



**REVISED FEBRUARY 2011**

**SECTION 1.0**

**INTRODUCTION**

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## **Section 1**

### **Introduction**

#### **1.0 Introduction and Project Overview**

This document presents proposed revisions to the Platform Hogan Development and Production Plan (DPP). The proposed revisions to the DPP address the development and production of oil and gas from the Carpinteria Field, including State Leases PRC-400, PRC-7911, and PRC-3133. Drilling, completing, equipping, and operating State Lease wells would be accomplished from Platform Hogan. (See Figure 1-1)

Revisions to the DPP have been developed to address all of the requirements specified in 30 CFR 250.241. Supporting information for the DPP, as required by 30 CFR 250.242 through 250.262, is provided in the supporting information document, which has been submitted with this DPP revision document.

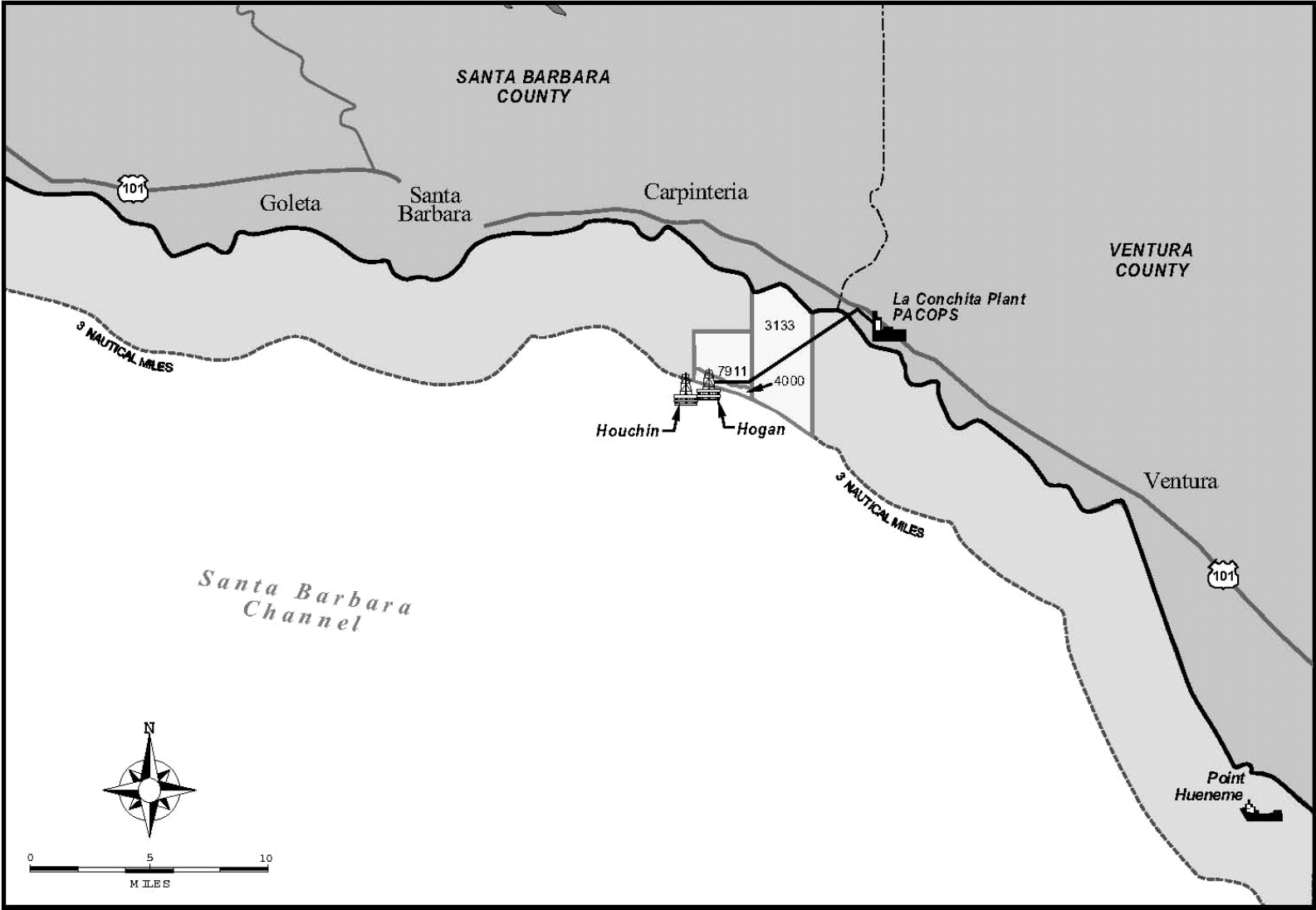
The proposed project concerns redevelopment of the Carpinteria Field oil and gas reserves which are located in State waters from Platform Hogan which is in Federal waters within Federal lease OCS P0166. The project will be executed by Carone Petroleum Corporation (CPC) and CPC's designated Carpinteria Field operator, Pacific Operators Offshore, LLC (PACOPS), previously Pacific Operators Offshore, Inc. (POOI).

The proposal is to drill as many as twenty-five (25) new operational wells (production or injection) from existing Platform Hogan. Conductors currently used for Federal wells on Hogan will be transitioned for use by State wells over time, as Federal wells become uneconomic. Therefore, there are sufficient well slots from the existing platforms to implement the State Leases POD drilling program without impacting Federal production. The exact number of wells needed to develop the field will not be known until sufficient wells have been completed and evaluated. The various geologic targets are expected to evolve and change as technical work continues and drilling results cause the program to be adjusted to fit within the infrastructure capacity, well slot availability, and potential "reallocation" of wells into possible plays that prove out more prolific at less risk than alternative plays. However, the overall "umbrella" State Leases POD is constant, that being to make as full of use out of the existing hardware infrastructure to develop the most economic reserve base possible given the geologic opportunities that are present. Proper oil field operation and management is an integral part of the State Lease POD.

State Leases will be developed using extended reach drilling technology with wells drilled from the existing Platform Hogan in Federal waters. By utilizing a Federal platform, the only physical drilling and production activity on State leases will be subsurface well bores located several thousand feet below the ocean floor. No new platforms are necessary nor proposed using this "subsurface" approach for the DPP.

The proposal is based upon placement of directional extended reach well bores extending approximately 1,400 to 13,000 feet "eastward" from Platform Hogan. These horizontal distances are well within existing technological capacity and are routinely accomplished within the industry. Drilling of new wells at the Carpinteria oil field is expected to last up to seven (7) years with production lasting through to the year 2040.

September 2009  
Project No. 0802-0031



PROJECT LOCATION  
FIGURE 1-1

Produced fluids from the State Leases will undergo partial processing and measurement within existing and new processing facilities located on Platform Hogan (see Section 5 - Platform Facilities and Production Measurement and Allocation Plan). From the platform, the produced fluids will be transported to shore through existing pipelines to the existing La Conchita onshore facility for processing. State and Federal Lease production will be measured and partially processed on Platform Hogan, and will be transported to shore in the same pipeline.

In order to accommodate the oil and gas production from the new State Leases in the Carpinteria Oil Field a 1,000 horsepower (bhp) drilling rig will be used. The drill rig is an all-electric rig and will have a 13,000 foot drilling range. In addition, the rig will utilize two 1,000 bhp triplex pumps, each equipped with centrifugal charge pumps. Current oil production from Platform Hogan is approximately 600 bbl/day). The expected average rate of oil and gas production from the proposed wells would be 150 barrels oil per day per well.

To summarize, the development and production of the Pico Sands within the Carpinteria Field will be accomplished by drilling extended reach wells from the existing Platform Hogan. Existing well slots, pipelines, equipment and other infrastructure will be used. Only minor modifications to existing equipment and facilities will be necessary to complete the proposed expansion of production.

This DPP revision document has been split into six (6) sections, which include the following:

- 1) **Introduction** – a brief summary of the proposed DPP revisions and a guide to the DPP revision document content and structure.
- 2) **Proposed Development Schedule** – Presents the proposed development and production schedule for the Carpinteria Oil Field.
- 3) **Platform Site and Construction** – Explains that there will be no new platform sites or construction, besides development wells associated with the development of the Carpinteria Oil Field.
- 4) **Drilling Facilities** – Provides an overview of the drilling facilities that will be necessary to develop the Carpinteria Oil Field.
- 5) **Platform Facilities** – Describes the existing oil and gas facilities in place on Platform Hogan. This section also explains the alterations that would be needed in order to develop oil and gas from the Carpinteria Oil Field. Oil and gas produced from the Carpinteria Oil field will use existing pipelines and facilities associated with and on Platform Hogan. The only changes will be the installation of one 1,000 bhp electrical drilling rig, and the two 1,000 bhp pumps associated with the drill rig. Maintenance and upgrades will occur as needed.
- 6) **Pipeline System** – Discusses that the existing oil and gas pipeline systems at the La Conchita processing facility can handle production from the Carpinteria Oil Field.

The applicant agrees that the development activities proposed for State of California leases PRC 4000, PRC7911 and PRC3133 which are the subject of this DPP revision will be covered by an appropriate bond under 30 CFR part 256, subpart I. To be clear, this bonding requirements under this subpart are strictly to cover the development activities proposed for the state leases mentioned above and in no way does the applicant agree that the requirements under 30 CFR part 256, subpart I modify in anyway the current bonding requirements or bonding agreements for Federal lease OCS P-0166.



**SECTION 2.0**  
**PROPOSED DEVELOPMENT SCHEDULE**

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## Section 2

### Proposed Development Schedule

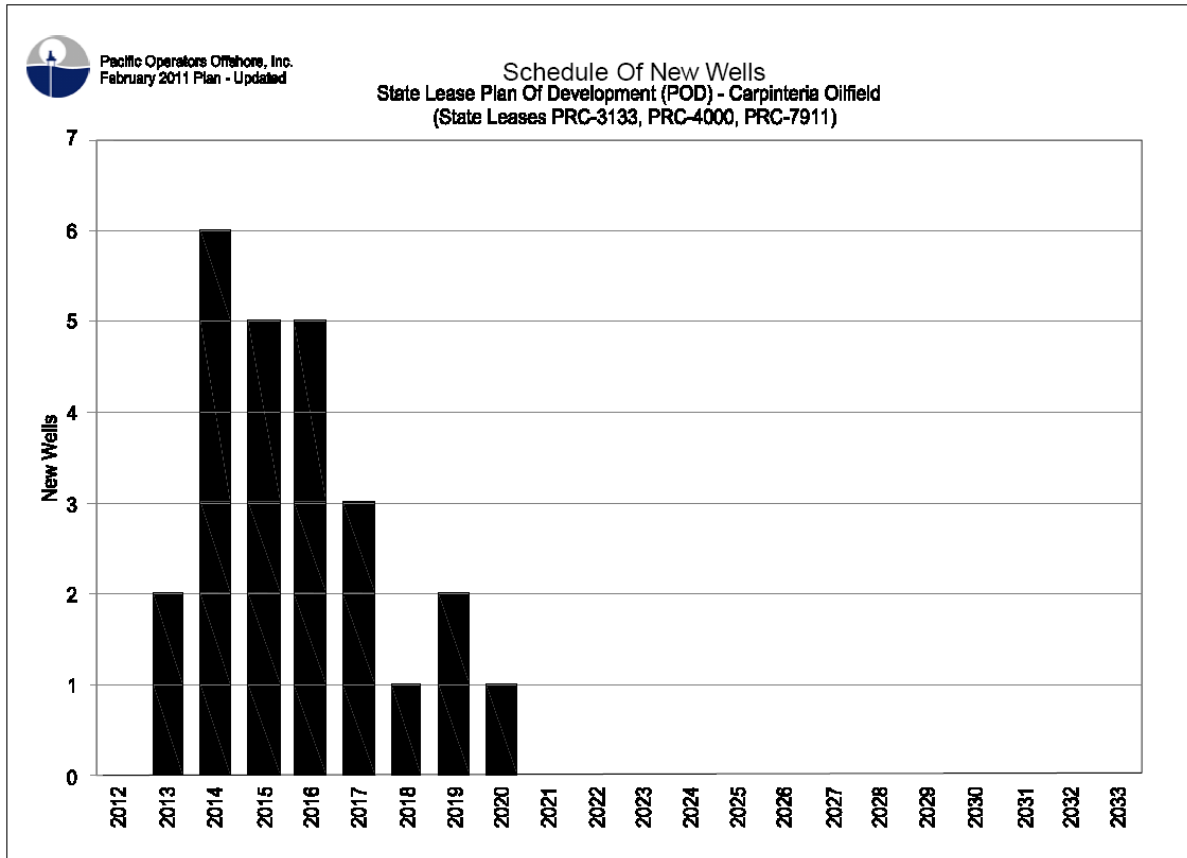
#### 2.0 Introduction

Presented below are two figures; Figure 2-1 and Figure 2-2, which show the proposed schedule of new wells and the production profile, respectively.

#### 2.1 Project Schedule

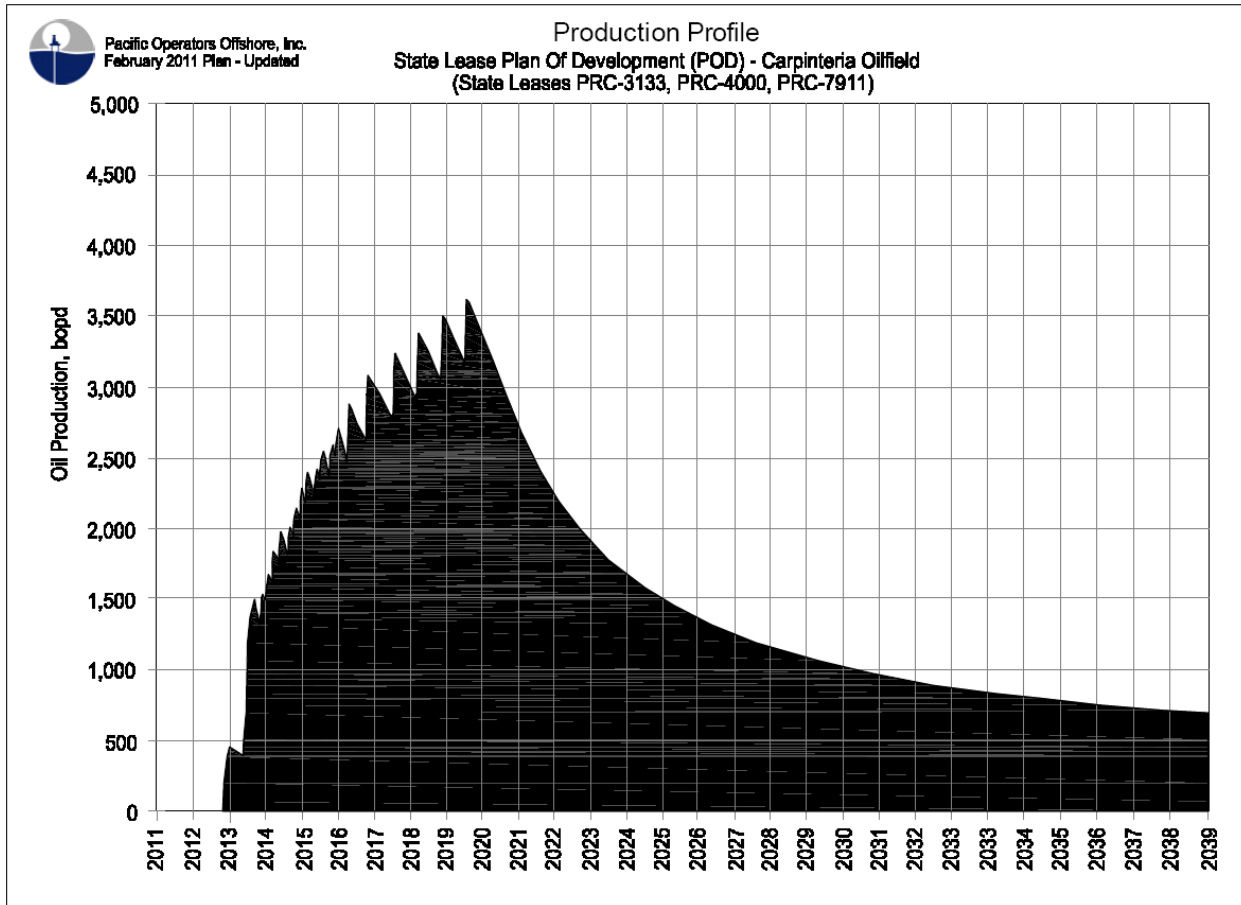
The well drilling is scheduled with drilling beginning in 2013 and extending until 2020.

Figure 2-1



Timing presented in Figure 2-1 could be moved forward or slipped based upon further geophysical, geological, and engineering work that high grades the play and/or the relative drilling/production results achieved.

Figure 2-2



It is estimated that production of State reserves will continue until economic production of Federal oil and gas reserves have been reached. A secondary recovery program on Federal lease OCS-P 0166 is expected to continue the economic life of the existing OCS operations past to 2039. The proposed State lease production plan has been developed to complement the OCS production operations and will not extend the life of the existing OCS production operations beyond what can economically and safely be recovered.

Once both Federal and State production has reached its economic life, all wells will be plugged and abandoned in accordance with either State or Federal requirement and the related offshore and onshore facilities will be decommissioned.



**SECTION 3.0**  
**PLATFORM SITE AND CONSTRUCTION**

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## **Section 3**

### **Platform Site and Construction**

#### **3.1 Platform Site**

No new platforms will be built to develop the reserves in the Carpinteria Field, therefore no revisions are needed to this section of the existing DPP. All of the development will occur from existing Platform Hogan using existing well slots and oil and gas handling equipment on the Platform. Minor equipment modifications will be needed, and these are described in detail in Section 5 - Platform Facilities and Production Measurement and Allocation Plan.

#### **3.2 Platform Modifications**

Additionally, during construction, a drilling rig of the type and configuration listed in Section 4.2 of the Revised DPP document will be temporarily installed on Platform Hogan. This rig will be transported and lifted onto the platform using a derrick barge similar to what has recently been used to install the drilling rig on Platform Houchin. During this same visit by the derrick barge, the existing platform workover rig will be de-mobilized. The derrick barge will not be anchored or moored during this lifting operation. It is typically tied to a platform leg on one end with tug boats pulling and maintaining its position from the opposite end. Once the drilling program has been completed, the drilling rig will be demobilized and a workover rig will be re-installed on the platform. The demobilization of the drilling rig and remobilization of the workover rig will also be performed by the derrick barge.

Once activities are complete, the wells would be decommissioned using a workover rig that is installed on the platform in accordance with standard well plug and abandonment requirements. Cement plugs would be set across the completion zone and at other locations to satisfy the regulatory requirements in place at the time of abandonment. The conductors would be removed using abrasive water jet technology and then cut and pulled in approximately 30' sections.

#### **3.3 New or Unusual Technology**

It is important to note that no new or unusual technology will be required to carry out the proposed development activity.



**REVISED FEBRUARY 2011**

**SECTION 4.0**

**DRILLING FACILITIES**

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## Section 4 Drilling Facilities

### 4.1 Introduction

This section addresses the drilling facilities that are proposed for the development of the Carpinteria Field reserves. It is anticipated that 25 new wells will be drilled over a seven (7) year time span. Contents of this section have been taken from Section 7 of the Updated Application to Develop State Leases, Carpinteria Field Area.

Drilling duration will depend on the mechanical condition of the hole and the objective of the directional well. The planned drilling program is expected to take seven (7) years. Only one drill rig will be used, and the drilling program is only planned to take place on Platform Hogan. Current oil production from Platform Hogan is approximately 600 bbl/day). The expected average rate of oil and gas production from the proposed wells would be 150 barrels oil per day per well.

With respect to 30 CFR 250.257(c) regarding transportation methods and quantities; the existing crew boat has the capability to transport up to 30,000 lbs of load from Venoco's Carpinteria pier. Heavier loads are transported from Port Hueneme via work boat. This is the method of transport that currently being utilized for Platform Hogan drilling operations. The quantities of drilling fluids and chemical products are included in the attached well models.

The remainder of this section provides information on the drilling rig, well construction, and drilling safety.

### 4.2 Drilling Rig

The following table is a description of a generic drilling rig sized to drill the State Leases Plan of Development (POD) Pico Sand and Northern Thrust Fault play wells.

<b>DRILLING RIG SPECIFICATION FOR PACOPS FEDERAL PLATFORMS (GENERIC SPECIFICATIONS)</b>	
<b>Drilling Of Pico Sand and Northern Thrust Fault Plays</b>	
Drilling Range:	<u>13,000'</u> with 4-1/2" drill pipe
Drawworks:	1000 horsepower electrically powered with D.C. motor(s)
Top Drive:	350 ton D.C. or A.C. driven electric top drive
Rotary table:	27-1/2" lockable rotary
Mast:	142' triple mast rated 500,000#. Static hook load of 700,000# with 10 (1-1/4") lines.
Traveling Assembly:	350-ton block hook. 350-ton swivel. 350 ton crown block
Substructure:	Box on Box substructure, 700,000# capacity.
Mud pumps:	Two 1000 horsepower triplex pumps driven by D.C. motors. Each equipped with centrifugal charge pumps.

<b>DRILLING RIG SPECIFICATION FOR PACOPS FEDERAL PLATFORMS (GENERIC SPECIFICATIONS)</b>	
<b>Drilling Of Pico Sand and Northern Thrust Fault Plays</b>	
Mud system:	1000-barrel capacity (500 active + 500 reserve). Equipped with mud agitation system, gas buster, and dual linear motion shakers, mud cleaner, and centrifuge.
Water tank:	250 barrel.
Power/Prime Movers	All Electric Rig. Receives power from platform grid.
SCR:	3 bay SCR system. Capable of powering all equipment including top drive.
BOPE:	13-5/8” x 5000 PSI class IV. Including choke manifold.
Emissions	All electric rig. Emission reduction from Platform while drilling rig is operating.
December , 2009	

4.2.1 Temporary Equipment Additions

The drilling rig of will be temporarily installed on Platform Hogan. This rig will be transported and lifted onto the platform using a derrick barge similar to what has recently been used to install the drilling rig on Platform Houchin. During this same visit by the derrick barge, the existing platform workover rig will be de-mobilized. The derrick barge will not be anchored or moored during this lifting operation. It is typically tied to a platform leg on one end with tug boats pulling and maintaining its position from the opposite end. Once the drilling program has been completed, the drilling rig will be demobilized and a workover rig will be re-installed on the platform. The demobilization of the drilling rig and remobilization of the workover rig will also be performed by the derrick barge.

4.3 Drilling Weights and Loads – Pico Sands And Northern Thrust Fault Plays

The following table summarizes the weights and imposed loads for a generic drilling rig sized to drill the proposed wells.

<b>DRILLING RIG WEIGHTS AND LOADS FOR PACOPS FEDERAL PLATFORMS (GENERIC SPECIFICATIONS)</b>	
<b>DRILLING OF PICO SAND AND NORTHERN THRUST FAULT PLAYS</b>	
<b><u>Generic Rig:</u></b>	<b><u>Weight,</u></b> <b><u>Lbs</u></b>
Substructure	120,000
Mast with traveling equipment	130,000
Top Drive	40,000

<b>DRILLING RIG WEIGHTS AND LOADS FOR PACOPS FEDERAL PLATFORMS (GENERIC SPECIFICATIONS)</b>	
<b>DRILLING OF PICO SAND AND NORTHERN THRUST FAULT PLAYS</b>	
Rotary	12,000
Spreader beams/skid base	40,000
Drawworks skid	45,000
Drawworks motor	11,000
Dog house/misc tools	20,000
Hook load 12,000 ft with 7" x 26 lb/ft casing + 100,000 lb overpull	400,000
Racking load 12,000' 20 lb/ft drill pipe + BHA (Bottom Hole Assembly)	250,000
<u>Total Load – Generic Drilling Rig</u>	<u>1,068,000</u>

<b><u>Generic mud system:</u></b>	<b><u>Weight, Lbs</u></b>
Active mud tank 500 bbl system	50,000
Reserve mud tank	25,000
Mud pumps	90,000
Motors	22,000
Solids control equipment	20,000
1,000 bbls 10 lb per gallon drilling fluid	420,000
<u>Total Load – Mud System with Mud</u>	<u>627,000</u>
<b><u>Misc Drilling Equipment Items:</u></b>	<b><u>Weight, Lbs</u></b>
SCR System	50,000
Water tank w/water	100,000
BOPE (Blow Out Preventer Equipment)	50,000
Tool House/Air Compressors	20,000
Cementing skid and bulk cement	400,000
Cuttings and bins	80,000
Bulk mud material	30,000
Logging skid	30,000

<u>Total Load – Misc Drilling Equipment</u>	<u>760,000</u>	
<b><u>Total Drilling Rig &amp; Equipment:</u></b>	<b><u>Weight, Lbs</u></b>	
Generic Drilling Rig (from above)	1,068,000	
Mud System with Mud (from above)	627,000	
Misc Drilling Equipment (from above)	760,000	
<b>TOTAL DRILLING RIG &amp; ASSOCIATED EQUIPMENT WEIGHTS &amp; LOADS</b>	2,455,000	Including fluid, hook & rack loads
September 24, 2009		

In 1998, Carone conducted structural and seismic assessments for Platform Hogan via a third party professional engineering firm (IDEAS) as a prelude to utilizing a drilling rig for the 1998 Federal Lease infill drilling program. Work at that time substantiated that the present structure could be used to accommodate a drilling operation consistent with the typical weights, loads, and equipment contingent described within this document.

In 2008, Carone conducted a detailed structural and seismic assessment for Platform Houchin via a third party professional engineering firm (MHPSE) prior to start of the 2009 Federal Lease infill drilling program. The Platform requalification assessment was approved on February 13, 2009, substantiating the integrity of the present structure to accommodate drilling operations consistent with the typical weights, loads, and equipment contingent described within this document.

In a letter dated July 23, 2009, the MMS (now BOEMRE) approved the CVA seismic reassessment and requalification report for Platform Hogan pursuant to 30 CFR 250.920, provided that PACOPS accomplishes all the recommendations detailed in the May 28, 2009 CVA report entitled, “Reassessment Recommendations PACOPS Platform Hogan OCS P-0166” and meets all recommendations from MMS (now BOEMRE) and CVA provided in the July 23, 2009 letter from the MMS. These requirements are listed below:

- 1) The CVA recommends that checks for localized rig loadings and tie-downs be performed by a professional engineer when actual configurations are known;
- 2) Submission of a detailed plan and schedule for initial Level 2 and 3 inspections;
- 3) Immediate execution of Level 2 and 3 inspections. Inspection reports are to be submitted to BOEMRE for approval prior to commencing re-drilling activities (in lieu of fatigue analysis, quadrennial inspections of Level 2 and 3 are to be performed);
- 4) Submission of a plan for remediation (if any) and follow-up inspections;
- 5) Execution of remediations or necessary repairs.

This report did not require any structural modifications to the platform at this time, therefore no modifications to the proposed project description are required.

The report did however recommend the immediate execution of Level 2 and 3 inspections. Carone is currently in the process of implementing this recommendation. This effort is being conducted concurrently on both Platform Hogan and Houchin. The first task in this program will involve the completion of a fatigue analysis of Platform Houchin. Once this analysis is completed, the third party

engineer will develop the Level 2 and 3 survey protocol for both platforms for submission and approval by the BOEMRE. Once approved by the BOEMRE, Carone will conduct the jacket inspections in accordance with the approved protocol. Carone will continue to update CSLC and BOEMRE staff on the progress of these activities.

#### 4.4 Circulating System

The drilling fluid circulation system utilized will be as follows:

<b>CIRCULATING SYSTEM (GENERIC SPECIFICATION FOR PICO SAND DRILLING)</b>	
Design Weight	Design mud weight is 10 pound per gallon for full capacity of the tanks.
Mud Capacity	Total active mud capacity is approximately 640 bbls excluding sand trap.
Tanks	Two steel tanks (approx 8' x 8' x 30'), one sand trap tank (approximately 100 bbl), complete with mixing platform and drainage system to collect and route all effluents from centrifugal pumps to one cuttings outlet.
Tank Compartment Design	All compartments have single underflow openings, except for adjustable overflow equalizer between degas and desand compartments and bottom type adjustable equalizer between utility and additions compartments. All compartments have electric agitators
Other Mud Process Equipment	Mud Cleaner Degasser Centrifuge Derrick flowline cleaner: Shale Shaker
March 31, 2009	

#### 4.5 Drilling Rig Description, Weights, Loads, Circulating System – Deeper Horizons

Detailed geophysical, geological, and engineering work for Deeper Horizons (Santa Margarita, Monterey, Vaqueros, Sespe) is in progress and is premature for specifics regarding a drilling rig system specification optimized to drill deeper horizons. Depth (TVD) and travel (MD) from Platform Hogan is not yet delineated. However, any such drilling rig will be of competent design, consistent with the integrity indicative of the drilling rig cited for Pico Sand drilling. Such a drilling program would be substantiated with structural and seismic loading assessments by third parties to assure safe operation from Platform Hogan.

If a different rig is necessary it will have no change to environmental impacts since the rig will be electrified.

#### 4.6 BOP Test Procedure and Frequency

The blowout equipment will be sized, specified, and tested in accordance with the BOEMRE regulation well control guidelines (currently 30 CFR Appendix D, paragraph 250.57). The BOPE and choke manifold will be hydrotested with water in accordance with applicable regulations. The BOPE will be tested when installed, before drilling out each string of casing, and once every 14 days.

#### **4.7 Directional Drilling Method**

A Geo-Steerable Measurement While Drilling (MWD) drilling system will be used to drill and steer the directional well bores to the targets. MWD system will provide both inclination and azimuth during the course of the directional portion of the well bore. Mud motors will be used for normal directional drilling. A rotary steerable system will be used as a contingency if “sliding” becomes difficult at extended reaches when using a mud motor system.

#### **4.8 Mud System**

The most probable mud system that will be utilized to drill these wells will be a low solids non-dispersed Cypan-type polymer mud. This system can be weighted up using barite although high mud weights are not anticipated. Bentonite will be used for viscosity and fluid loss control.

#### **4.9 Drill Cuttings and Mud Disposition**

Zero discharge of drilling mud and drill cuttings will be accomplished by utilizing the following methods that incorporate slurrification equipment in conjunction with the onboard drilling fluid and drill cuttings processing system.

Drill cuttings will be collected from the shale shakers, and other solids control equipment, and brought to a unit where they are ground to micron size. Drill water from the rig floor and other liquid waste generated in the drilling operation are blended with the drill cuttings into a slurry. This blended slurry will be pumped down a dedicated injection well (A-16A and A-36 following workover) or a dedicated well annulus into subsurface rock strata. Well A-16A is currently available for this purpose. Well A-36 will require a workover to remove the cement plugs and return the well to active status for this purpose. A generic equipment description is as follows:

- Two ~50 barrel grinding tanks
- Manifold connecting the grinding tanks
- One ~70 barrel catch tank
- Two 5”x6” centrifugal pumps
- One triplex injection pump
- One auger system

Probable slurry injection zones will be in the Pico formation. Similar slurry injections have been successfully used on the Pacific OCS and within State Waters.

Remaining Solid Waste: All other solid waste is transported from offshore and picked up by Consolidated Disposal Services and taken to the Oxnard dump site under the management of Del Norte Division, City of Oxnard. During routine non-drilling operations, average monthly disposal is 4 tons per month; during drilling operations, the average is 6.3 tons per month.

#### **4.10 Drilling Well Procedures**

Please refer to information included following Section 4.0 (State Lease Model Well Design).

\* proprietary copies only.

#### **4.11 Uncontrolled Well Release (Blowout Scenarios)**

The Carpinteria field is a mature field that currently is in an advanced state of depletion. The State portion of the field was initially developed in 1965 and produced continuously until 1993. In this regard, similar to the portion of the field that resides in Federal waters, the State portion of the field is not capable of flowing fluids to the surface from the target reservoir (the Pico or Repetto sands). Fully compliant BOP equipment will be used during the drilling of the wells, so if a kick was to occur, the well can be brought under control quickly using standard engineering and drilling practices.

The following information summarizes the potential worst-case discharge that could occur during drilling operations within the Carpinteria Field. The analysis is based on information provided by PACOPS for Platforms Hogan and Houchin within their existing Oil Spill Response Plan (OSRP) which has been summarized in Attachment 9 (Oil Spill Risk Assessment). It should be noted that per the requirements of 30 CFR 250.243(h) and the associated National Notice to Lessees and Operators (NTL) 2010-N06, PACOPS has provided an estimate of potential spill volumes associated with the unlikely event of an uncontrolled well release (blowout). In response to this requirement, PACOPS contracted with Gemini Solutions, Inc. (Gemini) of Richmond, Texas to conduct studies and model a worst-case discharge (WCD) scenario for the Carpinteria Field. Gemini completed studies for both Sub-Thrust and Supra-Thrust reservoirs in the Carpinteria Field project area. According to Gemini, “the models for each of these reservoirs show that the current reservoir pressures are lower than the pressure required for the wells to flow under a WCD scenario.... All models showed that the current reservoir pressures are too low to flow the wells in a WCD scenario.” As such, Gemini determined that the worst case discharge rates for the Carpinteria Field are zero (0) bbls from an uncontrolled well release (blowout). (Please refer to the Comment Letter attached to this submittal for a copy of all Gemini documents including the February 14th 2011 Summary Letter as well as three (3) PowerPoint presentations by Gemini discussing the Final Report dated 1/25/2011). For further information including detail regarding each of these potential spill scenarios based on the guidance provided by the BOEMRE (formerly MMS) Oil Spill Risk Analysis, please refer to Attachment 9.



**REVISED FEBRUARY 2011**

**SECTION 5.0**

**PLATFORM FACILITIES AND PRODUCTION MEASUREMENT AND  
ALLOCATION PLAN**

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## Section 5

### Platform Facilities and Production Measurement and Allocation Plan

#### 5.1 Introduction

This document is addressing Carone’s proposal to develop the Carpinteria Field from Platform Hogan. No new offshore structures will be needed to develop the field. The proposed plan will involve wells being drilled from Platform Hogan using extended reach drilling (ERD) technology. This section discusses existing facilities offshore, the platform safety systems and the commingling plan for Federal and State production.

#### 5.2 Platforms

The development plan requires no new platforms in State waters or in Federal waters. PACOPS operates two existing platforms in Federal waters installed and currently operating for Federal lease OCS P-0166.

##### 5.2.1 Platform Hogan (OCS P-0166)

The development plan is based on all State lease wells being physically drilled from Platform Hogan. Currently there are fewer than 25 conductors available, however conductors currently used for Federal wells on Hogan will be transitioned for use by State wells over time, as Federal wells become uneconomic. Therefore, there are sufficient well slots from the existing platforms to implement the State Leases POD drilling program without impacting Federal production.

<b>Platform Hogan (OCS P-0166) Carpinteria Field Development Impact Summary</b>			
	Modify Existing	New Build Required	Comment
Platform Hogan (1968) Fixed Jacket Platform	Modifications unnecessary with proposed State Leases POD.		All wells for State Leases will be drilled from Platform Hogan
Well Slots:	Reuse existing slots for all new and redrill wells. Replace conductors as necessary but not to exceed 39 conductors.		66 platform well slots 39 well conductors 36 current well bores 12 current productive wells
Test Separator	Utilize existing equipment for Federal production.	New separator for State production.	
Group Separator	Utilize existing group production separators	Utilize new group production separators for	

<b>Platform Hogan (OCS P-0166) Carpinteria Field Development Impact Summary</b>			
		State wells.	
Production Commingling		Proposed allocation plan will require the installation of a dedicated group separator and AWT for new State wells.	Reference “Measurement and Allocation Plan” provided in this section.
Fluid Capacities	Existing system adequate		Capacity – See Note 1
Crew Facilities	Existing facility adequate		
<p>Note 1: Existing infrastructure designed for higher past rates than required in future. The underlying philosophy of the State Leases POD is to utilize existing infrastructure and minimize extensive modification and/or new build facilities.</p> <p>March 31, 2009</p>			

**5.2.1.1 Permanent Equipment Modifications/Additions:**

Platform Hogan:

- a) New Equipment: (i) A new 3 phase separator for the State lease wells along with associated metering for each phase from the separator (oil, gas and water); (ii) A new AWT for the State lease wells; (iii) New metering (oil, gas and water) for the federal lease wells for each phase from a 3 phase federal production separator.
- b) Modification of Existing Equipment: (i) modification of an existing 2 phase separator to a 3 phase separator for the federal lease (OCS P-0166) well.

Platform Houchin:

- a) New Equipment: (i) New metering (oil, gas and water) for the federal lease wells for each phase from a 3 phase federal production separator.
- b) Modification of Existing Equipment: (i) modification of an existing 2 phase separator to a 3 phase separator for the federal lease (OCS P-0166) well.

Additional information regarding separation equipment and metering equipment and modification is addressed in Section 5.5 (Production Measurement and Allocation Plan).

**5.2.1.2 On-Platform Fuel Storage**

The average diesel used at the Platform is approximately 2,625 gallons per month. Approximately 90% of this volume is attributed to the diesel fired rig that is currently on the Platform. Therefore, non rig use averages approximately 260 gallons per month. During drilling operations for State lease wells, the diesel fired rig will be removed and therefore the fuel used would drop from avg. of 2,625 gpm to 260 gpm during the drilling program. It can be estimated that these numbers would realistically equate to average

storage quantities. Additionally, based on existing fuel usage offshore, the average fuel stored onboard should be approximately 1,500 to 2,000 gallons during the State Lease drilling.

### **5.3 Platform Safety Systems**

Platform Hogan is operated in conformance with all BOEMRE safety system requirements. A copy of the facility safety plan has been previously submitted to the BOEMRE.

### **5.4 Pollution Prevention Systems**

Platform Hogan has been designed to eliminate sources of water pollution during drilling and production operations. All platform discharges are conducted in conformance with General Permit No. CAG 28000 (Authorization to Discharge under the NPDES for Oil and Gas Exploration, Development and Production Facilities).

Both the drilling and production decks are equipped with curbing to prevent direct runoff to the ocean. All water used for deck wash down, cuttings wash, natural rainfall, and well cleanup fluids is collected in a skimming tank where all contaminants are separated from water. Sanitary facilities for the drilling and production crew are installed on Platform Hogan. These facilities discharge into a sewage treatment system, effluent is treated and discharged at 130 feet below MLLW level. All produced fluids and oil contaminated waste water are transported through pipelines to shore.

Production equipment and pipelines to shore are designed to operate automatically, however the platform is manned 24 hours a day. There are numerous alarm and shut in detectors located at various points on the platform. This automatic alarm and shut in system will close the wells below the ocean floor to prevent oil or gas leakage. A summary of these alarm and shut in functions are listed below;

#### **Shut in All Wells**

1. High separator pressure
2. Low separator pressure
3. High separator level
4. Manual Local – Can be manually shut in from four locations on Platform Hogan
5. Manual Remote – Can be manually shut in from shore via a communications cable.
6. Auto Remote – Automatic shut in is caused by a malfunction of onshore equipment.
7. Fire – Automatic shut in is activated by fusible plugs from various locations at well and separator areas.

#### **Alarm – Air Horn and Visual Indications**

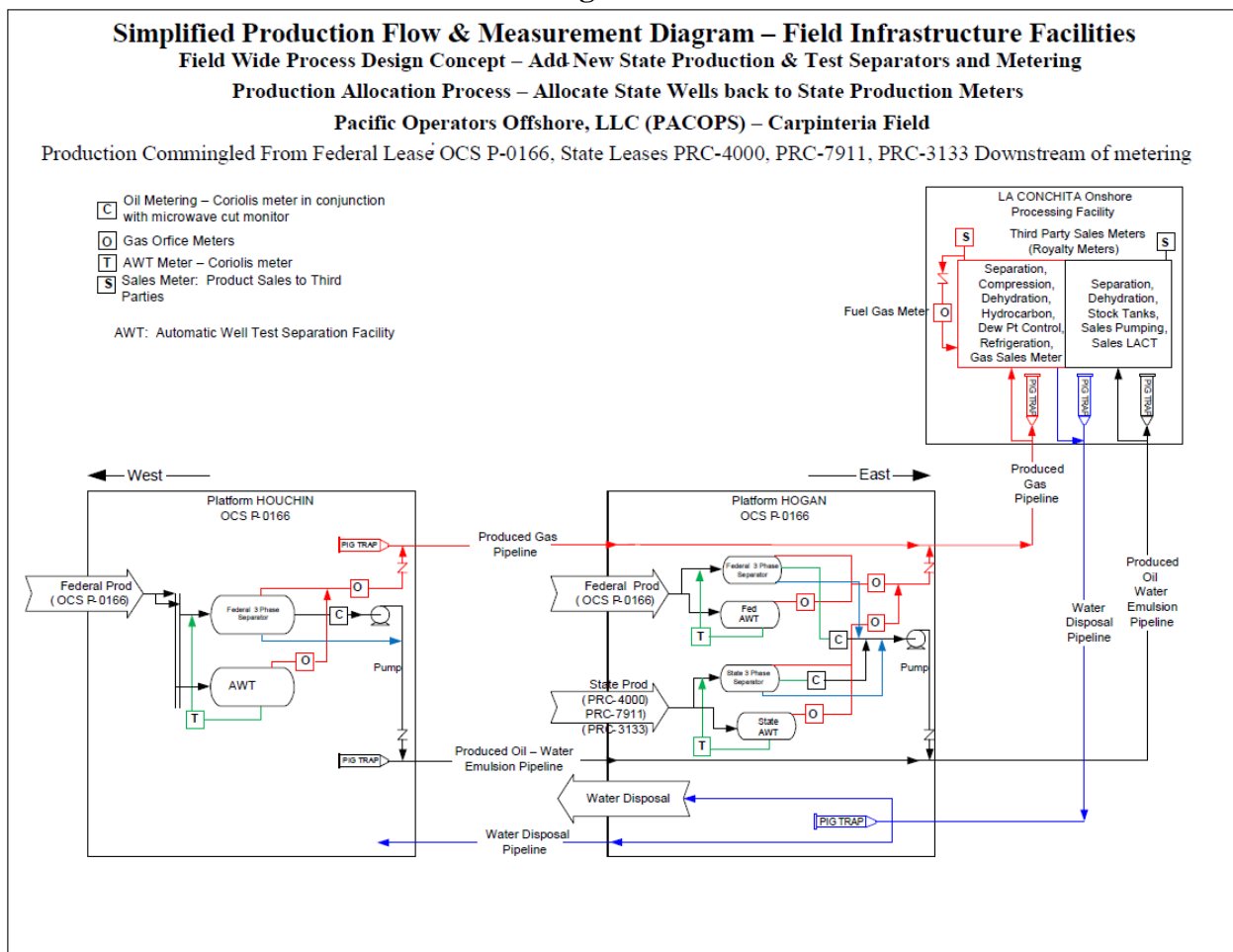
1. Intermedial high and low levels in separators and surge tanks
2. Low Pressure – Instrument air
3. Derrick light off
4. Gas leakage – Gas sensors will be mounted at various points on production and drilling deck.
5. Loss of purge air pressure.

### 5.5 Production Measurement and Allocation Plan - Oil and Gas Handling and Metering for the Carpinteria Field Oil and Gas (Commingling Plan)

Commingling of production will occur at Platform Hogan production facilities. Accounting of production from State and Federal wells will be accomplished through use of allocating sales volumes back to producing wells through use of production well test facilities. Royalty volumes of oil and gas would be the sum total of allocated sales to Federal and State wells. A revised Production Measurement and Allocation Plan (formerly titled Commingling Plan) will be submitted under separate cover once the revisions have been completed and approved in consultation with State Lands Commission staff. Revised flow measurement diagrams have been included in this section.

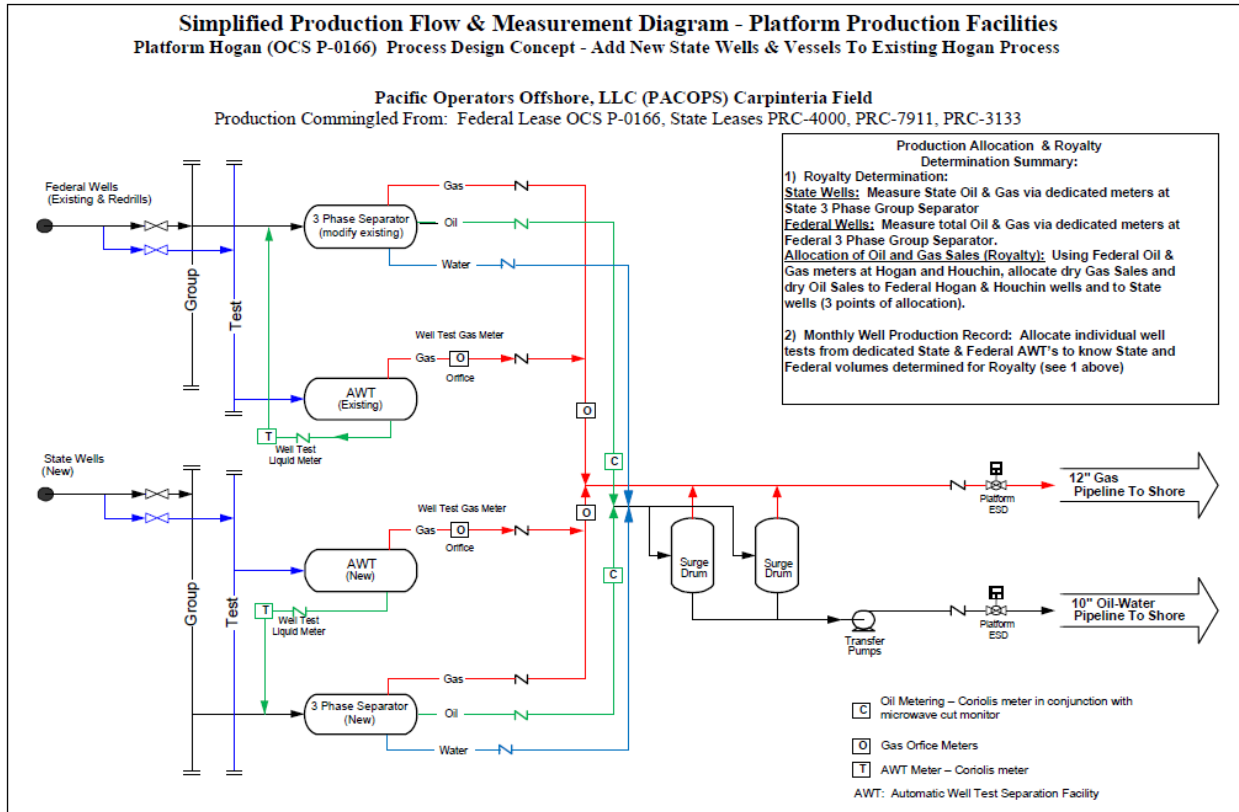
The proposed field infrastructure production facility flow with respect to production measurement and allocation from Federal and State leases is as diagrammed in **Figure 5-1**:

**Figure 5-1**



The proposed platform production facility flow with respect to production measurement is as diagrammed in **Figure 5-2**.

**Figure 5-2**



The current hydrocarbon measurement and royalty determination is summarized as follows:

Liquid Hydrocarbon Measurement – Crude Oil Sales Stream, Current Operation (Note 1)	
Stream Contents	Processed crude oil that has been separated from produced gas and water, dehydrated via heater treater, and degassed to stock tank conditions. NGLs recovered at gas hydrocarbon dew point control refrigeration unit are recovered, stabilized and spiked into crude oil.
Royalty Meter	La Conchita crude oil LACT. <span style="float: right;">Note 3</span>
Royalty Tank	None, crude oil sold at La Conchita crude oil LACT.
Run Ticket	Run tickets from La Conchita crude oil LACT.
Royalty Volume	Royalty volume determined directly from 3 <sup>rd</sup> party LACT volume.
Well Production	Allocate La Conchita oil sales volumes back to wells using well test volume allocation factor. <span style="float: right;">Note 2</span>

<b>Records</b>	<p>Note 1: Current operation_ is not commingled; it is 100% Federal production.</p> <p>Note 2: Production records are allocated sales volumes after processing shrinks and loss.</p> <p>Note 3: LACT system is compliant with 30CFR Part 250 Subpart L Section 250.1202, “Liquid Hydrocarbon Measurement”</p>
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<b>Gas Hydrocarbon Measurement -Natural Gas Sales Stream, Current Operation (Note 1)</b>	
<b>Stream Contents</b>	Processed natural gas that has been separated from produced oil and water, dehydrated, and refrigerated to achieve hydrocarbon dew point requirement for sales gas. NGLs removed at refrigeration unit are recovered, stabilized, and spiked into crude oil stream.
<b>Royalty Meter</b>	La Conchita Gas Sales Meter (Southern California Gas). <span style="float: right;">Note 3</span>
<b>Royalty Volume</b>	Royalty volume determined directly from 3 <sup>rd</sup> party gas sales meter volume.
<b>Well Production Records</b>	Allocate La Conchita gas sales volumes back to wells using well test volume allocation factor. <span style="float: right;">Note 2</span>
<p>Note 1: Current operation is not commingled; it is 100% Federal production.</p> <p>Note 2: Production records are allocated sales volumes after processing shrinks and loss.</p> <p>Note 3: Meter Compliant with 30CFR Part 250 Subpart L Section 250.1203, “Gas Measurement”</p>	

**5.5.2 Measurement and Allocation Plan (Proposed Federal and State Operation)**

Oil, gas, and water produced from State Leases will be measured in accordance with a production commingling plan compliant with applicable Federal code, 30 CFR Part 250 Subpart L Section 250.1200, “Oil and Gas Production Measurement, Surface Commingling, And Security”.

The Carpinteria Field commingling plan is based upon utilizing production well testing compliant with 30 CFR Part 250 Subpart L Section 250.1204, “Surface Commingling” to allocate La Conchita sales volumes back to individual wells. Production well testing will be compliant with Federal code, 30 CFR Part 250 Subpart K Section 250.1103 “Well Production Testing”.

Hydrocarbon measurement and royalty determination for the Commingling Plan is summarized as follows:

Liquid Hydrocarbon Measurement – Crude Oil Sales Stream, Commingled Production (Note 1)		
Stream Contents	Processed crude oil that has been separated from produced gas and water, dehydrated via heater treater, and degassed to stock tank conditions. NGLs recovered at gas hydrocarbon dew point control refrigeration unit are recovered, stabilized and spiked into crude oil stream.	No Process Change.
Royalty Meter	La Conchita crude oil LACT (Note 3).	No Change.
Royalty Tank	None, crude oil sold at La Conchita crude oil LACT.	No Change.
Run Ticket	Run tickets from La Conchita crude oil LACT.	No Change.
Royalty Volume	Allocate total La Conchita oil sales volumes back three (3) wet oil meters: <u>Federal Houchin Group Meter</u> , <u>Federal Hogan Group Meter</u> & <u>State Hogan Group Meter</u> . State and Federal royalty paid based upon allocation of La Conchita sales to these points of measurements.	Change Required
Well Production Records	Allocate La Conchita oil production volumes back to wells using same allocation procedure for oil sales (Note 2).	Change Required
<p>Note 1: Commingled Federal and State Production at Platform Hogan down stream of Group Meters (OCS P-0166).</p> <p>Note 2: Production records are allocated sales volumes after processing shrinks and loss.</p> <p>Note 3: LACT system compliant with 30CFR Part 250 Subpart L Section 250.1202, “Liquid Hydrocarbon Measurement”</p>		

Gas Hydrocarbon Measurement -Natural Gas Sales Stream, Commingled Production (Note 1)		
Stream Contents	Processed natural gas that has been separated from produced oil and water, dehydrated, and refrigerated to achieve hydrocarbon dew point requirement for sales gas. NGLs removed at refrigeration unit are recovered, stabilized, and spiked into crude oil stream.	No Process Change.
Royalty Meter	La Conchita Sales Meter (Southern California Gas) (Note 3).	No Change.
Royalty Volume	Allocate total La Conchita gas sales volumes back to three (3) wet gas meters: <u>Federal Houchin Group Meter</u> , <u>Federal Hogan Group Meter</u> & <u>State Hogan Group Meter</u> . State and Federal royalty paid based upon allocation of La Conchita sales to points of measurement.	Change Required.
Well Production Records	Allocate La Conchita gas sales volume back to wells using well tests and group wet gas meters (Note 2).	No Change.
<p>Note 1: Commingled Federal and State Production at Platform Hogan (OCS P-0166).</p> <p>Note 2: Production records are allocated sales volumes after processing shrinks and loss.</p> <p>Note 3: Meter compliant with 30CFR Part 250 Subpart L Section 250.1203, “Gas Measurement”</p>		

## 5.6 Accounting Allocation of State and Federal Production

Oil “stock tank” production and gas sales are presently allocated back to individual wells using the procedure in this section. The Federal-State commingling plan proposes to utilize the same well allocation algorithm to also determine Federal and State royalty volumes. The production allocation and sales allocation process is described in the following steps:

### 5.6.1 Ongoing Field Process 1: Record Field “Stock Tank” Production Volume Daily

- When: Ongoing activity during each allocation month.
- Frequency: Each day.
- Who/Where: PACOPS field operators at La Conchita onshore processing facility.
- What - Oil Determine total stock tank oil produced each day at the LACT tank (tank is immediately upstream of the LACT sales meter). Total daily stock tank oil production is measured and calculated as follows:
- Take: Closing Gage (today’s 55,000 bbl LACT tank volume), corrected to 60F.
- Less: Opening Gage (previous day 55,000 bbl LACT tank volume), corrected to 60F.
- Plus: Total LACT volume during the gage period (automatically corrected to 60F).
- Equals: Total stock tank oil produced during period (corrected to 60F std conditions)
- What - Gas Determine total plant tail gas produced each day. Total daily tail gas is measured and calculated as follows:
- First: Record the gas sales volumes for the latest 24-hour period that displays on the So Cal gas flow computer.
- Plus: No adjustments need be applied since sales gas is after total plant shrink, fuel, and losses.
- Equals: Total sales gas produced during period (corrected to 60F std conditions)
- Why: Record total volumes of oil and gas processed and delivered for sales daily. Daily volumes will be totaled for the month and allocated back to individual wells.

### 5.6.2 Ongoing Field Process 1: Record Daily Group Oil and Gas Meter Readings

- When: Ongoing activity during each allocation month.
- Frequency: Each day.
- Who/Where: PACOPS field operators at Platform Hogan and Platform Houchin.
- What - Oil Determine we oil produced each day from three (3) wet oil group meters (Federal Houchin, Federal Hogan & State Hogan).
- What - Gas Determine total wet gas produced each day from three (3) wet gas meters Federal Houchin, Federal Hogan & State Hogan).
- Why: Record total wet volumes of oil and gas produced via each metering point. Daily volumes will be totaled for the month and allocated back to individual wells.

### 5.6.3 Ongoing Field Process 2: Conduct Periodic Production Well Test

- When: Ongoing activity during each allocation month.
- Frequency: Test all wells a minimum of twice per month.
- Who/Where: PACOPS field operators at Platform Houchin and Hogan.

**What:** Switch an individual well into the test separator and conduct flow test. Normalize production volumes to a calendar day basis (BPD, MCFD). Record and enter the following well test data into production database:

Well Test Date

Well Test Oil (BOPD) Note 1

Well Test Water (BWPD) Note 1

Well Test Gas (MCFD) Direct measurement from gas orifice meter tube

Note 1: Calculated from gross liquid stream using Turbine Meter for total volume flow and Water Cut Probe to subdivide total flow into oil and water flow.

**Why:** Use as the measured volumetric basis for allocating Sales volumes (royalty) and production volumes back to individual wells.

#### **5.6.4 Ongoing Field Process 3: Record Well Downtime**

**When:** Ongoing activity during each allocation month.

**Frequency:** Whenever well downtime is incurred.

**Who/Where:** PACOPS field operators at Platform Houchin and Hogan.

**What:** Record well downtime to database. Well downtime is stored in the database at 15 minute resolution for each active well during the month.

**Why:** Adjust production allocation for well downtime.

#### **5.6.5 Allocation Step 1: Total Field “Stock Tank” Production Volume For Month**

**When:** After allocation month closes.

**Frequency:** Monthly.

**Who/Where:** PACOPS office personnel.

**What:** Sum the daily oil “stock tank” production volumes and daily gas sales volumes for the allocation month.

**Why:** Total oil “stock tank” production and gas sales volume will be allocated back to individual wells.

#### **5.6.6 Allocation Step 2: Interpolate Individual Well Production For Month**

**When:** After allocation month closes.

**Frequency:** Monthly.

**Who/Where:** PACOPS office personnel.

**What:** Interpolate production between each well test point. The interpolation algorithm is a linear interpolation that includes all well test for the month and the nearest well test for the proceeding and following the month being allocated. The interpolation process “digitizes” production rate for each well to a one hour resolution for the entire allocation month.

Why: Convert periodic instantaneous production rates from well testing into a continuous theoretical well production rate. The theoretical well test streams are used as the “prorate” basis for allocating “stock tank” production volumes back to individual wells.

### **5.6.7 Allocation Step 3: Individual Well Downtime**

When: After allocation month closes.

Frequency: Monthly.

Who/Where: PACOPS office personnel.

What: Well downtime is stored in the production record database at 15 minute resolution for each well. This step digitizes downtime on an hourly resolution. An entire hour is flagged as down for allocation purposes when any portion of an hour is recorded as down.

Why: Adjust continuous well production stream for well downtime.

### **5.6.8 Allocation Step 4: Allocation of Dry Oil Volumes and Dry Gas Volumes to Wet Meters**

When: After allocation month closes.

Frequency: Monthly.

Who/Where: PACOPS office personnel.

What: Allocate the total produced oil volumes and total produced gas volumes measured at LaConchita back to the Wet Meters to determine Dry Oil production and Dry Gas production at each wet meter allocation point.

Why: To determine production at each point of well allocation (Federal Hogan wells, Federal Houchin wells and State Hogan wells).

### **5.6.9 Allocation Step 5: Well And Field Theoretical Volume (Using Well Tests)**

When: After allocation month closes.

Frequency: Monthly.

Who/Where: PACOPS office personnel.

What: Sum the hourly theoretical production rates (based upon well tests) for each active well to obtain a total theoretical volume for each well for the allocation month. Sum the total theoretical monthly volumes for all wells to obtain a total theoretical volume for attributable to each wet meter (in other words, each wet meter for both oil and gas become points of allocation).

Why: Total theoretical volume is used to quantify the adjustment necessary to be applied to allocated volumes so total allocated volume equals total field “stock tank” production.

### **5.6.10 Allocation Step 6: Determine Total Field Adjustment Volume For Month**

When: After allocation month closes.

Frequency: Monthly.

Who/Where: PACOPS office personnel.

What - Oil: Determine how much difference there is between the total field theoretical volume (based upon well tests) and the total field oil “stock tank” production volume, calculated as follows:

Take: Total Field “Stock Tank” Production Volume For Month (Allocation Step 1).

Subtract: Total Field Theoretical Volume (from well test rates) (Allocation Step 5).

Equals: Total Field Adjustment Volume (amount theoretical volume differs from “stock tank” production)

What - Gas: Determine how much difference there is between the total field theoretical volume (based upon well tests) and the total field gas sales volume, calculated as follows:

Take: Total Field Gas Sales Volume For Month (Allocation Step 1).

Subtract: Total Field Theoretical Volume (from well test rates) (Allocation Step 5).

Equals: Total Field Adjustment Volume (amount theoretical volume differs from gas sales)

Why: Individual well theoretical volumes (based upon well test) for the month must be uniformly adjusted to achieve field total “stock tank” production volume for oil and field total gas sales volume for gas.

### **5.6.11 Allocation Step 7: Allocate Corrected Group Meter Production To Individual Wells**

When: After allocation month closes.

Frequency: Monthly.

Who/Where: PACOPS office personnel.

What: Allocate total field group meter production volumes back to individual wells. This process reconciles the difference between total theoretical volume (based upon well tests) and total oil “stock tank” production and gas sales volumes that are allocated back to the group meters from total production measured at La Conchita. Allocation to individual wells is based upon the relative volume contribution towards the group meter total that each well has contributed. The allocation calculation is performed by the following formula:

Oil:

Take: Well Theoretical Volume (1<sup>st</sup> part of Allocation Step 5).

Divide By Group Meter Theoretical Volume (2nd part of Allocation Step 5)

Multiply By Group Meter Adjustment Volume (Allocation Step 6)

Add: Well Theoretical Volume (1<sup>st</sup> part of Allocation Step 5).

Equals: Allocation Of Group Meter Production Back To A Given Well

Or in equation form, allocated “stock tank” volume back to and individual well equals:

$$\text{WellTheoreticalVolume} \frac{\text{WellTheoreticalVolume}}{\text{TotalFieldTheoreticalVolume}} \text{TotalFieldAdjustmentVolume}$$

Gas:

Take: Well Theoretical Volume (1<sup>st</sup> part of Allocation Step 5).  
Divide By Group Meter Theoretical Volume (2nd part of Allocation Step 5)  
Multiply By Group Meter Adjustment Volume (Allocation Step 6)  
Add: Well Theoretical Volume (1<sup>st</sup> part of Allocation Step 5).  
Equals: Allocation Of Gas Sales Back To A Given Well

Or in equation form, allocated gas sales volume back to and individual well equals:

$$\text{WellTheoreticalVolume} \frac{\text{WellTheoreticalVolume}}{\text{TotalFieldTheoreticalVolume}} \text{TotalFieldAdjustmentVolume}$$

Why: Total field oil “stock tank” volume and gas sales volume must be allocated back to individual wells for both official production records and to determine Federal and State royalties. The allocation logic honors the concept that allocation to individual wells must be on the prorated basis that each well has contributed to total monthly “stock tank” production.

#### **5.6.12 Allocation Step 7: Sum Well Allocated Volumes To Obtain Federal And State Volume**

When: After allocation month closes.  
Frequency: Monthly.  
Who/Where: PACOPS office personnel.  
What - Oil: Sum allocated volumes of oil for every Federal lease well to determine total Federal oil “stock tank” production volume. Sum allocated volumes for every State lease well to determine total State oil “stock tank” production volume.  
What - Gas: Sum allocated volumes for every Federal lease well to determine total Federal gas sales volume. Sum allocated volumes for every State lease well to determine total State gas sales volume.  
Why: Determine total oil “stock tank” production volume and gas sales volume attributable to Federal and State wells.

## **5.7 Meter Proving Accounting Allocation of State and Federal Production**

PACOPS anticipates regularly scheduled meter provings for the new wet oil meters and calibrations of the wet gas meters located at Platforms Hogan and Houchin. The existing LACT unit for dry oil sales is proven on a monthly basis at La Conchita plant. The existing gas sales meter is also calibrated on a monthly basis.



**REVISED FEBRUARY 2011**

**SECTION 6.0**

**PIPELINE SYSTEM AND ONSHORE FACILITIES**

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## Section 6

### Pipeline System and Onshore Facilities

#### 6.1 Introduction

No new pipelines or onshore facilities will need to be built to develop the field. The existing pipelines from Platform Hogan to the La Conchita onshore processing facility will be used to move the production of the Carpinteria Field. The La Conchita Facility is capable of handling oil and gas produced from the Carpinteria Field, and therefore no new facilities will be needed. The following discussion of the pipelines and onshore processing facilities were provided in the Updated Application to Develop State Leases in the Carpinteria Field Area from March 2009.

#### 6.2 Pipelines

As mentioned above, the development state waters portion of the Carpinteria Field will utilize existing pipeline infrastructure and requires no new pipelines to shore. The following summarizes the current deployment of pipelines:

<b>Carpinteria Field Development – Pipeline Impact Summary</b>			
	Modify Existing	New Build Required	Comment
10” Emulsion (Crude Oil & Produced Water)	Existing system adequate for State Leases Production.		Platform to shore. Note 1
12” Produced Gas	Existing system adequate for State Leases Production.		Platform to shore Note 1
10” Gas Lift (Currently not in service)	Existing system adequate for State Leases Production.		Shore to platforms Note 1
4” Water Injection/Disposal	Existing system adequate for State Leases Production.		Shore to platforms Note 1
Note 1: Existing pipeline infrastructure designed for higher past rates than required in future. The underlying philosophy of the State Leases Production is to utilize existing infrastructure and minimize modification and/or new build facilities.			

##### 6.2.1 Oil/Water Emulsion Pipeline To Shore

The condition and ongoing maintenance of the oil transport pipeline is a matter of continuing effort. Cathodic protection, coupons, weekly boat runs, external ROV surveys, internal smart pig surveys, tri-weekly monitoring of rust inhibitor chemical levels, and finally a computer controlled ultrasonic leak detection system capable of automatically shutting in both platforms comprise an entire suite of capacity to ensure an appropriately high degree of command and control over this asset. PACOPS routinely

submits various pipeline reports to the Minerals Management Service. These submissions and their respective findings have included the following submissions as received by BOEMRE (formerly MMS) from PACOPS within the 2000 calendar year:

*Cathodic Protection Survey*

All structure to sea potentials within acceptable NACE standard limits (May)

*Biennial Pipeline ROV Survey*

Bundle condition and cathodic potential reading found to be within NACE acceptable limits (November)

*UT (Ultrasonic Testing) Verification Survey*

All UT verifications indicate that pipeline within safe operating limits and pipeline condition complies with accepted engineering standards (May).

<b>10” Emulsion (Crude Oil &amp; Produced Water) Pipeline (Platforms To Shore)</b>	
Service/Fluids	Mixture of produced crude oil and produced water.
Status	Fully Operational.
Routing & Length	0.8 miles from Houchin to Hogan, 6.25 miles Hogan to La Conchita
Pipe Specification	10-3/4” OD x 0.365” WT API 5L Grade B, Seamless Line Pipe (10.020” ID)
Oil Line Pipe MAOP	1710 psig (72% SMYS)
Oil Pipeline System MAOP	500 psig (only 21% of line pipe SMYS)
Pipeline MOP	Present process configuration has set at 184 psig (process pump shutdowns).
Current Pressures	5,500 bpd (1000 bopd, 82% water cut): Present operating pressures typically run from 0 to 125 psig.
Capacity – Future High Rate Scenario	30,000 bpd (6,000 bopd, 80% water cut), Approx 160-175 psig at Hogan flowing to La Conchita.
Hydrogen Sulfide (H <sub>2</sub> S) Content	The Carpinteria field produces nil to no H <sub>2</sub> S. Pipeline is not within NACE MR-01-75 sour service criteria.
Cleaning (Pigging)	Line is pigged 3 times a week.  Cup pigs are normally used. Wire brush/cup pigs are run twice a month.
Inspection (Smart Pigging)	Smart pigging is conducted every other year:  2008 by H. Rosen using EGP& CDP  2006 by H. Rosen using EGP& CDP  2005 (February) by H. Rosen using EGP& CDP
Corrosion Monitoring	Corrosion coupons are changed out and analyzed biannually.

<b>10” Emulsion (Crude Oil &amp; Produced Water) Pipeline (Platforms To Shore)</b>	
	Smart pigs are run to monitor corrosion/wall thinning trending.
Corrosion Control	External – Cathodic protection applied at both ends of pipeline. Internal – Continuous corrosion inhibitor chemical injection. Internal – Regular cleaning pig runs.
	MAOP (Maximum Allowable Operating Pressure), MOP (Maximum Operating Pressure) SMYS (Specified Minimum Yield Strength) of pipe material  Note 1: Existing pipeline designed for higher past rates than required in future. The underlying philosophy of the State Leases POD is to utilize existing infrastructure and minimize extensive modification and/or new build facilities.

### 6.2.2 Gas Pipeline To Shore

<b>12” Produced Gas Pipeline (Platforms To Shore)</b>	
Service/Fluids	Produced natural gas
Status	Fully Operational.
Routing & Length	0.8 miles from Houchin to Hogan, 6.25 miles Hogan to La Conchita
Pipe Specification	12-3/4” OD x 0.406” WT API 5L Grade B, Seamless Line Pipe (11.938” ID)
Gas Line Pipe MAOP	1420 psig (64% SMYS)
Gas Pipeline System MAOP	720 psig (only 32% of line pipe SMYS)
Pipeline MOP	Present process configuration has set at 230 psig (maximum working pressure of platform separator vessels).
Current Pressures	500-750 Mscfd wet gas. Present operating pressures typically run from 25 to 46 psig. Operating pressures are estimated to range from 25 to 150 psig with future development.
Capacity – Future High Rate Scenario	At 22 MMscfd, approx 95-110 psig at Hogan flowing to 40 psig at La Conchita.
Hydrogen Sulfide (H <sub>2</sub> S) Content	The Carpinteria field produces nil to no H <sub>2</sub> S. Pipeline is not within NACE MR-01-75 sour service criteria.
Cleaning (Pigging)	The gas pipeline is not pigged.
Inspection (Smart Pigging)	Smart pigging is conducted every other year: 2008 by H. Rosen using EGP& CDP 2006 by H. Rosen using EGP& CDP

<b>12” Produced Gas Pipeline (Platforms To Shore)</b>	
	2005 (February) by H. Rosen using EGP& CDP
Corrosion Monitoring	Corrosion coupons are changed out and analyzed biannually.
Corrosion Control	External – Cathodic protection applied at both ends of pipeline. Internal – Continuous corrosion inhibitor chemical injection.
	MAOP (Maximum Allowable Operating Pressure), MOP (Maximum Operating Pressure) SMYS (Specified Minimum Yield Strength) of pipe material.  Note 1: Existing pipeline designed for higher past rates than required in future. The underlying philosophy of the State Leases POD is to utilize existing infrastructure and minimize extensive modification and/or new build facilities.

### 6.2.3 Water Disposal Pipeline To Platforms

<b>4” WATER DISPOSAL (SHORE TO PLATFORMS)</b>	
Service/Fluids	Deoiled, clarified produced water for disposal/reinjection offshore into producing sands
Status	Fully Operational.
Routing & Length	0.8 miles from Houchin to Hogan, 6.25 miles Hogan to La Conchita
Pipe Specification	4-1/2” OD x 0.337” WT API 5L Grade B, Seamless Line Pipe (3.826” ID)
Water Line Pipe MAOP	3770 psig (72% of SMYS)
Water Pipeline System MAOP	2160 psig (limited by ANSI 900 flanges) (only 41% of line pipe SMYS)
Pipeline System MOP	Present process configuration has set at 1200 psig (process pump shutdowns).
Current Pressures	Approximately 5000 bwpd. Present operating pressures typically run approximately 900 psig.
Capacity – Future High Rate Scenario	At approximately 1150 psig at La Conchita the capacity to Hogan is between 6,000 and 10,000 bwpd depending upon surface injection pressures required.
Hydrogen Sulfide (H <sub>2</sub> S) Content	The Carpinteria field produces nil to no H <sub>2</sub> S. Pipeline is not within NACE MR-01-75 sour service criteria.
Cleaning (Pigging)	Line is pigged once a week.  Cup pigs are normally used. Wire brush/cup pigs are run every other run.
Inspection (Smart Pigging)	No smart pigging has been done.

<b>4" WATER DISPOSAL (SHORE TO PLATFORMS)</b>	
Corrosion Monitoring	Corrosion coupons are changed out and analyzed biannually.
Corrosion Control	External – Cathodic protection applied at both ends of pipeline. Internal – Continuous corrosion inhibitor chemical injection. Internal – Regular cleaning pig runs.
<p>MAOP (Maximum Allowable Operating Pressure), MOP (Maximum Operating Pressure) SMYS (Specified Minimum Yield Strength) of pipe material.</p> <p>Note 1: Existing pipeline designed for higher past rates than required in future. The underlying philosophy of the State Leases POD is to utilize existing infrastructure and minimize extensive modification and/or new build facilities.</p>	

#### 6.2.4 Gas Lift Pipeline To Platforms

<b>10" GAS LIFT (SHORE TO PLATFORMS)</b>	
Service/Fluids	High pressure, dehydrated, NGL processed tail gas used for gas lift.
Status	Gas lift is not presently being used due to incomplete repairs near pig traps and will be brought back on line when needed (currently mothballed).
Routing & Length	0.8 miles from Houchin to Hogan, 6.25 miles Hogan to La Conchita
Pipe Specification	10-3/4" OD x 0.365" WT API 5L Grade B, Seamless Line Pipe (10.020" ID)
Gas Lift Line Pipe MAOP	1520 psig (64% of SMYS)
Pipeline System MAOP	1440 psig (limited by ANSI 600 flanges) (61% of line pipe SMYS)
Pipeline System MOP	Limited to 1150 psig (declared high pressure shut-down).
Current Pressures	Last operating pressures typically ran from 800 to 1100 psig.
Capacity – Future High Rate Scenario	At approximately 900 psig at La Conchita (present water disposal) the capacity to Hogan is at least 24,000 bwpd (45 psig pipeline drop, 2.8 fps) and 50,000 bwpd (approx 175 psig pipeline drop, 5.9 fps... within API 14E erosional criteria) on the upper end of capacity depending upon surface injection pressures required.
Hydrogen Sulfide (H <sub>2</sub> S) Content	The Carpinteria field produces nil to no H <sub>2</sub> S. Pipeline is not within NACE MR-01-75 sour service criteria.
Cleaning (Pigging)	Line has not been routinely pigged.
Inspection (Smart Pigging)	Smart pigging has been done once: 1999 by H. Rosen using CDP High resolution MFL.
Corrosion Monitoring	Line is currently out of service.

<b>10” GAS LIFT (SHORE TO PLATFORMS)</b>	
Corrosion Control	External – Cathodic protection applied at both ends of pipeline.  Internal – Line is currently out of service.
<p>MAOP (Maximum Allowable Operating Pressure), MOP (Maximum Operating Pressure) SMYS (Specified Minimum Yield Strength) of pipe material.</p> <p>Note 1: Existing pipeline designed for higher past rates than required in future. The underlying philosophy of the State Leases POD is to utilize existing infrastructure and minimize extensive modification and/or new build facilities.</p>	

**6.3 Onshore Facilities – La Conchita Facility**

Produced fluids from the State Leases will be processed in the La Conchita onshore facility operated by PACOPS. No new onshore facilities will be necessary in order to process the oil and gas produced from the Carpinteria Field. La Conchita processes required by State Leases POD are summarized as follows:

<b>Onshore Facilities – Process Systems Summary</b>			
Pertinent Item	Modifications	New Build Required	Comment
Inlet Separation	Existing facility adequate for State Leases POD.		Notes 1, 2
Oil Treating System: Heater Treaters, Oil Tanks, Sales Meter	Existing facility adequate for State Leases POD.		Notes 1, 2
Gas Processing System: Compression, Refrigeration, Dehydration, Sales Meter	Existing facility adequate for State Leases POD.		Notes 1, 2
Water Treating System: FWKO, Clarification Tanks, Water Tankage, Media Filters	Existing facility will require upgrading to handle increased state well water volumes.		Notes 1, 2
<p>Note 1: La Conchita operates under Ventura County Conditional Use Permit #3149-1</p> <p>Note 2: Existing infrastructure designed for higher past rates than required for future.</p>			

The onshore treating facility located adjacent to the community of La Conchita, CA is designed to dehydrate the oil and the gas. Processing of each stream is described as follows:

**Crude Oil:** Crude oil enters the dehydration plant via a 10” emulsion line connected to the offshore platforms. This line contains an oil/water emulsion which is approximately 15% oil and 85% water. The emulsion travels to a primary oil/water separator where residence time allows the oil and water to gravity separate. The oil floats to the top of the vessel and the water to the bottom. Oil is then discharged to a secondary separator vessel to allow for further dehydration of the oil. From the secondary separator, the oil is pumped to a 55,000 bbl stock tank. The oil is shipped from this tank into the Venoco pipeline system via a LACT unit.

Natural Gas: Associated gas produced from the offshore platforms are sent to shore via a 12” natural gas pipeline. Once the gas arrives at the La Conchita plant it sent to stage 1 of a 3 stage compressor. After exiting the 1st stage of compression, the gas flows to a hydrocarbon chilling unit to drop out the hydrocarbon liquids. The dry gas then enters the 2nd and 3rd stages of compression. After exiting the 3rd stage of compression, the gas is sent to a gas membrane unit which removes excess CO<sub>2</sub>. The low BTU waste gas (or permeate) from the membrane unit is sent to a flare to be burned. The processed gas is sent to a SoCal Gas sales unit for measurement and sales into the SoCal pipeline system.

Produced Water: Water enters the plant mixed with crude oil via the 10” emulsion line and travels to a primary oil / water separator (as discussed above under crude oil processing). The water leaves the bottom of the separator and travels to a flotation unit, where any remaining oil is removed. The clean water then ships to a series of sand filter units for final polishing and clarification prior to being sent to a storage vessel. From the storage vessel, the water is shipped back offshore for disposal via a 4” water line.

The produced water from the Federal wells are adequately treated and properly disposed of at this time. When water injection commences in 2012, the additional water volume is expected to be handled by the existing equipment. Water injection on the State Leases is envisioned to start on a limited basis and expanded as additional sections of the reservoir are developed. The existing FWKO will have to be modified, 2 retention tanks will need to be returned to service, the flotation tanks will need to be replaced with efficient WEMCO units, 2 additional media filters will need to be added, a smaller SWD vessel might be required to add to the retention time and finally the injection pumps will have to be modified. The above changes might be accomplished over time as water disposal/injection demand dictates. Prior to initiation of a waterflood, all produced water will be discharged into the ocean. Once water injection wells are completed, the produced water will be injected back into strata. An engineering firm will be contracted to properly design the above equipment in order to handle the additional water.

### 6.3.1 La Conchita - Capacity Summary

La Conchita onshore facility capacities applicable to the State Leases POD are as follows:

<b>Onshore Facilities – La Conchita Capacity Summary</b>			
	Design Capacity	Permit Capacity	Comment
Oil Inlet	27,000 bopd (Note 2)	No specific limit	Note 1
Oil Processing/Sales	27,000 bopd (Note 2)	* 55,000 bbl crude oil tank limited to 2.190 MMbo/year.	Note 1
Gas Inlet	22,000 Mscfd (Note 2)	No specific limit	Note 1
Gas Processing/Sales	22,000 Mscfd (Note 2)	No specific limit	Note 1
<b>Fuel Gas System:</b>			
4 Waukesha L7042G gas engines		* 39 MMscf/year	Note 1
Gas burners Used On Heaters and Reboilers		* 64.2 MMscf/year	Note 1
2 ea 1.1 MMbtu/hr flare stacks		* 96,769.4 MMbtu/year	Note 1
<b>Permitted Emissions:</b>			

<b>Onshore Facilities – La Conchita Capacity Summary</b>		
ROCs	* 8.11 tons/year	Note 1
Nitrogen Oxides	* 6.42 tons/year	Note 1
Particulate Matter	* 0.80 tons/year	Note 1
Sulfur Oxides	* 0.07 tons/year	Note 1
Carbon Monoxide	* 99.44 tons/year	Note 1
<p>* VCAPCD Permit To Operate #00033 (POOI, La Conchita Oil and Gas Plant) stipulation.</p> <p>Note 1: Existing facility designed for higher past rates than required in future. The underlying philosophy of the State Leases POD is to utilize existing infrastructure and minimize extensive modification and/or new build facilities.</p> <p>Note 2: Existing La Conchita infrastructure designed for higher past rates than required for future operations.</p>		

### **6.3.2 Onshore Waste Disposal**

All solid waste from the platforms is transported from offshore and is picked up by Consolidated Disposal Services and taken to the Oxnard dump site under the management of Del Norte Division, City of Oxnard. During routine non-drilling operations, average monthly disposal is 4 tons per month; during drilling operations, the average is 6.3 tons per month.