THE OFFSHORE CALIFORNIA PIPELINE INSPECTION SURVEY (OCPIS) PLAN

Prepared by
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Minerals Management Service
Pacific OCS Region Sponsored
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Executive Summary

The Offshore California Pipeline Inspection Survey (OCPIS) Plan was developed by a multi-agency team composed of representatives from the Minerals Management Service (MMS), Department of Transportation (DOT), California State Lands Commission (CSLC), California State Fire Marshal (CSFM) and the Division of Oil, Gas, and Geothermal Resources (DOGGR). The **OCPIS Plan** is intended to provide user agencies with an analytical framework for assessing the present condition and inspection needs of offshore pipelines as a necessary precursor to making informed decisions on the feasibility of operator's inspection plans, waiver requests and other related issues.

One of the key elements of the **OCPIS Plan** is the emphasis placed on coordination between agencies that have regulatory jurisdiction over offshore pipelines. The **OCPIS Plan** underscores the importance of coordination between agencies early in the process to identify issues and concerns and develop consensus on regulatory actions.

An integral part of the **OCPIS Plan** process is a detailed evaluation of the pipeline, its risk potential from accidents or failures and the operator's regulatory compliance history. At the cornerstone of the pipeline evaluation are 36 inspection criteria which influence the conduct and timing of internal and external pipeline inspections. The relative influence of each criterion on a particular survey strategy is subjectively determined and variable from line to line and setting to setting.

The **OCPIS Plan** is designed to: (1) provide regulators with a reasonable assessment of the inspection needs for individual pipelines; (2) permit operators to develop innovative inspection strategies that are tailored to the needs of individual lines based on established operational and environmental criteria unique to each; (3) improve the safety of offshore pipelines and reduce the risk of failure by requiring operators to conduct the most beneficial surveys based on the actual condition of the line; and (4) afford industry an opportunity to reduce survey costs as a benefit of diligent and innovative inspection and maintenance.

The **OCPIS Plan** was tested and refined during a simulated evaluation of Unocal's Dos Cuadras pipelines and the operator's request for a waiver of MMS inspection requirements (on the gas lines). The exercise indicated that the process and procedures worked well for assessing the inspection needs of pipelines and evaluating the operator's waiver request. The process is sufficiently comprehensive and flexible to be useful when considering each of the action items for which it was designed.

Nine recommendations are offered which could enhance the effectiveness of the MMS pipeline inspection program including implementation of the **OCPIS Plan** in concert with other affected agencies. Although a uniform pipeline inspection plan is not proposed or considered necessary, the current MMS inspection plan for POCS facilities, with certain refinements, is a comprehensive model for pipelines in both federal and state waters.

Introduction

The Minerals Management Service (MMS), in reviewing recent offshore pipeline inspection surveys, recognized the need for refinements which would benefit both government and industry. Realizing that other federal, state and local agencies have different inspection requirements on the same pipelines, the MMS invited interested agencies to participate in a technical workgroup to review existing federal and state agency requirements for external inspections for pipelines on the Pacific Outer Continental Shelf (POCS) and to develop guidelines to improve the quality of such surveys. The **Pipeline Inspection Quality Improvement Team (PIQIT)** convened in the Spring of 1994, as a multi-agency committee consisting of the MMS, Department of Transportation (DOT), California State Lands Commission (CSLC), California State Fire Marshal (CSFM) and the Division of Oil, Gas, and Geothermal Resources (DOGGR). By consensus of the participating agencies, the workgroup's charter was broadened to include pipelines in state waters and a review of internal inspection survey requirements.

Background

Over the years, various federal, state and local agencies have imposed internal and external inspection requirements on offshore pipelines in accordance with their respective jurisdictional authorities, responsibilities and interests (see Appendix 1). Due to the lack of uniformity in agency regulations and requirements, industry is often faced with redundant and sometimes contradictory inspection requirements. As a result, offshore pipeline operators are often required to perform internal and external inspections on pipelines at fixed intervals regardless of the pipeline condition or the need for inspection.

The PIQIT's Inspection Philosophy

At the outset, some participating agencies voiced an interest in standardizing as much as possible inspection requirements for offshore lines which at present vary considerably from agency to agency (see Appendix 2). In particular, differing frequency requirements for some surveys are a source of concern for some pipeline operators who desire more uniformity in agency inspection requirements and inspection intervals that are determined by the actual condition of the line.

After examining in great detail the many variables (see **Inspection Criteria**) which influence survey methodology and frequency, the team decided to develop a standardized process for evaluating pipeline inspection plans and industry requests to waive existing pipeline inspection requirements in lieu of a uniform inspection plan. Factors which influenced this decision are indicated below.

(1) Some agencies do not have the regulatory authority to mandate routine surveys except in response to a specific incident.

(2) The principle factors ("primary criteria") influencing surveys tend to be line specific and do not conform well to prescriptive inspection requirements.

(3) The team is unaware of any scientific or engineering data to support an inspection frequency that is more valid than the one and two year intervals currently established by various agencies for internal and external surveys.

(4) A uniform inspection policy will not mitigate all operator's concerns regarding current MMS pipeline inspection requirements which have generated numerous requests for waivers and may continue to generate waiver requests in the future.

(5) The uniform process we are advocating eliminates the need for uniform regulations and attendant statutory revisions that might be required for implementation by some agencies.

Given the limited number of offshore oil, gas and water pipelines currently in operation (78) or anticipated in the future, the PIQIT has concluded that the best approach to inspecting offshore pipelines is to critically examine each line individually and develop an inspection schedule for each based on the present condition and risk potential of the line. When this is not possible, MMS' existing policy and requirements (see Appendix 3), with certain refinements (see Recommendation #4), is an adequate default plan for POCS lines and a fairly comprehensive model for other agencies desiring a more uniform inspection plan.

The Offshore California Pipeline Inspection Survey (OCPIS) Plan

The **OCPIS Plan** is a consensus-based, decision-making process which is intended to provide user agencies with an analytical framework for assessing the present condition and inspection needs of submerged offshore pipelines associated with oil and gas production.

An integral part of the **OCPIS Plan** process is an evaluation of the pipeline's integrity, inspection and maintenance histories, risk potential for accidents or failures and the operator's regulatory compliance history. This detailed evaluation should:

(1) provide regulators with a reasonable assessment of the current condition and inspection needs for individual lines (or systems);

(2) permit operators to develop inspection schedules that are tailored to the needs of individual lines (or systems) based on the demonstrated operational and environmental considerations (criteria) specific to each;

(3) improve pipeline safety and reduce the risk of failure by requiring the operator to conduct the most beneficial surveys based on the actual condition of the line; and

(4) reduce operator's survey costs as a benefit of diligent and innovative inspection and maintenance.

The **OCPIS Plan** process and procedures (described below and detailed in checklists in the Appendices) is a sequential nine-step process which is intended to:

- identify agencies' issues and concerns,
- focus deliberations to resolve concerns,
- develop a partnership between agencies to exchange information and resolve differences through coordination and negotiation with operators,
- develop alternative inspection or remediation proposals as needed,
- build consensus among agencies and
- make appropriate recommendations.

The flow-chart process and checklist procedures have been presented in a structured format that is comprehensive, user-friendly and sufficiently flexible to be easily amended as time and experience dictate. Although the procedures were validated and fine-tuned in a simulated exercise (see **Pipeline Evaluation Workshop**), in actual practice, certain steps or procedures may be stressed or omitted as the situation warrants. For example, the user may not need to work through all of the steps and checklist procedures to achieve an appropriate and timely (consensus) response to an offshore incident that are necessary for evaluating an operator's waiver request or plan submittal. We are confident the **OCPIS Plan** will provide users with comprehensive and flexible guidelines that will help to focus and simplify their deliberations without needlessly exacerbating the process.

How the Process Works

The **OCPIS Plan** flow chart (Figure 1) and decision checklist (Appendix 4) are to be utilized when considering each of the following proposed actions:

(1) An operator's survey plan or request for a waiver from existing survey requirements;

(2) An agency's request for a change in current survey requirements; or

(3) An agency's requirement for an unscheduled inspection following an offshore incident or accident.

Once an action is initiated, either by an agency or an operator, a lead agency is identified. In general, the lead agency(ies) for **OCPIS Plan** actions will usually be one of the following:

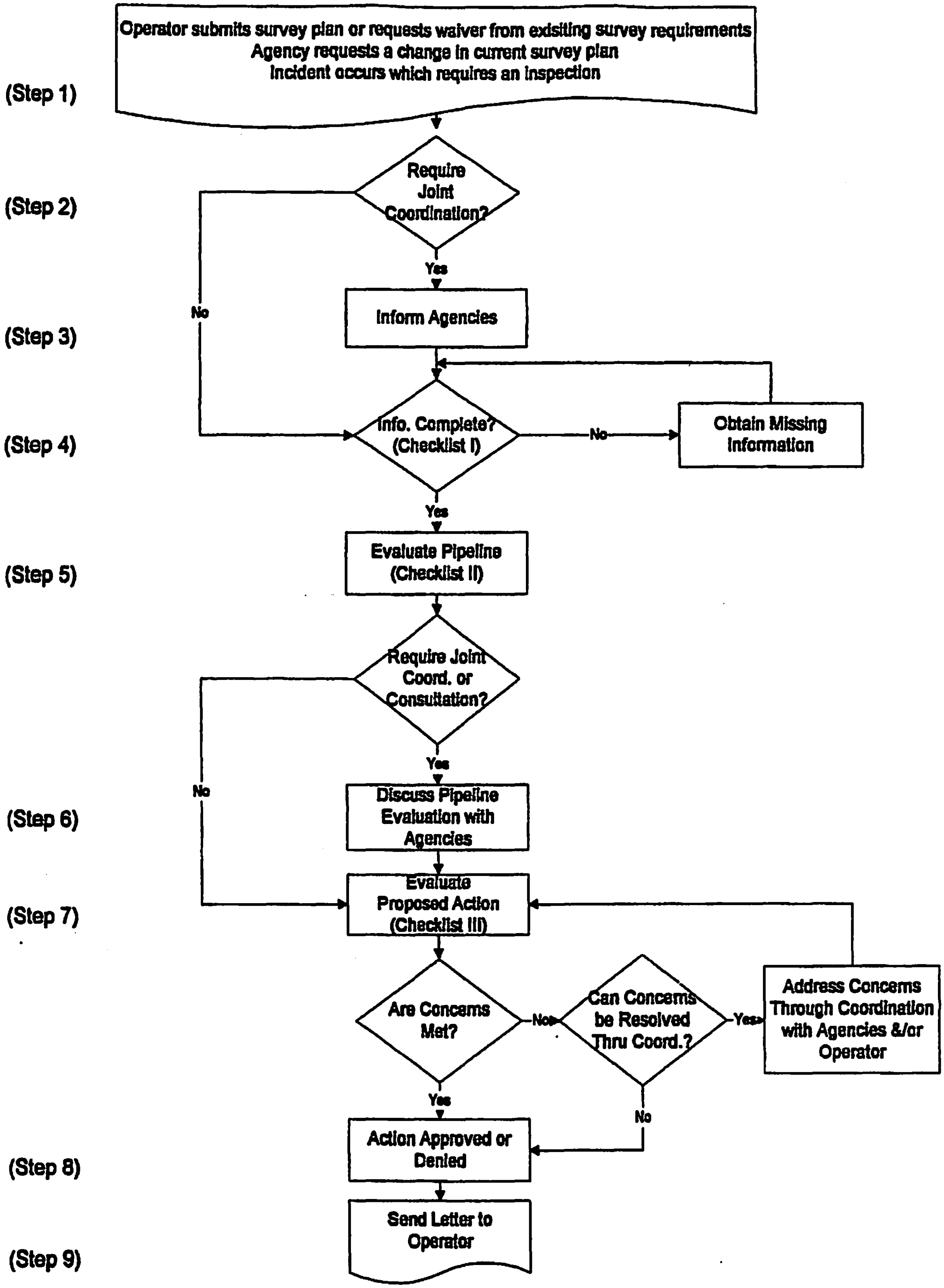
(1) The MMS for lines originating at a platform in federal waters or for an incident occurring in federal waters;

(2) The CSLC, DOGGR or CSFM (to be determined) for lines located entirely within state waters or for an incident occurring in state waters; or

(3) The agency initiating the action or whose requirements motivated the action.

Offshore California Pipeline Inspection Survey Plan

(Figure 1)



For example, using Torch Operating Company's Pt. Pedernales Pipeline (from Platform Irene to shore):

- if the operator submits a survey plan to the MMS for approval, MMS will assume the lead;
- if the operator submits a request for a waiver of a DOT requirement, the DOT will assume the lead;
- if an incident occurs on the state waters portion of the line, the CSLC or CSFM will assume the lead; or
- if MMS requests a revision to the operator's current inspection plan, MMS will assume the lead.

The lead agency will examine the jurisdictional issues and regulatory requirements of each affected federal, state and local agency and determine if a joint review or consultation is needed (see location map and tables presented in Appendices 5 and 6). If coordination is necessary, the lead agency will inform all affected agencies of the pending action (see list of contacts provided in Appendix 7).

The lead agency will then initiate an evaluation of the pipeline or system utilizing the procedures identified in the "Offshore California Pipeline Evaluation Checklist Parts I and II" (Appendices 8,9, and 11). The lead agency gathers pertinent design, operational, inspection, repair, environmental and other data and information from agencies' and operator's files (Checklist Part I). This information is synthesized by the lead agency to assess the present condition of the line, the compliance history of the operator and the potential for future pipeline failures (Checklist Part II).

The lead agency discusses the pipeline evaluation with the affected agencies and initiates an evaluation of the proposed action either independently or jointly with the affected agencies, as appropriate, using the "Offshore California Pipeline Evaluation Checklist Part III" as a guide (Appendices 10 and 11). The agencies identify and attempt to resolve concerns relating to the pipeline evaluation, the proposed action or an alternative recommended action(s) through coordination and negotiation with all parties including the operator. The agencies work towards achieving a consensus decision on the proposed action, if possible, and issue either joint or independent recommendations to their respective managements to approve or deny the proposed action (i.e, plan or waiver request) or to require an alternate inspection or remediation plan as appropriate. The operator is subsequently notified in writing of the agency's(ies') decision(s).

Inspection Criteria

An integral part of the **OCPIS Plan** process is the pipeline evaluation which is based on an analysis of eight general categories of information (containing 36 influential criteria) related to pipeline design, operation, inspection, maintenance, incident history, physical environment and other factors. Other criteria (e.g., pipeline age) were considered and omitted from the list if they were determined to exert little or no influence on the development or evaluation of a survey plan or waiver request for either internal or external surveys (see **Glossary** definition for "criteria/non-applicable"). The 36 influential criteria are compiled on Checklist Part I (Appendix 8) and synthesized and evaluated on Checklist Part II (Appendix 9). Definitions for various criteria and related terminology are provided in the **Glossary** (Appendix 12).

Individual criteria on Checklist Part I are relatively weighted as "primary", "secondary" or "non-applicable" depending on how much weight (or influence) should be placed on the factor in assessing internal and external survey methods and frequencies. The purpose of defining and weighting criteria was to provide an analytical basis for evaluating the integrity and inspection needs of offshore pipelines to assist in regulatory decision-making. However, the weight a user places on an individual criterion may be entirely subjective and in many cases line and setting dependent. The user must decide how much weight to place on a given criterion for a given situation or environment in reaching a decision.

"Primary criteria" are defined in the **Glossary** as "key factors which are considered in determining what, where, when and how surveys should be conducted...." The key factors which tend to influence the character, quality and timing of internal inspections include: pipe design criteria (e.g., diameter, wall thickness, steel grade), operating conditions (pressures, flow rate, product type and composition), pipeline characteristics (e.g., internal corrosion and corrosion controls, external cathodic protection type) internal inspection and maintenance histories and other factors (i.e., whether the line can be smart pigged). In contrast, with the exception of pipeline maintenance criteria and cathodic protection, the key factors influencing external inspections are markedly different from the above and equally diverse and include: external pipeline characteristics (e.g., type of cathodic protection, pipe coating, exposures and spans), proximity to biologically sensitive areas (e.g., hard bottoms), external inspection and maintenance histories, external corrosion and corrosion controls and offshore incidents (seismic/storm loads, third party damage).

"Secondary criteria" (e.g., most environmental factors) are defined as "factors which may alter or amend an existing survey strategy but are usually not crucial to the initial development or evaluation of the plan...." Secondary factors may become more influential decision-making tools under certain circumstances over the operational life of the pipeline.

What should be apparent from a cursory examination of the criteria listed on Checklist Part I is that the factors influencing internal and external inspections are numerous, diverse and, in most cases, line specific. With increased time and experience doing pipeline evaluations, it may be possible to identify one or two key indicator criteria which can be used as reliable yardsticks to streamline the process. "Age" is a criterion that is often used as an indicator of pipeline integrity for the purpose of predicting inspection needs. In actuality, it is not the age of the line that is the significant parameter but other design or operational characteristics (i.e., corrosion, rate of corrosion, ineffective corrosion controls, steel grade, wall thickness, etc.) which are the underlying causes of metal fatigue and pipe failures in offshore pipelines. For the present, we believe that the most conservative approach which will provide the desired margin of safety to the public and a long-term cost-benefit to industry is the detailed evaluation we are proposing using the 36 influential criteria as a guideline.

Pipeline Evaluation Workshop

The PIQIT convened a workshop in July and August, 1995, to validate and refine the **OCPIS Plan** process and procedures. During the four day exercise, workshop participants assessed the adequacy and utility of the **OCPIS Plan** by evaluating Unocal's request for a waiver of MMS pipeline inspection requirements issued in September, 1990, for the operator's Dos Cuadras interconnecting gas pipelines operating between Platforms B to A and Platform A to shore.

As part of the exercise, participants made a detailed evaluation of the integrity of the lines using the draft process and checklists as a guide. The team initially gathered pertinent engineering design, inspection and maintenance data and information on the lines from agency files and requested and received additional information from the operator. The team completed and evaluated Checklist Part I. During this phase of the exercise, the team determined that additional critical data and information germaine to the inspection, maintenance and risk assessment of the Dos Cuadras gas lines was needed. The exercise was temporarily haulted pending receipt of the information which we requested from the operator. The team utilized all the information and conducted an evaluation of the integrity of the gas lines and completed and evaluated Checklist Part II. Subsequently, the team examined the operator's waiver request and made recommendations to restructure Checklist Part III.

The **OCPIS Plan** process (flow chart) and procedures (checklists) were validated and amended during the exercise. The exercise verified the comprehensiveness of the checklists in identifying significant data and information gaps which needed to be addressed during the pipeline evaluation process. The operator was very helpful in providing the PIQIT with the data and information requested which greatly enhanced the value of the workshop.

The exercise demonstrated the usefulness of the team's concept in evaluating the integrity of offshore pipelines and illustrated some areas that needed refinement. The exercise also indicated that the draft process and procedures worked well for evaluating the operator's waiver request even though the team did not attempt to reach consensus on the proposed action, as that would have required consultation with the operator which was beyond the purpose and scope of the exercise.

By the close of the workshop, all participants were comfortable that the **OCPIS Plan** will provide agencies with a common set of evaluation criteria and a structured, consensus-building process with which to make informed decisions on a variety of technical issues related to pipeline inspection and maintenance. The team is confident that we are offering management a tested process that is sufficiently comprehensive and flexible to be useful when considering each of the action items identified on the flow chart.

Recommendations for MMS Management

The following recommendations (1-3) focus on the **OCPIS Plan** process which is the primary product the team would like management to adopt. The remaining recommendations (4-9), we believe, if adopted, would further enhance the effectiveness of the MMS POCS Region's pipeline inspection program.

1. Implement the **OCPIS Plan** process and procedures. MMS should review annually and revise as needed.

2. Develop an MOU with **OCPIS Plan** agencies to implement jointly Recommendation #1.

3. Issue waivers to inspection requirements only to operators who have demonstrated a satisfactory history of compliance and whose lines are adequately inspected and maintained.

4. Restate POCSR pipeline inspection policy and revise current inspection requirements (issued in September, 1990) stressing an inspection philosophy that:

   (a) is flexible, cost-effective and possibly risk-based (see item 8),

   (b) affords maximum safety and does not compromise on the hallmark of zero-tolerance for pollution,

   (c) recognizes the uniqueness and small number of POCS pipelines, the political sensitivity of pipelines and pollution and that most pollution from pipelines is the result of third party damage, not line failures,

   (d) requires an initial baseline survey that is repeated in two years,

   (e) states a default policy with a minimum frequency (e.g., internal and external surveys conducted at least once a year or every two years; annual cathodic protection surveys; use of pressure tests if lines are not smart piggable),

   (f) illustrates the compatibility, utility and need for various inspection tools and techniques.

5. Update and finalize external pipeline survey requirements using side scan sonar.

6. Develop guidelines for external visual/cathodic protection surveys using remote operated vehicles (ROV).

7. Develop MMS POCSR NTL on pipeline inspections.

8. Review MMS Gulf of Mexico Region proposed risk-based pipeline inspection program and consider if a similar program should be adopted in POCSR given the political climate and constraints (i.e., zero-tolerance for pollution).

9. Examine procedures to reduce the risk of third-party damage (e.g., one-call system, improved pipeline location maps/charts).

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Appendix 1. Overview of Regulatory Jurisdiction

Safety regulation of marine pipelines is shared by the following federal and state agencies offshore California:

U.S. Department of the Interior, Minerals Management Service

The Minerals Management Service (MMS) currently has shared jurisdiction with the Department of Transportation (DOT) for regulating oil and gas pipelines on the Pacific Outer Continental Shelf (POCS). MMS authority is granted under the Outer Continental Shelf Lands Act of 1978 (43 U.S.C. 1334). Regulations exclusive to DOI pipelines are contained in 30 CFR Part 250, Subpart J. Under the existing 1976 Memorandum of Understanding (MOU) with DOT, DOI pipelines are all pipelines upstream from the outlet flange at each facility where hydrocarbons are produced, or where produced hydrocarbons are first separated, dehydrated, or otherwise processed to each production well on the OCS. In addition, those pipelines necessary for the development of a lease (e.g. gas-lift gas or supply pipelines), are under DOI's exclusive control.[1]

Under OCSLA, the MMS issues either lease term permits or rights-of-way approvals for all OCS pipelines. The agency may prescribe, as conditions to these permits and approvals, stipulations necessary to protect human, marine and coastal environments, life, property and mineral resources. In pursuit of its goal of "maximum environmental protection", the agency has applied its inspection requirements (pursuant to 30 CFR 250.161 (e)(1) and 250.155) to all DOT regulated pipelines on the POCS and lines extending from facilities in federal waters into state waters. The MMS issued inspection requirements to POCS pipeline operators in September 1990 (see Appendix 3).

The Oil Pollution Act of 1990 (OPA 1990), as implemented by Presidential Executive Order 12777 (October, 1991), expanded MMS responsibility for pollution prevention associated with marine pipelines. The OPA gave the MMS regulatory responsibility for ensuring spill prevention and response capability for all offshore pipelines including those in state waters.

U.S. Department of Transportation, Office of Pipeline Safety

The Research and Special Programs Administration's (RSPA) Office of Pipeline Safety (OPS), within the Department of Transportation (DOT), is responsible for enforcing the design, construction, operation and maintenance requirements on pipelines transporting hazardous liquids and natural gas to shore downstream from the outlet flange at each OCS facility as indicated above.

For offshore California, RSPA/OPS is responsible for inspection and enforcement of gas pipelines in federal waters, as described above. The California State Fire Marshal (CSFM) has inspection and enforcement authority for hazardous liquid pipelines in state waters, as indicated below.

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[1]MMS and DOT are considering redefining each agency's regulatory jurisdiction. The current proposal would grant DOI exclusive inspection authority for lines upstream from the last processing facility on the OCS.

DOT regulations contained in 49 CFR Part 192 (Transportation of Natural and Other Gas by Pipeline) prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas on the OCS. Regulations contained in 49 CFR Part 195 (Transportation of Hazardous Liquid by Pipeline) prescribe safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide.

California State Fire Marshal

The California State Fire Marshal (CSFM) has exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines and is an agent for the DOT to implement the federal Hazardous Liquid Pipeline Safety Act and federal pipeline safety regulation (Part 195) as to those portions of interstate pipelines located within the state. The CSFM, under California Government Code Chapter 5.5, also places additional safety requirements on intrastate hazardous liquid pipelines.

California State Lands Commission

The California State Lands Commission (CSLC), under Division 6 of the California Public Resources Code, has exclusive jurisdiction over all ungranted tidelands and submerged lands owned by the state and is further authorized to make and enforce all reasonable and proper rules and regulations consistent with law for the purpose of carrying out the provisions of that division. The regulations which the CSLC has written for oil and gas pipeline inspection operations and maintenance are contained in the California Code of Regulations Title 2, Division 3, Article 3.3/ Section 2132 (h).

California Department of Conservation, Division of Oil, Gas, and Geothermal Resources

The Division of Oil, Gas, and Geothermal Resources (DOGGR) is mandated by Section 3106 of the Public Resources Code to supervise the drilling, operations, maintenance and abandonment of wells and the operation, maintenance and removal or abandonment of tanks and facilities attendant to oil and gas production, including pipelines not subject to regulation pursuant to Chapter 5.5 (commencing with Section 51010) of Part 1 of Division 1 of Title 5 of the Government Code that are within an oil and gas field, to prevent, as far as possible, damage to life, health, property and natural resources.

The offshore pipelines that are under the jurisdiction of the DOGGR are all pipelines that are entirely within the administrative boundaries of the DOGGR oil fields and are not under the jurisdiction of the CSFM. This normally includes only natural gas and water lines, but an exception being the oil/water line from Platform Emmy to shore. (There is no primary separation on Platform Emmy and thus the line is not subject to regulation by the CSFM.)

Appendix 2. Post-Installation Inspection Requirements

	Federal Agencies			State Agencies		
Inspection	MMS	DOT (gas lines)	DOT (oil lines)	CSFM	DOGGR	CSLC
External	ROV or high or ultra-high side scan sonar or other method acceptable to RS. (30 CFR 250.155(a) /250. 161(a)(1) & 9/90 LTL)	No Requirement	No Requirement	No Requirement	Order any tests or inspections deemed necessary. (PRC 3106 and PRC 3224)	Visual inspection of all unburied oil and gas pipelines for damage, corrosion and conditions that may be hazardous. (CCR:Section 2132(h)(6)(A))
External Frequency	In alternating years with internal survey. SSS technique shall be used at least once every 6 years.	No Requirement	No Requirement	No Requirement	As ordered	Annually
Internal	Internal survey tool that identifies damage or corrosion. (30 CFR 250.155(a) /250.161(a)(1) & 9/90 LTL)	If corrosive gas is being transported, coupon or some other means must be used to monitor the effectiveness of the steps being taken to minimize internal corrosion. (49 CFR 192.477)	If corrosion inhibitors are used, must monitor for effectiveness by using coupons or other monitoring equipment. (49 CFR 195.418)	Same as DOT oil.	Order any tests or inspections deemed necessary. (PRC 3106 and PRC 3224)	1) Where mechanically possible, all oil & gas pipelines shall be inspected using an electronic survey tool. CCR:Section 2132(h)(6)(B) 2) Examine coupons or other monitoring equipment to ensure effectiveness of corrosion inhibitors. (CCR:Section 2132(h)(5))
Internal Frequency	In alternating years with external survey.	Twice each calendar year, not to exceed 7 ½ months.	Twice each calendar year, not to exceed 7 ½ months.	Same as DOT oil.	As ordered	1) Annually or as authorized 2) Every 6 months

Post-Installation Inspection Requirements (con't.)

	Federal Agencies			State Agencies		
Inspection	MMS	DOT (gas lines)	DOT (oil lines)	CSFM	DOGGR	CSLC
Cathodic Protection	Pipelines protected by rectifiers or anodes shall be inspected. (30 CFR 250.155(a)(b) / 250.161(a)(1) & 9/90 LTL)	1) Conduct tests to determine whether cathodic protection is adequate. (49 CFR 195.465(a)) 2) Inspect each cathodic protection rectifier. (49 CFR 195.465(b)) 3) Each current switch, diode or interference bond must be electrically checked for proper performance. (49 CFR 192.465(c))	1) Conduct tests to determine whether cathodic protection is adequate. (49 CFR 195.416(a)) 2) Inspect each cathodic protection rectifier. (49 CFR 195.416(c))	Same as DOT oil.	Order any tests or inspections deemed necessary. (PRC 3106 and PRC 3224)	1) Tests shall be conducted on all cathodically protected pipelines to assure an adequate level of protection. (CCR: Section 2132(h)(4)) 2) Rectifiers shall be inspected by a qualified electrical inspector. (CCR: Section 2132(h)(4)) 3) Rectifier outputs shall be checked. (CCR: Section 2132(h)(4))
Cathodic Protection Frequency	Annually, not to exceed 13 months.	1) Each calendar year, not to exceed 15 months. 2) Six times per year at intervals not exceeding 2 ½ months. 3) Six times per year at intervals not exceeding 2 ½ months.	1) Each calendar year, not to exceed 15 months. 2) Six times per year at intervals not exceeding 2 ½ months.	Same as DOT oil.	As ordered	1) Annually 2) Every 3 months 3) Daily
Pressure Test	With water 1.25 times MAOP for 8 hours when uprated or reactivated after being out of service for more than 1 year. With water or natural gas 1.25 times MAOP for 2 hours after repair. (30 CFR 250.153(b)(1) and (2))	Consult DOT - Office of Pipeline Safety for requirements.	Replacement pipe must be tested for 4 hours at 125% of MOP & 4 hours at 110% of MOP or , if entirely visible, for 4 hours total at 125% of MOP. (49 CFR 195.303)	Test for 4 hours at 125% of MOP. (CA Government Code Chapter 5.5 Section 51013.5)	Order any tests or inspections deemed necessary. (PRC 3106 and PRC 3224)	If electronic survey tool cannot be used, the pipelines shall be pressure tested to 1.5 times MOP for 8 hours. (CCR: Section 2132(h)(6)(C))

Post-Installation Inspection Requirements (con't.)

	Federal Agencies			State Agencies		
Inspection	MMS	DOT (gas lines)	DOT (oil lines)	CSFM	DOGGR	CSLC
Pressure Test Frequency	No Routine Requirement	No Requirement	No Requirement	Annually for pipelines with no pressure limiting device. For pipelines over 10 years of age: -Every 5 years -Every 3 years if no cathodic protection - Every 2 years if on CSFM list of higher risk pipelines - Every year if on CSFM list of higher risk pipeline and has no cathodic protection.	As ordered	Annually, if no electronic survey.
Visual	The ocean surface shall be inspected visually for leakage by boat or aircraft. (30 CFR 250.155(a) & 9/90 LTL)	Inspect the surface conditions on or adjacent to each right-of-way. (49 CFR 192.705)	Inspect the surface conditions on or adjacent to each right-of-way. (49 CFR 195.412)	No Requirement	Order any tests or inspections deemed necessary. (PRC 3106 and PRC 3224)	The ocean surface above all pipelines shall be inspected visually for indication of leakage, using aircraft or boats. (CCR: Section 2132(h)(6)(D))
Visual Frequency	Once a week	Each calendar year, not to exceed 15 months.	26 times a year, not to exceed 3 weeks.	No Requirement	As ordered	Once a week

Appendix 3. MMS Pacific OCS Region Pipeline Inspection Requirements

The MMS, POCS Region issued the following inspection requirements for all DOI and DOT regulated pipelines in the Pacific OCS on September 17, 1990:

1) The ocean surface along the pipeline route shall be inspected for leakage a minimum of once every week by boat or aircraft. Records of these inspections with the dates, methods and results shall be maintained at the field location by the pipeline operator and submitted to the Regional Supervisor, Office of Development, Operations and Safety (RS, ODOS), annually by April 1.

2) The external and internal inspections are to be conducted in alternating years by a third party, within an interval not to exceed thirteen months, on all oil, gas and water pipelines (i.e., external - April 1993, internal - April 1994, external - May 1995). Inspection plans are to be submitted to the RS, ODOS by the pipeline operator for approval a minimum of 30 days before the survey is conducted. Records of the inspections with results shall be maintained at the field location by the pipeline operator and submitted to the RS, ODOS within 60 days after the actual survey is conducted. If a pipeline safety or commercial fishing hazard is found to exist, a report detailing the problem must be submitted along with the records.

External surveys shall be conducted using a ROV with video and sonar, a high- or ultra-high resolution Side Scan Sonar (SSS) or other method acceptable to the RS, ODOS to identify burial conditions, protrusions, structural integrity, damage or corrosion to the pipeline(s). The external survey should include inspection of the pipeline risers and riser clamps; grout bags, spans, debris or any other object which might constitute a pipeline safety concern or hazard to commercial fishermen or other users; identification of weight or other coating damage; observations of the rectifiers or anodes; and visual inspection above the splash zone. Videotape recordings must be traceable to survey map coordinates. Also, an external survey using SSS shall be conducted at least once every 6 years.

The final report for the external survey shall be submitted in duplicate and include a description of all aspects of the survey and a map indicating locations of buried or spanned sections, debris, grout bags, coating damage, anodes or rectifiers along the pipeline route, with exact locations of problem areas. The final report shall include a copy of the annotated video tape with all objects which might constitute a pipeline safety concern or hazard to commercial fishermen or other users.

Internal surveys shall be conducted to identify damage or corrosion using an internal survey tool approved by the RS, ODOS. One copy of the survey logs shall be submitted along with the results.

3) Operators are encouraged to inspect and report the condition of offshore power cables at the same time external surveys of adjacent pipelines are conducted.

4) A "Notice to Mariners" containing information on the survey shall be published at least 30 days before conducting any external survey operation.

5) For continuity, pipelines entering state waters should be internally and externally inspected as close to shore as possible.

6) A pipeline shall be visually inspected upon the report of any equipment being dropped overboard which might damage a pipeline, or construction occurring within its vicinity, and a report submitted to the Camarillo or Santa Maria District Supervisor, as appropriate, describing the incident and the results of the investigation.

7) Pipelines protected by rectifiers or anodes shall be inspected annually within an interval not to exceed thirteen months by taking measurements of pipe-to-electrolyte potential. Records of these inspections with results and conclusions are to be submitted annually with the internal or external survey report. For pipelines entering state waters, rectifier or anode inspections shall be conducted as close to shore as possible.

Appendix 4. OFFSHORE CALIFORNIA PIPELINE INSPECTION SURVEY (OCPIS) PLAN DECISION CHECKLIST (See Figure 1)

STEP 1. Action identified that requires a decision: (check one)

Operator submits a survey plan ______
Operator requests a waiver from current requirements ______
Agency requests a change in current survey plan ______
Pipeline incident requires an inspection ______
- Describe:____
____

STEP 2. Agency receiving or initiating action examines jurisdictional issues and regulatory requirements and determines if a joint review or consultation is required.

Agencies with inspection authority over the pipelines and their requirements __________
____
____

Conflicting jurisdictional requirements between agencies ____________________
____
____

Lead agency(ies) ____
Additional agencies needing notification ____________________________
____

Interagency agreements and conditions _______________________________
____
____

STEP 3. Lead agency informs affected agencies of pending action if decision process includes joint review or consultation.

Agencies contacted ____
Agencies requiring joint review ________________________________

STEP 4. Lead agency compiles data and information for pipeline evaluation using "Offshore California Pipeline Evaluation Checklist Part I." (check)

Missing data and information obtained from operators ______
Checklist Part I completed ______

STEP 5. Lead agency evaluates pipeline using "Offshore California Pipeline Evaluation Checklist Parts I & II." (check)

Checklist Part II completed ______

STEP 6. Lead agency discusses pipeline evaluation with affected agencies if decision process includes joint review or consultation.

Agencies consulted ______

STEP 7. Lead agency evaluates the proposed action independently or jointly with affected agencies, as appropriate, using "Offshore California Pipeline Evaluation Checklist Part III." Agencies identify and attempt to resolve concerns through plan revisions. Plan revisions reevaluated to determine if concerns are adequately addressed. (check/explain)

Agency concerns ______

- if concerns are resolved (go to Step 8) ______
- if concerns may be resolved through coordination, attempt to resolve concerns ______
- if concerns cannot be resolved through coordination (go to Step 8) ______

Unresolved concerns ______

Checklist Part III completed ______

Final recommendation ______

STEP 8. The proposed action is approved or denied.

Action approved ______ Conditions ______

Action denied ______ Explain ______

Alternate plan or remediation ______

STEP 9. Operator is notified in writing of agency(ies) decision. (check one)

Joint actions ______

Independent action(s) ______

Appendix 5a

Appendix 6: Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines

	Federal		State			Local
Operator of Pipeline **Facility** **Pipeline**	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
CalResources Elly to Eureka 10" water injection	X					
Elly to Shore 16" oil	X	X	X	X		
Emmy to Shore 8" oil/water			X		X	
Emmy to Shore 3" gas (high pressure)		X	X		X	
Emmy to Shore 4" sour gas (low pressure)		X	X		X	
Eureka to Elly 12" oil/water	X	X				
Eureka to Elly 6" gas	X	X				
Chevron Gail to Grace 8" oil	X	X				
Gail to Grace 8" gas	X	X				

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		**State**			**Local**
Operator of Pipeline **Facility** **Pipeline**	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Chevron Gail to Grace 8" sour gas [1]	X	X				
Grace to Shore 10" oil	X	X	X	X		County of Santa Barbara, City of Carpinteria
Grace to Shore 12" & 10" gas	X	X	X			County of Santa Barbara, City of Carpinteria
Hermosa to Shore 24" oil/water	X	X	X	X		County of Santa Barbara
Hermosa to Shore 20" sour gas	X	X	X			County of Santa Barbara
Hidalgo to Hermosa 16" oil/water	X	X				
Hidalgo to Hermosa 10" sour gas	X	X				
Exxon Belmont Is. to Shore 3" oil/water[2]			X	X		
Belmont Is. to shore 3" gas[2]		X	X		X	

[1] The Pipeline is called "sour gas" to differentiate it from the other 8" gas pipeline which is currently carrying sweet gas.
[2] Out of Service

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		State			Local
Operator of Pipeline Facility Pipeline	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Exxon[3] Harmony to Shore 20" oil/water	X	X	X	X		County of Santa Barbara
Shore to Harmony 12" water return	X					County of Santa Barbara
Harmony to Hondo 12" gas	X	X				
Heritage to Harmony 20" oil/water	X	X				
Hondo to Harmony 14" oil/water	X	X				
Mobil Holly to Shore 6" oil/water			X	X		
Holly to Shore 6" gas		X	X		X	
Pacific Interstate Offshore Habitat to Shore 12" gas	X	X	X			

[3]Gas pipeline from Platform Hondo to shore is listed under Pacific Offshore Pipeline.

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		**State**			**Local**
Operator of Pipeline **Facility** **Pipeline**	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Pacific Operators Offshore Hogan to Shore 10" oil/water	X	X	X	X		
Hogan to Shore 12" gas	X	X	X			
Hogan to Shore 10" gas lift	X	X	X			
Hogan to Shore 4" water return	X					
Houchin to Hogan 10" oil/water	X	X				
Houchin to Hogan 10" gas lift	X					
Houchin to Hogan 12" gas	X	X				
Houchin to Hogan 4" water return	X					

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		**State**			**Local**
Operator of Pipeline **Facility** **Pipeline**	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Pacific Offshore Pipeline Hondo to Shore 12" sour gas	X	X	X			
Texaco E & P, Inc.[4] Harvest to Hermosa 12" oil/water	X	X				
Harvest to Hermosa 8" sour gas	X	X				
THUMS Chaffee Is. to White Is. 8" oil/water				X		City of Long Beach, Dept. of Oil Properties
Chaffee Is. to White Is. 8" gas		X			X	City of Long Beach, Dept. of Oil Properties
Chaffee Is. to White Is. 12" water injection					X	City of Long Beach, Dept. of Oil Properties
Freeman Is. to White Is. 8" oil/water				X		City of Long Beach, Dept. of Oil Properties
Freeman Is. to White Is. 6" gas		X			X	City of Long Beach, Dept. of Oil Properties

[4]Gas pipeline from Platform Habitat to shore listed under Pacific Interstate Offshore.

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		State			Local
Operator of Pipeline **Facility** **Pipeline**	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
THUMS Freeman Is. to White Is. 12" water injection					X	City of Long Beach, Dept. of Oil Properties
Grissom Is. to Shore 14" oil/water				X		City of Long Beach, Dept. of Oil Properties
Grissom Is to Shore 12" gas		X			X	City of Long Beach, Dept. of Oil Properties
Grissom Is. to Shore 10" water injection					X	City of Long Beach, Dept. of Oil Properties
White Is. to Grissom Is. 12" oil/water				X		City of Long Beach, Dept. of Oil Properties
White Is. to Grissom Is. 12" gas		X			X	City of Long Beach, Dept. of Oil Properties
White Is. to Grissom Is. 18" water injection					X	City of Long Beach, Dept. of Oil Properties
Torch Operating Irene to Shore 20" oil/water	X	X	X	X		County of Santa Barbara
Irene to Shore 8" sour gas	X	X	X			County of Santa Barbara

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		State			Local
Operator of Pipeline Facility Pipeline	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Torch Operating Shore to Irene 8" water return	X					
Rincon Is. to Shore[5] 6" oil			X	X		
Rincon Is. to Shore[5] 6" gas			X		X	
Unocal A to Shore 12" oil	X	X	X	X		
A to Shore 12" gas	X	X	X			
A to Shore 6" water	X					
B to C 6" water injection	X					
B to Tie-in (A) 12" oil	X	X				
B to Tie-in (A) 12" gas	X	X				

[5]Pipeline is not submerged and not included on the location map (Appendix 5).

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		State			Local
Operator of Pipeline **Facility** **Pipeline**	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Unocal B to Tie-in (A) 6" water	X					
C to B 6" oil	X	X				
C to B 6" gas	X	X				
Edith to Elly 6" oil	X	X				
Edith to Eva 6" gas	X	X	X			
Esther to Shore 10" oil/water			X	X		
Unocal Esther to Shore 3" gas		X	X		X	
Eva to Shore 8" oil/water			X	X		
Eva to Shore 8" gas		X	X		X	

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		State			Local
Operator of Pipeline Facility Pipeline	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Unocal Gilda to Shore 12" oil/water	X	X	X	X		
Gilda to Shore 10" gas	X	X	X			
Shore to Gilda 6" water return	X					
Gina to Shore 10" oil/water	X	X	X	X		
Gina to Shore 6" gas or water (Currently gas)	X	X	X			
Hillhouse to A 8" oil	X	X				
Hillhouse to A 8" gas	X	X				
Hillhouse to A 6" spare	X					
Henry to Hillhouse 8" oil	X	X				

Federal, State and Local Agencies with Inspection Requirements on Offshore California Pipelines (con't.)

	Federal		**State**			**Local**
Operator of Pipeline **Facility** **Pipeline**	**MMS**	**DOT**	**SLC**	**CSFM**	**DOGGR**	**Counties & Cities**
Unocal Henry to Hillhouse 8" water	X					
Henry to Hillhouse 6" gas	X	X				

Appendix 7. OCPIS Plan Contacts

Federal Agencies:

Department of Transportation:
US DOT/RSPA/OPS Western Region
Ed Ondak, Regional Director
2nd Floor, DPS-28
555 Zang Street
Lakewood, CO 80228
(303) 231-5701

Minerals Management Service:
Thomas W. Dunaway
Regional Supervisor, Office of Development, Operations and Safety
770 Paseo Camarillo
Camarillo, CA 93010
(805) 389-7550

State Agencies:

California State Fire Marshal:
Nancy Wolfe, Division Chief
California State Fire Marshal
Pipeline Safety Division
7171 Bowling Drive, Suite 600
Sacramento, CA 95823
(916) 262-1957

California State Lands Commission:
Paul B. Mount II
Chief, Mineral Resources Management Division
200 Oceangate, 12th Floor
Long Beach, CA 90802-4471
(310) 590-5205

California Department of Conservation:
Pat Kinnear
District Supervisor
Division of Oil, Gas, and Geothermal Resources
?00 South Hill Road, Suite 116
Ventura, CA 93003-4458
(805) 654-4761

Richard K. Baker
District Supervisor
Division of Oil, Gas, and Geothermal Resources
245 West Broadway, Suite 475
Long Beach, CA 90802
(213) 590-5311

William E. Brannon
District Supervisor
Division of Oil, Gas, and Geothermal Resources
5075 South Bradley Road, Suite 221
Santa Maria, CA 93455
(805) 937-7246

Local Agencies:

County of Ventura:
Lynne Kada
Resource Management Agency
800 S. Victoria Avenue, # 1740
Ventura, CA 93003
(805) 654-2466

County of Santa Barbara:
William Douros
Department of Planning and Development, Energy Division
1226 Anacapa Street, 2nd Floor
Santa Barbara, CA 93101
(805) 568-2040

The City of Long Beach:
Bruce Jackson
Department of Oil Properties
?1 East Ocean Blvd., Suite 500
Long Beach, CA 90802
(310) 570-3945

The City of Carpinteria:
Ray Severn, Director
Community Development Office
5775 Carpinteria Avenue
Carpinteria, CA 93013-2697
(805) 684-5405 ext. 401

Appendix 8. OFFSHORE CALIFORNIA PIPELINE EVALUATION CHECKLIST
PART I: DATA AND INFORMATION

Criteria I/E

A. Pipe specifications:

	Criteria I/E
Diameter ____________	P/N
Wall thickness ____________	P/N
Process of Manufacture ____________	P/N
Steel grade ____________	P/N
Flange rating ____________	P/N
Installation date ____________	S/N

B. Operating conditions:

	Criteria I/E
Normal operating pressure ____________	P/N
Maximum operating pressure (MAOP) ____________	P/N
Flow rate ____________	P/N
Product type and composition ____________	P/S
% Water ______ % CO_2 ______ ppm H_2S ______ Other ____________	

C. Environmental factors:

	Criteria I/E
Water depth ____________	N/S
Geological/geotechnical conditions along route ____________	N/S
Effects of currents on pipeline integrity ____________	S/S
Proximity to environmentally sensitive habitats ____________	S/P

D. Present pipeline characteristics:

	Criteria I/E
Is line smart piggable? ____________	P/S
Types of internal corrosion controls ____________	P/N
Type of cathodic protection ____________	P/P
Type of external coating ____________	S/P
Buried or exposed sections ____________	S/P
Spanned sections ____________	S/P

Criteria Key: P-primary, S-secondary, N-non-applicable, I-internal survey, E-external survey

Action :__________ Operator: __________ Pipeline:__________ Date: __________

OFFSHORE CALIFORNIA PIPELINE EVALUATION CHECKLIST PART I: DATA AND INFORMATION:

	Criteria I/E
E. Inspection history:	
Date, results and quality of most recent:	
- internal inspection ______	P/S
- external inspection ______	N/P
- cathodic protection survey ______	N/P
- pressure test ______	P/N
Extent, location and rate of:	
- internal corrosion ______	P/N
- external corrosion ______	S/P
F. Maintenance history:	
Date, location and description of repairs:	
- leaks ______	P/P
- spans ______	P/P
- other safety deficiencies (specify) ______	P/P
- third party damage ______	P/P
What maintenance records are available? ______	P/P
Additional corrective and preventive maintenance ______	P/P

Criteria Key: P-primary, S-secondary, N-non-applicable, I-internal survey, E-external survey

Action :______ Operator: ______ Pipeline:______ Date: ______

	Criteria I/E
G. Recent incidents:	
Impacts on pipeline integrity from:	
- seismic loads ______	S/P
- storm loads ______	S/P
- third party damage ______	S/P
H. Waiver history (explain): ______	S/S

Criteria Key: P-primary, S-secondary, N-non-applicable, I-internal survey, E-external survey
Action :______ Operator: ______ Pipeline:______ Date: ______

Appendix 9. OFFSHORE CALIFORNIA PIPELINE EVALUATION CHECKLIST PART II: ANALYSIS AND CONCLUSIONS

A. Pipeline evaluation:

Present condition of the aggregate pipeline:

- Internal ____

____

- External ____

____

Present condition of the riser:

- Internal ____

____

- External ____

____

Problem areas identified in past inspections ______________________________

____

____

B. Compliance history (waiver requests):

Operator's diligence in inspecting the line ______________________________

____

Operator's diligence in maintaining the line ______________________________

____

C. Risk assessment:

Identify potential for pipeline failure(s) due to each of the following (individually or collectively):

- internal corrosion ______________________________________

____

- external corrosion ______________________________________

____

- leaks ____

____

- spans ____

____

- third-party damage ______________________________________

____

- natural phenomena ______________________________________

____

- weight-coating damage ___________________________________

____

- operator non-compliance __________________________________

____

- other: (specify) ____

____

Action: ____________ Operator: ________________ Pipeline: __________________ Date: _____

Appendix 10. OFFSHORE CALIFORNIA PIPELINE EVALUATION CHECKLIST PART III: RECOMMENDATIONS

A. Identify action or incident: ____________________

B. Identify agency concerns: ____________________

Can concerns be resolved through coordination with agencies or operator? _____ **If no, explain:**

____

____

Resolution: ____________________

____

C. Alternative actions:

Plan or waiver approved ____ Conditions of approval: ____________________

____

____

Plan or waiver disapproved/denied _____ Explain: ____________________

____

____

Alternate inspection plan recommended (explain): ____________________

____

____

- internal inspection (smart pig, other): ____________________

____

- pressure test: ____________________

____

- external inspection (SSS, diver/ROV visual search, other): ____________________

____

- cathodic protection: ____________________

____

- no survey required: ____________________

____

Remediation recommended (explain): ____________________

____

- replacement, upgrade or improvements: ____________________

____

- reduce operating pressure: ____________________

____

- other (specify): ____________________

____

D. Final Recommendation: ____________________

____

____

____

____

Appendix 11. OFFSHORE CALIFORNIA PIPELINE EVALUATION CHECKLIST PARTS I, II & III: CONTINUATION SHEET

Checklist Part and Item: ______________________________

Action: ____________ Operator: ________________ Pipeline: __________________ Date: _____

Appendix 12. Glossary

Buried/exposed sections: portions of an offshore pipeline buried by design or covered by sediment from natural causes. If portions of the pipeline are always or periodically covered, this must be considered when determining if an external inspection plan is feasible or what the best tool is for inspecting the pipeline.

Cathodic protection (CP): technique used to prevent external corrosion of metal by the use of sacrificial anodes or impressed electric current.

CCR: California Code of Regulations

CFR: Code of Federal Regulations

Coating: material applied to the exterior and/or interior surfaces of a pipeline for a variety of purposes. The primary uses for coatings are corrosion control and added weight to provide negative buoyancy for marine environments.

Corrective and preventive maintenance: measures taken to maintain pipeline integrity, such as increasing the use of inhibitors or frequency of cleaning pigs; replacing an anode sled; installing clamps over dents, etc. These measures are taken to alleviate known or potential pipeline problems.

Criteria/primary: key factors which are considered in determining what, where, when and how surveys should be conducted. (These are also the key factors considered when evaluating an operator's request for a waiver of existing pipeline inspection requirements).

Criteria/secondary: factors which may alter or amend an existing survey strategy but are usually not crucial to the initial development or evaluation of the plan (or waiver request). Secondary criteria may be upgraded to primary during the operational life of the pipeline.

Criteria/non-applicable: factors which exert little or no influence on the development or evaluation of a survey plan (or waiver request).

Currents: persistent or episodic hydrodynamic conditions which could approach or exceed pipeline design criteria anywhere along its alignment or are capable of producing effects which may compromise pipeline integrity (i.e., spanning, slope erosion, abrasion). Pipeline exposure to the direct and indirect effects of currents can be a factor in the choice of technique and/or frequency for conducting external and internal surveys.

Data quality: the completeness, reliability, repeatability, resolution and demonstrated utility of data.

Date/results of last inspection (internal/external/CP/pressure test): the documented results and the amount of time that has elapsed since the prior inspection.

Flange rating: the ANSI B16.5 flange class designation which limits the maximum operating pressure for flanges for a given temperature (e.g., a pipeline system operating at 80 degrees F with a Class 600 flange would have a maximum allowable operating pressure of 1440 psig).

Flow rate: the movement of product through the pipeline expressed in barrels per day (BPD) for liquids or thousand cubic feet (MCF) per day for gas. The ability to run an internal inspection device through the line is dependent on achieving a minimum flow rate.

Geological and geotechnical conditions: natural and man-made conditions which have a potential to impact pipeline safety (i.e., "shallow geohazards" such as shallow/active faults, unstable slopes, rocky substrate, sediments with high liquefaction potential or very low shear strength, dynamic seafloor processes). The presence of potentially hazardous geologic conditions may influence the choice of external survey technique and frequency, but has no direct influence on the conduct of internal surveys.

Internal corrosion control: method of preventing or monitoring internal corrosion using inhibitors, smart pigs and corrosion coupons.

Internal/external corrosion and rates: a sequential set of information which documents metal loss resulting from corrosion. The corrosion rate can be used to monitor the condition of the pipeline.

Inspection diligence: pipeline surveys (internal, external and cathodic potential) conducted in a regular and timely interval using appropriate techniques. A review of compliance history of other agencies (federal, state and local) can help evaluate inspection diligence.

Inspection frequency: time interval between successive inspections of a similar type.

Installation date: date pipeline construction was completed.

Jurisdictional authority/interagency agreements: federal, state and local agencies exercise inspection and enforcement authority for offshore pipelines in accordance with responsibilities defined in federal and state statutes, ordinances, Executive Orders and interagency agreements (MOA's). As segments of many offshore pipelines are located in federal and state waters, each regulatory agency needs to know the jurisdictional authorities of the other agencies with authority/responsibility for inspections, throughput and pollution abatement for each line. Each agency will consider the jurisdictional requirements of other agencies prior to issuing survey requirements or waivers.

Leaks, spans or other safety deficiencies: a pipeline that has a history of problems related to maintenance, such as leaks from corrosion, insufficient support of spans, or any other related safety deficiencies that could impact pipeline integrity. These may indicate the need to increase inspection frequencies or at least not allow for a decrease in the inspection interval.

Maintenance diligence: regular maintenance of the pipeline, including cleaning pigs, preventive maintenance, replacements and corrosion inhibitors.

Maximum Allowable Operating Pressure (MAOP): the least of the following: internal design pressure of the pipeline, valves, flanges and fittings; eighty percent of the hydrostatic pressure test of the pipeline; or the MAOP of the receiving pipeline when the proposed pipeline and the receiving pipeline are connected at a subsea tie-in.

Pipe diameter: the nominal outside diameter of the pipe in inches. Pipe diameter can limit the ability to run an internal inspection device (pig). A small diameter or change in diameter in the pipeline could preclude the use of a pig.

Pipe specification: the industry standard to which the pipe was manufactured, typically, American Petroleum Institute (API 5L) or American Society for Testing and Materials (ASTM A53).

PPM: parts per million.

PRC: public resources code.

Process of manufacture: method of pipe manufacture (e.g., Seamless (SMLS), Electric Resistance Welded (ERW) or Submerged Arc Welded (SAW)).

Product type and composition: type of liquid or gas transported (e.g., crude oil, oil emulsion, sour gas, sweet gas, wastewater).

Proximity to environmentally sensitive habitats: pipeline location in the vicinity of sites that are designated as susceptible to long term damage from an oil spill. These sites include wetlands, estuaries, lagoons, habitats of rare species, areas of vulnerable and sensitive species (e.g., "diving birds", marine mammals), important spawning and nursery areas for fishery species and parks. The coastline has been charted for these sites which can be found in U.S. Coast Guard Area Contingency Plans.

Record availability: maintenance records showing pipeline repairs, previous inspection reports, pressure test results, cathodic protection readings, etc. needed to evaluate the pipeline condition. Adequate records are needed to develop a baseline on which to make an educated judgement on inspection frequency.

Regulatory constraints: federal, state and local inspection requirements which are codified in regulations or issued in explanatory documents (Notice to Leasee/Letter to Leasee) or as project permit conditions. As segments of offshore pipelines are regulated independently by various agencies, each agency issuing requirements for pipeline inspection surveys will do so in accordance with that agency's regulations and mindful of the jurisdictional requirements of other agencies.

Seismic/storm loading: episodic (natural) phenomena which may compromise the structural integrity or operational safety of pipelines.

Smart piggability: ability to run an instrumented internal inspection device (pig) on a specific pipeline.

Spans: unsupported or suspended segments of a pipeline. Spans of sufficient length can compromise the stability/integrity of a pipeline. Pipelines with spans approaching critical lengths may need to be monitored more frequently to determine if the span is increasing.

Steel grade: the chemical composition and tensile strength of the pipe. Most common grades are Grade B and various X grades (e.g., Grade B has a minimum yield strength of 35,000 psi and X42 has a minimum yield strength of 42,000 psi).

Third party damage: damage to a pipeline from a third party would include impacts from anchors, trawling gear or dropped objects. Third party impacts could cause external damage to the pipeline coating, dents or possible breaks in the pipeline. A susceptibility to this type of damage could indicate the need for more frequent external and internal inspections.

Waivers requested: operator requests for a variance from a regulation or policy.

Waivers granted: variance which has been approved for a specified period of time.

Wall thickness: the nominal wall thickness of the pipe in inches. A reduction in wall thickness may indicate the need to reduce operating pressure, replace or repair pipe.

Water depth: the height of the column of water overlying the pipeline alignment. Water depth can limit the options available for external inspections (e.g., shallow water may preclude vessel supported operations and depth limits exist on diver operations). Water depth has no influence on the frequency or technique for internal inspections.