it is actuated.		
250.1066	**What are the safety equipment requirements for a bi-directional pipeline?**		
	(a) Bidirectional pipeline means a pipeline designed and configured to transport fluids in either direction.		
	(b) You must comply with the safety equipment requirements for a bi-directional pipeline in the following table:	1. (2) SDV same comments and recommendation as for 250.1064.	
	Safety equipment: (1) PSHL sensors — You must protect both ends of a bi-directional pipeline with PSHL sensors that directly or indirectly shut in all delivering sources. Requirements for the setting levels of the PSHL sensors are specified at § 250.1063(b)(2) and (3).		
	Safety equipment: (2) Automatic SDV — You must equip both ends of a bi-directional pipeline with an automatic SDV that: (i) Is actuated by the platform's automatic- and remote-emergency shut-in systems; (ii) Is located immediately upon boarding the platform. If the SDV is on a horizontal section, you must locate it in an unclassified area (a classified area is defined in API RP 500 and API RP 505, both documents incorporated by reference as specified in § 250.198) and no more than 10 feet from the		

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	boarding pipeline riser. This requirement applies only to pipelines installed or modified after [INSERT THE EFFECTIVE DATE OF THE RULE]; and (iii) Closes within 45 seconds after it is actuated. (3) Block valve: You must equip a bi-directional pipeline that connects to a pipeline at a subsea tie-in with a block valve at the tie-in assembly.		
250.1067	**When must I provide redundant safety equipment?**		
	(a) If the maximum source pressure (MSP) is from a well, and it exceeds the MAOP of the pipeline, you must protect the pipeline by using either: (1) One surface safety valve (SSV) controlled by a PSH sensor, and a PSV that relieves in a safe and pollution-free manner; or (2) Two SSV's controlled by independent PSH sensors connected to separate relays and sensing points.	1. The requirements outlined in this section are more liberal than the requirements discussed with GOM TAOS personnel and are at odds with some architecture of systems discussed. The Pipeline and GOM TAOS groups need to get together on this area and send a single message to operators on what might be deemed acceptable. 2. The proposed regulation does not appear to be consistent with API RP 14 C. PSV protection is not acceptable in all cases which is the reason for two SSVs with independent sensors. 3. Is the PSV required to be full flow or just enough to relieve what may leak past the single SDV? 4. We note that some configurations utilize three SDVs to achieve the double block. The first block would be the boarding SDV. The second block would be the receiving valve and the bypass valve on a receiver.	
	(b) For pipelines installed after [INSERT THE EFFECTIVE DATE OF THE RULE], if the MSP is from a well, and it is more than $1^{1/2}$ times the MAOP of the pipeline, you must protect the pipeline by using two SSV's controlled by independent PSH sensors connected to separate relays and sensing points, and one PSV that		

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	relieves in a safe and pollution-free manner.		
	(c) If the maximum source pressure (MSP) is not from a well, and it exceeds the MAOP of the pipeline, you must protect the pipeline by using either: (1) One shutdown valve (SDV) controlled by a PSH sensor, and a PSV that relieves in a safe and pollution-free manner; or (2) Two SDV's controlled by independent PSH sensors connected to separate relays and sensing points.		
	(d) If you use the configuration specified in paragraph (c)(1) above, you must set the PSV to activate at a pressure between 5 and 10 percent above the MAOP.		
250.1068	**What are the safety equipment requirements for a pipeline pump?**		
	(a) *General*. You must do both of the following: (1) Protect a pipeline pump according to section A7 of API RP 14C (incorporated by reference as specified in § 250.198). Requirements for setting the levels of the PSHL sensors are specified at § 250.1063(b)(2) and (3). (2) Set any PSV you installed on the pipeline to protect the pump to activate at a pressure less than the MAOP of the pipeline.	1. We recommend that a paragraph be added to address midline booster pump stations.	
	(b) *Time delays for pumps*. During startup and idle operations, you may apply industry standard Class B, Class C, and Class B/C logic to all PSL sensors installed on pipeline pumps. You do not need a departure approval to use these types of time delay circuitry if the time delay does not exceed 45 seconds. You must obtain a departure approval under the provisions of § 250.142 from the appropriate District Manager before you use a time delay greater than 45 seconds. (1) *Class B logic* allows for a PSL sensor on pipeline pumps to be bypassed for a fixed time period (typically less than 15 seconds, but not more than 45 seconds). (2) *Class C logic* allows for a PSL sensor to be bypassed until the component comes into full		

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	service. (3) *Class B/C logic* allows for a PSL sensor to incorporate a combination of Class B and Class C circuitry. This device is used to ensure that a PSL sensor is not unnecessarily bypassed during start-up and idle operations (e.g., Class B/C bypass circuitry activates when a pump is shut down during normal operations). The PSL sensor remains bypassed until the pump start circuitry is activated and either: (i) The Class B timer expires after 45 seconds from start activation; or (ii) The Class C bypass is initiated until the pump builds up pressure above the PSL set point and the PSL comes into full service.		
	(c) *PSL Sensors and bypass circuits*. When the PSL sensor comes into full service, the PSL sensor is fully active. If the PSL sensor should trip while the pump is running, the pump will shut down and the Class B/C bypass circuit will remain inactive until the safety system devices are cleared and reset.		
250.1069	**What must I do if safety equipment fails to operate as intended?**		
	If any safety equipment required by this subpart experiences a failure you must follow the requirements of paragraphs (a) through (e) of this section.		
	(a) *Suspending operations*. You must shut in the pipeline immediately.	(a) The requirements to immediately shut in the system for a non functioning sensor or safety device is counterproductive and should not be seen as a "safe' action. Start up operations and resuming normal operations are more risky than addressing malfunctioning safety systems. If we can immediately provide an equivalent degree of safety or have one (redundancy) that was previously installed, we should not have to shut in and then restart up. We note that this is allowed under the current regulations. Furthur, this is allowed in the proposed 250.1085 when safety equipment is removed. Further, we note that this allowed for safety systems in	**(a) *Suspending operations*.** You must shut in the pipeline immediately unless: (1) an equivalent level of safety (redundancy in device) has been previously installed; or (2) an equivalent degree of protection can be immediately provided and an appropriate warning sign is placed on the failed safety equipment; or (3) permission is received from the Regional Supervisor to stay operational

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		accordance with Subpart H. We see no rationale for making the requirements in Subpart J and H different. Examples: If an SDV develops a small leak, suggest we do not have to shut in, as long as the leakage can be managed. Suggest we be allowed to schedule the maintain without having to take shut in until this can be accomplished. In many cases, a spurious signal may sent. There needs to be time for the operator to diagnosis the problem and confirm that safety equipment has actually failed.	
	(b) *Out-of-service notification*. You must notify the Regional Supervisor: (1) If the safety equipment remains out of service for more than 12 hours in the GOMR; and (2) Immediately after the safety equipment is out of service in the POCSR and AKOCSR.	1. If the pipeline has been shut-in, we see no benefit to this notification. Notification should only be made if permission to remain on line is desired. We view this as burdensome on both MMS and industry. Further, in NTL 2007-G12, MMS has advised in the GOM Region, they only want to be notified after hours for a pipeline emergency. Therefore, if equipment fails on Friday at 6:00 pm, what benefit is there in faxing, emailing or electronically submitting a notice after the 12 hours has elapsed?	**(b) *Out-of-service notification***. You must notify the Regional Supervisor: (1) If you seek permission to remain on line without shutting in the GOMR; and (2) Immediately after the safety equipment is out of service in the POCSR and AKOCSR. :
	(c) *Resuming operations*. You may resume operation of the pipeline after you: (1) Repair the failed safety equipment (see § 250.1094 through 1096); (2) Replace the failed safety equipment (see § 250.1093); or (3) Provide an equivalent degree of protection and place an appropriate warning sign on the failed safety equipment.	(3) Since no approval process is proposed, we assume that it is up to the operator to determine what an equivalent degree of protection is.	
	(d) *Corrective action notification*. If you shut in your pipeline because of a safety equipment failure and were required by paragraph (b) of this section to notify the Regional Supervisor, you must also notify the Regional Supervisor immediately when you repair the safety equipment and resume operating the pipeline, or	1. Please see our comments above concerning shutting in the pipeline. 2. We don't understand why this notification needs to be "immediate". In the GOM NTL 2007-G12 calls for repair notifications to be made during normal office hours.	You must notify the Regional Supervisor: (1) when you repair or replace the safety equipment if you were required by paragraph (b) of this section to notify the Regional Supervisor; and (2) if you resume operation of a pipeline in accordance with paragraph (c) of this section

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	when you have provided an equivalent degree of protection and resume operating the pipeline.	3. We also note that that there are no details on the notification to be provided. We encourage MMS to develop an electronic notification system such as eWell for these notifications.	
	(e) *Repair application*. If the corrective action you take to address a safety equipment failure necessitates a repair (see § 250.1094), you must submit a repair application in accordance with § 250.1095(a) and receive approval from the Regional Supervisor before you perform the work.		
Pipeline Leak Detection			
250.1071	**When do I need to use a leak detection system?**		
	If your pipeline transports liquid hydrocarbons to shore, or if the Regional Supervisor otherwise requires it, you must use a computational pipeline monitoring (CPM) system or equivalent methodology to detect leaks by continuously determining or calculating the imbalance between the incoming (receipt) and outgoing (delivery) volumes of a pipeline. A CPM system means an algorithmic monitoring tool that allows you to respond to a pipeline operating anomaly that may indicate a release of liquid hydrocarbons. You must:	1. Most liquid pipelines transporting product to shore are under DOT jurisdiction and these regulations should only be applicable to pipelines under DOI jurisdiction. 2. We question the benefit of mandating these system for all pipelines. Does MMS have records that reflect the need to mandate for all lines. 3. The proposed ruling mandates the use of a volumetric system where it is a "may be required" system in the current regulations. Pressure monitoring systems normally function as first indicators and volumetric systems depend on communications and accurate input. On multiple user lines this volumetric input can be a source of error not related to actual line integrity. If the final rule retains a leak detection system requirement, we request the option to utilize pressure monitoring systems and not mandate total use of volumetric programs. Are pressure monitoring systems considered "equivalent methodology"	If your pipeline transports liquid hydrocarbons to shore and is under DOI jurisdiction….
	(a) Equip your CPM system with an alarm that		

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	signals when the imbalance exceeds a predetermined threshold for a selected time interval; and		
	(b) Use SCADA technology to gather, process, and display the data you use in your CPM system. SCADA is an acronym for supervisory control and data acquisition, the technology that makes it possible to monitor and control pipelines remotely.	1. Provision should be made for the use of "SCADA or equivalent technology" for gathering process information regarding pipeline leak detection. MMS stated on pg 56445 of the Federal Register that the proposed rule "recommends" the use of current technology, and that this technology includes "but is not limited to" CPM systems using SCADA. Section 250.1071 does state that "you must use CPM or equivalent technology," however it appears in section "B" that SCADA "MUST" be used. The leak detection system should only have to provide the monitor capability.	(b) Use SCADA or equivalent technology to gather, process, and display the data you use in your CPM system. SCADA is an acronym for supervisory control and data acquisition, the technology that makes it possible to monitor and control pipelines remotely. For leak detection purposes, only monitoring is required.
Pipeline Internal Corrosion Control and Flow Assurance			
250.1074	**What are the general requirements for internal corrosion control?**		
	You must establish and implement internal corrosion control measures (e.g., running pipeline scrapers; dehydrating; using corrosion inhibitors, bactericides, or oxygen scavengers) to protect the pipeline over its service life.	1. This should be an integral part of the Pipeline Operations and Maintenance Section of the Integrity Management Program required in Section 250.1079. We recommend that the paragraph be deleted. Alternative, reference 250.1079 for clarity. 2. We note that monitoring and inspection results are key to when specific action is prudent..	You must establish monitoring and implement internal corrosion control measures, as required, (e.g., running pipeline scrapers; dehydrating; using corrosion inhibitors, bactericides, or oxygen scavengers) to protect the pipeline over its service life and describe the program in the Pipeline Operations and Maintenance Section of the Integrity Management program required in 250.1079.
250.1075	**What are the general requirements for flow assurance?**		
	You must establish and implement measures (e.g., chemical additives, routine pigging) to ensure that adequate flow can be sustained throughout the service life of a pipeline under all expected flow conditions for the range of pressures, temperatures, fluid properties, and phase conditions expected during start up, normal, shut down, and emergency operations.	1. This should be an integral part of the Pipeline Operations and Maintenance Section of the Integrity Management Program required in Section 250.1079. We recommend that the paragraph be deleted. Alternative, reference 250.1079 for clarity. 2. The key element is the monitoring systems	You must establish monitoring and implement measures, as required, (e.g., chemical additives, routine pigging) to ensure that adequate flow can be sustained throughout the service life of a pipeline under all expected flow conditions for the range of pressures, temperatures, fluid properties, and phase conditions expected during start up, normal, shut down, and emergency

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		that would indicate when certain activities may be necessary for continued service. The proposed rule misses the point of establishing a monitoring program to identify when specific action is prudent.	operations and describe the program in the Pipeline Operations and Maintenance Section of the Integrity Management program required in 250.1079.
Pipeline Operations and Maintenance			
250.1078	**What are the general requirements for operating and maintaining a pipeline?**		
	You must operate and maintain a pipeline in a manner that:		
	(a) Protects life, property, and the environment for the service life of the pipeline;		
	(b) Ensures that all pipelines, appurtenances, and safety equipment are not subjected to operating conditions that exceed applicable design parameters and the MAOP;		
	(c) Anticipates the detrimental effects of corrosion; product composition; thermal cycling; pressure fluctuations; hydrate, asphaltene, or paraffin formation; sediment transfer or scour (due to wave action and currents); storm or ice scouring; gross seafloor movement (such as mudslides, faults, and subsidence); hurricanes; earthquakes; subfreezing temperatures; and other natural or manmade phenomena;		
	(d) Maintains the approved burial depth throughout the life of the pipeline including after the pipeline is decommissioned in place; and		
	(e) Does not interfere with other uses of the OCS.		
250.1079	**What written procedures must I establish before I operate an OCS pipeline?**	1. Since written procedures as detailed below are not currently required, it will take industry some time to prepare these plans and procedures. It is also not clear if this requirement is applicable to pipelines currently in operation on the OCS. 2. We note that DOT has its own requirements for pipelines under their jurisdiction. Until MMS and DOT agree on common requirements for OCS pipelines, we request that this requirement	**What written procedures must I establish before I operate an OCS pipeline under DOI jurisdiction installed 2 years after the effective date of the rule ?** Alternatively, if these plans are applicable to both new and existing pipelines: **What written procedures must I establish within 4 years after the effective date of this rules in order to operate an OCS pipeline under DOI jurisdiction?**

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		only be applicable to pipelines under DOI jurisdiction. 3. The current DOT requirements for Integrity Management Programs only apply to High Consequence Areas (HCA's), with most of the offshore areas not currently covered as HCA's. MMS should consider making these requirements only applicable to HCA's. 4. The procedures and plans as described below leave many decisions up to the individual operator to decide, such as timing, methods, etc. This is acceptable to us, but if MMS has expectations, we would like that clarified. Otherwise, MMS should anticipate and accept a wide variety of plans.	
	(a) *Operations and maintenance manual*. You must prepare a written operations and maintenance manual for your OCS pipelines that complies with the regulations in this subpart and includes provisions for all of the following: (1) Conducting normal operations; (2) Conducting periodic surveillance and inspections; (3) Performing systematic and routine preventive maintenance; (4) Ensuring that safety system components are functioning properly; (5) Resuming operations after a storm; (6) Monitoring and mitigating the effects of internal and external corrosion and erosion; (7) Monitoring and mitigating the effects of paraffin, wax, and hydrate formation; (8) Responding to foreseeable abnormal operating conditions, malfunctions, failures, or personnel error; and (9) Identifying and responding to conditions that could affect safe operations.	.	
	(b) *Integrity management program*. You must have a written pipeline integrity management program for your OCS pipelines that includes the	1. (b)(1) We assume that operators are allowed to establish their own schedule and that MMS has no expectations on when the baseline	

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	seven elements listed in this paragraph. (1) *Baseline integrity assessment*. A plan and a risk-based schedule for obtaining baseline information on the integrity of each pipeline by either: (i) Using an in-line inspection tool (e.g., smart pig) to detect corrosion or deformation anomalies; (ii) Performing hydrostatic pressure tests (see § 250.1058) to test tensile strength; or (iii) Using other technology that can provide an equivalent understanding of the condition of your pipelines. (2) *Information analysis*. An analysis that integrates all other available information (e.g., inspections, tests, surveys, and monitoring results) about pipeline integrity. (3) *Review*. Provisions to review the integrity assessment results and information analysis by a qualified person. (4) *Remedial actions*. Criteria for performing prompt remedial actions to address anomalous conditions you discover through integrity assessment or information analysis. (5) *Periodic assessment and evaluation*. Provisions for periodically reassessing and re-evaluating the integrity of the pipeline at a frequency based on specific risk factors such as proximity to environmentally sensitive areas, product being transported, previous failure history, and water depth. (6) *Preventive and mitigation measures*. Provisions for identifying and taking preventive and mitigation measures to enhance safety and environmental protection such as SCADA systems, cathodic protection monitoring, and shorter inspection intervals. (7) *Program effectiveness*. Provisions for measuring the effectiveness of your integrity management program.	integrity assessments are completed. If this is not accurate, please clarify. 2. (b)(1)(iii) we note that completing a baseline integrity assessment for subsea production systems will be difficult. Inline inspections are usually not possible and hydrotests after the line is in service may not be possible and is often impractical. What other technology would MMS consider providing an equivalent understanding of the condition of the pipelines? Does the original hydrotest satisfy this requirement? 3. (b)(3) Uses the term “qualified “ person. Since this is not defied it will surely lead to variations among the operators. If MMS has expectation on who is qualified, then please clarify. 4. (b)(4) We assume the operator can determine the anomalies that need to be addressed and which ones don’t and how they are addressed. If this is not correct, please clarify. Also, we suggest using “as soon as reasonably practical” in lieu of “prompt”. 5. (b)(5) We assume the operator can set the timeframe for periodic assessment and evaluations If MMS has an expectation on frequency, then please clarify.	
	(c) *Emergency plan*. You must prepare a written emergency plan that you will immediately		

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	implement in the event of a pipeline failure, accident, or other emergency that includes provisions for: (1) Training personnel responsible for executing emergency actions; (2) Establishing an effective communication system; (3) Conducting periodic drills; (4) Ensuring personnel safety; (5) Evacuating platforms; (6) Limiting property damage; (7) Minimizing pollution and protecting the environment; (8) Conducting remote operations, if applicable; (9) Making construction information and operating history available to appropriate personnel; (10) Notifying appropriate government agencies; (11) Investigating failures; and (12) Reviewing performance during drills and actual emergencies.		
	(d) ***Personnel qualification program***. You must have a written qualification program for individuals who perform pipeline operation, maintenance, and repair duties for you that may affect the safe operation or integrity of a pipeline. This program must include provisions for: (1) Identifying covered tasks; (2) Ensuring through periodic evaluation that the individuals who perform covered tasks are qualified; (3) Evaluating an individual if you have reason to believe that the individual's performance of a covered task contributed to an incident; (4) Evaluating an individual if you have reason to believe that the individual is no longer qualified to perform a covered task; (5) Communicating changes that affect covered tasks to individuals performing those tasks; and (6) Complying with 30 CFR 250, Subpart O-Well Control and Production Safety Training, as applicable.	1. To alleviate confusion and duplication of efforts for operators who operate both DOT and DOI pipelines, it is recommended MMS adopt current Operator Qualification Language found in 49 CFR 192 and 195	

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(e) Implementation procedures. You must establish procedures to make sure that your personnel implement and follow the provisions of your operations and maintenance manual, integrity management program, emergency plan, and personnel qualification program.</td><td></td><td></td></tr>
<tr><td></td><td>(f) Annual review. You must review your operations and maintenance manual, integrity management program, emergency plan, and personnel qualification program at least annually and make any necessary changes to ensure that they remain effective.</td><td></td><td></td></tr>
<tr><td></td><td>(g) Inspection. You must make copies of your operations and maintenance manual, integrity management program, emergency plan, and personnel qualification program available to MMS personnel at the nearest OCS facility upon request.</td><td>1. It is impracticable to provide paper copies of all of the manuals at each OCS facility, especially unmanned facilities. We recommend that they be available to MMS personnel at the nearest field office or other locations conveniently available to the District Supervisor. Alternatively, they could be provided within 60 days to MMS upon request.</td><td>(g) Inspection. You must make copies of your operations and maintenance manual, integrity management program, emergency plan, and personnel qualification program available to MMS personnel at the nearest OCS field office or other locations convenient to the District Supervisor upon request.</td></tr>
<tr><td>250.1080</td><td>When must I mark the MMS-assigned pipeline segment number on a pipeline?</td><td></td><td>When must I mark the MMS-assigned pipeline segment number on a pipeline above the waterline?</td></tr>
<tr><td></td><td>You must comply with the marking requirements indicated in the following table:
<table>
<tr><th>Type of pipeline</th><th>When you must mark the pipeline segment number</th></tr>
<tr><td>(a) New pipeline</td><td>Before you operate a pipeline you construct after [INSERT THE EFFECTIVE DATE OF THE REGULATION], you must durably mark the MMS-assigned pipeline segment number on the pipeline at each platform.</td></tr>
<tr><td>(b) Existing pipeline</td><td>If you constructed a pipeline before [INSERT THE EFFECTIVE DATE OF THE REGULATION], you must durably mark the MMS-assigned pipeline segment number on the pipeline at each platform no later than [INSERT THE DATE 6 MONTHS AFTER THE EFFECTIVE DATE OF THE REGULATION].</td></tr>
<tr><td>(c) Exceptio</td><td>You are not required to separately mark the MMS-assigned pipeline segment number</td></tr>
</table></td><td>1. We assume that this requirement is applicable only to segments above the waterline.

2. We assume that it is up to each operator to determine the size of the letters, location of markings, etc. If MMS has expectations, please clarify.

3. (b) 6 months is too short a timeframe to mark all of the pipeline segments above water. We recommend that making this 18 months. This would also allow planning in conjunction with an annual inspection.</td><td>(b) If you constructed a pipeline before [INSERT THE EFFECTIVE DATE OF THE REGULATION], you must durably mark the MMS-assigned pipeline segment number on the pipeline at each platform no later than [INSERT THE DATE 18 MONTHS AFTER THE EFFECTIVE DATE OF THE REGULATION].</td></tr>
</table>

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	n — on a pipeline to comply with paragraphs (a) or (b) of this section if you durably mark the component identification (see API RP14C, section 2.4 (incorporated by reference as specified in § 250.198)) on the pipeline using the MMS-assigned pipeline segment number as the unique identifier (e.g., KAH-1425, where 1425 is the MMS-assigned pipeline segment number).		
250.1081	**How do I determine the MAOP of a pipeline?**	1. The concept of a single MAOP for deepwater pipelines is not practical. We recommend MMS establish a mechanism for including variation of the MAOP along the pipeline length. 2. MMS' current system of assigning pipeline MAOP does not handle such things as external water pressure. We invariably get assigned the wrong MAOP that has to be corrected or alternatives approved. MMS needs to have a system in place to properly assign MAOPs in accordance with the regulations.	
	The MAOP of a pipeline must not exceed the lowest of the following:		
	(a) The internal design pressure of the horizontal component and risers;		
	(b) The pressure ratings of appurtenances		
	(c) Eighty percent of the hydrostatic test pressure of the pipeline; or		
	(d) If applicable, the MAOP of a connecting pipeline.	1. It should be recognized that MMS has previously established safety system requirements in 250.1067 that allow for a higher pressure pipeline to be tied into a lower pressure pipeline. 2. For subsea tie-ins, a higher pressure pipeline should be allowed to tie-into a lower pressure pipeline when the operator shows that flow and friction loss coupled with a downstreams relief system on the lower pressure line will prevent the lower pressure line from being overpresssured.	.
250.1082	**What must I do if the pipeline transports H_2S?**		

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	***(a)Contingency Plan for operations*.** Before you operate a pipeline which transports a product with an H_2S concentration that, if released, could result in atmospheric concentrations of 20 ppm or more, you must prepare an $H_{2G1}S$ Contingency Plan in accordance with § 250.490(f) that covers your pipeline operations. You do not need to prepare an $H_{2G1}S$ Contingency Plan if the pipeline is covered under an appropriate facility plan.		
	(b) *H_2S dispersion modeling report*. Before you operate a pipeline which transports a product with an $H_{2G1}S$ concentration greater than 500 ppm, you must model a potential worst-case accidental $H_{2G1}S$ release from the pipeline and prepare a report. The modeling report must include: (1) The data you used in the model (e.g., meteorological data) in an electronic format acceptable to the Regional Supervisor; (2) A site-specific analysis of your pipeline operation that considers any nearby human-occupied OCS platforms, shipping lanes, fishery areas, and other points where humans may be subject to potential exposure from an accidental H_2S release; and (3) If the accidental release could result in an $H_{2G1}S$ concentration of 10 ppm or greater at an onshore area, an analysis consistent with the risk management plan (RMP) methodologies of the EPA as outlined in 40 CFR part 68.		
	(c) *Batch treatment*. The Regional Supervisor may require that you batch treat your pipeline if there are indications that H_2S could be detrimentally affecting the pipeline.		
250.1083	**What are the requirements for conducting remote operations during a platform evacuation?**		
	(a) *Pipeline shut-in*. When you evacuate your personnel from an OCS platform due to an impending storm or other emergency, you must shut in any connecting pipeline unless you have		

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	remote operations capability.		
	(b) *Remote operations*. You may conduct remote operations on the pipeline during an evacuation only if: (1) The Regional Supervisor grants you prior approval; (2) Your pipeline has remote monitoring and remote shut-in capabilities; (3) You immediately shut in any pipeline that transports liquid hydrocarbons or H_2S, or any pipeline that transports natural gas (if the pipeline experiences an upset condition) when the sustained wind speeds of any storm reach 74 mph over any part of the pipeline; and (4) You design time-delay circuitry (local storm timers) to shut in a pipeline no more than 4 hours after the capability to monitor and control a process is lost, and include this circuitry in the SCADA logic.		
	(c) *Resuming operations*. You may not remotely resume operation of a shut-in pipeline if any part of the pipeline was within 25 miles (or other distance specified by the Regional Supervisor) of the eye center path of a major storm (74 mph or greater).		
250.1084	**What are the requirements for testing pipeline safety equipment?**	1. This is an area where the DOT regulations are different from those proposed. Until MMS and DOT can agree upon common requirements, we recommend that these regulations only be applicable to pipelines under DOI jurisdiction.	**What are the requirements for testing pipeline safety equipment for pipelines under DOI jurisdiction (Pipeline safety equipment for pipelines under DOT jurisdiction should be tested in accordance with 49 CFR 192 and 195.)?**
	(a) You must periodically test your pipeline safety equipment to ensure that it is in good mechanical condition, properly installed, and able to perform safety functions in accordance with the requirements in the following table. You must conduct all tests using the test procedure specified in the appropriate subsection of API RP 14C, appendix D, section D4, table D2 (incorporated by reference as specified in § 250.198). Safety | Freque | Subsect | If | Then	1. (a)(1) Since these are new requirements, existing FSVs may not have testing ports or testing kits installed which will make testing FSVs difficult to accomplish. FSVs typically do not seal tight and are more to reduce the flow and rely on backside pressure to maintain the seal over surfaces where liquids have flowing. We do not see much benefit in modifying or replacing existing installations in order to test the FSV. We recommend that existing FSVs be grandfathered. New FSVs can be equipped to test.	(a)(1) *FSV.* You must test each required FSV installed after the effective date of this rulemaking, except those installed underwater, for leakage **(b) *Recordkeeping***. You must retain the records of the results of the tests required by paragraph (a) of this section at the pipeline operators field office nearest the OCS facility or other locations conveniently available to the District Supervisor for at least 2 years, and make them available to

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	equipment	ncy	ion		you must	(b) The OCS facility the devices are located on may not have record keeping facilities.	MMS upon request.
	(1) *FSV*. You must test each required FSV, except those installed underwater, for leakage	At least annually, with no more than 13 months between tests	d	The FSV does not operate properly, or if the flow rate exceeds 200 cubic centimeters/minute for liquid flow or 5 cubic feet/minute for natural gas flow	Repair or replace the FSV.		
	(2) *PSHL sensors*. You must conduct an external pressure test of each required PSHL sensor	At least monthly, with no more than 6 weeks between tests	g	(i) The PSHL sensor does not operate properly (ii) The PSHL sensor set pressure tolerance is plus or minus 5 percent or five psi, whichever is greater	Repair or reglace the PSHL sensor. Adjust the set point(s) of the PSHL sensor.		
	(3) *PSV*. You must conduct an external pressure test of each required PSV	At least annually, with no more than 13 months between tests	i	(i) The PSV does not operate properly (ii) The PSV set pressure tolerance is plus or minus two psi for pressures up to and including 70 psi, or plus or minus 3 percent for pressures	Repair or replace the *PSV*. Adjust the set point of the PSV.		

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				above 70 psi			
	(4) *SDV*. For each required SDV, you must conduct a(an):						
	(i) Operations test	At least monthly, with no more than 6 weeks between tests	k (option 1)	The SDV does not operate properly	Repair or replace the SDV.		
	(ii) Full valve closure test	At least annually, with no more than 13 months between tests	k (option 2)	The SDV does not operate properly, or if the flow rate exceeds 200 cubic centimeters/ minute for liquid flow or 5 cubic feet/minute for natural gas flow	Repair or replace the SDV.		
	(iii) Pressure holding test	If required by the Regional Supervisor	Not addressed	To be determined by the Regional Supervisor	To be determined by the Regional Supervisor.		
	(5) *SSV*. You must	At least monthly,	m	The SSV does not operate	Repair or replac		

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	conduct a pressure holding test of each required SSV | with no more than 6 weeks between tests | | properly, or if any fluid flow is observed during the test | e the SSV.		
	(b) *Recordkeeping*. You must retain the records of the results of the tests required by paragraph (a) of this section at the nearest OCS facility for at least 2 years, and make them available to MMS upon request.		
250.1085	**What must I do when safety equipment is removed from service?**	This section is confusing since it has different requirements and is far apart from 250.1069. This should be combined with that section.	
	(a) *Removal from service notification*. You must notify the Regional Supervisor: (1) If the safety equipment remains removed from service for more than 12 hours in the GOMR; or (2) Immediately after the safety equipment is removed from service in the POCSR and AKOCSR.		
	(b) *Equivalent degree of protection*. You may continue to operate the pipeline only if you: (1) Provide an equivalent degree of protection; and (2) Place an appropriate warning sign on the equipment removed from service.		
	(c) *Follow-up notification*. If you are required by paragraph (a) of this section to notify the Regional Supervisor immediately that safety equipment is out of service, you must also notify the Regional Supervisor immediately in the POCSR and AKOCSR, and within 12 hours in the GOMR, when you return the safety equipment to service, or when you provide an equivalent degree of protection.		
250.1086	**What must I do when a pipeline is taken out of service?**		
	(a) *Definition*. Out-of-service pipeline means a pipeline that has not been used to transport oil,	1. As commented earlier, pipelines may also transport chemicals or seawater. Also, for	(a) Out-of-service pipeline means a pipeline that has not been used to transport oil, natural gas,

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	natural gas, sulphur, or produced water for more than 30 consecutive days. The out-of-service period begins on the 31st day of inactivity.	subsea production systems, pipelines may also be used for USV/SSV testing, annulus maintenance activities, hot oiling, etc. 2. This definition is alarming for subsea production systems which have sections that will not operate for extended periods of time. Many subsea flowline systems are designed where entire segments do not experience flow for extended periods of time (so-called dead legs) for flow assurance and flow optimization reasons. These segments are still very much a part of the flow system (e.g. they may be used for hot oil start up circulation after extended shut-down) but they do not see normal production flow For example: where a looped system has been installed production will periodically flow either up both lines or up a single line, depending on the flow rates and characteristics. Production may or may not be routinely be flowed through a pigging loop connecting two pipelines. The requirement to treat these lines as out of service and the associated actions would result in significant downtime, cost and deferred production without any real improvement in integrity. MMS needs to establish different criteria for pipelines that are a part of a subsea production system.	sulphur, chemicals, seawater or produced water for more than 30 consecutive days (b) For pipelines that are part of a subsea production system out of service pipelines means a pipeline that is no longer used for the service it was intended for more than 30 consecutive days.
	(b) *Isolation*. You must immediately equip an out-of-service pipeline with either a blind flange or a block valve locked in the closed position at each end.	1. We do not agree that isolation must be provided immediately. The pipeline has already not been in use for 30 days by definition. In lieu of "immediate" we suggest 7 days. That would give us some flexibility to work around poor weather, etc.	**(b) *Isolation***. Within 7 days, you must equip an out-of-service pipeline with either a blind flange or a block valve locked in the closed position at each end.
	(c) *Safety equipment*. During the 30-day period	1. Testing of inactive safety systems is of little	

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	of inactivity preceding the date that a pipeline attains out-of-service status, you must maintain and test all required pipeline safety equipment.	value and these systems should be tested prior to being placed back into service.	
	(d) *Out-of-service report*. You must submit a written report to the Regional Supervisor within 48 hours after a pipeline attains out-of-service status. In the out-of-service report, you must include: (1) The name of the company submitting the report; (2) The name and telephone number of your contact; (3) The MMS-assigned pipeline segment number; (4) The reason you took the pipeline out of service; (5) An estimate of the time that the pipeline will remain out of service; and (6) Confirmation that you have isolated the pipeline as required by paragraph (a) of this section.	1. We suggest that MMS develop an electronic eWell type notification type submittal. It should also be included in the list of notifications in 250.1006(c). 2. Further we recommend the notification being within 30 days after a pipeline attains out of service status. This matches the reporting for putting a pipeline back in service.	**d) *Out-of-service report***. You must submit a written report to the Regional Supervisor within 30 days after a pipeline attains out-of-service status
	(e) *Flush and fill*. When a pipeline is out of service for one year, you must: (1) Immediately flush the pipeline with seawater until the returns comply with appropriate EPA NPDES standards; (2) Fill the pipeline with inhibited seawater; (3) Retain the records of your flush and fill activities at your nearest OCS facility until the pipeline is reactivated; (4) Make the records available to MMS upon request; and (5) If you discharge any returns into the water column, dispose of them in accordance with applicable laws and regulations.	1. We do not agree with flushing the pipeline until the returns comply with appropriate EPA standards since EPA has not established standards for flushing pipelines. In the GOM, the closest would be the discharge of hydrostatic test water of existing pipe, which includes toxicity testing which must be performed in a lab and is not something that can be determined onsite. The various EPA regions and permits have varying requirements for discharges. This requirement should be removed. The discharge of fluids is already covered in (e)(5). 2. Deepwater pipelines taken out of service, but being kept for future potential deepwater service should be “Pickled” so that hydrates are not formed once the line is returned to service. Exceptions for deepwater oil and gas lines should take this into consideration since deepwater pipelines are susceptible to flow assurance issues related to hydrates. Does	(e)(1) Immediately flush the pipeline with seawater

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		MMS consider "pickling" to be equivalent to filling with inhibited seawater?	
	(f) *Reactivation*. Before you reactivate an out-of-service pipeline, you must test all required safety equipment in accordance with the procedures in § 250.1084.		
	(g) *Reactivation report*. Within 30 calendar days after you reactivate an out-of-service pipeline, you must submit a written report to the Regional Supervisor. In the reactivation report, you must include the: (1) Name of the company preparing the report; (2) Name and telephone number of your contact; (3) MMS-assigned pipeline segment number; (4) Date you returned the pipeline to service; and (5) Report of the hydrostatic pressure test (see § 250.1061(a)), if required by § 250.1060(a)(4).	1. We suggest that MMS develop an electronic eWell type notification type submittal. It should also be included in the list of notifications in 250.1006(c).	
	(h) *Decommissioning an out-of-service pipeline*. You must decommission (see § 250.1105 through 250.1113) a pipeline within 1 year after: (1) It has been out of service for 5 years; or (2) You determine that it will be out of service for 5 years or more.		
250.1087	**What must I do if a pipeline is shut in?**		
	Before you resume operations after your pipeline was shut in, you must determine that the pipeline does not leak by conducting a visual survey of the pipeline route (see § 250.1103(a)) and a leak test (see § 250.1059). These requirements are applicable if your pipeline was shut in because:		
	(a) The eye center path of a major storm (winds 74 mph or greater) passed within 25 miles (or other distance specified by the Regional Supervisor) of any part of the pipeline;		
	(b) You had indications that pipeline integrity may have been compromised; or		
	(c) Your pipeline had an unexplained automatic shut-in (e.g., a PSL shut-in).	1. It is unreasonable to conduct a visual survey and/or leak test each time a pipeline has an inadvertent shut-in. We assume this only applies if we fail to determine the cause of a shut in (accidental valve closure on a downstream	

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		platform, sensor failure, etc). If this is not your intent, please clarify.	
250.1088	**What must I do if a pipeline leaks?**		
	If your pipeline experiences an accidental leak, you must:		
	(a) Immediately suspend operations and not resume operations until the pipeline is repaired in accordance with § 250.1094 through 250.1096; and		
	(b) Notify the Regional Supervisor immediately, or as soon as practicable, after you discover that a pipeline is leaking.	(b) we suggest adding "once the situation is stabilized" which corresponds to immediate notifications made under Incident Reporting in 250.189.	(b) Notify the Regional Supervisor immediately once the situation is stabilized, or as soon as practicable, after you discover that a pipeline is leaking.
250.1089	**What must I do if I need to flare or vent gas from a pipeline?**	Flaring and venting Requirements are covered in Subpart K. We recommend that this section be deleted due to duplication and to ensure that conflicts do not occur.	Delete this section.
	(a) *Approval*. You must receive approval from the Regional Supervisor to flare or vent natural gas from your pipeline during blowdown, unless the blowdown discharge point is downstream of the royalty meter (see subpart K, redesignated § 250.1155).		
	(b) *Report*. You must submit a written report to the Regional Supervisor that includes the location, time, flare or vent volume, and the reason for flaring or venting, within 72 hours after you complete the flaring or venting operations (see subpart K, redesignated § 250.1155).		
	(c) *Extended flaring or venting*. If you need to flare or vent natural gas from a pipeline for 48 continuous hours or more, you must adhere to the requirements in subpart K, redesignated § 250.1155.		
250.1090	**When must I provide impact protection for existing risers?**		
	You must provide impact protection to all pipeline risers installed prior to April 1, 1988, and that are outside of the platform structure, whenever:		
	(a) The Regional Supervisor determines that significant damage potential exists;		
	(b) You perform maintenance or repair		

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	operations on any existing pipeline riser that is protected by a pipe-in-pipe configuration; or		
	(c) You perform major repairs or modifications on any pipeline riser that is not protected.	1. Modifications is a broad spectrum of activities including physical changes and such changes as flow direction. We suggest this be limited to physical modifications.	(c) You perform major repairs or physical modifications on any pipeline riser that is not protected.
250.1091	**When will MMS suspend or temporarily prohibit pipeline operations?**		
	The Regional Supervisor may suspend or temporarily prohibit any pipeline operation if:		
	(a) The Regional Supervisor determines that continued activity would threaten or result in serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life); property; mineral resources; or the marine, coastal, or human environment;		
	(b) The Regional Supervisor determines that you have failed to comply with a provision of the OCSLA or any other applicable law, a provision of this part or other applicable regulations, or a condition of a pipeline application approval or a pipeline ROW grant; or		
	(c) Prohibiting the pipeline operation is in the interest of national security or defense.		
Pipeline Modifications and Repairs			
250.1093	**What must I do to modify an approved pipeline?**		
	(a) *Definition*. Modifying a pipeline means significantly changing an approved pipeline. Modifications include changing a pipeline route; installing, modifying, or replacing a subsea tie-in valve assembly; adding, modifying, or replacing safety equipment; changing service; changing flow direction; installing or replacing a pig receiving/launching assembly; changing a pipeline riser configuration; changing the MAOP; replacing or adding anodes; and adding a hot-tap. Modifications do not include routine operations such as performing a hydrostatic pressure test; pigging; injecting chemicals; flushing and filling a pipeline; installing a blind	1. Replacing safety equipment that is not different should not be a modification. Suggest this should be "changing" safety equipment and in the "do not include" sentence include a statement on replacing safety equipment.	**(a) *Definition*.** Modifying a pipeline means significantly changing an approved pipeline. Modifications include changing a pipeline route; installing, modifying, or replacing a subsea tie-in valve assembly; adding, modifying, or installing different safety equipment; changing service; changing flow direction; installing or replacing a pig receiving/launching assembly; changing a pipeline riser configuration; changing the MAOP; replacing or adding anodes; and adding a hot-tap. Modifications do not include routine operations such as performing a hydrostatic pressure test; pigging; injecting chemicals; flushing and filling a pipeline; installing a blind

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	flange on an out-of-service pipeline; installing a clamp, sleeve, or wrap to mitigate pipe wall loss; and performing other routine operations or preventive maintenance.		flange on an out-of-service pipeline; installing a clamp, sleeve, or wrap to mitigate pipe wall loss; replacing safety equipment with that of the same type and design and performing other routine operations or preventive maintenance.
	(b) *Modification application.* Before you conduct any operations to modify a pipeline, you must submit three copies of a modification application to the Regional Supervisor for approval. In the modification application, you must include each of the elements required by the following paragraphs (b)(1) through (b)(7) of this section. (1) The MMS-assigned pipeline segment number. (2) Those items in your approved pipeline application (see § 250.1014 through 250.1030) affected by the proposed modification. (3) The step-by-step procedures you will follow in making the modification, including the measures you will take to: (i) Ensure safety; (ii) Minimize pollution; (iii) Comply with burial and covering requirements; and (iv) Perform any required hydrostatic pressure or leak test. (4) If required by the Regional Supervisor, a work plan that describes the specific measures you intend to take, and the specific procedures you intend to follow, to ensure the safety of offshore workers and to prevent pollution. The work plan must include or consider: (i) The operating history of the pipeline you plan to modify, including past modifications or repairs, and the operating conditions peculiar to the pipeline; (ii) Reasonable measures to ensure that pressure in the pipeline is equal to the external pressure; (iii) Reasonable measures to ensure that you purge combustibles and H_2S from the pipeline	(b) The detailed information being requested indicates that MMS wants to take an active role in the operations which is a departure from the past agency posture and indicates a shift in MMS approach to actual work being carried out. We are concerned that MMS lacks the operational/worksite experience to add value to this effort and by approving work to this detail has some responsibility if things should go wrong. We also note that there is no timeframe for MMS to approve the modification application and believe this should be added. We are concerned with the cycle time for approval. Further, the requirements as written are more applicable for a physical modifications such as cutting into pipe. The application requirement should be simplified for such things as changing the flow direction. We suggest MMS rework this paragraph. (b)(2) We do not understand why we are required to provide the environmental information in 250.1030 for a pipeline modification. In most cases, this will simply be “the proposed modification does not affect any of the information provided in 250.1030.” However, since providing the information in 250.1030 is a new requirement in this rulemaking, none of the currently approved pipeline applications will have this information. Surely it is not MMS intent that we have to provide all the information in 250.1030 for each and every modification on all pipelines previously permitted in the GOM. We suggest that you eliminate this requirement.	(2) Those items in your approved pipeline application (see § 250.1014 through 250.1029) affected by the proposed modification. (i) Address safety (4) If required by the Regional Supervisor, a work plan that describes the specific measures you intend to take, and the specific procedures you intend to follow, to address the safety of offshore workers and to prevent pollution.

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	immediately before you conduct the modification; (iv) Advance notification to facility workers (both company and contract) concerning significant aspects of the upcoming modification; (v) Re-notification of all facility workers immediately before you attempt to de-pressurize, cut into, or open the pipeline to perform the modification; (vi) Onsite supervision during the entire modification operation; and (vii) Safeguards to ensure that the pipeline remains isolated during the entire modification operation so that facility workers are not endangered by pressure, H_2S, or explosive or combustible products. (5) Requests for alternative compliance (see § 250.141) necessitated by the modification. (6) If applicable, an electronic file containing the digital coordinates of sufficient points to provide an accurate representation of the proposed modified route, including turns, for both the pipeline and umbilicals. (7) Payment of a nonrefundable service fee (see § 250.125 for amount).	(b)(3)(i) Address safety is what we do in procedures and work plans. We recommend this phrase be used in lieu of "ensure" throughout this paragraph. (b)(4)(i) These records are already provided to the agency and should not be required to be provided again, unless the agency specifically requests them.	
	(c) ***Hot tap modification application****.* If you plan to modify a pipeline by installing a hot tap, your modification application must include, in addition to the requirements in paragraph (b) of this section: (1) The design specifications for the hot tap; (2) A drawing of the proposed hot tap assembly; (3) A plat that shows the location of the hot tap, specifies its location in both X-Y coordinates and latitude and longitude in NAD 27 for the GOMR (Gulf) and POCSR, or NAD 83 for AKOCSR and GOMR (Atlantic), and shows the water depth (feet); and (4) A description of the hot tapping operations.		
	(d) ***Affected States.*** Unless each affected State has given general concurrence, or the Regional Director determines that a State is not an affected State, you must provide the information		

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	required by § 250.1016(a) if your planned modification of an approved ROW pipeline involves: (1) Installation of additional pipe (except those modifications that involve only minor reconfiguration of existing pipelines); (2) Installation of a new accessory platform; or (3) Changing the product from natural gas to oil.		
	(e) ***MMS review****.* A pipeline modification application is subject to the same review requirements as those for a new pipeline application (see § 250.1009).		
	(f) ***Relocation notification.*** If the approved pipeline modification involves the relocation of a pipeline, you must notify the Regional Supervisor at least 48 hours before you begin the work, using Form MMS-153 (Notification of Pipeline Installation/Relocation/Hydrotest).		
	(g) ***Modification report****.* Within 30 calendar days after you complete any pipeline modification that changed the location plat, or that required a hydrostatic pressure test, you must submit a written modification report to the Regional Supervisor. In the modification report you must include all of the following: (1) The MMS-assigned pipeline segment number. (2) If applicable, a location plat based on the NAD 27 for the GOMR (Gulf) and POCSR, or NAD 83 for AKOCSR and GOMR (Atlantic), at a minimum scale of 1 inch = 2,000 feet that: (i) Depicts the actual location of the modification; (ii) Includes the latitude and longitude coordinates in both NAD 27 and NAD 83, and the X-Y coordinates in NAD 27 for the GOMR (Gulf) and POCSR, or NAD 83 for the AKOCSR and GOMR (Atlantic), of the key points of the modification; and (iii) Includes a certification by a registered engineer or land surveyor that attests to the accuracy of the "as-built" locations of the pipeline as modified.	30 days is too short	Within 60 calendar days…

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	(3) If applicable, an electronic file containing the digital coordinates of the key points of the "as-built" pipeline and umbilical routes, including turns, as modified. You must report the digital data in decimal degrees latitude and longitude, based on NAD 83. (4) Confirmation that the modification was accomplished as approved by the Regional Supervisor. (5) If applicable, a report of the hydrostatic pressure test (see § 250.1061) required by § 250.1060(a)(2), (3), or (6). (6) If applicable, the pipe-to-electrolyte potential measurements required by § 250.1043(b).		
250.1094	**What are the general requirements for repairing a pipeline?**		
	Repairing a pipeline means performing remedial work as a result of a failure and/or the leaking of a pipeline or associated equipment, or a reduction in wall thickness that would have required a reduction in the MAOP. You must repair a pipeline in a manner that:	1. We assume that installing a clamp, sleeve, or wrap to mitigate pipe wall loss that would not have required a reduction in the MAOP is not a repair. If this is not correct, please clarify.	
	(a) Meets or exceeds the original design specifications of the pipeline, appurtenances, and safety system components;		
	(b) Prevents unauthorized discharges;		
	(c) Does not unreasonably interfere with other uses of the OCS; and		
	(d) Does not cause undue or serious harm or damage to the human, marine, or coastal environment.		
250.1095	**What must I do to commence and complete a repair?**		
	(a) *Repair application.* Before you conduct any repair work on a pipeline, you must submit one copy of an application to the Regional Supervisor for approval. You may submit this repair application at the same time as, or after, you make the notification required by § 250.1088(b). The repair application must include all of the elements required by the following paragraphs (a)(1) through (a)(9) of this section.	1. Repair applications should not be required if operators are repairing the pipeline to its original design using pre-approved repair methods. MMS should provide approved repair methods for existing pipelines and allow operators to proceed without formal approval. MMS may list expectations operators are to use during these operations. The application and approval process is unnecessary and prolongs downtime.	

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	(1) The MMS-assigned pipeline segment number. (2) The location (latitude and longitude in NAD 27 for the GOMR (Gulf) and POCSR, and in NAD 83 for AKOCSR and GOMR (Atlantic)) and water depth (feet) of the repair. (3) A description of the damaged component, and the reason for the repair. (4) For pipelines that transport liquids, an estimate of the volume spilled (barrels), including slick size and appearance, if applicable. (5) For pipelines that transport natural gas, an estimate of the volume of gas leaked (MMCF), including sheen/boil size and appearance, if applicable. (6) Specifications of any new pipe, spool piece, clamps, or other materials you will use in making the repair. (7) The step-by-step procedures you will follow to make the repair, including the measures you will take to: (i) Ensure safety; (ii) Minimize pollution; (iii) Comply with burial and covering requirements; and (iv) Conduct any required hydrostatic pressure or leak test. (8) If required by the Regional Supervisor, a work plan that describes the specific measures you intend to take, and the specific procedures you intend to follow, to ensure the safety of offshore workers and to prevent pollution. The work plan must include or consider: (i) The operating history of the pipeline you plan to repair, including past modifications or repairs, and the operating conditions peculiar to the pipeline; (ii) Reasonable measures to ensure that pressure in the pipeline is equal to the external pressure; (iii) Reasonable measures to ensure that you purge combustibles and H_2S from the pipeline	2 The “safe-out” of a damaged pipeline (on the riser or prior to the boarding SDV or after the departing SDV) should not require a repair procedure. These safe-out procedures are necessary to conduct a failure analysis that will determine the cause of the failure and will then lead to the proper design of a repair. 3. Insitu pipelines repairs are complex and dynamic responses to a upset or adnormal condition where the integrity of the system is breached. The specific repair requirements are not necessarily know until the leak is found, investigative work is carried out and a plan formulated to address timely and safe repair to the system. Several repair methods may be carried out to the job site and once investigative efforts are completed a better understanding of the extent of the damages and how best to repair may be developed. We do not see the value of the development of a repair plan before we are aware of the extent of the damage and the various potential repair schemes are evaluated by the owners and operators of the system is made. Once mobilized for the actual work, submittals of detailed plans may slow up work, confine the effort to pre-prescribed work and if field conditions change necessitate a re-submittal of plans which takes time and is very costly to system downtime. We believe that continuing to inform the MMS of the progress of field investigative work and discussing of the plans to repair can be effective in getting a timely repair carried 4 We note that MMS has not included a timeframe in which they will approve a repair application. We are concerned with cycle time and recommend that MMS include a timeframe in which they will review the application.	

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	immediately before you commence the repair work; (iv) Advance notification to all facility workers concerning significant aspects of the upcoming repair work; (v) Re-notification of all facility workers immediately before you attempt to de-pressurize, cut into, or open the pipeline to perform the repair work; (vi) Onsite supervision during the entire repair operation; and (vii) Safeguards to ensure that the pipeline remains isolated during the entire repair operation so that facility workers are not endangered by the release of pressure, H_2S, or explosive or combustible products. (9) Payment of a nonrefundable service fee (see § 250.125 for amount).	5. If MMS rejects a repair plan will they propose an alternate or is industry forced to continue to "guess" at how MMS would like the repair to be carried out? Does approval of the repair plan indicate MMS participation in the decision and hence responsible in some way for the selected method? 6. The Pre-approval" ' for pipeline repairs is a sticky point and operator's responsibility to promptly react to a breach in integrity in a system is going to be important. We need to make sure the requirement does not preclude us being able to stabllize the situation and perform any tasks necessary to address pollution concerns. Including the potential to clamp and remove fluids in the line that may be a problem. 8. Since repair could include something as simple as replacing a gauge or instrument valve, a simplified application and approval process should be developed separately from one in which the line pipe must be approved. 7. We recommend that MMS rework this paragraph.	
	(b) ***MMS review***. The Regional Supervisor will review the pipeline repair application to ensure that the proposed operations conform to the regulations in this subpart.	1. We note that you use the term "review" not "approve" . Yet, in paragraph (a), we have to submit the application for approval. Please clarify. 2. If MMS must approve the application before the work commencing, a timeframe for that approval needs to be established. This particularly true when repairs need to be made immediately.	
	(c) ***Pressure testing***. You must comply with the		

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	pressure testing requirements in § 250.1060(b) and (c).		
	(d) *Cathodic protection system measurements*. When you conduct underwater repairs, you must measure the pipe-to-electrolyte potential at the location of the repair site if your pipeline: (1) Is located in the AKOCSR; or (2) Is located in either the GOMR or POCSR and either: (i) The pipeline is composed of any pipe that is more than 20 years old; or (ii) The life expectancy of the cathodic protection system cannot be calculated.	1. Since pipe-to electrolyte readings have to be taken annually, we do not understand the benefit of taking these readings at the location of a pipeline repair. Please clarify what how this information will be utilized.	
	(e) *Repair report.* You must submit a written repair report to the Regional Supervisor within 30 calendar days after you complete a repair. In the repair report, you must include: (1) The MMS-assigned pipeline segment number; (2) The actual location of the repair (latitude and longitude in NAD 27 for the GOMR (Gulf) and POCSR, and in NAD 83 for the AKOCSR and GOMR (Atlantic)) and water depth (feet); (3) Confirmation of the failure or damage to the pipeline as originally reported to the Regional Supervisor; (4) Confirmation that the repair was accomplished as approved by the Regional Supervisor; (5) For pipelines that transport liquids, an estimate of the volume that spilled (barrels), if any, while you performed the repair work; (6) A report of any hydrostatic pressure test (see § 250.1061(a)) required by § 250.1060(b) and (c); (7) The results of any leak test (see § 250.1061(b)) required by § 250.1060(b)(1) or (c)(1); and (8) The pipe-to-electrolyte potential measurements required by paragraph (d) of this section.	1. The prescriptive report being required is significantly more detailed than previously required by MMS and the industry would like to know why such detail is necessary. Many of the items noted are already in the agency records and can be looked up in agency records inlieu of the need to re-create then again. Please advise why duplicate information is necessary. 2. Request that 30 days be changed to 60 days.	**e) *Repair report.*** You must submit a written repair report to the Regional Supervisor within 60 calendar days after you complete a repair. In the repair report, you must include:

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(f) Failure analysis and examination. The Regional Supervisor may require you to analyze a pipeline failure, and examine samples of a failed pipe or associated equipment in a laboratory to determine the cause of failure. When so directed, you must submit a comprehensive written report of your findings to the Regional Supervisor.</td><td></td><td></td></tr>
<tr><td>250.1096</td><td>What must I do to repair a pipeline using a clamp?</td><td></td><td></td></tr>
<tr><td></td><td>When repairing a pipeline using a clamp, you must comply with the requirements in the following table:
<table>
<tr><th>If you use . . .</th><th>Then . . .</th></tr>
<tr><td>(a) A clamp to make a repair on a pipeline</td><td>You must use a full encirclement clamp with a rated working pressure equal to or greater than the MAOP of the pipeline.</td></tr>
<tr><td>(b) A clamp on the horizontal component or on the riser below the splash zone</td><td>You may use a welded clamp or a mechanical clamp.</td></tr>
<tr><td>(c) A mechanical clamp to temporarily repair a riser in or above the splash zone</td><td>You must: (1) Submit a repair application (see § 250.1095(a)) to the Regional Supervisor for approval to make a permanent repair. (2) Within 30 calendar days after you install the mechanical clamp, complete the permanent repair using a welded clamp, spool piece, or other method approved by the Regional Supervisor.</td></tr>
</table></td><td>1. The MMS should consider the installation of the temporary clamp and the permanent repair as one repair. The MMS has charged a repair fee for both installations in the past.

2. These repairs should be pre-approved if using equipment and/or methods already approved by the MMS.

3. MMS should allow for pipeline repairs using double grip and seal connectors, provided that technology has been properly qualified for the specific use.

4. We assume that this paragraph only applies to clamps and MMS is not precluding the use of other proven technologies to repair a pipeline.</td><td></td></tr>
<tr><td>250.1097</td><td>When do I need to submit a corrective action plan and report?</td><td></td><td></td></tr>
<tr><td></td><td>(a) Plan. The Regional Supervisor may require you to submit a corrective action plan for approval if there are internal or external conditions that could detrimentally affect a pipeline including, but not limited to:
(1) Conditions that might affect the performance or integrity of pipeline valves and fittings at a</td><td>1. What needs to be included in a corrective action plan and how does this differ from a repair application or modification application. Please clarify.</td><td></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	subsea tie-in; (2) Conditions that could cause interference with navigation or other uses of the OCS; (3) Riser or riser clamp damage; (4) Pipeline exposure or displacement; or (5) Anomalies and metal loss.		
	(b) *Submittal.* You must submit the corrective action plan required by paragraph (a) of this section to the Regional Supervisor. If the remedial work under the corrective action plan requires MMS approval of a modification application (see § 250.1093(a)) or a repair application (see § 250.1095(a)), you may include the appropriate application in your corrective action plan.		
	(c) *Report.* The Regional Supervisor may require you to submit a written report, within 30 calendar days after you complete the corrective action, confirming that you carried out your corrective action plan as approved.	1. We request 60 days to match the repair and modification report requirements.	**(c) *Report.*** The Regional Supervisor may require you to submit a written report, within 60 calendar days after you complete the corrective action, confirming that you carried out your corrective action plan as approved.
Pipeline Surveying, Monitoring and Inspection			
250.1100	**What are the general requirements for surveying, monitoring, and inspecting a pipeline?**		
	You must survey, monitor, and inspect all pipelines, including shut in pipelines, in a manner that:		
	(a) Periodically verifies the integrity of the pipeline and risers;		
	(b) Prevents unauthorized discharges		
	(c) Does not unreasonably interfere with other uses of the OCS; and		
	(d) Does not cause undue or serious harm or damage to the human, marine, or coastal environment.		
250.1101	**What must I do to survey and monitor a pipeline or route?**	1. This is an area where MMS and DOT regulations do not conform. We recommend that this be applicable to pipelines under DOI requirements until such time that MMS and DOT agree on compatible regulations.	**What must I do to survey and monitor a pipeline or route under DOI jurisdiction (Pipelines under DOT should be surveyed and monitored in accordance with the regulations in 49 CFR 192 and 195)?**

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(a) Surveying. You must conduct a visual survey of each of your pipeline routes at least monthly (or at a frequency specified by the Regional Supervisor) for indication of pipeline leaks. You may conduct this visual survey from a helicopter, marine vessel, or vehicle; by walking on ice; or by other means approved by the Regional Supervisor. The survey must be conducted during daylight hours (except in the AKOCSR). You must retain the results of the visual survey for at least 2 years, and make them available to MMS upon request.</td><td>1. We assume an operator can propose an alternate survey and monitoring method and schedule and submit it for approval by the Regional Supervisor if desired. Please confirm.</td><td></td></tr>
<tr><td></td><td>(b) Product monitoring. You must monitor the products transported in the pipeline to ensure that your internal corrosion and flow assurance measures remain effective.</td><td></td><td></td></tr>
<tr><td>250.1102</td><td>What inspections are required for my pipeline or route?</td><td></td><td></td></tr>
<tr><td></td><td>You must conduct the inspections in the following table:
<table>
<tr><th>Component and conditions for inspection</th><th>Inspection requirements</th><th>Reporting and recordkeeping requirements</th></tr>
<tr><td>(a) All risers</td><td>You must: (1) Conduct a visual inspection of each pipeline riser in and above the splash zone at least annually for indications of damage or corrosion (2) In conjunction with the platform inspections required by § 250.919, inspect the underwater portions of each pipeline</td><td>You must retain the records of the riser inspections for at least 2 years on the nearest OCS facility, and make them available to MMS upon request.</td></tr>
</table></td><td>1. (a)(2) We assume that the frequency for inspection of the subsea part of the riser is the same as the Level II frequency for platform inspection. If this is not correct, please clarify.

2. (a) (1) Visual inspection at the splash zone will require dives and very favorable weather conditions. We assume that an operator could submit an alternate program for monitoring the riser at the splash zone to the Regional Supervisor for approval. If our understanding is not correct, please clarify.

3. (a)(1) Please clarify that this is an external visual inspection.

4. (a) Riser may be located on a platform that doesn't support records retention.

5. (b) Flexjoint inspections should be conducted every two years in lieu of annually. Results should be due by Nov 1 of each year (to match structural inspection report). If damage is discovered then reported within 30 days.</td><td>(a) You must: (1) Conduct an external visual inspection of each pipeline riser in and above the splash zone

(a) You must retain the records of the riser inspections for at least 2 years at the pipeline operator's nearest field office nearest the OCS facility or other locations conveniently available to the District Supervisor, and make them available to MMS upon request.
<table>
<tr><td>(b) All flexible joints on risers</td><td>You must: (1) Conduct a visual inspection of the flexible joints on each riser at least every 2 years (2) If the results of an inspection required by item (1) of this paragraph indicate that a</td><td>You must submit the results of each flexible joint inspection to the Regional Supervisor by Nov 1 of each year. If damage is found, the results must be reported within 30 calendar days</td></tr>
</table></td></tr>
</table>

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		riser for indications of corrosion, soil erosion, or damage		6. (d) The CP reading reports should be submitted to MMS at the same time as the structural CP readings.	
	(b) All flexible joints on risers	You must: (1) Conduct a visual inspection of the flexible joints on each riser at least annually (2) If the results of an inspection required by item (1) of this paragraph indicate that a flexible joint shows signs of deterioration, conduct the required inspections at least every 6 months	You must submit the results of each flexible joint inspection to the Regional Supervisor within 30 calendar days after you complete the inspection.		
	(c) Impressed current sources if your pipeline is protected by rectifiers or other impressed current sources	You must inspect the impressed current sources at least six times each year (with no more than 10 weeks between inspections) to determine if the pipeline is adequately protected	You must retain the records of the impressed current source inspections for at least 2 years on the nearest OCS facility, and make them available to MMS upon request.		
	(d) Anode systems if your pipeline is cathodically protected by anodes and if	You must measure the pipe-to-electrolyte potential annually by	You must submit the pipe-to-electrolyte potential measurements to the Regional		

	flexible joint shows signs of deterioration, conduct the required inspections at least every 6 months	after you complete the inspection.

(d) You must submit the pipe-to-electrolyte potential measurements to the Regional Supervisor no later than Nov 1 of the same year,

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>
<table>
<tr><td>your pipeline is:

(1) Located in the POCSR or AKOCSR; or
(2) Located in the GOMR and either:
(i) The pipeline is composed of any pipe that is more than 20 years old; or
(ii) The life expectancy of the cathodic protection system cannot be calculated.</td><td>September 30 of each year</td><td>Supervisor no later than October 31 of the same year, or within 60 calendar days of the measurements, whichever is earlier.</td></tr>
</table>
</td><td></td><td></td></tr>
<tr><td>250.1103</td><td>What additional inspections or surveys may the Regional Supervisor require?</td><td></td><td></td></tr>
<tr><td></td><td>The Regional Supervisor may require you to conduct the inspections or surveys in the following table:
<table>
<tr><th>Type of inspection the regional supervisor may require</th><th>Inspection requirements</th><th>Reporting and record keeping requirements</th></tr>
<tr><td>(a) Horizontal components inspection</td><td>Conduct a visual or remote inspection of the horizontal component of your pipeline</td><td>Submit a report on the results of the horizontal component inspection to the Regional Supervisor.</td></tr>
</table>
</td><td>1. The performance based integrity management program should determine the “optimal” method and frequency of integrity assessment, e.g. technique, frequency, and extend of monitoring, inspection and testing activities. Worth noting is that a large number of GoM lines can not be made subject to ILI, and will required application of emerging technologies to provide adequate basis for proper integrity assessments. ILI is not a reasonable requirement unless Pipeline Design specifications ensure such operation can be performed.</td><td></td></tr>
</table>

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
			The Regional Supervisor will specify the contents and submittal deadline of the report.		
	(b) Pipeline inspection after a storm. If any portion of your pipeline within 25 miles (or other distance specified by Regional Supervisor) of the eye (central path) of a major storm (74 mph or greater)	(1) Survey the pipeline route (2) Conduct a visual inspection of the above-water portion of the pipeline riser for damage to the riser and clamps (3) Inspect the underwater portion of the pipeline riser (including clamps, VIV suppression, and connection devices) for evidence of displacement or exposure (4) Inspect the horizontal component from the base of the riser to a point at least 200 feet away from the base of the riser for evidence of displacement or exposure (5) Conduct an underwater visual inspection by	Submit a report of the results of the post-storm inspection(s) listed in this paragraph to the Regional Supervisor. The Regional Supervisor will specify the contents and submittal deadline of the report.		

Proposed Section Number	Proposed Text			Summary of Comments and Rationale	Proposed Language
		divers or ROV of each of your pipeline valves, crossings, and tie-ins to determine: (i) Whether or not any valves or fittings became exposed; and (ii) The extent of any damage, including damage to protective devices, mats, and sandbags			
	(c) Pipeline Inspection after an earthquake. If any portion of your pipeline mayhave been affected by an earthquake	Conduct surveillance, inspection, and monitoring of the pipeline	Submit a report on the results of the post-earthquake surveillance, inspections, or monitoring to the Regional Supervisor. The Regional Supervisor will specify the contents and submittal deadline of the report.		
	(d) Ultrasonic test (UT) inspection	Conduct a UT inspection of your pipeline	Submit a report on the UT inspection results to the Regional Supervisor. The Regional Supervisor will specify the contents and submittal deadline of the		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	<table><tr><td></td><td></td><td>report.</td></tr><tr><td>(e) In-line inspection</td><td>Conduct an in-line inspection of your pipeline using smart pigs</td><td>Submit a report on results of the in-line inspection to the Regional Supervisor. The Regional Supervisor will specify the contents and submittal deadline of the report.</td></tr><tr><td>(f) Trawl test or other survey</td><td>Conduct a trawl test, diver survey, or ROV survey, or use another method approved by the Regional Supervisor, to determine whether the pipeline interferes with other uses of the OCS</td><td>Submit a report on the results of the trawl test, diver survey, or ROV survey to the Regional Supervisor. The Regional Supervisor will specify the contents and submittal deadline of the report.</td></tr></table>		
Pipeline Decommissioning			
250.1105	**When do I accrue pipeline decommissioning obligations?**		
	You accrue pipeline decommissioning obligations when you are, or become:		
	(a) A lessee, or the owner of operating rights, of a lease on which there is a lease term pipeline; or		
	(b) The holder of a pipeline ROW on which there is a pipeline, accessory, or appurtenance (including umbilicals).		
250.1106	**When must I decommission a pipeline?**		
	You must decommission your pipeline within 1 year after:		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(a) The pipeline has been out of service for 5 years (see § 250.1086(h)(1));</td><td></td><td></td></tr>
<tr><td></td><td>(b) You determine that a pipeline will be out of service for 5 years or more (see § 250.1086(h)(2));</td><td></td><td></td></tr>
<tr><td></td><td>(c) For ROW pipelines, your pipeline ROW grant terminates (see § 250.1138(b)); or</td><td></td><td></td></tr>
<tr><td></td><td>(d) For lease term pipelines, your OCS lease terminates.</td><td></td><td></td></tr>
<tr><td>250.1107</td><td>What must I do to decommission a pipeline in place?</td><td></td><td></td></tr>
<tr><td></td><td>You may decommission a pipeline in place when the Regional Supervisor determines that the pipeline does not constitute a hazard or obstruction to navigation and commercial fishing operations, unduly interfere with other uses of the OCS, or have adverse environmental effects. To decommission a pipeline in place you must meet the requirements in the following table.
<table>
<tr><th>Requirement</th><th>What you must do to meet the requirement</th></tr>
<tr><td>(a) Application</td><td>Submit a pipeline decommissioning application to the Regional Supervisor in accordance with § 250.1109(a)(1), and receive approval from the Regional Supervisor before you begin the work.</td></tr>
<tr><td>(b) Purging and flushing</td><td>(1) You must either: (i) Pig the pipeline, including risers, using a pig that will displace the entire contents of the pipeline; or (ii) Flush the pipeline, including risers, with seawater until the returns comply with appropriate EPA NPDES standards. (2) If you discharge any flushed returns into the water column, you must dispose of them in accordance with applicable laws and regulations.</td></tr>
<tr><td>(c) Filling</td><td>Fill the pipeline, including risers, with seawater.</td></tr>
<tr><td>(d) Records</td><td>For each pipeline decommissioned in place after (INSERT THE EFFECTIVE DATE OF THE REGULATION), retain the records of your flushing and filling activities and make them available to MMS upon request for the life of the</td></tr>
</table></td><td>1.(b)(1) Please see our comments on flushing in 250.1086.

(h)(2) What is the significance of 2624ft water depth? If a line is decommissioned in water depths greater than 1000 ft, repair spool pieces and other appurtenances should be kept intact. We assume we could submit such a plan in our application for approval by the Regional Supervisor. If our understanding is not correct, please clarify.</td><td>(b)(1) You must either: (i) Pig the pipeline, including risers, using a pig that will displace the entire contents of the pipeline; or (ii) Flush the pipeline, including risers, with seawater.</td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	pipeline.		
	(e) Disconnecting: Disconnect the pipeline from connecting platforms, pipelines, and subsea manifolds.		
	(f) Cutting and plugging: Cut and plug each end of the pipeline.		
	(g) Protecting ends: Protect the ends of the pipeline as follows: (1) If the pipeline end is in a water depth less than 200 feet, bury the end to a depth at least 3 feet below the seafloor, and cover it with either sand bags or a concrete mat. If you use sand bags, they must have a slope above the seafloor of 1:3 (rise:run). If you use a concrete mat, the edges of the mat must be below the seafloor. (2) If the pipeline end is in a water depth 200 feet or greater but less than 500 feet, you may either bury the end to a depth at least 3 feet below the seafloor, or cover the end with a concrete mat. If you use a concrete mat, the edges of the mat must be below the seafloor. (3) If the pipeline end is in a water depth 500 feet or greater, you may forego burial and covering if the Regional Supervisor determines that the pipeline end is not an obstruction to other uses of the seafloor or area.		
	(h) Removing appurtenances: Remove all pipeline appurtenances unless: (1) The Regional Supervisor determines that the appurtenance would not unduly interfere with other uses of the seafloor or area; or (2) The water depth is greater than 2,624 feet.		
	(i) Decommission umbilicals in place: Decommissioning all umbilicals in place in accordance with the requirements of paragraphs (a) through (g) of this section.		
250.1108	**What must I do to decommission a pipeline by removal?**		
	To decommission a pipeline by removal, you	1. (b)(1) Please see our comments to 250.1086	(b)(1) (1) You must either: (i) Pig the pipeline,

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>must:<table><tr><th>Requirement</th><th>What you must do to meet the requirement</th></tr><tr><td>(a) Application</td><td>Submit a pipeline decommissioning application to the Regional Supervisor in accordance with § 250.1109(a)(2), and receive approval from the Regional Supervisor before you begin the work.</td></tr><tr><td>(b) Purging and flushing</td><td>(1) You must either: (i) Pig the pipeline, including risers, using a pig that will displace the entire contents of the pipeline; or (ii) Flush the pipeline, including risers, with seawater until the returns comply with appropriate EPA NPDES standards. (2) If you discharge any flushed returns into the water column, you must dispose of them in accordance with applicable laws and regulations.</td></tr><tr><td>(c) Removing umbilicals</td><td>Remove all umbilicals in accordance with the requirements of paragraphs (a) and (b) of this section.</td></tr><tr><td>(d) Removing the pipeline</td><td>Physically remove the pipeline.</td></tr></table></td><td>concerning flushing.</td><td>including risers, using a pig that will displace the entire contents of the pipeline; or (ii) Flush the pipeline, including risers, with seawater.</td></tr>
<tr><td>250.1109</td><td>How do I obtain approval to decommission a pipeline?</td><td></td><td></td></tr>
<tr><td></td><td>(a) To obtain approval to decommission a pipeline, you must:<table><tr><th>What to submit</th><th>Application contents</th></tr><tr><td>(1) Submit three copies of a pipeline decommissioning application to the Regional</td><td>(i)The MMS-assigned pipeline segment number; (ii) Reason for the decommissioning; (iii) Proposed decommissioning procedures, including those to comply with the requirements of § 250.1107; (iv) Length (feet) of pipe to be decommissioned; (v) Length (feet) of pipe that will remain in place; (vi) Requests for alternative compliance or a departure under § 250.141 or 250.142; and (vii) If the application is to</td></tr></table></td><td>1. (a)(1) Clarify that the requirement pertains to decommission in place and (a)(2) is to decommission by removal.

2. If all of the requirements in 250.1107 and 1108 are met by the proposed decommissioning activities, we do not understand why an application must be submitted for approval. Notification should be sufficient. An application is appropriate if alternative compliance or waivers are requested.</td><td>(a)(1) Submit three copies of a pipeline decommissioning in place application to the Regional Supervisor for approval

(a)(2) Submit three copies of a pipeline decommissioning by removal application to the Regional Supervisor for approval</td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	Supervisor for approval: decommission a lease term pipeline, payment of a nonrefundable service fee (see § 250.125 for amount). (2) Submit three copies of a pipeline decommissioning application to the Regional Supervisor for approval: (i) The MMS-assigned pipeline segment number; (ii) The reason for the decommissioning; (iii) Your proposed removal procedures, including decommissioning those to comply with the requirements of § 250.1108; (iv) A description of the vessel(s) you will use to remove the pipeline, including anchor pattern(s), if required by the Regional Supervisor. (v) The length (feet) of pipe to be removed; (vi) The length (feet) of pipe that will remain in place; (vii) Plans for transportation of removed pipe for disposal or salvage; (viii) Plans to protect archaeological and sensitive biological features during removal operations; (ix) An assessment of the environmental impacts of the removal operations, and the procedures and mitigation measures that you will take to minimize such impacts; (x) A projected pipeline removal schedule; (xi) If the application is to decommission an ROW pipeline by removal: (A) A coastal zone consistency certification according to 15 CFR 930.57, for each affected State; and (B) Evidence that you have sent your decommissioning application, consistency certification (see 15 CFR 930.57), and all necessary data and information (see 15 CFR 930.58) to each affected State for their consistency determination under the CZMA; and (xii) If the application is to decommission a lease term pipeline, payment of a nonrefundable service fee (see § 250.125 for amount).		
	(b) *Electronic submission.* You may submit part or all of your decommissioning application electronically (see § 250.186(a)(3)). If you prefer to submit your application electronically, you should consult with the Regional Supervisor for	1. We encourage MMS to continue developing their electronic submittal program.	

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>further guidance.</td><td></td><td></td></tr>
<tr><td></td><td>(c) Withdrawal of application. You may withdraw your decommissioning application at any time, for any reason, by notifying the Regional Supervisor in writing.</td><td></td><td></td></tr>
<tr><td>250.1110</td><td>How does MMS process a decommissioning application?</td><td></td><td></td></tr>
<tr><td></td><td>After you submit a decommissioning application, the Regional Supervisor will process it as shown in the following table.
<table>
<tr><th>Processing step</th><th>What the Regional Supervisor will do</th></tr>
<tr><td>(a) Completeness review.</td><td>Determine whether your decommissioning application (either in place or by removal) is complete, and will notify you in writing of any problem or deficiency. The Regional Supervisor will not begin processing your application until it is complete.</td></tr>
<tr><td>(b) Compliance review</td><td>Review the proposed operations described in your decommissioning application to ensure that they conform to the OCSLA (43 U.S.C.1331, et seq.), other applicable laws, and MMS regulations.</td></tr>
<tr><td>(c) Environmental impact evaluation</td><td>Evaluate the environmental impacts of the operations described in your decommissioning application, and prepare environmental documentation under NEPA (42 U.S.C. 4321, et seq.) and the implementing regulations (40 CFR parts 1500 through 1508).</td></tr>
<tr><td>(d) Amendments</td><td>During the review of your decommissioning application, the Regional Supervisor may require you, or you may elect, to change the application.</td></tr>
<tr><td>(e) MMS decision</td><td>Review your decommissioning application, notify you in writing of the decision, and either: (1) Approve the application, if it complies with all applicable requirements, and inform you of any conditions of approval; or (2) Require you to amend the application, and inform you of the reasons for requiring the amendment,</td></tr>
</table></td><td>1. We note that a timeframe for approval is not given. We request MMS to establish a timeframe for reviewing and approving the application.</td><td></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	if the proposed decommissioning operations would probably cause serious harm or damage to life (including fish or other aquatic life); property; mineral resources (in areas leased or not leased); the national security or defense; or the marine, coastal, or human environment.		
250.1111	**After I decommission a pipeline, what information must I submit?**		
	Within 30 calendar days after you decommission a pipeline, you must submit a written decommissioning report to the Regional Supervisor that includes:	1. We request the timeframe to be changed to 90 days.	Within 90 calendar days after you decommission a pipeline, you must submit a written decommissioning report to the Regional Supervisor that includes:
	(a) The MMS-assigned pipeline segment number;		
	(b) A summary of the decommissioning operation, including the date the work was completed;		
	(c) A description of any mitigation measures you took; and		
	(d) A statement signed by your authorized representative which certifies that the pipeline was decommissioned according to the approved application.		
250.1112	**When must I remove a pipeline decommissioned in place?**		
	If the Regional Supervisor subsequently determines that the pipeline decommissioned in place is an obstruction to other uses of the OCS, you must remove the pipeline in accordance with the requirements in § 250.1108, 1109(a)(2), and 1111.		
250.1113	**What are the requirements for re-commissioning a decommissioned pipeline?**		
	(a) *Re-commissioning*. Before re-commissioning a decommissioned pipeline, the current lessee, current designated lease operator, or former pipeline ROW holder, as applicable, must: (1) Submit an application under § 250.1007(a), including the MMS-assigned pipeline segment		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	number, and receive approval from the Regional Supervisor. (2) If the application is to re-commission a pipeline as an ROW pipeline, include: (i) An application for a pipeline ROW grant, if applicable (see § 250.1125(a)), and receive approval from the Regional Supervisor; and (3) Hydrostatically pressure test the pipeline in accordance with § 250.1060(a)(5). (4) Conduct all inspections required by the Regional Supervisor, including those in § 250.1102(b), (c), and (d) and § 250.1103(a), (d), and (e).		
	(b) *Re-commissioning report.* Within 30 calendar days after you re-commission a decommissioned pipeline, you must submit a written re-commissioning report to the Regional Supervisor that includes all of the following: (1) The MMS-assigned pipeline segment number. (2) A location plat based on the NAD 27 for the GOMR (Gulf) and POCSR, or NAD 83 for AKOCSR and GOMR (Atlantic), at a minimum scale of 1 inch = 2,000 feet. The location plat must depict the actual location of the re-commissioned pipeline. (3) An electronic file of the digital coordinates of the key points of your "as-built" pipeline route, as re-commissioned. You must report the digital data in decimal degrees latitude and longitude, based on NAD 83. (4) Confirmation that the re-commissioning was accomplished as approved by the Regional Supervisor. (5) A report of the hydrostatic pressure test (see § 250.1061) required by § 250.1060(a)(5).	1. We request the timeframe be changed to 90 days.	(b) Within 90 calendar days after you re-commission a decommissioned pipeline, you must submit a written re-commissioning report to the Regional Supervisor that includes all of the following:
Pipeline Right-of-Way (ROW) Grants			
250.1115	**What is a pipeline ROW grant?**		
	A pipeline ROW grant is an authorization issued by MMS for the use of submerged lands for the construction and operation of an associated ROW pipeline to transport oil, natural gas,		

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	sulphur, or other associated products.		
	(a) *Authority*. MMS grants a pipeline ROW pursuant to section 5(e) of the OCSLA (43 U.S.C. 1334(e)).		
	(b) *Term*. A pipeline ROW granted by MMS under the provisions of this subpart remains in effect until it is relinquished, cancelled, or forfeited, or until it expires.		
	(c) *Dimensions*. A pipeline ROW includes the site on which the pipeline, and any associated appurtenances and accessories, are or will be situated. (1) The width of the pipeline ROW is 200 feet centered on the pipeline. (2) The site of an accessory includes the areal extent of anchor chains, pipeline risers, and other facilities and devices associated with the accessory.	Please clarify how the length of the ROW is to be determined for pipelines with SCRs.	The pipeline ROW length is the total length (feet) of the proposed pipeline route from originating structure to terminating structure. For pipelines that include a catenary riser, the ROW length is from the originating structure to the operator defined riser touchdown point.
	(d) *Conveyed rights.* If the Regional Supervisor approves a pipeline ROW grant, you have the: (1) Exclusive right and privilege to construct, maintain, and operate the associated pipeline for the purpose of transporting oil, natural gas, sulphur, or other associated products; and (2) Right to be notified and consulted if any proposed OCS operations will cross or otherwise impact your pipeline ROW.		
250.1116	**When must I obtain a pipeline ROW grant?**		
	Before you may construct an ROW pipeline, or use an existing pipeline that qualifies as a ROW pipeline, the Regional Supervisor must grant you a pipeline ROW in accordance with the provisions of this subpart. You must receive a separate pipeline ROW grant for each ROW pipeline, even if the new pipeline ROW grant would overlap another pipeline ROW grant.		
250.1117	**Who can be a pipeline ROW grant holder?**		
	(a) *Entities*. A pipeline ROW holder must be one of the following: (1) A citizen or national of the United States; (2) An alien lawfully admitted for permanent residence in the United States as defined in 8		

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	U.S.C. 1101(a)(20); (3) A private, public, or municipal corporation recognized by the United States and organized under the laws of the United States or a territory thereof, the District of Columbia, or any State; or (4) An association (including a partnership) of such citizens, nationals, resident aliens, or private, public, or municipal corporations.		
	(b) *Qualification file.* In the pipeline ROW grant application required by § 250.1125(a), you may reference statements and records you previously submitted to an MMS OCS Region regarding incorporation, and the person(s) authorized to act on behalf of your corporation or association (see § 250.1126(b) and (c)) and to receive process and notifications. The Regional Supervisor will maintain this information in a qualification file. If you choose to establish a qualification file, you must ensure that it contains accurate and up-to-date information to avoid delays in reviewing your pipeline ROW grant application.		
	(c) *Disqualification.* The Director may disqualify you from acquiring any new pipeline ROW grants, or from holding any existing pipeline ROW grants, if your operating performance is unacceptable. The Director will give you notice and an opportunity for a review by MMS before disqualifying you.		
250.1118	**What are the financial security requirements for holding a pipeline ROW grant?**		
	(a) *ROW grant financial security.* You (the applicant) must furnish the Regional Director with a bond or other security in the sum of $300,000 for each pipeline ROW grant you hold. This security is in addition to any security required of a lessee by 30 CFR 256, subpart I, Bonding.		
	(b) *ROW grant area financial security.* In lieu of providing the security required by paragraph (a) of this section, you may maintain with the Regional Director, or furnish to the Regional Director, a bond or other security in the sum of $1 million that covers all of the pipeline ROW		

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	grants you hold in an MMS OCS Region. The following table shows MMS regions and the areas they encompass. <table><tr><th>MMS OCS regions are . . .</th><th>For OCS areas adjacent to the . . .</th></tr><tr><td>(1) Alaska OCS Region (AKOCSR).</td><td>State of Alaska.</td></tr><tr><td>(2) Gulf of Mexico OCS Region (GOMR).</td><td>Atlantic Coast States or in the Gulf of Mexico.</td></tr><tr><td>(3) Pacific OCS Region (POCSR).</td><td>States of California, Oregon, Washington, or Hawaii.</td></tr></table>		
	(c) *Additional financial security.* The Regional Director may require you to provide additional security (*i.e.*, security above the sum of $300,000 specified in paragraph (a) of this section, or the sum of $1 million specified in paragraph (b) of this section). (1) The Regional Director will base the determination and the amount of additional security on an evaluation of your ability to carry out present and future financial obligations under the pipeline ROW grant, including your obligation to maintain and remove an accessory to the ROW pipeline. (2) During the evaluation, the Regional Director will give you an opportunity to submit written or oral statements. (3) If the Regional Director requires additional security, you may either increase the amount of your existing bond or other security, or provide a supplemental bond(s) or other security.		
	(d) *General requirements.* Any bond or other security you provide under this section must: (1) Be submitted on Form MMS-2030 (Outer Continental Shelf (OCS) Pipeline Right-of-Way Grant Bond); (2) Be payable upon demand to the Regional Director; (3) Guarantee your compliance with the terms and conditions of the pipeline ROW grant, your obligations under the grant, the OCSLA (43		

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	U.S.C.1331, *et seq.*), other laws, and applicable MMS regulations; (4) If the security is a bond, be issued by a surety that the U.S. Department of the Treasury certifies as an approved surety on Federal bonds and that is listed in the current Treasury Circular No. 570; (5) If the security is a bond, be executed by authorized officials representing you and the surety; (6) If the surety is a corporation, be signed by an authorized corporate officer and attested to with its embossed corporate seal; and (7) Be non-cancelable, except as provided in § 250.1120 and 250.1124.		
	(e) *State law.* If the security is a bond, the bond must continue in full force and effect even if the surety's obligation has been diminished, terminated, or canceled under State law.		
250.1119	**When will MMS terminate the period of liability of my financial security?**		
	The Regional Director will not terminate the period of liability of your bond or other security for a pipeline ROW grant except under the conditions in this section.		
	(a) If your surety requests termination of liability from the Regional Director, the Regional Director will approve the request and terminate that period of liability within 90 calendar days after receipt of the request.		
	(b) If you intend to maintain the pipeline ROW grant, or have not fulfilled all decommissioning or other obligations, you must provide the Regional Director with a replacement bond or other security of equivalent value.		
	(c) When the Regional Director terminates the period of liability of a bond or other security, the period during which obligations continue to accrue ends. This termination does not relieve the surety of the responsibility for obligations and responsibilities that accrued during the period of liability and before the date of termination. The obligations and responsibilities that accrue during		

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	a period of liability also include those that began accruing before the beginning of the period of liability and have not been fulfilled.		
	(d) If the Regional Director terminates the period of liability, but the bond or other security is not cancelled, the surety that provided the bond will continue to be liable for accrued obligations until they have been fulfilled.		
250.1120	**When will MMS cancel my financial security?**		
	The Regional Director will cancel your bond or other security, and thus relieve the surety of accrued obligations, only if you request cancellation from the Regional Director and either:		
	(a) The Regional Director determines that there are no outstanding obligations; or		
	(b) You provide the Regional Director with a replacement bond or other security of equivalent value in which: (1) The new surety agrees to assume all outstanding liabilities under the bond or other security to be cancelled; and (2) The new bond or other security is in an amount equal to or greater than the bond or other security to be cancelled.		
250.1121	**What happens if my financial security is reduced or lapses?**		
	(a) *Reduced financial security value.* If the value of a required pipeline ROW grant bond or other security is reduced because of a default, or for any other reason, you must provide the Regional Director with additional coverage sufficient to meet the security required by § 250.1118(a) or (b) and, if applicable, § 250.1118(c). You must provide this additional coverage within 30 calendar days, or within a shorter period if required by the Regional Director, after the value of your security coverage is reduced.		
	(b) *Lapse of financial security.* If your surety is decertified by the Department of the Treasury, becomes bankrupt or insolvent, or has its charter		

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	or license suspended or revoked, your security coverage terminates immediately. In that event, you must: (1) Notify the Regional Director within 72 hours; and (2) Provide the Regional Director with a new bond or other security sufficient to meet the security required by § 250.1118(a) or (b) and, if applicable, § 250.1118(c) You must do this within 15 calendar days after your security coverage terminates, or within a shorter period if required by the Regional Director.		
250.1122	**How will MMS determine that my financial security is forfeited?**		
	(a) The Regional Director will pursue forfeiture of all or part of your bond(s) or other security if the Regional Director finds that either: (1) You refuse, or are unable, to comply with the terms and conditions of the pipeline ROW grant, your obligations under the grant, the OCSLA (43 U.S.C. 1331, *et seq.*), other laws, or applicable MMS regulations; or (2) You have otherwise defaulted under any condition imposed when the Regional Director accepted the bond or other security.		
	(b) The Regional Director may pursue forfeiture of your bond(s) or other security without first making demands for performance against you.		
	(c) In pursuing forfeiture of your bond(s) or other security, the Regional Director will: (1) Notify you and your surety in writing that the forfeiture process has begun, and include the reasons for the forfeiture and the amount to be forfeited; (2) Base the amount to be forfeited on an estimate of the total cost to bring your pipeline ROW grant into compliance, or to correct any default; and (3) Advise you and your surety in writing that you may avoid forfeiture if, within 5 working days either: (i) You agree to, and demonstrate that you will,		

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	bring your pipeline ROW grant into compliance or correct any default within a timeframe prescribed by the Regional Director; or (ii) Your surety agrees to, and demonstrates that it will, bring your pipeline ROW grant into compliance or correct any default within a timeframe prescribed by the Regional Director, even if the cost of compliance or correcting the default exceeds the amount of your bond or other security.		
	(d) If you or your surety refuse, or are unable, to comply with the conditions in paragraph (c)(3) of this section, the Regional Director will determine that your bond or other security is forfeited, and will: (1) Collect the forfeited amount; (2) Use the collected funds to bring your pipeline ROW grant into compliance, or to correct any default; (3) Initiate proceedings to recover from you all costs in excess of the amount the Regional Director collected from your forfeited bond or other security, if the collected funds are insufficient to bring your pipeline ROW grant into compliance or to correct any default; and (4) Return any funds collected from the forfeited bond or other security that were not used to bring your pipeline ROW grant into compliance or to correct any default.		
	(e) If your bond or other security is forfeited, you must furnish the Regional Director with a new bond or other security sufficient to meet the security required by § 250.1118(a) or (b) and, if applicable, § 250.1118(c). You must do this within 15 calendar days after your bond or other security was forfeited, or within a shorter period if required by the Regional Director.		
250.1123	**What penalties can MMS assess if my financial security is not sufficient, is reduced or lapses, or is forfeited?**		
	If you fail to provide any additional security required by the Regional Director (under §		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>250.1118(c)), replace or provide additional coverage for a devalued bond or other security (under § 250.1121(a)), or replace a lapsed or forfeited bond or other security (under § 250.1121(b) or § 250.1122), then:</td><td></td><td></td></tr>
<tr><td></td><td>(a) The Regional Director may assess penalties under 30 CFR 250, subpart N, Outer Continental Shelf (OCS) Civil Penalties;</td><td></td><td></td></tr>
<tr><td></td><td>(b) The Regional Supervisor may suspend the pipeline ROW grant in accordance with § 250.1135(b); and</td><td></td><td></td></tr>
<tr><td></td><td>(c) The Secretary may cancel the pipeline ROW grant in accordance with § 250.1137(a)(4).</td><td></td><td></td></tr>
<tr><td>250.1124</td><td>What happens to my financial security after a pipeline ROW grant terminates?</td><td></td><td></td></tr>
<tr><td></td><td>When your pipeline ROW grant terminates (either by relinquishment, cancellation, forfeiture, or expiration), your surety(s) remains responsible, and the Regional Director will retain your bond or other financial security as shown in the following table:
<table>
<tr><th>For . . .</th><th>the period of liability ends . . .</th><th>and . . .</th></tr>
<tr><td>(a) Securities provided under § 250.1118(a) or (b)</td><td>When the Regional Director determines that you have fulfilled all of your obligations under the pipeline ROW grant</td><td>(1) The Regional Director will cancel your financial security 7 years after the pipeline ROW grant terminates; 6 years after you complete all secured obligations; or at the conclusion of any appeals or litigation related to your secured obligation, whichever is the latest. (2) The Regional Director will reduce the amount or return a portion of your bond or other security if the Regional</td></tr>
</table></td><td></td><td></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language

		Director determines that a lesser amount is required to cover any unforeseen events under your accrued obligations.
(b) Additional securities provided under § 250.1118(c)	When the Regional Director determines that you have fulfilled all of your obligations covered by the additional security	The Regional Director will cancel your financial security either: (1) When you meet your secured obligations; or (2) Seven years after the pipeline ROW grant terminates; if the Regional Director determines that the amount required to cover unforeseen events under your accrued obligations is greater than the amount of the security you provided under § 250.1118(a) or (b); or (3) At the conclusion of any appeals or litigation related to your secured obligation; whichever is the latest.

250.1125	**How do I submit an application for a pipeline ROW grant?**		
	(a) *Application*. You must submit one original and two copies of an application for a pipeline ROW grant to the Regional Supervisor. You must attach the ROW grant application to the application for the associated ROW pipeline (see § 250.1007(a)), and include the information required by § 250.1126 in your ROW grant application.		

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	(b) *Service fee.* With each pipeline ROW grant application you submit, including an application for a pipeline ROW grant to convert an existing lease term pipeline to an ROW pipeline or an application to for an ROW grant for an existing pipeline, you must include payment of the applicable nonrefundable service fee (see § 250.125 for the amount).		
	(c) *Submitting additional information.* The Regional Supervisor may require your ROW grant application to include information in addition to that required by § 250.1126, if the Regional Supervisor determines that it is necessary to evaluate the application.		
	(d) *Electronic submission.* You may submit part or all of your pipeline ROW grant application electronically (see § 250.186(a)(3)). If you prefer to submit your pipeline ROW grant application electronically, you should consult with the Regional Supervisor for further guidance.		
	(e) *Withdrawal of application.* You may withdraw your pipeline ROW grant application at any time, and for any reason, by notifying the Regional Supervisor in writing.		
250.1126	**What information must I include in an application for a pipeline ROW grant?**		
	(a) *Cover letter.* You must provide a cover letter that states: (1) You are submitting the pipeline ROW grant application pursuant to section 5 of the OCSLA (43 U.S.C. 1334(e)) or section 8 of the OCSLA (43 U.S.C. 1337(p)(1)(B)) and the regulations contained in 30 CFR 250, subpart J; (2) You consent to be bound by the provisions of the OCSLA (43 U.S.C. 1331, *et seq.*) and other applicable laws, MMS regulations, and the terms and conditions of the pipeline ROW grant; (3) The purpose(s) for which you will use the pipeline ROW grant; and (4) The name, title, and signature of your authorizing official. This information must be the same as the information you provide or reference		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>in your MMS qualification records (see § 250.1117(b)).</td><td></td><td></td></tr>
<tr><td></td><td>(b) Qualification. You must provide information regarding your qualification to be a pipeline ROW holder as follows:
<table>
<tr><th>If you are . . .</th><th>You must provide . . .</th></tr>
<tr><td>(1) An individual</td><td>A statement of citizenship or nationality.</td></tr>
<tr><td>(2) An alien lawfully admitted for permanent residence in the United States</td><td>Evidence of such status.</td></tr>
<tr><td>(3) A corporation</td><td>(i) A statement certified by the Secretary or Assistant Secretary of the corporation with the corporate seal showing the State where it is incorporated; and (ii) The name(s), title(s), and signature(s) of the person(s) authorized to act on behalf of the corporation.</td></tr>
<tr><td>(4) An association (including a partnership)</td><td>(i) A certified copy of the articles of association; and (ii) The name(s), title(s), and signature(s) of the person(s) authorized to act on behalf of the association.</td></tr>
</table></td><td></td><td></td></tr>
<tr><td></td><td>(c) Reference to qualification records. In lieu of providing the information required by paragraphs (b)(3) and (4) of this section, you may reference statements and records you previously submitted to MMS regarding the corporation or association, and the persons authorized to act on behalf of the corporation or association (see § 250.1117(b)). If you choose this alternative, you must state that the company official who signed the cover letter has the authority to:
(1) Submit the pipeline ROW grant application;</td><td></td><td></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(2) Bind the corporation or association to compliance with the terms and conditions of the pipeline ROW grant; and (3) Bind the corporation or association to compliance with the various statements and certifications made in your pipeline ROW grant application.		
	(d) *Identified ROW pipeline operator.* If the pipeline ROW grant holder will not be the operator of the associated pipeline, you must identify the operator and provide its MMS company number, if any.		
	(e) *Bond or other financial security.* You must describe your bond or other security coverage for the proposed pipeline ROW (see § 250.1118(a) or (b)).		
	(f) *Additional financial security.* If the Regional Director determines that you must provide additional security, you must describe such security (see § 250.1118(c)).		
	(g) *Accessory footprint.* If your pipeline ROW will include a site for an accessory, you must provide the size of the affected area (acres), and information that shows how you determined the size (see § 250.1130(a)(2)) and the maximum water depth.		
	(h) *Payments*. You must include your service fee and rental payments, made payable to the Minerals Management Service. If you pay by credit card, follow the instructions in § 250.125(b)(1). If you pay by check, your check must identify the check number, date, and name of the financial institution upon which the check is written. You must provide additional information that includes: (1) Total amount of the service fee (see § 250.125(b)); (2) Total amount of the pipeline rental, and the time period it covers (see § 250.1130(a)(1)); (3) Total amount of rental for an accessory site (if applicable), and the time period it covers (see § 250.1130(a)(2)); and		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(4) Total payment amount.</td><td></td><td></td></tr>
<tr><td>250.1127</td><td>How does MMS process an application for a pipeline ROW grant?</td><td></td><td></td></tr>
<tr><td></td><td>(a) Compliance review. The Regional Supervisor will review your pipeline ROW grant application to ensure that it complies with the OCSLA (43 U.S.C.1331, et seq.), other applicable laws, and MMS regulations.</td><td></td><td></td></tr>
<tr><td></td><td>(b) Amendments. During the review of your pipeline ROW grant application, the Regional Supervisor may require you, or you may elect, to change the application.</td><td></td><td></td></tr>
<tr><td></td><td>(c) Decision. The Regional Supervisor will review your pipeline ROW grant application, and take one of the following actions:
<table>
<tr><th>The Regional Supervisor will . . .</th><th>If . . .</th><th>And the Regional Supervisor also . . .</th></tr>
<tr><td>(1) Approve your application for a pipeline ROW grant in writing</td><td>It complies with all applicable requirements</td><td>(i) Will simultaneously approve the associated pipeline (see § 250.1012(a)) and, if applicable, any associated accessory (see § 250.1142(e)(1)); and (ii) May require you to meet certain conditions.</td></tr>
<tr><td>(2) Require you amend your application for a pipeline ROW grant</td><td>The Regional Supervisor determines that it is inconsistent with the OCSLA (43 U.S.C. 1331, et seq.), applicable MMS regulations, or other Federal laws</td><td>Will notify you in writing of the decision, and describe the changes you must make to your pipeline ROW grant application to ensure it complies with all applicable requirements.</td></tr>
</table></td><td></td><td></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	(3) Deny your application | (i) The application for the associated pipeline is disapproved under § 250.1012(b); (ii) You do not qualify to hold a pipeline ROW grant, or are unable to post the required bonds or other security; (iii) You do not comply with applicable requirements, and are unable to amend the application to achieve compliance; or (iv) The proposed pipeline ROW will cross any OCS lands (e.g., fairways or anchorage areas) that are under the jurisdiction of another Federal agency and that agency does not consent to the pipeline ROW grant | Will issue the decision to you in writing, and state the reasons for the denial.		
250.1128	**When will MMS temporarily suspend or prohibit construction of an ROW pipeline?**		
	The Regional Supervisor may suspend or temporarily prohibit construction operations if the Regional Supervisor determines that a significant change in conditions occurred after the Regional		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>Supervisor granted a pipeline ROW, but before you complete construction of the associated ROW pipeline.</td><td></td><td></td></tr>
<tr><td>250.1129</td><td>What must I do if the as-built location of the associated ROW pipeline deviates from the approved pipeline ROW grant?</td><td></td><td></td></tr>
<tr><td></td><td>The Regional Supervisor will notify you in writing if the Regional Supervisor determines that the as-built location of the associated ROW pipeline deviates from the approved pipeline ROW grant. Within 60 calendar days after the date you submitted the pipeline construction report to the Regional Supervisor (see § 250.1050(a)), you must:</td><td></td><td></td></tr>
<tr><td></td><td>(a) Notify the lessee or designated lease operator of each lease, and the pipeline ROW holder of each pipeline ROW, that is crossed or could be affected by the associated pipeline as constructed;</td><td></td><td></td></tr>
<tr><td></td><td>(b) Provide the Regional Supervisor with evidence of such notification; and</td><td></td><td></td></tr>
<tr><td></td><td>(c) Submit an application under § 250.1132(a)(3) to the Regional Supervisor for approval to modify the pipeline ROW grant.</td><td></td><td></td></tr>
<tr><td>250.1130</td><td>What rental fees and payment schedules apply to a pipeline ROW grant?</td><td></td><td></td></tr>
<tr><td></td><td>(a) Rental fees. For the first calendar year, or fraction thereof, that you hold a pipeline ROW grant, and for each calendar year thereafter that the grant remains in effect, you must pay MMS an annual rental as follows:
(1) You must pay $70.00 for each statute mile, or part of a statute mile, of the OCS that your pipeline ROW crosses; and
(2) If you hold a pipeline ROW grant that includes a site for an accessory to your pipeline, you must pay MMS an additional annual rental according to the following table:
<table>
<tr><th>If your accessory site is or will be located in water depths . . .</th><th>You must pay MMS an additional annual rental of . . .</th></tr>
<tr><td>(i) Less than 656 feet</td><td>$5.00 per acre, with a minimum of $450 for</td></tr>
</table></td><td>1. We note that the rental fee has been substantially increased from $15/mile to $70/mile which is 467% increase.</td><td></td></tr>
</table>

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	<table><tr><td></td><td>use of the affected area.</td></tr><tr><td>(ii) 656 feet or greater</td><td>$7.50 per acre, with a minimum of $675 for use of the affected area.</td></tr></table>		
	(b) *Affected area.* For purposes of this section, the affected area includes the areal extent of anchor chains, risers, appurtenances, and other devices associated with the accessory.		
	(c) *Payment schedule and deadline.* You may make the rental payments required by paragraph (a) of this section to MMS on an annual basis, for a 5-year period, or for multiples of 5 years. All payment periods begin on January 1. You must pay all rental fees in advance and before the beginning of the payment period.		
	(d) *Late rental payments.* You will be subject to an interest charge if you do not make a rental payment by the deadline specified in paragraph (c) of this section. (1) MMS will assess interest on a late payment on unpaid and underpaid amounts from the date the amounts are due. (2) MMS will assess interest only on the amount not received. (3) MMS will assess interest only for the number of days the payment is late. (4) The interest charge on a late rental payment will be at the underpayment rate established by the Internal Revenue Service Code, 26 U.S.C. 6621(a)(2) (Supp. 1987). (5) MMS may offset an overpayment you made on the rental for a pipeline ROW grant that you hold against an underpayment you made on a different pipeline ROW grant that you hold to determine the net underpayment for which interest is due.		
250.1131	**What are the terms and conditions for holding a pipeline ROW grant?**		
	(a) *Compliance.* You must comply with the OCSLA (43 U.S.C. 1331, *et seq.*), as amended, other applicable laws, and MMS regulations.		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>(b) Address changes. You must update your qualification file (see § 250.1117(b)) within 30 calendar days after a change of address as follows:
<table>
<tr><th>If you are . . .</th><th>You must provide . . .</th></tr>
<tr><td>(1) An individual</td><td>Your change of address.</td></tr>
<tr><td>(2) A corporation or association</td><td>Address of your principal place of business, or name and address of the officer or agent authorized to act on your behalf and to be served with process.</td></tr>
</table></td><td></td><td></td></tr>
<tr><td></td><td>(c) Non-interference. Your pipeline ROW grant does not allow you to prevent or interfere in any way with the management, administration, or the granting of other rights by the United States, either before or after the pipeline ROW is granted by MMS.</td><td></td><td></td></tr>
<tr><td></td><td>(d) Occupancy and use. You must allow the occupancy and use by the United States, its lessees or designated lease operators, or other pipeline ROW holders of any part of the pipeline ROW grant not actually occupied, or necessarily incident to its use, for any necessary operations involved in the management, administration, or the enjoyment of other granted rights.</td><td></td><td></td></tr>
<tr><td></td><td>(e) Compensation and indemnification. You must:
(1) Compensate the United States, its lessees, or other pipeline ROW holders, as the case may be, for the full value of all damages to the property of the United States or of its lessees or pipeline ROW holders; and
(2) Indemnify the United States against any and all liability for damages to life, person, or property arising from the occupation and use of the area covered by the pipeline ROW grant.</td><td></td><td></td></tr>
<tr><td></td><td>(f) Federal Energy Regulatory Commission (FERC) determination. The pipeline associated with the pipeline ROW grant must transport, or you must purchase, oil or natural gas produced from submerged lands of the OCS in the vicinity</td><td></td><td></td></tr>
</table>

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	of the pipeline in such proportionate amounts as FERC may determine to be reasonable. The FERC will make this determination only after a full hearing with due notice thereof to the interested parties, taking into account, among other things, conservation and the prevention of waste.		
	(g) *Open and nondiscriminatory access*. (1) Unless otherwise exempted by FERC under section 5(f)(2) of the OCSLA (43 U.S.C. 1334(f)(2)), you must provide open and nondiscriminatory access to the associated ROW pipeline to both owner and non-owner shippers. (2) The express condition that ROW oil and natural gas pipelines must transport or purchase without discrimination is within MMS's delegated authority to enforce, even when those pipelines are also under FERC jurisdiction by separate authority. To the extent that the oil or natural gas pipelines are subject to FERC's jurisdiction, MMS intends to defer to FERC its authority to decide whether those pipelines have complied with the open and nondiscriminatory access requirements. For pipelines not under FERC jurisdiction, MMS will decide whether those pipelines have complied with the open and nondiscriminatory access requirements of the OCSLA. All complaints by shippers alleging that pipelines have not complied with the open and nondiscriminatory access requirements are subject to the regulations in 30 CFR part 291.		
	(h) *Expansion of throughput capacity*. You must comply with the provisions of section 5(f)(1)(B) of the OCSLA (43 U.S.C. 1334(f)(1)(B)), under which FERC may order expansion of the throughput capacity of an associated ROW pipeline that was approved after September 18, 1978, and that is not located in the Gulf of Mexico or the Santa Barbara Channel.		
	(i) *Open for inspection*. You must keep the area covered by the pipeline ROW grant, and all		

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	improvements thereon, open for inspection by MMS.		
	(j) *Nondiscrimination in employment*. You must comply fully with Executive Order 11246, section 202, paragraphs (1) through (7), as amended (reprinted in 41 CFR 60-1.4(a)), and must not discriminate against any employee or applicant for employment on the basis of race, color, religion, sex, or national origin.		
	(k) *Sabotage or subversive activity*. You must immediately notify the Regional Supervisor, by the fastest possible means of communication, if you discover any evidence of sabotage or subversive activity involving or endangering any pipeline, accessory, vessel, aircraft, or any operation conducted under the pipeline ROW grant.	1. (K) While we understand MMS concern, sabotage is not always easy to determine and may only be recognized after investigation. In those cases, notification will be immediately upon assessment that sabotage or subversive activities have occurred.	
250.1132	**How do I modify a pipeline ROW grant?**		
	(a) *Application*. You must submit one executed original and two copies of an application to modify a pipeline ROW grant to the Regional Supervisor for approval if you plan to: (1) Cease pipeline operations, and need to maintain the pipeline ROW grant in effect; (2) Change the purpose(s) for which the grant was made; (3) Change the route of the associated ROW pipeline; or (4) Establish a site for an accessory, or change the footprint of an accessory.		
	(b) *Associated pipeline application*. For those applications specified in paragraphs (a)(2), (a)(3), and (a)(4) of this section, you must attach the application to modify the pipeline ROW grant to the application to modify the associated ROW pipeline (see § 250.1093(a)).		
	(c) *Application contents*. Your application to modify a pipeline ROW grant must include: (1) Company name; (2) Contact name, telephone number, telefax number, and e-mail address; (3) Reason for the modification, and a description		

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	of the proposed modification to the pipeline ROW grant; (4) MMS-assigned pipeline ROW number, the segment number of the associated pipeline, and, if applicable, the name of any accessory; (5) Name, title, and signature of your authorizing official. This information must be the same as the information you provided or referenced in the MMS qualification records; (6) If you propose to cease pipeline operations: (i) Date that you stopped using the pipeline; (ii) Steps you will take to resume operations under the pipeline ROW grant; (iii) The approximate date you intend to resume operations; and (iv) Plans for maintaining the associated ROW pipeline in the interim; (7) If the modification results in additional rental (see § 250.1130), payment for the increase in the manner prescribed in § 250.1126(h); and		
	(d) *MMS actions*. The Regional Supervisor will review your application to modify a pipeline ROW grant, along with your application to modify the associated ROW pipeline (see § 250.1093(a)), to ensure that it complies with the OCSLA (43 U.S.C. 1331, *et seq.*), other applicable laws, and applicable MMS regulations, and will take one of the actions prescribed in § 250.1127(c).		
250.1133	**How does temporary cessation and cessation of pipeline operations affect a pipeline ROW grant?**		
	(a) *Definitions*-(1) *Temporary cessation of pipeline operations* means the use of a pipeline associated with a pipeline ROW grant for a purpose other than that for which the grant was made for a period of 180 consecutive calendar days or less. (2) *Cessation of pipeline operations* means the use of a pipeline associated with a pipeline ROW grant for a purpose other than that for which the grant was made for a period of more than 180 consecutive calendar days. Simply maintaining		

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	pressure on the pipeline is not using the pipeline for the purpose for which the grant was made.		
	(b) *Temporary cessation of pipeline operations*. Temporary cessation of pipeline operations will not cause the associated pipeline ROW grant to expire.	1. Other than out of service notifications, are there any other temporary cessation notifications or submittals? 2. Is there a cost recovery required for a Temporary Cessation? We recommend that the fee structure for cessations be clarified.	
	(c) *Cessation of pipeline operations*. Cessation of pipeline operations, whether voluntary or resulting from a suspension or temporary prohibition of operations directed by MMS, will cause the associated pipeline ROW grant to expire unless the Regional Supervisor approves an application to modify the pipeline ROW grant (see § 250.1132(a)(1)) to allow for a cessation of operations for a specified time period.	1 180 days is too tight a time frame within which to manage pipeline ROWs for potential expiration. Expiration upon 2 year continuous non-use in the absence of a MMS approved cessation of operations maintaining the OCS ROW beyond the allowed continuous non-use period. Presently DOI regulations for BLM interior oil & gas pipelines provide for pipeline right of way expiration upon lapse of 2 years non-use at 43 CFR 2886.17 (d). This 2 year non-use regulation is much more manageable. Presently, our position is that OCS ROWs do not expire until the grant's purpose ceases to exist or permanent discontinuance of use. Reference is made to the present applicable OCS reg 30 CFR 250.1014 as follows: "When pipeline right-of-way grants expire. Any right-of-way granted under the provisions of this subpart remains in effect as long as the associated pipeline is properly maintained and used for the purpose for which the grant was made, unless otherwise expressly stated in the grant. Temporary cessation or suspension of pipeline operations shall not cause the grant to expire. However, if the purpose of the grant ceases to exist or use of the associated pipeline is permanently discontinued for any reason, the grant shall be deemed to have expired."	(c) (2) **(c) *Cessation of pipeline operations***. Cessation of pipeline operations, whether voluntary or resulting from a suspension or temporary prohibition of operations directed by MMS, will cause the associated pipeline ROW grant to expire upon 2 years of continuous non use unless the Regional Supervisor approves an application to modify the pipeline ROW grant (see § 250.1132(a)(1)) to allow for a cessation of operations for a specified time period.
	(d) *Obligations*. If MMS approves your		

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	application to modify the pipeline ROW grant to cease operations, you must: (1) Continue to pay the annual rentals required by § 250.1130(a); (2) Adhere to the requirements for out-of-service pipelines in § 250.1086; and (3) If, at any time, you determine that cessation of pipeline operations will continue for 5 years or more, or for a shorter period as specified by the Regional Supervisor, you must submit to the Regional Supervisor, within 60 days: (i) A request to relinquish the pipeline ROW grant (see § 250.1136(a)); and (ii) An application to decommission the associated pipeline (see § 250.1107 or 1108).		
250.1134	**How do I assign a pipeline ROW grant?**		
	(a) *Assignment request*. You may assign a pipeline ROW grant by submitting two originals of Form MMS-149 (Assignment of Federal OCS Pipeline Right-of-Way Grant) to the Regional Supervisor for approval. The assignment must transfer the pipeline ROW grant in its entirety and to only one assignee. Your assignment request must include: (1) The MMS-assigned pipeline ROW number, the segment number of the associated pipeline, and, if applicable, the name of any accessory; (2) The names and MMS company numbers for both the assignor and the assignee; (3) The names and telephone numbers of the contacts for both the assignor and the assignee; (4) The names, titles, and signatures of the authorizing officials for both the assignor and the assignee; (5) Payment of a nonrefundable service fee (see § 250.125 for the amount); (6) A statement from the assignee that the assignee agrees to comply with, and to be bound by, the terms and conditions of the pipeline ROW grant; (7) The same showing of qualifications of the assignee as is required of an applicant for a	There are sometimes several segment numbers associated with one pipeline ROW grant, and there may be a case where a company may not want to assign all of the segment numbers associated with that pipeline ROW grant. With the complicated subsea production architectures that are currently being executed, this problem is likely to grow. MMS should develop a clear and easily understood mechanism to cover these situations. It is our understanding that when these circumstances currently occur, the original ROW holder retains the ROW grant and pipeline segment numbers that are being retained by the current ROW owner. The company that is acquiring the pipeline then must apply for a new ROW and MMS assigns a new segment number to that pipeline. We request that MMS include in the regulation the mechanism for a partial ROW assignment process.	

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	pipeline ROW grant in § 250.1117; (8) A statement describing how the assignee will comply with the financial security requirements of § 250.1118; (9) The name of the identified operator, if the company that will operate the associated pipeline will not be the assignee; (10) A revised safety flow schematic that shows the new transfer point, if the assignment will result in a change of the jurisdictional transfer point of the associated pipeline; and (11) The information required by § 250.1028 and 250.1029.		
	(b) *Rental payments for a pipeline ROW grant pending assignment*. If you have submitted a request to assign a pipeline ROW grant, you (the assignor) will be billed for the annual pipeline ROW rental payment if the payment is due (see § 250.1130(c)) and the Regional Supervisor has not yet approved the assignment. MMS will not mediate any financial disputes between an assignor and an assignee.		
	(c) *Effective date*. The assignment takes effect on the date the Regional Supervisor approves it.		
	(d) *Assignor obligations*. The assignor is liable for all obligations that accrue under a pipeline ROW grant before the date the Regional Supervisor approves the assignment. An assignment approval by MMS does not relieve the assignor of liability for accrued obligations that the assignee, or a subsequent assignee, fails to fulfill.		
	(e) *Assignee obligations*. The assignee and each subsequent assignee: (1) Agrees to be bound by the terms and conditions of the pipeline ROW grant; and (2) Is liable for all obligations that accrue under a pipeline ROW grant after the date the Regional Supervisor approves the assignment.		
	(f) *Disqualification*. The Director may disqualify you from acquiring any pipeline ROW grants by assignment if your operating performance is		

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	unacceptable. The Director will give you adequate notice, and an opportunity to have your case reviewed, before disqualification.		
	(g) *Financial securities*. After the Regional Supervisor approves an assignment of a pipeline ROW grant, you may request that the Regional Director approve a "Termination of the Period of Liability" for your pipeline ROW area bond or other security and any additional securities (see § 250.1119) if you: (1) No longer hold any pipeline ROW grants in an MMS OCS Region; and (2) Do not plan to become a pipeline ROW grant holder in the near future in that MMS OCS Region.		
250.1135	**When may MMS suspend a pipeline ROW grant?**		
	The Regional Supervisor may suspend a pipeline ROW grant if:		
	(a) The Regional Supervisor suspends or temporarily prohibits operation of the associated ROW pipeline under § 250.1091;		
	(b) You fail to provide any additional security required by the Regional Director (see § 250.1118(c)), replace or provide additional coverage for a de-valued bond or other security (see § 250.1121(a)), or replace a lapsed or forfeited bond or other security (see § 250.1121(b) and 1122) within the prescribed time period; or		
	(c) The Regional Supervisor determines that you have failed to comply with a provision of the OCSLA (43 U.S.C.1331, *et seq.*) or any other applicable law, a provision of applicable regulations, or a stipulation, term, or condition of the pipeline ROW grant.		
250.1136	**How do I relinquish a pipeline ROW grant?**		
	(a) *Relinquishment request*. You may voluntarily surrender a pipeline ROW grant, or a portion of a pipeline ROW grant, by filing one original and two copies of a relinquishment request with the Regional Supervisor for		

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	approval. You must attach the relinquishment request to the application required by § 250.1107 or 250.1108 to decommission the associated ROW pipeline and, if applicable, the application required by § 250.1727 to decommission an associated accessory. Your relinquishment request must include: (1) Company name; (2) Contact name, telephone number, telefax number, and e-mail address; (3) Reason you are requesting relinquishment of the pipeline ROW grant; (4) MMS-assigned pipeline ROW number, the segment number of the associated pipeline, and, if applicable, the name of any accessory; (5) Name, title, and signature of your authorizing official which must be the same as the information you provide or reference in your MMS qualification records; (6) Payment of a nonrefundable service fee (see § 250.125 for the amount); and (7) A statement that you will adhere to the requirements of § 250.1138(a) and (b).		
	(b) *Rental payment for a pipeline ROW grant pending relinquishment*. If you have submitted a request to relinquish a pipeline ROW grant, you will be billed for the annual pipeline ROW rental payment if the payment is due (see § 250.1130(c)) and the Regional Supervisor has not yet approved the relinquishment.		
	(c) *Delinquent payments*. The Regional Supervisor will not approve your relinquishment request until you have paid all outstanding rentals and fines.		
	(d) *Effective date*. The relinquishment takes effect on the date the Regional Supervisor approves it.		
	(e) *Financial securities*. After the Regional Supervisor approves the relinquishment of a pipeline ROW grant you may request that the Regional Director approve a "Termination of the Period of Liability" for your pipeline ROW area		

<table>
<tr><th>Proposed Section Number</th><th>Proposed Text</th><th>Summary of Comments and Rationale</th><th>Proposed Language</th></tr>
<tr><td></td><td>bond or other security and any additional securities (see § 250.1119) if you:
(1) No longer hold any pipeline ROW grants in an MMS OCS Region; and
(2) Do not plan to become a pipeline ROW grant holder in the near future in that MMS OCS Region.</td><td></td><td></td></tr>
<tr><td>250.1137</td><td>When will a pipeline ROW grant be cancelled, be forfeited, or expire?</td><td></td><td></td></tr>
<tr><td></td><td>Your ROW grant will be cancelled, be forfeited, or expire as shown in the following table.
<table>
<tr><th>Termination type</th><th>When termination will occur</th></tr>
<tr><td>(a) Cancellation</td><td>The Secretary may cancel a pipeline ROW grant if:</td></tr>
<tr><td></td><td>(1) The Secretary cancels MMS approval of the application for the associated ROW pipeline pursuant to § 250.1013;</td></tr>
<tr><td></td><td>(2) You no longer qualify to hold a pipeline ROW grant;</td></tr>
<tr><td></td><td>(3) You are disqualified from holding pipeline ROW grants according to § 250.1117(c); or</td></tr>
<tr><td></td><td>(4) You fail to provide any additional security required by the Regional Director (see § 250.1118(c)), replace or provide additional coverage for a de-valued bond or other security (see § 250.1121(a)), or replace a lapsed or forfeited bond or other security (see § 250.1121(b) and 1122) within the prescribed time period.</td></tr>
<tr><td>(b) Forfeiture</td><td>You may forfeit a pipeline ROW grant, in an appropriate judicial proceeding instituted by the United States, in accordance with the provisions of § 23 of the OCSLA (43 U.S.C. 1349) if:</td></tr>
<tr><td></td><td>(1) You fail to comply with the provisions of § 5(e) of the OCSLA (43 U.S.C. 1334(e)), or the regulations prescribed in this subpart;</td></tr>
<tr><td></td><td>(2) The Director determines that you have not provided open access or</td></tr>
</table></td><td></td><td></td></tr>
</table>

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	nondiscriminatory access to a shipper; or (3) There is substantial deviation of an associated ROW pipeline (as constructed) from the pipeline ROW grant, and the Regional Supervisor has not approved a modification to the pipeline ROW grant. (c) *Expiration* A pipeline ROW grant expires if: (1) You do not construct the associated pipeline within 5 years after the grant was approved by the Regional Supervisor; (2) You ceased pipeline operations and did not obtain approval from the Regional Supervisor pursuant to § 250.1132(a)(1); (3) You permanently discontinue using the associated ROW pipeline for any reason; or (4) You cease operations for 5 years.		
250.1138	**What must I do after a pipeline ROW grant terminates?**		
	(a) *Pipeline operation.* After a pipeline ROW grant terminates, for any reason (relinquishment, cancellation, forfeiture, or expiration), you must no longer use the associated pipeline.		
	(b) *Decommissioning.* Within 1 year after a pipeline ROW grant terminates, you must decommission: (1) The associated ROW pipeline in accordance with the requirements of § 250.1106 through 1109 and § 250.1111; and (2) Any associated accessory in accordance with the requirements of § 250.1725 through 1730 and § 250.1741 through 1743.		
	(c) *Failure to comply.* If you fail to decommission the associated pipeline and any accessory within the prescribed time period: (1) You remain liable for decommissioning costs, and responsible for accidents or damages that might result from such failure; and		

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	(2) The violation may be subject to a civil penalty under 30 CFR 250, subpart N, Outer Continental Shelf (OCS) Civil Penalties.		
	(d) *Obligations.* You remain liable for all obligations that accrued under a pipeline ROW grant before the date the pipeline ROW grant terminated.		
Accessories to Right-of-Way (ROW) Pipelines			
250.1140	**What are the requirements for an accessory to an ROW pipeline?**		
	(a) *General.* You must design, fabricate, install, and maintain an accessory to an ROW pipeline in accordance with the requirements of 30 CFR 250, subpart I, Platforms and Structures.		
	(b) *Surface safety system.* You must protect personnel, the environment, and the accessory with a basic and ancillary surface safety system. You must design, analyze, install, test, operate, and maintain the surface safety system in accordance with the applicable requirements of subpart H of this part, Oil and Gas Production Safety Systems.		
	(c) *Existing OCS platforms.* If you plan to convert an existing OCS platform to an accessory, you must decommission all wells on the platform in accordance with the requirements of § 250.1715 and 250.1716 before the Regional Supervisor will approve the accessory application (see § 250.1141(a)).		
250.1141	**How do I obtain approval to install, operate, and maintain an accessory?**		
	(a) *Accessory application.* Before you install, operate, and maintain an accessory to a ROW pipeline, you must submit three copies of an application to the Regional Supervisor for approval. You must attach the accessory application to the application for the associated ROW pipeline. Your accessory application must include all of the following: (1) The following information, based on the type of platform:	1. An application before you maintain an accessory seems onerous. Maintenance includes painting, valve repair, air system upkeep, etc., all of which shouldn't require an application. Please clarify. 2. The definition of an “accessory” includes more than platforms. Are there application requirements for non platform accessories?	**a) *Accessory application.*** Before you install and operate an accessory to a ROW pipeline

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For . . .	Your application must include . . .	and . . .
(i) New platforms	the information required by § 250.905 and 912, if applicable	
(ii) Existing platforms that are being converted for a different use	the information required by § 250.905	the results of your platform assessment in accordance with API RP 2A-WSD, section 15, Reuse (incorporated by reference as specified in § 250.198).
(iii) Existing platforms that are completing ongoing activity	the information required by § 250.905	the results of your platform assessment in accordance with API RP 2A-WSD, section 17, Assessment of Existing Platforms (incorporated by reference as specified in § 250.198.

(2) The MMS-assigned pipeline ROW number and the segment number of the associated pipeline, if the accessory will be under an existing pipeline ROW grant.
(3) The maximum anchor radius (feet) of the construction vessel you will use to install the accessory.
(4) Information on air emission sources that includes:
(i) The rated output (horsepower) of each tug, construction vessel, and service vessel or equipment;
(ii) An estimate of the number of vessel or equipment trips per year;
(iii) An estimate of the time (days) that each

3. (4) We suggest that air emission, discharge and waste information to be submitted conform to the requirements in Subpart B for EPs and DOCDs for consistency for both MMS and Industry.

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	vessel/equipment will be within 25 miles of the accessory; (iv) An estimate of the number of component connections (e.g., valves, flanges) on the accessory; (v) The contents and capacity (gallons) of hydrocarbon storage tanks, and their average daily and annual throughput (gallons/day and gallons/year); and (vi) Documentation of any emission control technologies you will employ. (5) Information on combustion emission sources that includes: (i) The rated output (horsepower) of each emission source (e.g., crane, compressor, generator, dehydrator); (ii) The run time (hours/day and days/year) for each emission source; and (iii) The average hourly and annual throughput of gas through glycol dehydrators. (6) Information on wastes generated at the accessory that includes, as appropriate: (i) The type and general characteristic of the wastes that will be generated by operations at the accessory and released (locally) into the ocean; (ii) The amount of waste to be discharged (gallons); (iii) The average maximum discharge rates (gallons/day); (iv) A description of any waste treatment or storage; and (v) The discharge location and method for each type of discharge. (7) The safety system design and installation information required by § 250.802(e).		
	(b) *Electronic submission*. You may submit part or all of your accessory application electronically (see § 250.186(a)(3)). If you prefer to submit your application electronically, you should consult with the Regional Supervisor for further guidance.	1. We encourage the use of electronic submittals.	

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	(c) *Withdrawal of application.* You may withdraw your accessory application, at any time, and for any reason, by notifying the Regional Supervisor in writing.		
250.1142	**How does MMS process an accessory application?**		
	(a) *Completeness review.* The Regional Supervisor will determine whether your accessory application is complete, and will notify you in writing of any problem or deficiency. The Regional Supervisor will not begin processing your application until it is complete.	1. Please provide a timeframe for the completeness review. We suggest that it be the same as for the ROW pipeline application.	
	(b) *Compliance review.* The Regional Supervisor will review the proposed operations described in your accessory application to ensure that they conform to the OCSLA (43 U.S.C. 1331, *et seq.*), other applicable laws, and MMS regulations.		
	(c) *Environmental impact evaluation.* The Regional Supervisor will evaluate the environmental impacts of the operations described in your accessory application, and prepare environmental documentation under NEPA (42 U.S.C. 4321, *et seq.*) and the implementing regulations (40 CFR parts 1500 through 1508).		
	(d) *Amendments.* During the review of your accessory application, the Regional Supervisor may require you, or you may elect, to change the application.		
	(e) *MMS decision.* The Regional Supervisor will review your accessory application and will notify you in writing of the decision. The Regional Supervisor will either: (1) Approve the application if it complies with all applicable requirements, and inform you of any conditions you may be required to meet; or (2) Disapprove the application, and inform you of the reasons for disapproval if the: (i) Proposed accessory operations would probably cause serious harm or damage to life (including fish or other aquatic life); property;	1. Please provide a timeframe for the application approval. We suggest that it be the same as for the ROW pipeline application. 2. It is not clear if the approval to install an accessory will be separate from the ROW pipeline application approval or will be contained within the pipeline application approval. Please clarify. 3. In the approval letter, we request that MMS list all notifications required along with the	

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	mineral resources (in areas leased or not leased); the national security or defense; or the marine, coastal, or human environment; and you cannot amend the proposed accessory operations to avoid such condition(s); or (ii) Regional Supervisor has disapproved your application for a connecting ROW pipeline (see § 250.1012(b)) or denied your application for the associated pipeline ROW grant (see § 250.1127(c)(3)).	contact information.	
250.1143	**Who do I need to notify before I install an accessory?**	1. The notification requirements for an accessory platform should be the same as those in Subpart I . Please clarify	
	(a) *Military installations*. Before you install an accessory in an established military warning area or water test area, you must notify the commander of the military installation that exercises jurisdiction of the area concerning the control of electromagnetic emissions and the use of vessels, equipment, and aircraft in the area.	1. See our previous comments concerning notifying military installations.	
	(b) *U.S. Coast Guard (USCG).* You are encouraged to notify the applicable USCG Marine Safety Office at least 30 calendar days before you conduct accessory installation operations so that a Notice to Mariners can be prepared.	1. Please see our previous comments concerning notifying USCG.	
	(c) *National Geospatial-Intelligence Agency (NGA).* You must notify the NGA in Bethesda, Maryland before you begin accessory installation operations.	1. Who is this? Why do we need to notify them? How do we contact them? Written, fax, e-mail? What information is required in the notification?	
250.1144	**What information must I submit after an accessory is installed?**		
	You must submit three copies of an accessory installation report to the Regional Supervisor within 45 calendar days after you complete accessory installation. The installation report must include:	1. Installation report for an accessory platform should match the requirements in Subpart I for platform installations. Please clarify. 2. If this report is required, we request 90 days.	You must submit three copies of an accessory installation report to the Regional Supervisor within 90 calendar days after you complete accessory installation. The installation report must include:
	(a) The MMS-assigned pipeline ROW number and the segment number of the associated pipeline;		

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	(b) The dates you started and concluded accessory installation operations; and		
	(c) An "as built" location plat that depicts the accessory, based on the NAD 27 for the GOMR (Gulf) and POCSR, or on the NAD 83 for the AKOCSR and GOMR (Atlantic), drawn at a minimum scale of 1 inch = 2,000 feet.		
250.1145	**What accessory inspections must I conduct?**		
	You must conduct structural and pollution inspections on your accessory as required by this section.		
	(a) *Structural inspections*. If the accessory is a platform, you must do all of the following: (1) Periodically inspect the platform in accordance with a comprehensive in-service inspection plan as required by § 250.919(a). (2) As required by § 250.919(b), submit a written report, by November 1 of each year, of the inspections that you conducted during the preceding 12 months. The report must include: (i) The MMS-assigned pipeline ROW number and the segment number of the associated pipeline, and the MMS complex identification number for the platform; (ii) The extent and area of each inspection; (iii) The type of inspection conducted (i.e., visual, magnetic particle, ultrasonic); (iv) The results of the inspection; (v) A discussion of the overall condition of the platform; and (vi) A description of any necessary repairs.	1. Please clarify who the report is to be submitted to.	
	(b) *Pollution inspections*. If the accessory is a compressor or booster platform, you must inspect the accessory daily in accordance with § 250.301 for evidence of pollution. You must retain the inspection records for at least two years, and make them available to MMS upon request.		
250.1146	**What must I do to modify an accessory?**		
	Before you conduct any operations to modify an approved accessory, you must submit three copies of a modification application to the		

Proposed Section Number	Proposed Text	Summary of Comments and Rationale	Proposed Language
	Regional Supervisor for approval. In the accessory modification application, you must include:		
	(a) The MMS-assigned pipeline ROW number and the segment number of the associated pipeline;		
	(b) Those items in your approved application affected by the proposed modification;		
	(c) If required by the Regional Supervisor, the step-by-step procedures you will follow to modify the accessory; and		
	(d) If the accessory is a platform, the results of your platform assessment, based on platform assessment initiators listed in sections 17.2.1 through 17.2.5 of API RP 2A-WSD (incorporated by reference as specified in § 250.198).		
250.1147	**When must I decommission an accessory?**		
	Within 1 year after an accessory has not been used for 5 years, or within 1 year after you determine that an accessory will not be used for 5 years or more, you must decommission the accessory (see § 250.1725 through 1730 and § 250.1740 through 1743).		

MMS Subpart "J" Presentation
Deepwater Pipelines

Suggested Considerations

February 22, 2008

Objective of Subpart J Modification

- Provide (increased) assurance of Integrity (i.e., Safety and Environmental)
- Facilitate production of Oil and Gas as efficiently as possible

To achieve this we need:

- Application of appropriate technology that provides maximum benefit
- Clarity in regulatory requirements

Subpart “J” Considerations

- Existing and future deepwater infrastructure share most of the same issues and concerns. Implementation of Subpart J in its current form will not increase assurance of integrity or remove ambiguity

- Subsea Systems with flowlines and umbilicals are not specifically addressed in Subpart “J”, are typically complex systems, have unique requirements and are a significant (and increasing) component in Gulf of Mexico production.

- The expanded scope of Subpart “J” encompasses design, installation, commissioning, operation, surveillance and abandonment. Are the overlaps with other Regulatory and MMS directives understood?

Specific Comments

Section: 250.1086 – Definitions

What must I do when a pipeline is taken out of service?

1. **Add an additional Pipeline Classification for inactive pipelines that are internally protected and may return to production "Inactive-Integrity Ensured".**

   – **The pipeline classifications would then be: 1. Production-In Service, 2. Production-Out of Service, 3. Inactive-Integrity Ensured (instead of Not Producing) and 4. Service Lines.**

Rationale:

- **Rule created a new definition of OCS Pipeline thereby imposing new requirements on DOT pipelines not regulated by MMS. Proposed rule negates or obviates the current MOU in place between DOT ad DOI as it relates to requirements and regulatory oversight of pipelines on the OCS**

- **By design, subsea systems have sections that will not operate for extended periods of time. The general policy is to ensure these sections contain fluids that are inert with respect to the risk of internal corrosion. The requirement to treat these lines as out of service and the associated actions would result in significant downtime, cost and deferred production without any real improvement in integrity.**
  - **At present they may fall under OOS flowline and require periodic notification and retesting without specific approved variance by MMS.**
  - **This has been a subsea system issue for a long time.**

Specific Comments

Section: 250.1086 – Out-of-Service Report

What must I do when a pipeline is taken out of service?

1. Maintain or increase reporting time.

Rationale:

- **Regulatory Agencies and Operators are already pressed to deliver the established requirements and replies.**
  - **What is the justification for the substantial reduction in reporting time from 60 days to 48 hours? Does this add any value?**
  - **The Reactivation Report is not required for 30 days.**

Specific Comments

Section: 250.1079 - Integrity Management

What written procedures must I establish before I operate an OCS pipeline?

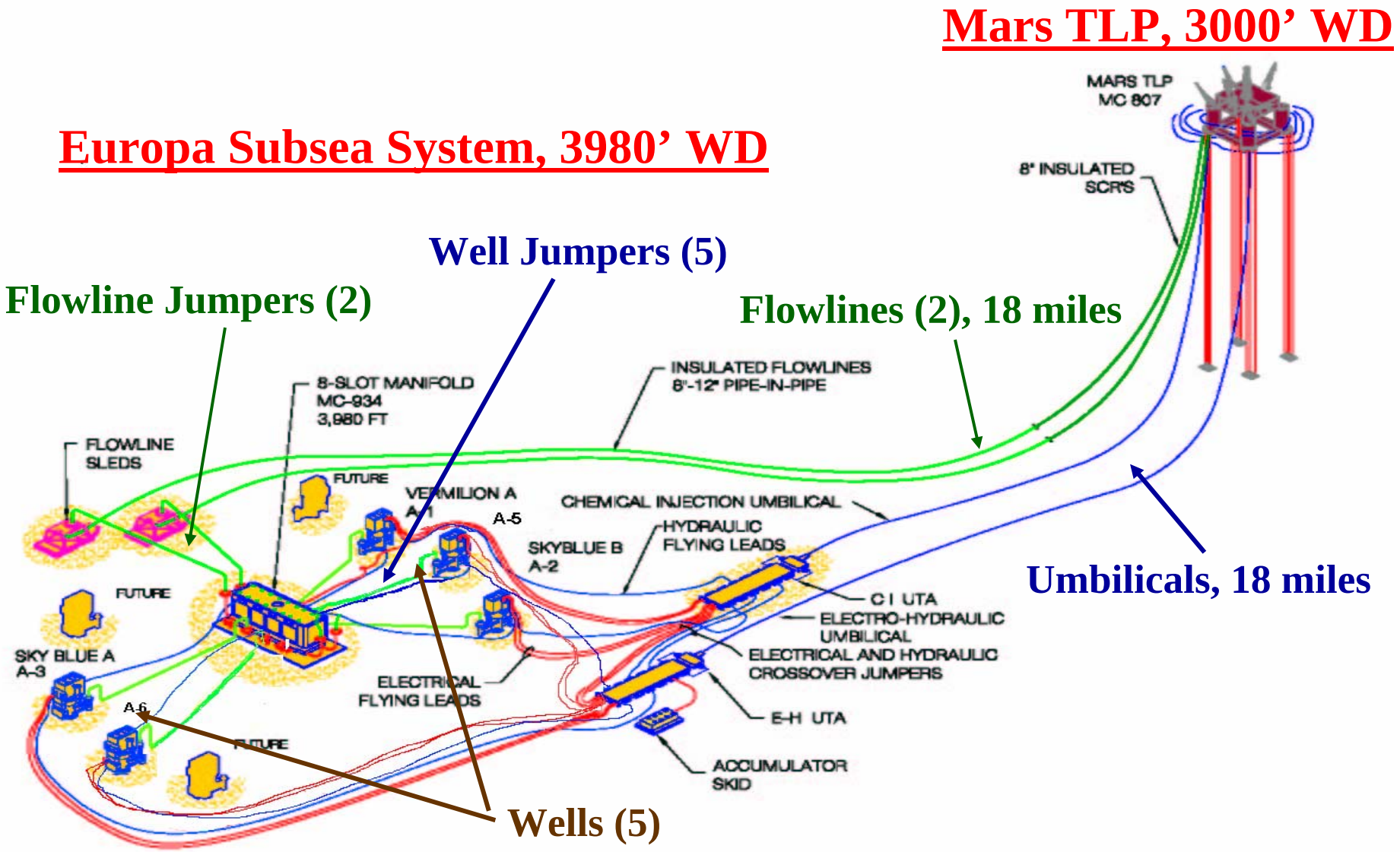
1. We suggest that the MMS confirm support of a PRCI (Pipeline Research Council International), formerly DNV, Integrity Management Best Practices JIP for subsea pipelines to establish a guideline for integrity management that addresses the technical limitations of different assessment methods and lay the foundation for standard subsea pipeline integrity management procedures.

- **Note: this was initiated pro-actively by the industry prior to the proposed modification of subpart J. The project is funded through the PRCI**

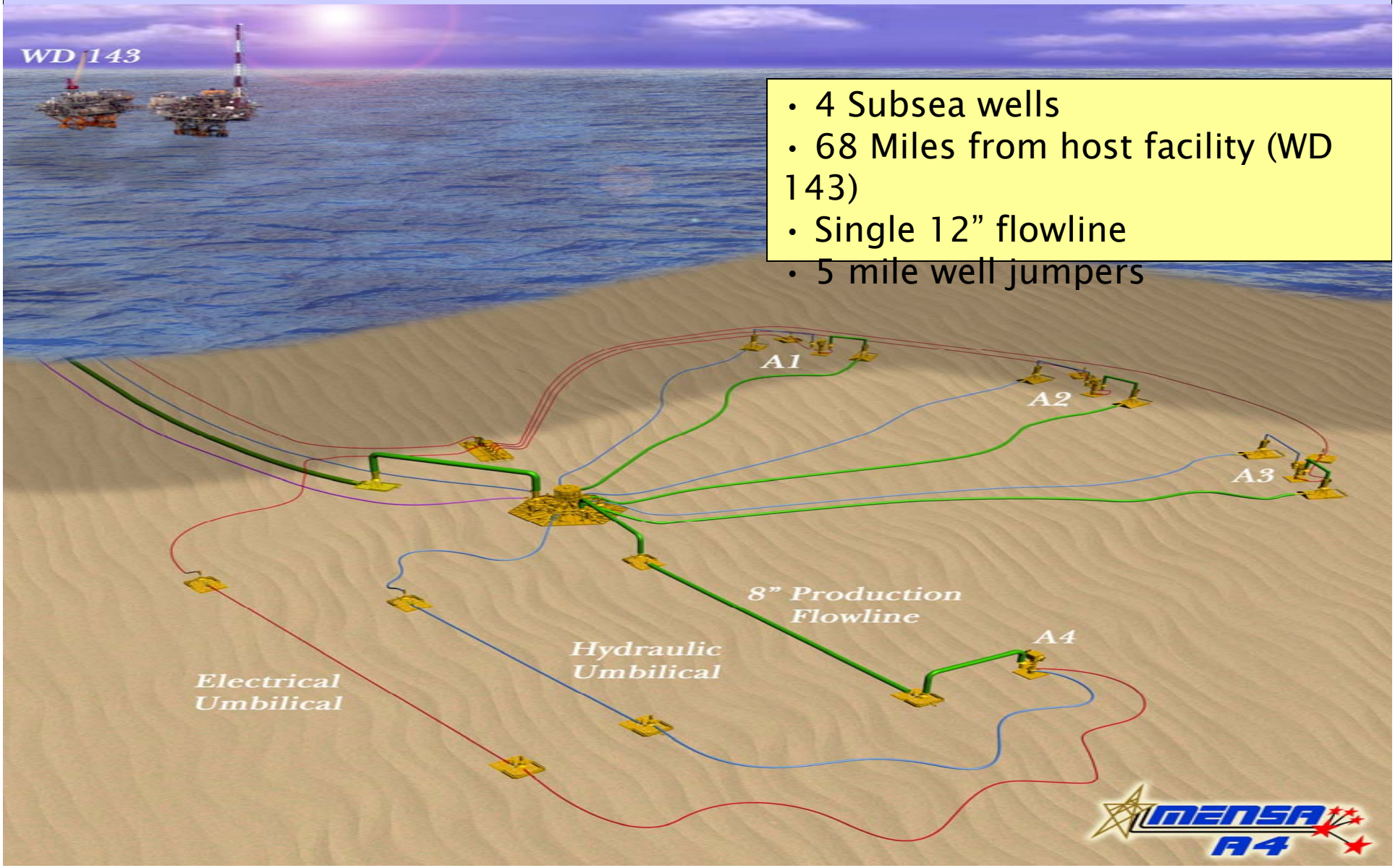
Rationale:

- **The proposed Subpart "J" is very specific to the tools and methods required to validate integrity. However, direct assessment methods have very limited application in deepwater due to:**
  - **Technical limitations of ILI**
  - **Current and future design do not accommodate ILI**
- **Primary Industry concern is based on the inadequacy of current direct assessment technology to address the integrity of subsea flowlines. As a result a condition monitoring approach is required**
- **The Operators generally support the PRCI Best Practices JIP for developing a standardized process of ensuring integrity of subsea pipelines.**

Europa Subsea Field Configuration

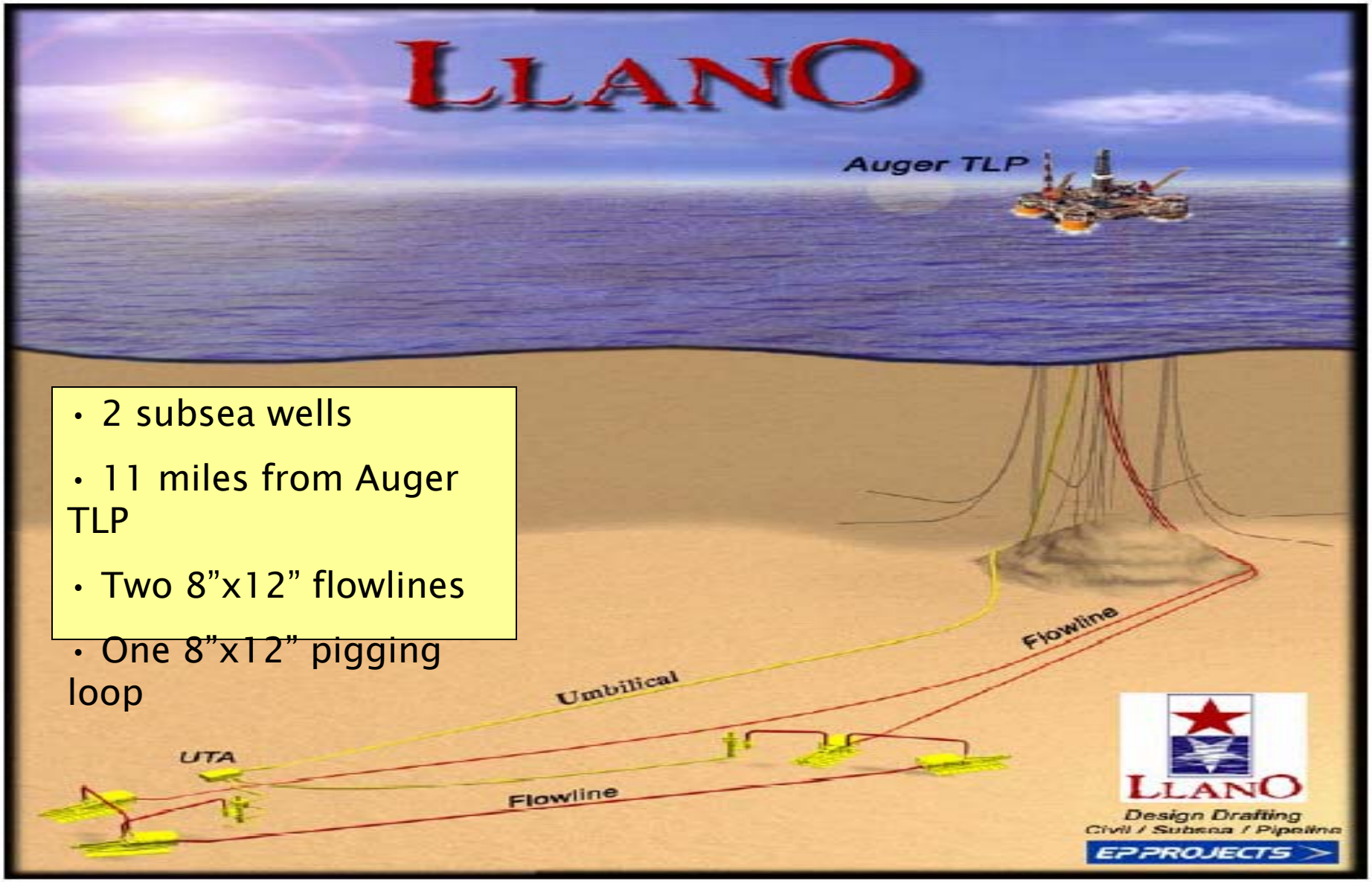


Mensa Field Configuration

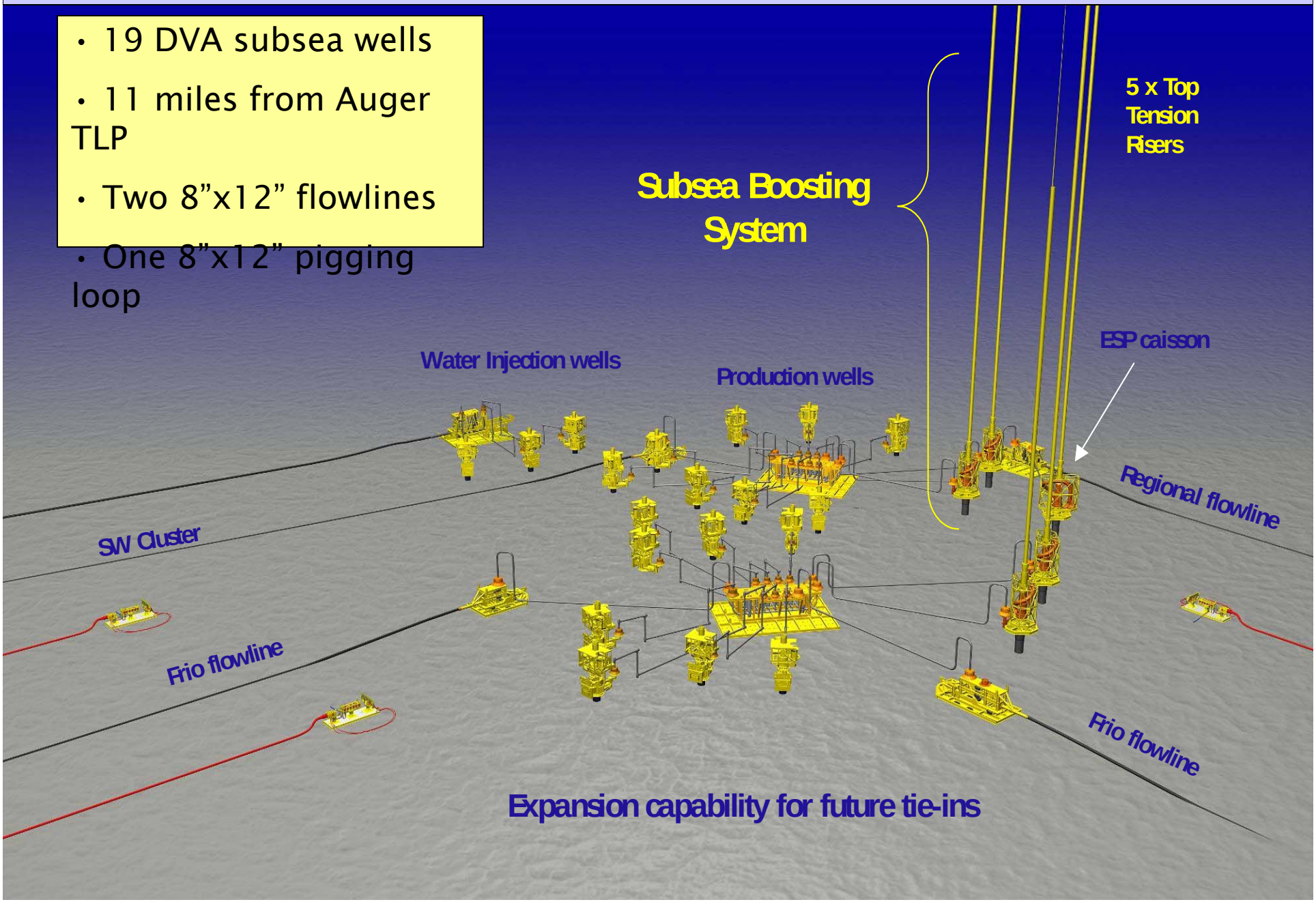


- 4 Subsea wells
- 68 Miles from host facility (WD 143)
- Single 12" flowline
- 5 mile well jumpers

Llano Field Configuration



Perdido Near-host Seafloor Layout



Specific Comments

Section: 250.1006 – Reporting Time Frame

When must I submit the applications, requests, plans and reports, and make the notifications required by this subpart?

1. **We recommend keeping the reporting time frame as it is currently defined.**
2. **Proposed rule should include language that establishes time clocks around permitting processes similar to that for EPs and DOCDs (i.e. Agency turnaround re: completeness, determination, approval, denial decisions) and more reasonable timelines for completion documentation submittals.**

Rationale:

- **This topic does not improve integrity.**
- **Deadlines for CVA reports, completion reports, as-built information, etc. has been shortened from 60 and 90 days to either 30 or 45 days and deadlines are added where no time was previously specified.**
- **The ability to process and transfer data in a short time frame has improved, the complexity of design and installation continues to increase the time needed to complete reports.**
- **By shortening the timeframe for submittals while at the same time increasing the amount of information requested, there is a significant potential for slowing down the submittal/approval process.**
- **Agency response times have been problematic.**

Specific Comments

<u>Section: 250.1006</u>
Lack of Recognition of Limitations of and Impact to Existing Infrastructure

1. **Any rule should specifically recognize the inherent practical limitations of the existing infrastructure.**

Rationale:

- **Given the broad applicability of the rule and what constitutes an affected pipeline, thousands of lines on the OCS (including interconnecting pipelines) would be impacted by the new requirements, coming at a significant cost and impact to ongoing operations.**

- **The rule imposes new requirements for safety devices, pigging, and inspection of existing lines. Many of the new requirements are not feasible to implement with existing infrastructure. Application of some of these new requirements would result in significant costs; would take a long time to implement and in many cases are impractical for ongoing operations on the OCS.**

Specific Comments

Sections: 250.1054, 250.1055, 250.1056

Certificated Verification Agent (CVA) Requirements

What must the CVA do to verify the pipeline riser design, fabrication and installation?

1. **The MMS should be very clear regarding the minimum CVA requirements to prevent broad interpretation, unproductive work and extended Agency review time.**

Rationale:

- **CVA requirements will likely become impediments to deepwater developments on GoM OCS; program requires independent third party of design instead of third party design review and analysis in lieu of validation of application of sound engineering principles in design.**
- **The proposed program is not consistent in the level of details with the Platform CVA program (the intent is verification not re-analysis).**
- **If Consulting Firms who are now doing riser design, fabrication and installation work, are giving to the MMS CVA requirements may be counter-productive.**
    - **Some consulting firms are expanding the scope of their design review beyond what we believe the intention of the MMS initially was.**
- **Do the review Agencies (MMS) have sufficient time to actually verify the technical information requested?**

Specific Comments

250.1079 (1/2)

What written procedures must I establish before I operate an OCS pipeline?

Written Manuals and Program Documents

Utilize the Operators existing plans and processes.

- **Operators have plans and processes are in place that represent the spirit of the procedures. The generation of a separate document is not productive and offers no additional assurance.**

Personnel Qualification Program

Rewording suggestion "You must have a written qualification *or certification program or defined processes* for individuals who perform pipeline operation, maintenance, and repair duties for you that may affect the safe operation or integrity of a pipeline."

Inspection

Aspects of the desired written plans may be confidential to the Operator therefore, any documents provided to the MMS should be maintained as confidential and not shared with others without written permission.

These topics should be discussed at the Annual Performance Review or at an equivalent venue.

Specific Comments

250.1079 (2/2)

What written procedures must I establish before I operate an OCS pipeline?

Integrity Management Program section 1-iii

Rewording suggestion "Using other technology that can provide an equivalent understanding of the condition of the pipeline *including an appropriate condition monitoring program*."

Integrity Management Program section 2 Information analysis

Rewording suggestion "An analysis *or tool* that integrates all other available information (e.g., inspections, tests, surveys, and monitoring results) about pipeline integrity."

Integrity Management Program section 5 Periodic assessment and evaluation

Rewording suggestion "Provisions *or a condition monitoring program* for periodically reassessing and re-evaluating the integrity of the pipeline at a frequency based on specific risk factors such as proximity to environmentally sensitive areas, product being transported, previous failure history, and water depth."

These topics should be discussed at the Annual Performance Review or at an equivalent venue.

250.1060-1061 – Repairs of Existing Infrastructure

1. The proposed rule is unclear as to acceptable instrumentation required to support leak tests of repaired lines. Result is lack of consistent requirements imposed on operators thereby creating an unpredictable regulatory process.

2. The rule is too prescriptive and limiting on the means to validate the adequacy of repairs (ex. Welded clamp repair, use of visible/non-visible spool piece).

3. The proposed rule requires approval prior to making repairs which will increase cycle times and prolong shut-ins.

Rationale:

- **Lack of clarity in requirements and varying interpretations by MMS personnel lead to confusion regarding what is required to comply; resulting in more costly and delayed repairs with impact on timely restoration of production.**
- **Different instrumentation is required for pipeline leak tests analysis and hydro-tests evaluations.**
- **Requirements for approval of "like" repairs have been inconsistent.**

Other Subpart "J" Comments

250.1093 (b) Modification Application - Currently, ROW pipeline modifications and new ROW pipeline applications do not require the items that are part of 250.1030 (EIA). Maintenance activities should be excluded from this topic.

250.1102 Inspections (b) Flex Joints - Underwater flex joint inspections require mobilization of divers and all related support equipment. Recommend inspections every 2 years (currently being adopted as an internal requirement in Shell)

250.1081 Pipeline Design Pressure – To prevent confusion we need to recognize that design pressure (and MAOP) varies along a deepwater flowline. Recommend that flowline coming from deepwater to surface define 2 MAOP's (a surface MAOP, and subsea termination MAOP)

250.1030 - The MMS must be very clear regarding the minimum EIA requirements to prevent broad interpretation and unproductive work.

Summary

Revision of Subpart J is appropriate; However, unless key issues are addressed and changes are made we will fail in our objective of improving our assurance of Integrity.

Other Comments

250.1093

What must I do to modify an approved pipeline?

250.1093 (b) Modification Application - Currently, ROW pipeline modifications and new ROW pipeline applications do not require the items that are part of 250.1030 (EIA). Maintenance activities should be excluded from this topic. For example, if a modification is proposed for an existing ROW pipeline, the items listed in 250.1030 would be a burden; i.e. replacing or adding Anodes will be considered a modification (currently it is considered maintenance with no applicable fees and a notification only to MMS and lease owners and ROW holders, this is another issue as well), by adding the requirements listed below, this would slow down the application process. Reason - for existing ROW pipelines this information was not required in the original application process, therefore it is not readily available and will need to be created and put together in the application process. Recommend to delete this item as a requirement for lease or ROW pipeline modifications.

Other Comments

250.1102

What inspections are required for my pipeline or route?

250.1102 Inspections (b) Flex Joints - Underwater flex joint inspections require mobilization of divers and all related support equipment. There is no historical precedence to suggest that annual visual inspections are necessary and offer any additional Integrity value. We suggest that inspections be conducted every two years and if any deterioration is found an appropriate follow-up program be established (this is based on the fact that there is no definition for deterioration and it can be present in may forms that do not represent an integrity threat).

Other Comments

Section: 250.1081

How do I determine the MAOP of a pipeline in Deepwater?

250.1081 Pipeline Design Pressure – To prevent confusion we need to recognize that design pressure (and MAOP) varies along a deepwater flowline.

1. **Recommend that flowline coming from deepwater to surface define 2 MAOP's (a surface MAOP, and subsea termination MAOP)**
2. **The detailed variation in MAOP along the flowline will be defined in the permit application.**

Rational:

- **Currently there is confusion A flow line Failure to recognize variable design pressure along deepwater flowlines, which results is assigning flowline segments an incorrect single MAOP.**
- **Pipelines should be rated to the internal pressure service requirements.**

Other Comments

Section: 250.1030
Environmental Impact Analysis Information for ROW Pipelines

250.1030 - The MMS must be very clear regarding the minimum EIA requirements to prevent broad interpretation and unproductive work.

Rational:

- **The EIA requirements for ROW pipelines have uncertain requirements.**
- **For longer tie-backs, some flowlines will be ROW pipelines.**
- **The requirements for the EIA are extensive, requiring description of all direct and indirect environmental impacts which would include not only the flowline routes but any accessory associated with the flowline.**
- **Some required information appears to be a duplication of information previously submitted- *I.e.Exploration Plan/DOCD***

Recommendations

We appreciate the extension of time afforded the industry and the opportunity to engage in discussion today but…

We strongly urge the agency to reconsider their current path and engage industry in the development of rules

Subpart J Workshop

February 22, 2008

Comments on Pipeline Applications

OFFSHORE OPERATORS COMMITTEE

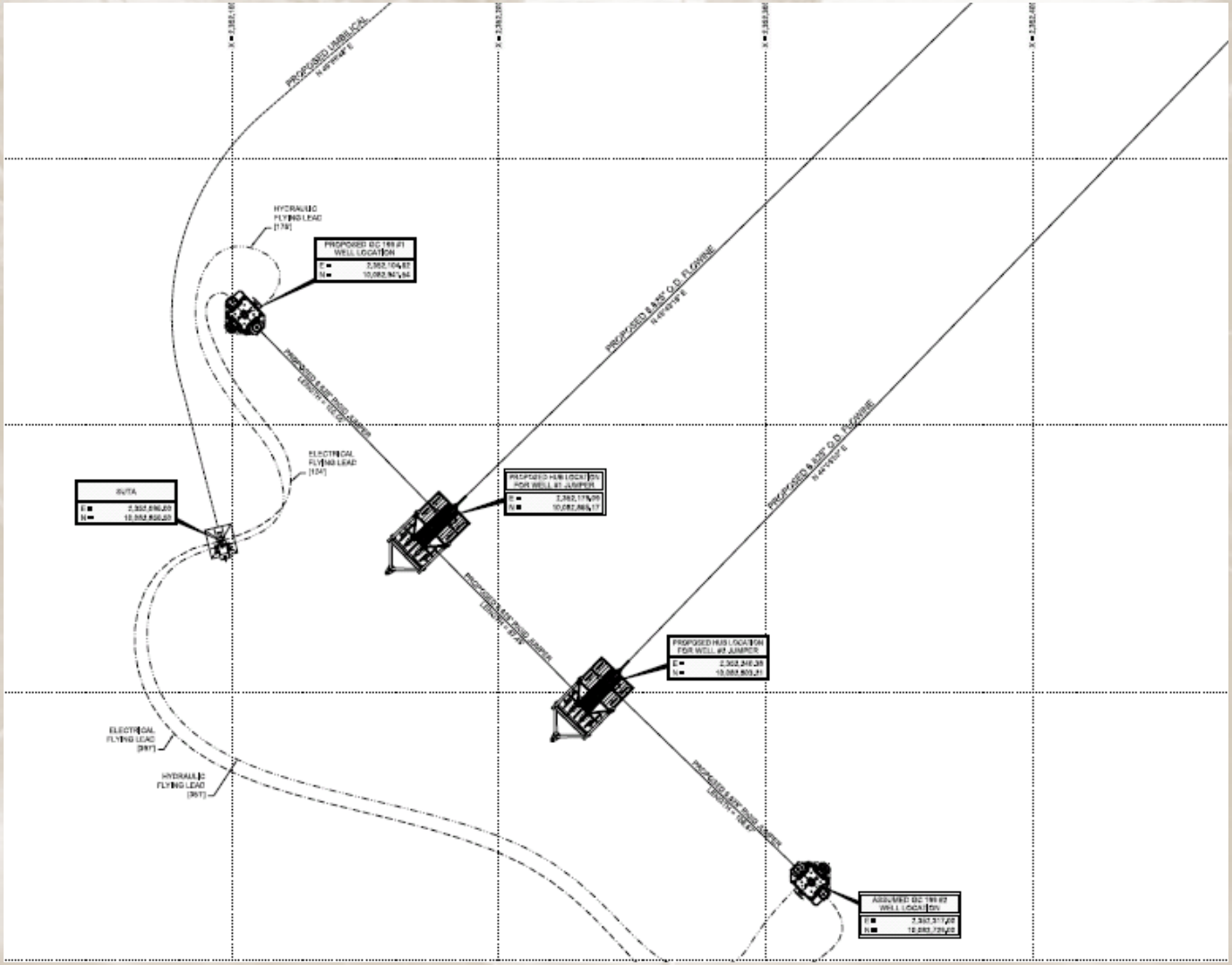
Other Applications

- Encourage consistency with other applications such as EPs and DOCDs
  - Number of copies; paper vs CD
  - Availability on the MMS website
  - Environmental Information
  - Processing time limits

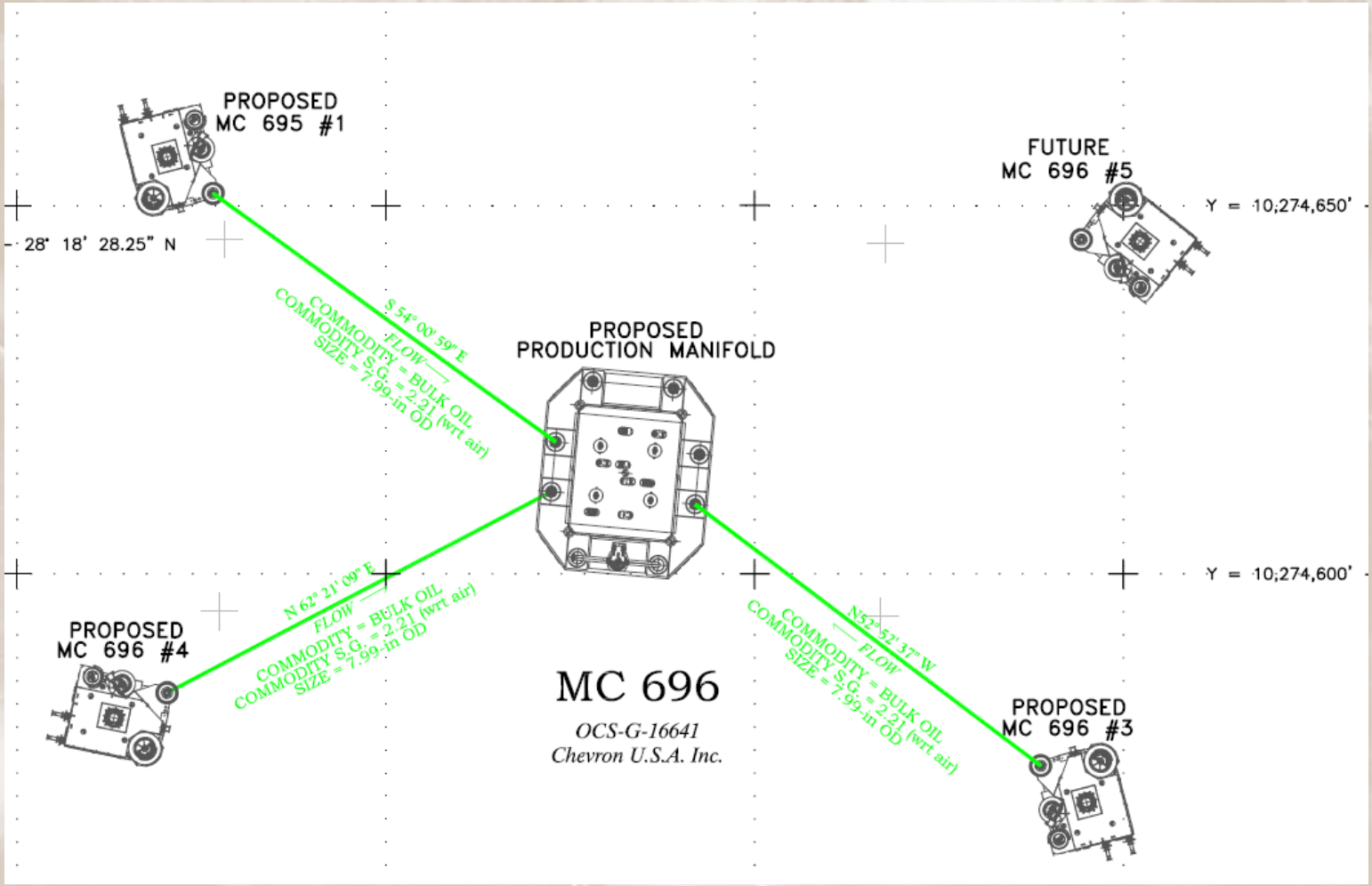
Terminology

- Subsea Systems
  - Terminology
    - Major/Minor Manifolds (Accessory Appl is applicable only to platforms)
    - Jumpers
    - Piles
  - ROW vs Lease Term
    - Segment Numbers
    - End of ROW
  - Out of Service

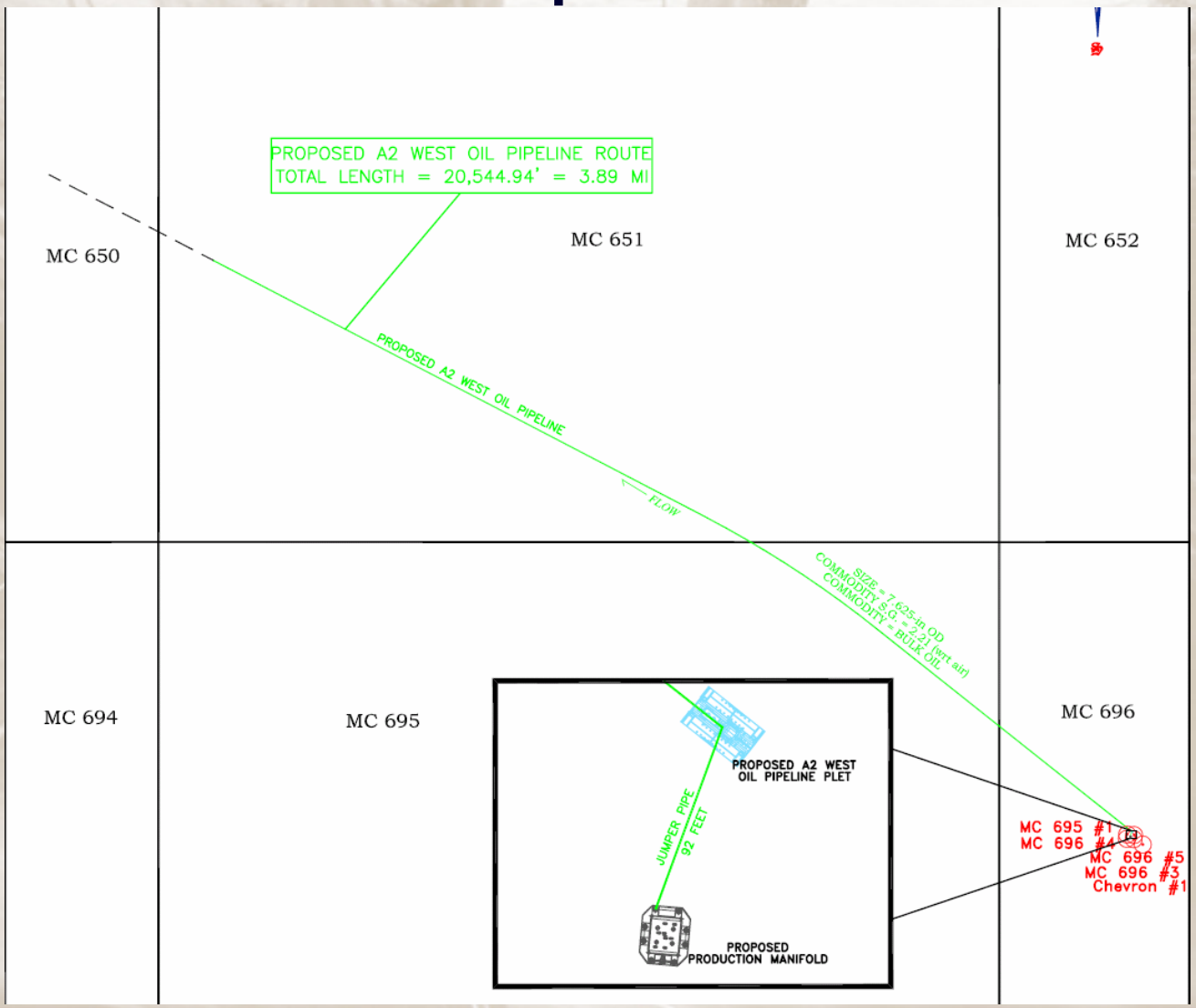
Example


PROPOSED UMBILICAL
HYDRAULIC FLYING LEAD [178']
PROPOSED 6.625" O.D. FLOWLINE
ELECTRICAL FLYING LEAD [154']
RVTA
ELECTRICAL FLYING LEAD [397']
HYDRAULIC FLYING LEAD [397']

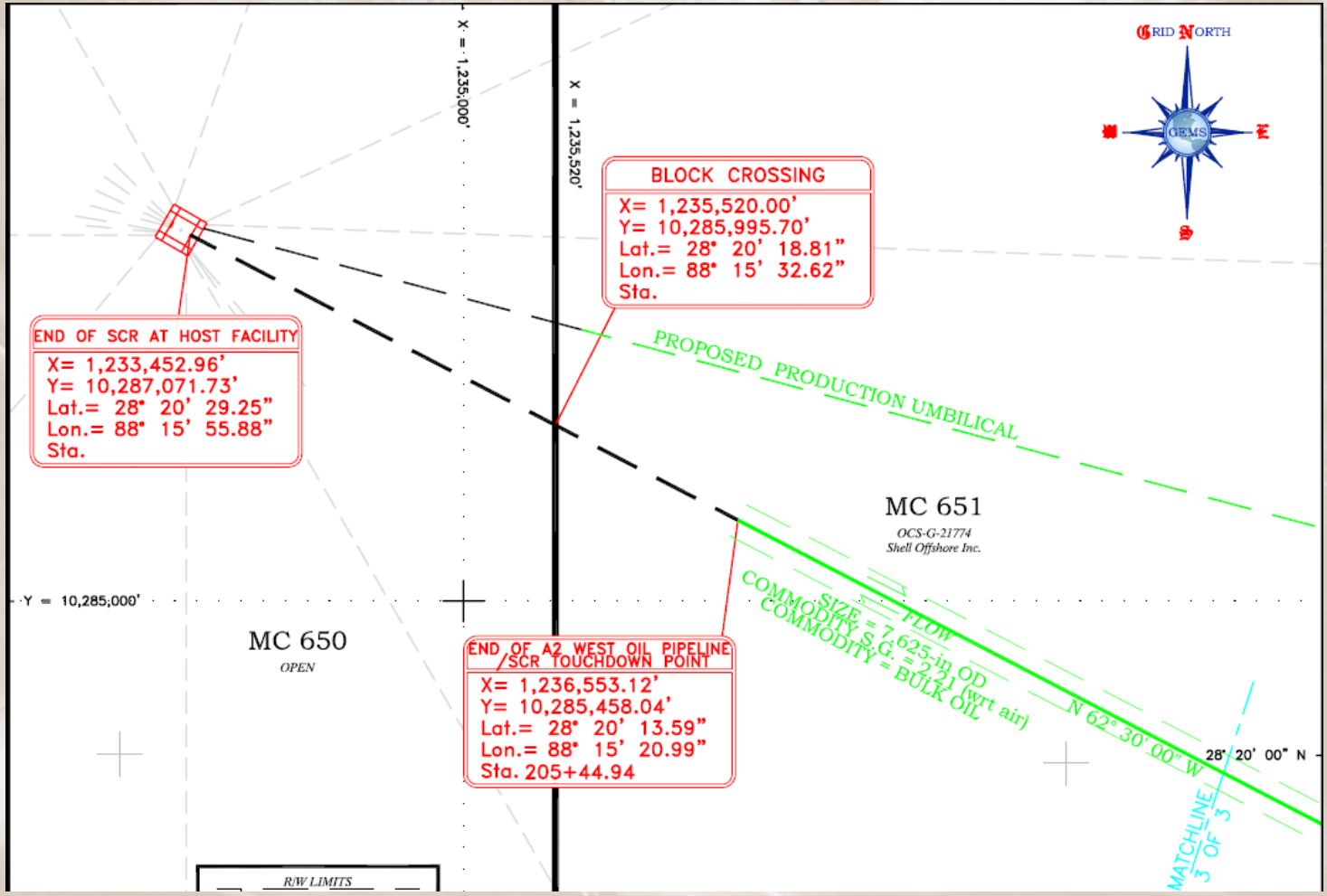
Example


PROPOSED
MC 695 #1
FUTURE
MC 696 #5
Y = 10,274,650'
28° 18' 28.25" N
S 54° 00' 59" E
FLOW
COMMODITY = BULK OIL
COMMODITY S.G. = 2.21 (wrt air)
SIZE = 7.99-in OD
PROPOSED
PRODUCTION MANIFOLD
Y = 10,274,600'
N 62° 21' 09" E
FLOW
COMMODITY = BULK OIL
COMMODITY S.G. = 2.21 (wrt air)
SIZE = 7.99-in OD
N52°52'37" W
FLOW
COMMODITY = BULK OIL
COMMODITY S.G. = 2.21 (wrt air)
SIZE = 7.99-in OD
PROPOSED
MC 696 #4
PROPOSED
MC 696 #3
MC 696
OCS-G-16641
Chevron U.S.A. Inc.

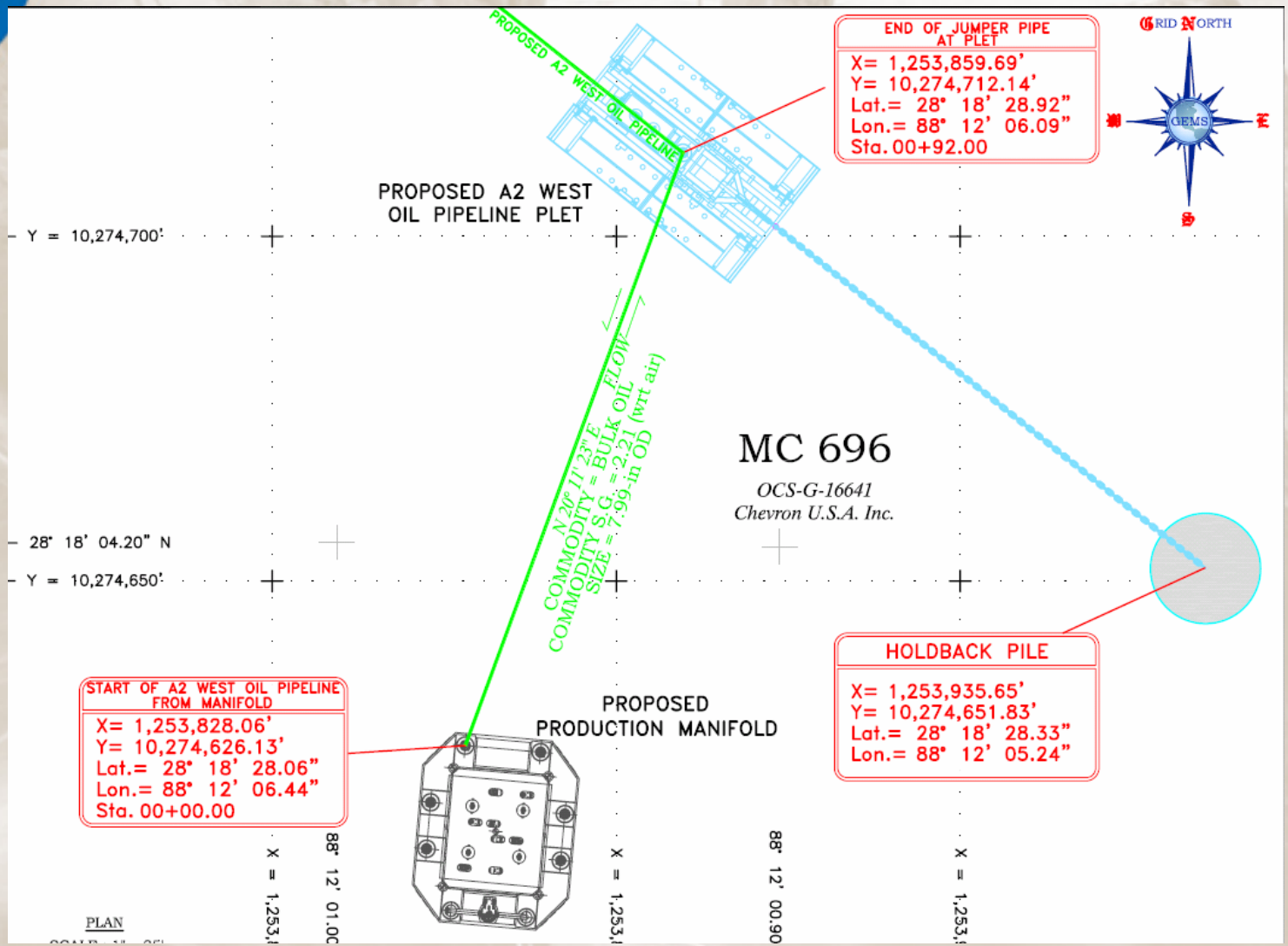
Example


PROPOSED A2 WEST OIL PIPELINE ROUTE
TOTAL LENGTH = 20,544.94' = 3.89 MI
MC 650
MC 651
MC 652
MC 694
MC 695
MC 696
PROPOSED A2 WEST OIL PIPELINE
FLOW
SIZE = 7.625-in OD
COMMODITY S.G. = 2.21 (wrt air)
COMMODITY = BULK OIL
PROPOSED A2 WEST OIL PIPELINE PLET
JUMPER PIPE 92 FEET
PROPOSED PRODUCTION MANIFOLD
MC 695 #1
MC 696 #4
MC 696 #5
MC 696 #3
Chevron #1

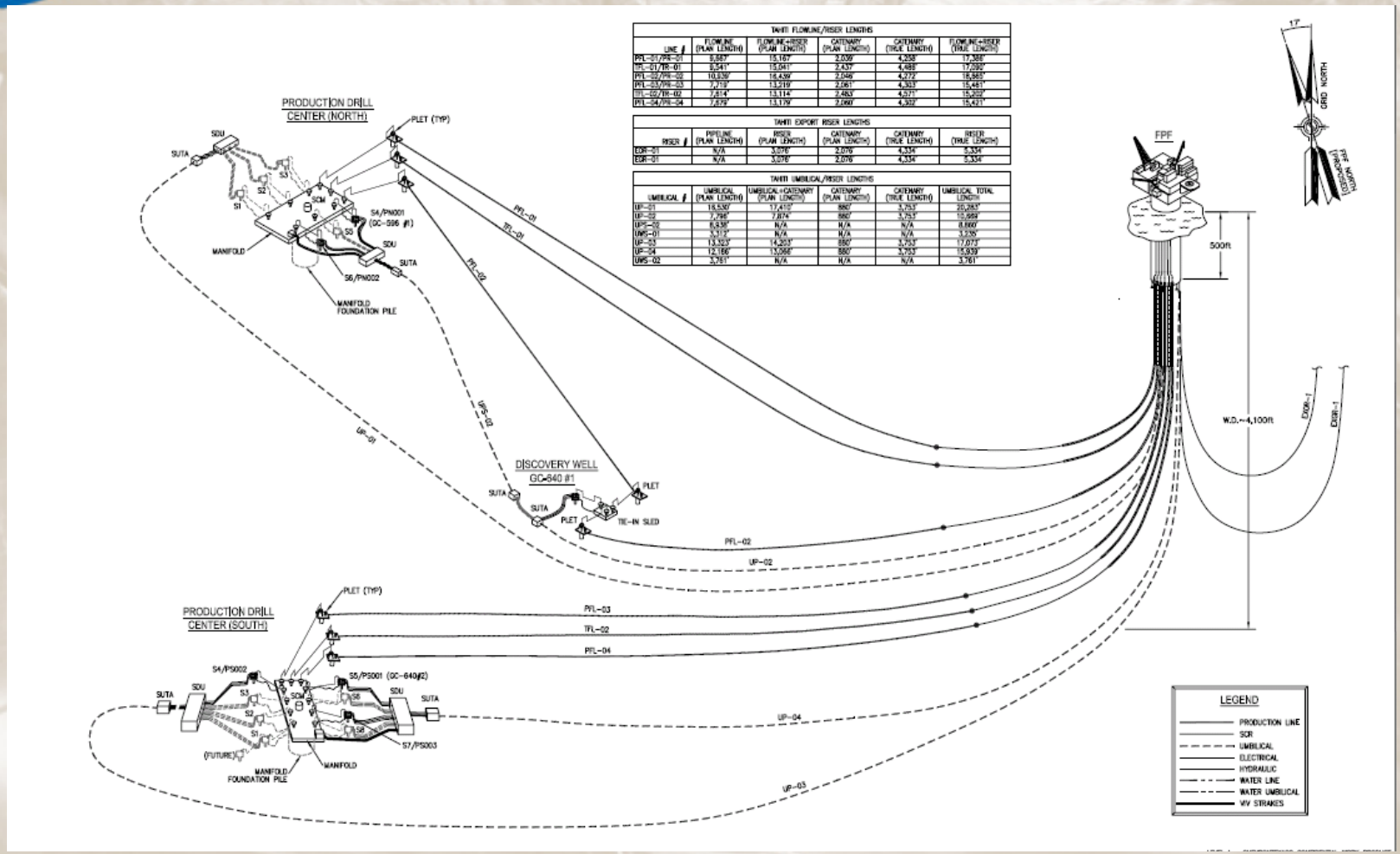
Example


X = 1,235,000'
X = 1,235,520'
Y = 10,285,000'
GRID NORTH
GEMS
BLOCK CROSSING
X= 1,235,520.00'
Y= 10,285,995.70'
Lat.= 28° 20' 18.81"
Lon.= 88° 15' 32.62"
Sta.
END OF SCR AT HOST FACILITY
X= 1,233,452.96'
Y= 10,287,071.73'
Lat.= 28° 20' 29.25"
Lon.= 88° 15' 55.88"
Sta.
PROPOSED PRODUCTION UMBILICAL
MC 651
OCS-G-21774
Shell Offshore Inc.
MC 650
OPEN
END OF A2 WEST OIL PIPELINE /SCR TOUCHDOWN POINT
X= 1,236,553.12'
Y= 10,285,458.04'
Lat.= 28° 20' 13.59"
Lon.= 88° 15' 20.99"
Sta. 205+44.94
SIZE = 7.625-in OD
COMMODITY S.G. = 2.21 (wrt air)
COMMODITY = BULK OIL
FLOW
N 62° 30' 00" W
28° 20' 00" N
MATCHLINE 3 OF 3
R/W LIMITS

Example


PROPOSED A2 WEST OIL PIPELINE
END OF JUMPER PIPE AT PLET
X= 1,253,859.69'
Y= 10,274,712.14'
Lat.= 28° 18' 28.92"
Lon.= 88° 12' 06.09"
Sta. 00+92.00
GRID NORTH
GEMS
PROPOSED A2 WEST OIL PIPELINE PLET
Y = 10,274,700'
28° 18' 04.20" N
Y = 10,274,650'
N 20° 11' 23" E
COMMODITY = BULK OIL
COMMODITY S.G. = 2.21 (wrt air)
SIZE = 7.99-in OD
FLOW
MC 696
OCS-G-16641
Chevron U.S.A. Inc.
HOLDBACK PILE
X= 1,253,935.65'
Y= 10,274,651.83'
Lat.= 28° 18' 28.33"
Lon.= 88° 12' 05.24"
START OF A2 WEST OIL PIPELINE FROM MANIFOLD
X= 1,253,828.06'
Y= 10,274,626.13'
Lat.= 28° 18' 28.06"
Lon.= 88° 12' 06.44"
Sta. 00+00.00
PROPOSED PRODUCTION MANIFOLD
88° 12' 01.00
88° 12' 00.90
PLAN

Example



TAHITI FLOWLINE/RISER LENGTHS

LINE #	FLOWLINE (PLAN LENGTH)	FLOWLINE+RISER (PLAN LENGTH)	CATENARY (PLAN LENGTH)	CATENARY (TRUE LENGTH)	FLOWLINE+RISER (TRUE LENGTH)
PFL-01/PR-01	8,961'	13,197'	2,039'	4,358'	17,355'
TFL-01/TR-01	9,541'	13,041'	2,437'	4,488'	17,029'
PFL-02/PR-02	10,839'	16,439'	2,046'	4,272'	18,885'
PFL-03/PR-03	7,719'	13,219'	2,061'	4,303'	15,461'
TFL-02/TR-02	7,614'	13,114'	2,463'	4,571'	15,233'
PFL-04/PR-04	7,879'	13,179'	2,060'	4,302'	15,421'

TAHITI EXPORT RISER LENGTHS

RISER #	PIPELINE (PLAN LENGTH)	RISER (PLAN LENGTH)	CATENARY (PLAN LENGTH)	CATENARY (TRUE LENGTH)	RISER (TRUE LENGTH)
EGR-01	N/A	3,076'	2,076'	4,334'	5,334'
EGR-01	N/A	3,076'	2,076'	4,334'	5,334'

TAHITI UMBILICAL/RISER LENGTHS

UMBILICAL #	UMBILICAL (PLAN LENGTH)	UMBILICAL+CATENARY (PLAN LENGTH)	CATENARY (PLAN LENGTH)	CATENARY (TRUE LENGTH)	UMBILICAL TOTAL LENGTH
UP-01	15,530'	17,410'	880'	3,753'	20,283'
UP-02	7,780'	7,874'	880'	3,753'	12,669'
UMB-02	8,636'	N/A	N/A	N/A	8,660'
UMS-01	3,317'	N/A	N/A	N/A	3,335'
UP-03	13,323'	14,203'	880'	3,753'	17,073'
UP-04	12,186'	13,066'	880'	3,753'	15,939'
UMS-02	3,761'	N/A	N/A	N/A	3,781'

Example

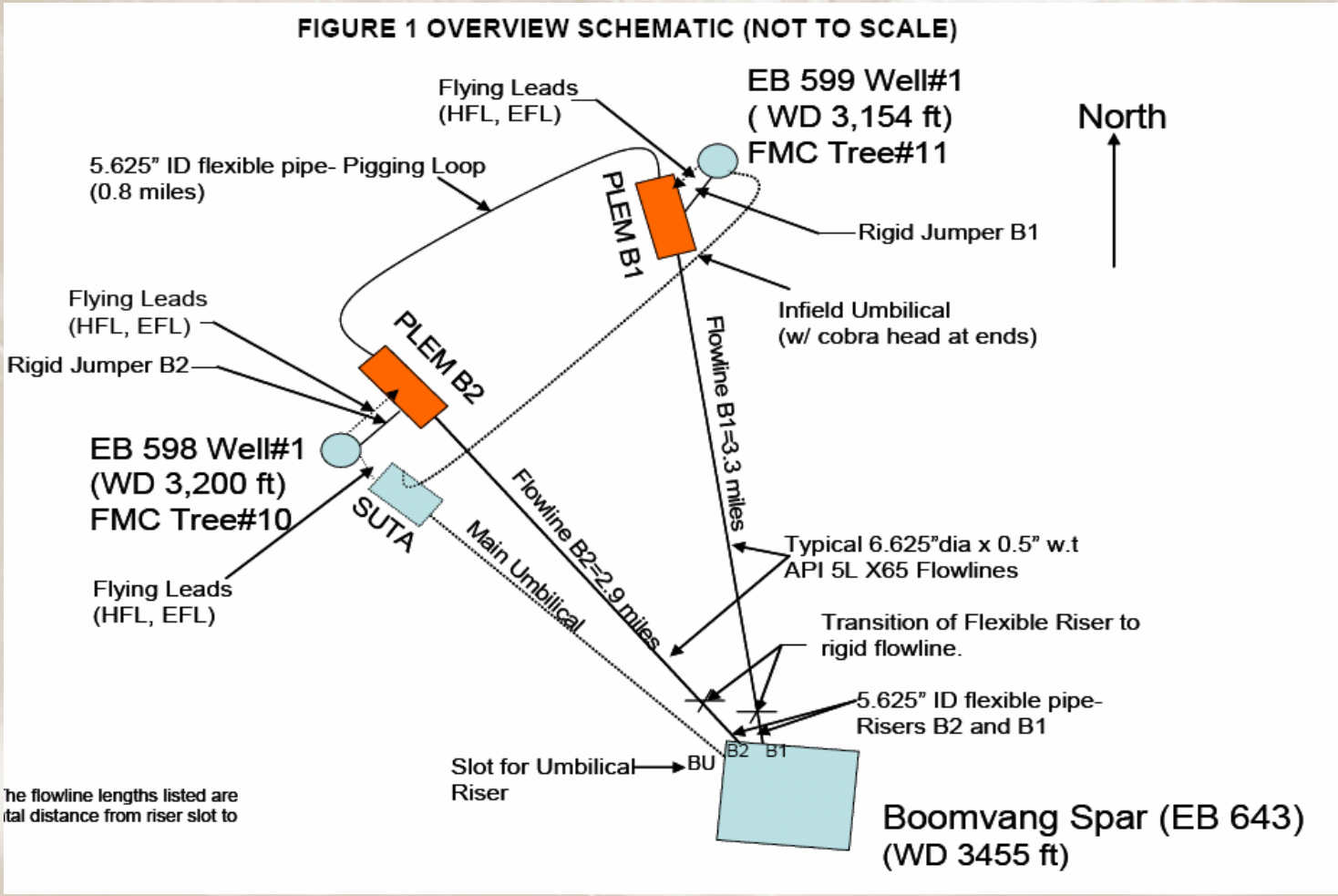
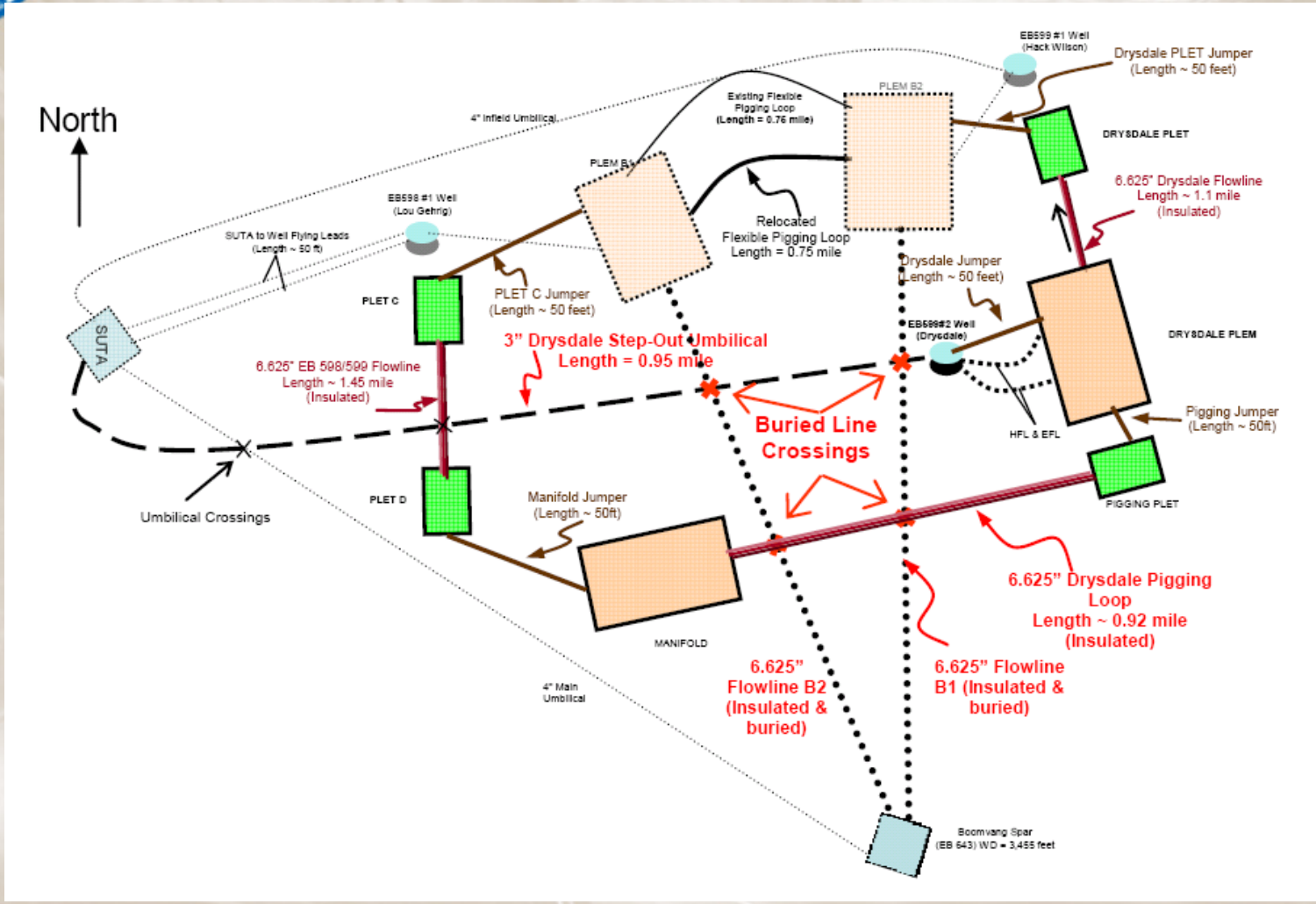


FIGURE 1 OVERVIEW SCHEMATIC (NOT TO SCALE)
Flying Leads
(HFL, EFL)
EB 599 Well#1
(WD 3,154 ft)
FMC Tree#11
North
5.625" ID flexible pipe- Pigging Loop
(0.8 miles)
PLEM B1
Rigid Jumper B1
Infield Umbilical
(w/ cobra head at ends)
Flying Leads
(HFL, EFL)
Rigid Jumper B2
PLEM B2
Flowline B1=3.3 miles
EB 598 Well#1
(WD 3,200 ft)
FMC Tree#10
SUTA
Main Umbilical
Flowline B2=2.9 miles
Typical 6.625"dia x 0.5" w.t
API 5L X65 Flowlines
Flying Leads
(HFL, EFL)
Transition of Flexible Riser to
rigid flowline.
5.625" ID flexible pipe-
Risers B2 and B1
B2 B1
Slot for Umbilical
Riser
BU
he flowline lengths listed are
tal distance from riser slot to
Boomvang Spar (EB 643)
(WD 3455 ft)

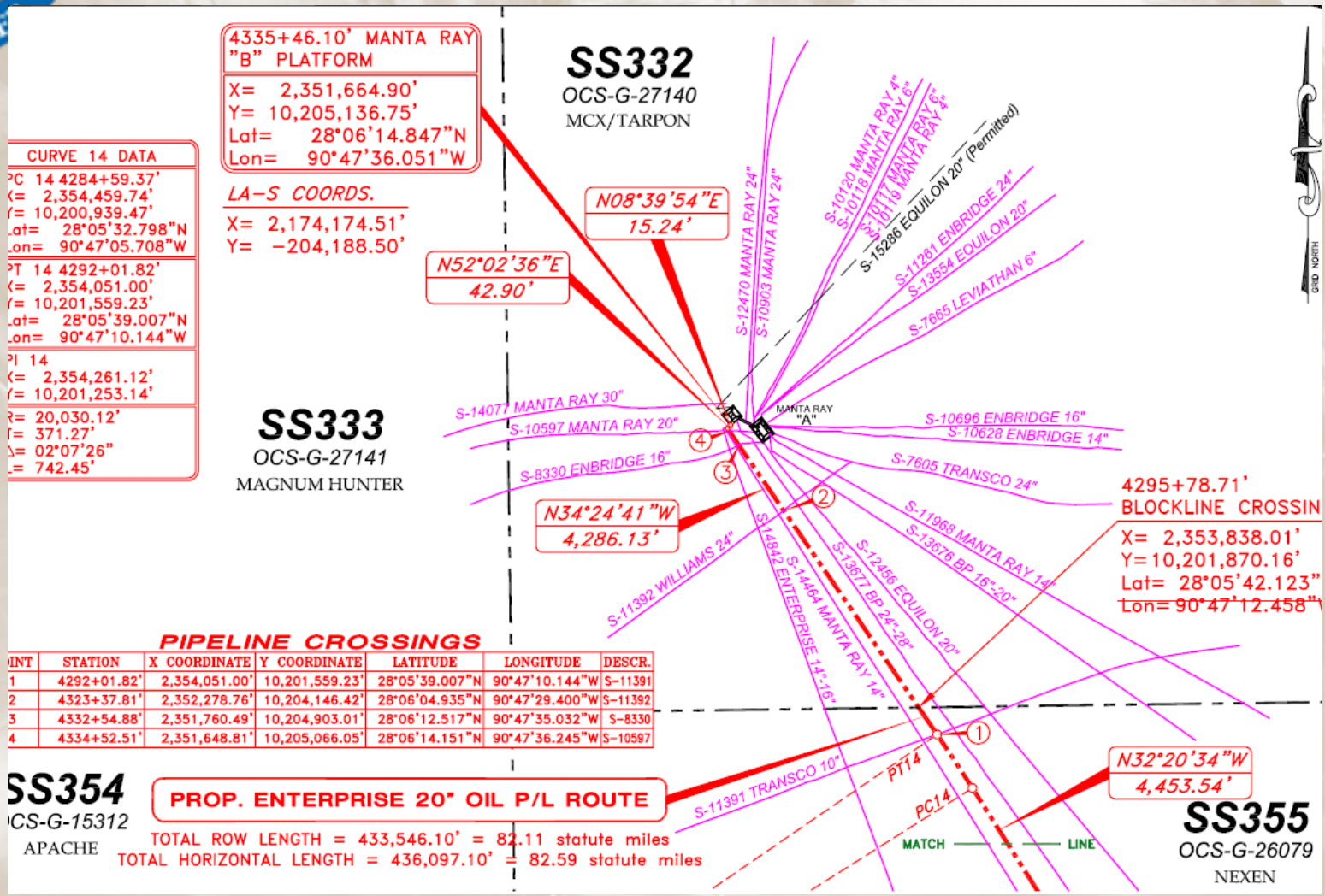
Example


North
4" Infield Umbilical
Existing Flexible Pigging Loop (Length = 0.76 mile)
PLEM B2
EB599 #1 Well (Hack Wilson)
Drysdale PLET Jumper (Length ~ 50 feet)
DRYSDALE PLET
6.625" Drysdale Flowline Length ~ 1.1 mile (Insulated)
PLEM B1
EB598 #1 Well (Lou Gehrig)
SUTA to Well Flying Leads (Length ~ 50 ft)
Relocated Flexible Pigging Loop Length = 0.75 mile
Drysdale Jumper (Length ~ 50 feet)
PLET C
PLET C Jumper (Length ~ 50 feet)
EB598#2 Well (Drysdale)
DRYSDALE PLEM
SUTA
3" Drysdale Step-Out Umbilical Length = 0.95 mile
6.625" EB 598/599 Flowline Length ~ 1.45 mile (Insulated)
Buried Line Crossings
HFL & EFL
Pigging Jumper (Length ~ 50ft)
Umbilical Crossings
PLET D
Manifold Jumper (Length ~ 50ft)
PIGGING PLET
6.625" Drysdale Pigging Loop Length ~ 0.92 mile (Insulated)
MANIFOLD
6.625" Flowline B2 (Insulated & buried)
6.625" Flowline B1 (Insulated & buried)
4" Main Umbilical
Boomvang Spar (EB 643) WD = 3,455 feet

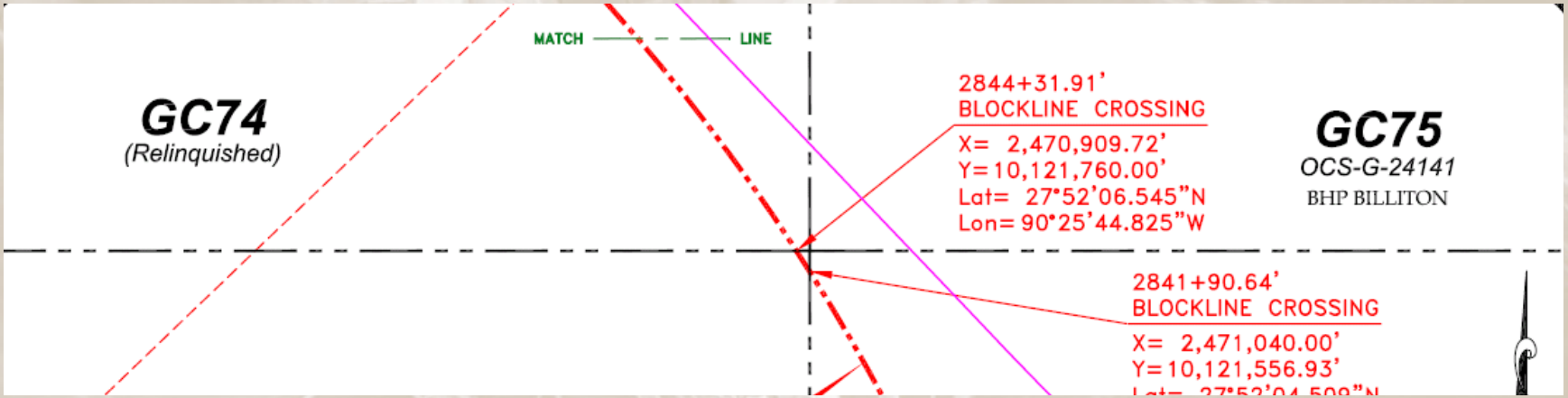
Notification to Operators

- Impacted
  - Easy to tell what leases/pipelines are crossed
  - Don’t know what “impacted” means.
- No requirement to notify umbilical operator
- Rationale for providing complete application
  - Brief description of pipeline
  - Plat

Example


4335+46.10' MANTA RAY "B" PLATFORM
X= 2,351,664.90'
Y= 10,205,136.75'
Lat= 28°06'14.847"N
Lon= 90°47'36.051"W
LA-S COORDS.
X= 2,174,174.51'
Y= -204,188.50'
CURVE 14 DATA
PC 14 4284+59.37'
X= 2,354,459.74'
Y= 10,200,939.47'
Lat= 28°05'32.798"N
Lon= 90°47'05.708"W
PT 14 4292+01.82'
X= 2,354,051.00'
Y= 10,201,559.23'
Lat= 28°05'39.007"N
Lon= 90°47'10.144"W
PI 14
X= 2,354,261.12'
Y= 10,201,253.14'
R= 20,030.12'
T= 371.27'
Δ= 02°07'26"
L= 742.45'
SS332
OCS-G-27140
MCX/TARPON
N08°39'54"E
15.24'
N52°02'36"E
42.90'
S-12470 MANTA RAY 24"
S-10903 MANTA RAY 24"
S-10120 MANTA RAY 4"
S-10118 MANTA RAY 6"
S-10117 MANTA RAY 6"
S-10115 MANTA RAY 6"
S-15286 EQUILON 20" (Permitted)
S-11261 ENBRIDGE 24"
S-13554 EQUILON 20"
S-7665 LEVIATHAN 6"
GRID NORTH
SS333
OCS-G-27141
MAGNUM HUNTER
S-14077 MANTA RAY 30"
S-10597 MANTA RAY 20"
S-8330 ENBRIDGE 16"
MANTA RAY "A"
S-10696 ENBRIDGE 16"
S-10628 ENBRIDGE 14"
S-7605 TRANSCO 24"
4295+78.71'
BLOCKLINE CROSSIN
X= 2,353,838.01'
Y= 10,201,870.16'
Lat= 28°05'42.123"
Lon= 90°47'12.458"
N34°24'41"W
4,286.13'
S-11392 WILLIAMS 24"
S-14842 ENTERPRISE 14"-16"
S-14464 MANTA RAY 14"
S-13677 BP 24"-28"
S-12456 EQUILON 20"
S-11968 MANTA RAY 14"
S-13676 BP 16"-20"
PIPELINE CROSSINGS
INT | STATION | X COORDINATE | Y COORDINATE | LATITUDE | LONGITUDE | DESCR.
1 | 4292+01.82' | 2,354,051.00' | 10,201,559.23' | 28°05'39.007"N | 90°47'10.144"W | S-11391
2 | 4323+37.81' | 2,352,278.76' | 10,204,146.42' | 28°06'04.935"N | 90°47'29.400"W | S-11392
3 | 4332+54.88' | 2,351,760.49' | 10,204,903.01' | 28°06'12.517"N | 90°47'35.032"W | S-8330
4 | 4334+52.51' | 2,351,648.81' | 10,205,066.05' | 28°06'14.151"N | 90°47'36.245"W | S-10597
SS354
OCS-G-15312
APACHE
PROP. ENTERPRISE 20" OIL P/L ROUTE
TOTAL ROW LENGTH = 433,546.10' = 82.11 statute miles
TOTAL HORIZONTAL LENGTH = 436,097.10' = 82.59 statute miles
S-11391 TRANSCO 10"
PT14
PC14
MATCH LINE
N32°20'34"W
4,453.54'
SS355
OCS-G-26079
NEXEN

Example


MATCH LINE
GC74
(Relinquished)
2844+31.91'
BLOCKLINE CROSSING
X= 2,470,909.72'
Y=10,121,760.00'
Lat= 27°52'06.545"N
Lon=90°25'44.825"W
GC75
OCS-G-24141
BHP BILLITON
2841+90.64'
BLOCKLINE CROSSING
X= 2,471,040.00'
Y=10,121,556.93'

Riser CVA

- Development will be impeded if Riser Design CVA must be completed prior to fabrication commencing
- Verification vs Independent Analysis
- CVA should not make recommendations to MMS on areas which they are not required to verify
  - Marine growth
  - ISIP
- Purpose of Interim Reports?
- No approval of fabrication or installation final reports—what does MMS do with these?

Operation and Maintenance Plans

- Are these plans applicable to existing lines or only lines installed after the effective date of the regulation?
- Phase in period—2 to 4 years
- IMP should only be applicable to HCAs
- Avoid duplication of effort
- Expect wide variety of plans

Repair Applications

- Standard repair procedures
- Application cycle time
- Rejected applications

Notifications

- eWell type notifications and reports should be developed
- Purpose of notifications
  - Our installation/hydrotest plans change at the last moment…when do we need to re-notify you?
  - Safety equipment repairs, replacement
  - After hours notification
- Consistent with other regulations

Notifications