FREEPORT-MCMORAN
OIL & GAS

2015 Drilling, Re-drilling, Well Abandonment, and Well Pad Restoration Plan Inglewood Oil Field

Baldwin Hills CSD Section E.26.c

APPLICANT'S COPY

September, 2014

Freeport-McMoRan Oil & Gas
5640 South Fairfax Avenue
Los Angeles, CA 90056

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N/A *: Not Applicable since no Mid-Zone Supplement required this Drilling Plan year

1 Introduction

This section of the Drilling Plan discusses the various regulations and agreements that cover the drilling plan.

1.1 Community Standards District

The Baldwin Hills Community Standards District (CSD) was adopted by the Los Angeles County Regional Planning Commission on October 28, 2008 and became effective on November 28, 2008. The CSD governs operations on the unincorporated portion of the Inglewood Oil Field located in the Baldwin Hills Zoned District. The field is operated by Freeport-McMoRan Oil & Gas (FM O&G). The goal of the CSD is to ensure that oil field operations are conducted in a safe manner and are compatible with the surrounding uses. Effective May 31, 2013 Plains Exploration & Production Company (PXP) merged with and into FM O&G. In various areas of this document we are quoting the CSD language. Please note that even though the ordinance references PXP, as successor in interest and current operator of the oil field, FM O&G is responsible for implementation and adherence to the terms of the CSD.

The CSD requires that, before the end of each calendar year, the operator shall develop and deliver to the Director of Regional Planning, County of Los Angeles, a Drilling, Re-drilling, Well Abandonment, and Well Pad Restoration Plan (hereinafter referred to as the Plan or the Annual Plan or the 2015 Plan or the 2015 Drilling Plan) describing all drilling, re-drilling, well abandonment, and well pad restoration activities that may be conducted during the upcoming calendar year. Specifically, section E.26.c. of the CSD states the following:

Drilling, Re-drilling, and Reworking Operations. The operator shall comply with all of the following provisions:

c. Annual Drilling, Re-drilling, Well Abandonment, and Well Pad Restoration Plan. Before the end of each calendar year, the operator shall develop and deliver to the director an annual drilling, re-drilling, well abandonment, and well pad restoration plan that shall describe all drilling, re-drilling, well abandonment, and well pad restoration activities that may be conducted during the upcoming calendar year. Drilling and re-drilling shall be scheduled to avoid over concentration of such activities in that year in any one area if located near a developed area. The operator may at any time submit to the director proposed amendments to the then current annual plan. No drilling, re-drilling, or abandonment activity may be commenced unless it is described in a current annual plan (or amendment thereto) which has been approved by the director. The annual plan (and any amendments) shall be provided to the CAP (Community Advisory Panel) for review and comment. All comments on the annual plan from the CAP shall be submitted to the director in writing, and, if timely submitted, will be considered as part of the director's review and approval. The director shall complete the review of the annual plan (and any amendments) within 45 days of receipt, and shall either approve the annual plan or provide the operator with a list of deficiencies. The annual plan shall comply with the provisions of this subsection, and shall include the following:

i. The maximum number of wells proposed to be drilled or re-drilled;

ii. *Approximate location of all wells proposed to be drilled or re-drilled;*

iii. *Approximate location of all proposed new well pads, including their size and dimensions;*

iv. *Estimated target depth of all proposed wells and their estimated bottom hole locations;*

v. *A discussion of the steps that have been taken to maximize use of existing well pads, maximize use of re-drilled wells, and maximize the consolidation of wells;*

vi. *Location of all proposed well abandonments, if known, in accordance with DOGGR (California Division of Oil and Gas and Geothermal Resources) integrity testing program of idle wells;*

vii. *Location of all well pads proposed to be abandoned and restored;*

viii. *A proposed schedule and phasing of the drilling, re-drilling, well abandonment, well pad abandonment, and restoration activities;*

ix. *A discussion of the latest equipment and techniques that are proposed for use as part of the drilling and re-drilling program to reduce environmental impacts; and*

x. *A topographic vertical profile showing proposed location of new wells that reflects local terrain conditions and that addresses the potential visibility of existing and proposed well and other production facilities from residential and recreation areas.*

1.2 Settlement Agreement

On July 15, 2011, FM O&G's predecessor company and Los Angeles County entered into a Settlement Agreement and Mutual Release with Community Health Councils, Inc., Natural Resources Defense Council, Mark Salkin, City of Culver City, Concerned Citizens of South Central Los Angeles, and Citizen's Coalition for a Safe Community relative to a series of lawsuits that had been filed against the County's adoption of the CSD in 2008. Sections 1, 2, 3, 4, 6, and 10 of the Settlement Agreement pertain directly to the preparation and implementation of the Annual Plan.

With regards to Section 4 (b) of the Settlement Agreement, FM O&G's predecessor made a request on October 10, 2011 that the Director of Los Angeles County Department of Regional Planning allow an increase of the number of wells that may be drilled or re-drilled annually from 30 to 35 wells. On December 12, 2011 the Director of Los Angeles County Department of Regional Planning concluded that the CSD has been effective in protecting the health, safety and general welfare of the public and authorized the drilling or re-drilling of up to 35 wells per calendar year.

The relevant verbatim excerpts follow below:

Section 1: Slant Drilling

a. *Deep Zone Wells. Pursuant to the CSD, PXP is required to develop and submit to the County an annual drilling, re-drilling, well abandonment and well pad restoration plan (hereinafter "Annual Drilling Plan"). For any and each* *well that FM O&G proposes to drill where the Top Hole (as defined in paragraph 1.e below) is closer than 800 feet to a Sensitive Developed Area (as defined in paragraph 1.e below) and the Bottom Hole (as defined in Paragraph 1.e below) is located in any deep zone (presently identified as the Nodular Shale and Sentous zones and any other zones approximately 8,000 feet or deeper), as a supplement to its Annual Drilling Plan ("Deep Zone Supplement"), PXP will provide a study of the technical feasibility and commercial reasonability of Slant Drilling (as defined in paragraph 1.e below) each of the new deep zone wells in order to locate the Top Hole of any such well away from any Sensitive Developed Area in order to further mitigate potential impacts to such Areas. The Deep Zone Supplement will be reviewed by the County and County-retained expert or experts as part of the County's review of the Annual Drilling Plan. This study will provide a narrative to justify the proposed surface location and shall provide sufficient detail to allow the County to review the extent to which it may be technically feasible and commercially reasonable to locate the Top Hole away from Sensitive Developed Areas in order to further mitigate potential impacts to such Areas and still reach the targeted Bottom Hole location. PXP shall provide to the County any additional information as may be reasonably requested by the County or its expert which is necessary to complete its review. If such information is considered proprietary, the County and its expert will enter into a confidentiality agreement with PXP to protect such information. The narrative will be reviewed by the Director of Regional Planning prior to the approval of the Deep Zone Supplement. If approved by the Director, PXP will Slant Drill in order to locate the Top Hole away from Sensitive Developed Areas consistent with the narrative prepared by PXP that justifies the surface location.*

b. *Mid-Zone Wells. For wells where the Top Hole is closer than 800 feet to a Sensitive Developed Area and the Bottom Hole is located in a mid-zone (approximately 3,500 to 7,999 feet deep, presently identified as the Rubel, Moynier, Bradna and City of Inglewood zones), PXP shall document such locations in a supplement to the Annual Drilling Plan ("Mid-Zone Supplement"). PXP shall use commercially reasonable efforts to locate new mid-zone wells and well pads away from Sensitive Developed Areas in order to further mitigate impacts to such Areas. The Mid-Zone Supplement shall explain why it is not technically feasible and commercially reasonable to locate the Top Hole away from Sensitive Developed Areas in order to further mitigate impacts to such Areas. The referenced mid-zone well pad assessment will be reviewed by County-retained experts and the County. PXP shall provide to the County any additional information as may be reasonably requested by the County or its expert which is necessary to complete its review. If such information is considered proprietary, the County and its expert will enter into a confidentiality agreement with PXP to protect such information. The County shall approve the mid-zone well locations as part of its review of the Mid-Zone Supplement if consistent with this paragraph.*

c. *Shallow Wells. Drilling of wells where the Bottom Hole is less than approximately 3,500 feet deep (hereinafter "Shallow Wells") and above the* *zones identified in 1(b) as mid-zones, shall be located away from Developed Areas (as defined in the CSD) and shall be identified in the Annual Drilling Plan. Drilling of Shallow Wells may proceed pursuant to said drilling plan after the County approves the portion of the Annual Drilling Plan related to Shallow Wells as set forth in the CSD.*

d. *Supplement Review. Upon receipt, the County shall promptly forward the Drilling Plan Supplements ("Supplements" defined to be a Deep Zone Supplement, a Mid-Zone Supplement, or both) filed by PXP to the Community Advisory Panel ("CAP") established pursuant to the CSD for its review and comment. The County will allow the CAP or CAP members two weeks from the date the County provided Supplements to the CAP to provide their written comments on the Supplement to the County. The County may review and approve the Annual Drilling Plan and related Supplements in phases consistent with the terms herein, but shall conduct its review of the Annual Drilling Plan and Mid-Zone Supplement within 45 calendar days after their submission to the County and either approve the Supplement or provide PXP with a list of deficiencies within that 45-day timeframe as set forth in the CSD. The Drilling Plan Supplements will only include the study referenced in 1(a) and other relevant or required information related to the location of proposed wells. The County shall conduct its review of the Deep Zone Supplement within 45 calendar days after its submission and either approve the Supplement or provide PXP with a list of deficiencies within that 45-day timeframe after considering any timely CAP comments concerning the Deep Zone Supplement. The County will not delay its review of the Annual Drilling Plan or any supplements thereto. PXP may drill any wells approved under the Annual Drilling Plan regardless of the status of the County's review of the Supplements. Similarly, PXP may drill any wells approved under a Supplement regardless of the status of the Annual Drilling Plan review and approval. Changes to well pad locations that result from review of the Supplements will not require resubmittal of the Annual Plan or delay any drilling under the Annual Plan, beyond the time necessary to implement such changes.*

e. *Definitions. "Top Hole" shall mean the surface location from which drilling is commenced. "Bottom Hole" shall mean the underground location at which drilling terminates. "Slant Drilling" shall mean non-vertical drilling, directional drilling, or drilling at a relatively significant angle. "Sensitive Developed Area" shall mean a lot or parcel that contains a single or multi-family residence, existing park, school or health care facility.*

f. *Environmental Consideration. The County shall lessen or disapprove any otherwise required Slant Drilling if more remote drilling would result in more significant adverse environmental impacts on balance and the County shall consider any timely comments by the CAP assessing this balance.*

g. *Non-interference. This paragraph 1 of the Settlement Agreement shall be construed in connection with the entire CSD. Except as expressly set forth above, this paragraph shall not be construed to interfere with PXP's business in the Oil Field.*

Section 2: Noise

a. *The CSD currently provides that hourly, A-weighted equivalent noise levels associated with drilling, re-drilling and reworking wells shall not elevate baseline levels (which shall not include drilling, re-drilling or reworking operations} by more than five A-weighted decibels ("dBA") at the Oil Field boundary of any Developed Area. Instead of the referenced five dB A provision, PXP shall limit the night time (10 p.m. to 7 a.m.) noise levels at Developed Areas to no more than three dBA above a one-hour baseline average for the defined nighttime period, but at no time will PXP be required to maintain noise levels below the baseline nighttime noise levels. Furthermore, PXP and the County determined the baseline noise levels at four additional Oil Field boundary locations near Developed Areas, selected by PXP and the County, in addition to the seven utilized in the EIR for a total of 11 locations. If PXP violates the above noise requirements, no new drilling or re-drilling permits shall be issued by the County until PXP, in consultation with the County, identifies the source of the noise and PXP takes steps necessary to assure compliance with the above-specified threshold.*

b. *If drilling, re-drilling or reworking operations elevate nighttime baseline noise levels by more than 10dBA for more than 15 minutes in any one hour as independently verified and determined by the County, PXP, in consultation with the County, shall identify the cause and source of the noise and take steps to avoid such extended periods of noise elevation in the future. This provision does not negate the CSD noise limits between 7 a.m. to 10 p.m.*

***Section 3: Number of Drill Rigs**. Notwithstanding the CSD's allowance for operation of a maximum of three drill rigs at any one time on the Oil Field, FM O&G shall limit to two the number of drill rigs in use at any one time.*

***Section 4: Number of wells.** Notwithstanding the aggregate and annual well-drilling limits in the CSD, PXP shall comply with the following limits:*

a. *Notwithstanding Section 22.44.142. H of the CSD, no more than 500 new wells (inclusive of Bonus Wells and wells drilled since approval of CSD) shall be drilled pursuant to the CSD (hereinafter "Director's Review") through October 1, 2028, or during the remaining life of the CSD, whichever is later.*

b. *Until such time as PXP has drilled or re-drilled 50 wells since the adoption of the CSD, or 24 months from the date of this Agreement, whichever is sooner ("Time Period One"), no more than 30 wells may be drilled or re-drilled in any calendar year pursuant to a Director's Review as set forth in the CSD (hereinafter Director's Review). At the end of Time Period One, and if the County determines, pursuant to its review of the CSD by the Director of Regional Planning, that the CSD has been effective in protecting the health, safety, and general welfare of the public, thereafter (the "Full Operational Period") no more than 35 wells may be drilled or re-drilled in the calendar year pursuant to Director's Review.*

c. *In Time Period One, for each well abandoned within 800 feet of any Developed Area (the "800-foot zone") by PXP since adoption of the CSD and in full compliance with the California Department of Conservation's Division of Oil, Gas and Geothermal Resources ("DOGGR") standards for abandonment at the time of abandonment, PXP may drill two additional new wells outside of the 800-foot zone (hereinafter "Bonus Wells"), up to a maximum of 45 drilled* *and re-drilled wells (30 wells plus 15 Bonus Wells) in any calendar year within Time Period One pursuant to Director's Review and subject to review and approval in the Annual Drilling Plan. Subject to the annual and aggregate limits on number of wells, Bonus Wells earned by abandonment may be drilled at any time during the life of the CSD.*

d. In the Full Operational Period, for each well abandoned within the 800-foot zone, FM O&G may drill two additional new wells outside the 800-foot zone up to a maximum of 53 drilled and re-drilled wells (35 wells plus 18 Bonus Wells) in that year pursuant to Director's Review and subject to review and approval in the Annual Drilling Plan. Subject to the aggregate and annual limits on number of wells, Bonus Wells earned by abandonment may be drilled at any time during the life of the CSD.

e. The Developed Area as used in the CSD with respect to the 400-foot buffer zone (Section 22.44.142.E.) shall remain unchanged (static or fixed) from what it was determined to be on the effective date of the CSD.

Section 6: Clean Technology Assessment. *The CSD requires PXP to consider proven reasonable and feasible technological improvements which are capable of reducing the environmental impacts of drilling and re-drilling. (County Code section 22.44.142.E.26.f) The CSD also requires that the Annual Drilling Plan include a discussion of the latest equipment and techniques that are proposed for use as part of its drilling and re-drilling program to reduce environmental impacts. (County Code section 22.44.142.E.26.c.ix) Pursuant thereto, PXP shall address in each Annual Drilling Plan the availability and feasibility of the use of natural gas-powered drill rigs or other technology capable of reducing environmental impacts, for the drilling of wells proposed in the Annual Drilling Plan (collectively "Clean Technology"). During the Periodic Review provided in 22.44.142 G.7, the County will evaluate such technology for brand new equipment that PXP intends to lease, acquire or otherwise use and require PXP to implement such technology to the extent the technology is feasible and available on a commercially reasonable basis.*

Section 10: Well Plugs. *DOGGR requires oil field operators to utilize a minimum 25-foot cement surface plug at the top of a well when abandoning any such well pursuant to Title 14 of the California Code of Regulations section 1723.5. To augment this requirement, for all wells abandoned at the Oil Field from the date of this Agreement, PXP shall utilize a total of 150-foot cement surface plug.*

2 2015 Plan

2.1 Plan Overview

This Plan covers activities for the 2015 calendar year. FM O&G's plan proposes drilling and re-drilling 53 wells (see Attachment 1 for the location of the proposed wells) using 2 drilling rigs in accordance with the CSD and Settlement Agreement. The 53 wells are comprised of 34 producers and 19 injectors, of which 1 injector is a re-drill. Drilling and re-drilling activities will conform to the setback requirements contained in the CSD, Section E.2.n as follows:

Drilling and Re-drilling Setbacks: The following setbacks shall apply within the oil field *for drilling and re-drilling:*

i. *At least 400 feet from developed areas*
ii. *At least 20 feet from any public roadway*

Developed areas are defined in the CSD as "*Any lot or parcel of land containing any residential, commercial, industrial, or office structure, or used for residential, commercial, industrial, or office purposes (provided that no lot or parcel of land on the oil field shall be considered to be developed area solely because of the presence thereon of the Cone Trust House or of a structure used by any operator for administrative functions associated with the oil field); or any lot or parcel of land containing any public park, house of worship, cemetery, school, parking lot, or any recreation area which has been developed and opened for public use."*

Two types of wells are drilled in the oil field; injection and production wells. *Injection wells* are used to pump fluids into the oil bearing geologic formation at depth, sweeping the oily water to nearby *production wells* for recovery.

Wells are drilled by erecting temporary well derricks, or drilling rigs and related components, and drilling to total depth. The well is drilled and completed in accordance to regulated conditions specified by the California Division of Oil and Gas and Geothermal Resources (DOGGR). The geologic zones of interest for FM O&G's 2015 Plan range at a subsurface depth of between 1,000 feet and 6,400 feet maximum vertical depth. Note that individual well depths will vary depending on location in the field. Wells in the shallow zones typically take approximately 8 to 10 days to drill and mid-zone wells typically take approximately 12-14 days to drill, including mobilization and demobilization of drilling equipment.

Under the terms of the Settlement Agreement, deep zone wells are defined as wells presently identified as the Nodular Shale and Sentous zones and any other zones approximately 8,000 feet or deeper. Mid zone wells are defined as wells approximately 3,500 – 7,999 feet deep, presently identified as the Rubel, Moynier, Bradna and City of Inglewood zones. Shallow wells are defined as wells approximately 3,500 feet deep and above the zones identified in 1(b) of the Settlement Agreement as mid-zones, which would include the Vickers and Rindge zones and the Investment

Supplement plans are required for any deep or mid zone wells where the top hole (surface) location is closer than 800' to a sensitive developed area.

Of the 53 wells in the 2015 Plan, only four target a non-shallow zone, the Moynier formation, which is considered a "mid-zone." Since all four of these wells have a surface hole location outside the 800 feet from a sensitive developed area the preparation of a Mid-Zone Supplement is not required.

Based on the uncertainty that any given well will perform as anticipated, FM O&G prepared a plan as discussed in the sections that follow.

A drilling and re-drilling schedule was developed utilizing up to 2 drilling rigs on the field simultaneously for portions of the 2015 Plan year.

Planned activities of well abandonment and well pad abandonment and restoration are also listed below in Table 4 and will begin upon approval by the Director.

2.2 CSD Plan Requirements

i. The Maximum Number of Wells Proposed to be Drilled or Re-drilled

Drilling activities were reinitiated in June, 2010 after a 3 year suspension while waiting on the certification of an Environmental Impact Report and LA County approval of a new Community Standards District (CSD) for the Baldwin Hills area. Since inception of the CSD through June 30, 2014, 127 wells have been drilled and 32 wells have been abandoned; of which 20 were within 800 feet of Developed Areas (see Table 5). Five bonus wells were used in the 2011 Drilling Plan Year, leaving 35 bonus well credits to apply towards future drilling activities. Bonus wells can be drilled at any time during the life of the CSD and must be located outside the 800-foot zone.

Commencing in 2012, the CSD and Settlement Agreement allow for a maximum of 53 wells to be drilled and re-drilled (35 wells plus 18 bonus wells) in any one calendar year.

The CSD allows for a maximum of 600 wells to be drilled or re-drilled over the next 20 years for an average of 30 wells per year. Effective July 15, 2011, however, Section 4.a. of the Settlement Agreement commits FM O&G to limiting the total number of new wells that will be installed through 2028 to 500. See Table 1 below for a cumulative status summary of the number of wells drilled by year since inception of the CSD. As part of this total, Sections 4.b. – d. of the Settlement Agreement commits FM O&G to further limiting the number of new wells that can be installed in any one year. Specific details of the limitations follow.

Section 4.b. of the Settlement Agreement commits FM O&G to limiting the number of new wells installed to 30 per year until such time as 50 new wells had been installed from the time of the County's approval of the CSD. Following the installation of 50 new wells, the Settlement Agreement allows the operator to apply to the County for approval to install up to 35 new wells per year. FM O&G's predecessor applied for this well increase on October 10, 2011 and was granted approval by the County on December 12, 2011.

Additional provisions in the Settlement Agreement allow FM O&G to drill up to 18 wells per year using a system of "bonus credits" generated from abandonment of idle wells that sit within 800' of any Developed Areas. With approval of the Planning Director and the use of "bonus credits", FM O&G could potentially drill a total of 53 wells in any given year.

The 2015 drilling program will commence on January 1, 2015 under the 2015 Annual Drilling Plan. The 2015 Drilling Plan includes a maximum of 53 wells. Of the 53 wells there are 26 carry-over wells from the approved 2014 Annual Drilling Plan that were not drilled in 2014. One of the 26 carry-over wells is a re-drill of an existing injector, which is the only re-drill in the 2015 Annual Drilling Plan. The breakdown of the wells planned for the 2015 Plan is as follows:

A. 35 wells as allowed by the CSD and Settlement Agreement,
B. 18 bonus wells (FM O&G currently has 35 unused bonus well credits approved by the County), and
C. 22 new plugging and abandonment operations (P&A) to perform in 2015. 5 of these would generate an additional 10 bonus well credits that could be used in future drilling years after approval by the County.

Schedule 1 represents the proposed 2015 drilling schedule based on the use of 2 drilling rigs concurrently. Though the locations and respective schedule reflect geologic targets based on the best geologic and reservoir data available, new well performance data, economic conditions, company plans and reallocation of budgets may alter the schedule and number of wells drilled in 2015. In no case, will the number of wells drilled in 2015 exceed 53 wells.

To execute the 2015 Plan, FM O&G will need to utilize a number of “bonus wells” as allowed for under Sections 4.c. and d. of the Settlement Agreement. Table 5 catalogues the number of “bonus wells” FM O&G has generated through the abandonment of wells within 800’ of developed areas (“800-foot zone”). Table 4 itemizes the wells to be plugged and abandoned in 2015 and which wells generate “bonus wells” while Table 2 shows which proposed 2015 wells that would qualify to be drilled as bonus wells.

Prior to drilling or re-drilling the 53 locations in 2015 as discussed above, FM O&G will prepare and submit Notices of Intent to drill (NOI’s) to DOGGR for drilling or re-drilling permits. FM O&G will also prepare and submit the respective Site Plan Review Applications for all individual wells to the Los Angeles County Planning Department for review and approval. No well can be drilled until DOGGR has approved the NOI and the County has issued a site plan approval.

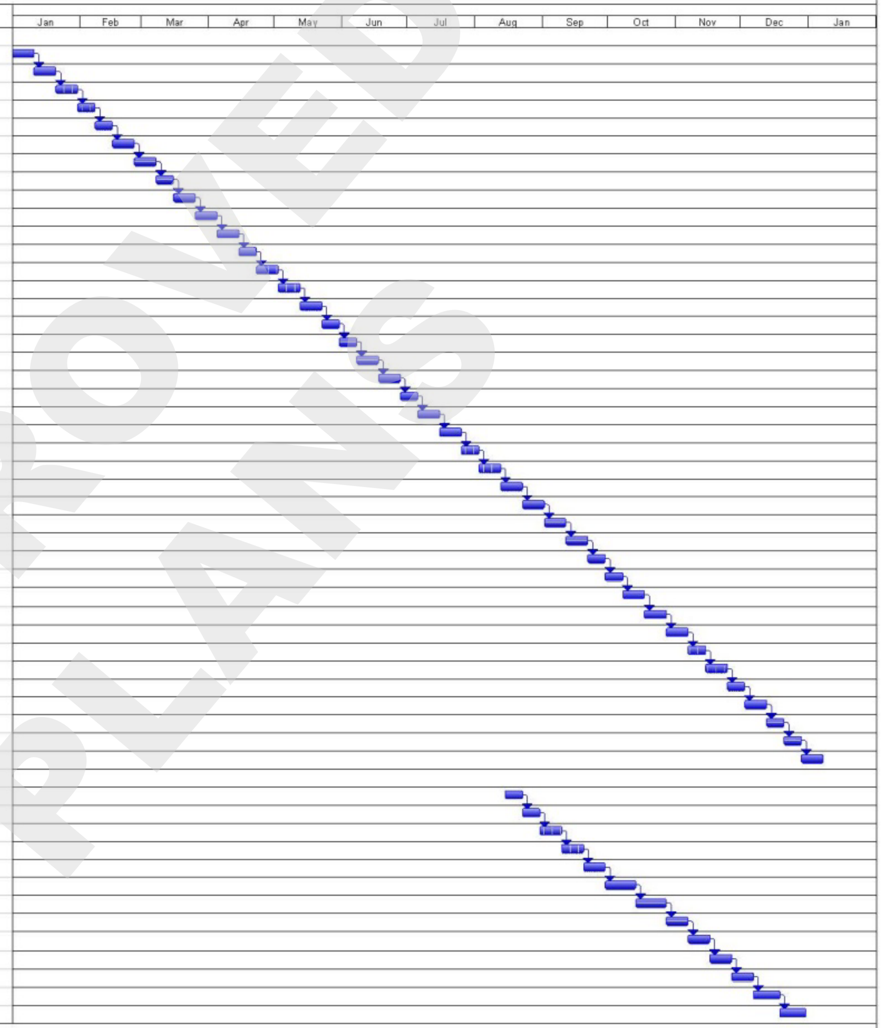
In addition, FM O&G will secure approval from the County Fire Department for producer wells. FM O&G will not commence drilling or re-drilling activities for any well until well drilling approvals from Fire Department (where applicable); DOGGR and Los Angeles County Planning Department are obtained for that well.

Table 1 - Number of Wells Drilled Since Inception of the CSD

Number of Wells Drilled Since Inception of the CSD		
YEAR	**NUMBER OF WELLS**	**BONUS WELLS USED**
2009	0	0
2010	19	0
2011	40	5
2012	20	0
2013	30	0
2014 (through July 30, 2014)	**18**	**0**
Total (through July 30, 2014)	**127**	**5**

2015 CSD Schedule for Drill Plan

ID	CSD Well Number	Task Name	Well Type	Duration	Start	Finish
1		**Rig 1**		**372 days**	**Thu 1/1/15**	**Fri 1/8/16**
2	1	BC 6621	Producer	10 days	Thu 1/1/15	Sun 1/11/15
3	2	LAI1 5664	Producer	10 days	Sun 1/11/15	Wed 1/21/15
4	3	LAI1 4483	Injector	10 days	Wed 1/21/15	Sat 1/31/15
5	9	LAI1 4472	Injector	8 days	Sat 1/31/15	Sun 2/8/15
6	4	LAI1 6863	Producer	8 days	Sun 2/8/15	Mon 2/16/15
7	6	LAI1 6853	Producer	10 days	Mon 2/16/15	Thu 2/26/15
8	5	VRU 4353	Injector	10 days	Thu 2/26/15	Sun 3/8/15
9	7	LAI1 4571	Injector	8 days	Sun 3/8/15	Mon 3/16/15
10	8	VIC1 4321	Producer	10 days	Mon 3/16/15	Thu 3/26/15
11	10	VRU 4451	Producer	10 days	Thu 3/26/15	Sun 4/5/15
12	11	VRU 4341	Producer	10 days	Sun 4/5/15	Wed 4/15/15
13	12	BC 6622	Injector	8 days	Wed 4/15/15	Thu 4/23/15
14	13	LAI1 5464	Producer	10 days	Thu 4/23/15	Sun 5/3/15
15	14	BC-STK 6774	Producer	10 days	Sun 5/3/15	Wed 5/13/15
16	19	STK-BC 6783	Injector	10 days	Wed 5/13/15	Sat 5/23/15
17	15	BC 6634	Producer	8 days	Sat 5/23/15	Sun 5/31/15
18	21	BC 6623	Injector	8 days	Sun 5/31/15	Mon 6/8/15
19	16	VRU 4351	Injector	10 days	Mon 6/8/15	Thu 6/18/15
20	17	LAI1 5554	Producer	10 days	Thu 6/18/15	Sun 6/28/15
21	30	LAI1 5641	Injector	8 days	Sun 6/28/15	Mon 7/6/15
22	23	LAI1 5622	Producer	10 days	Mon 7/6/15	Thu 7/16/15
23	20	LAI1 5621	Producer	10 days	Thu 7/16/15	Sun 7/26/15
24	18	TVIC 3243	Producer	8 days	Sun 7/26/15	Mon 8/3/15
25	22	LAI1 4583	Producer	10 days	Mon 8/3/15	Thu 8/13/15
26	29	BC 6753	Producer	10 days	Thu 8/13/15	Sun 8/23/15
27	36	LAI1 6842	Producer	10 days	Sun 8/23/15	Wed 9/2/15
28	24	VIC1 4434	Injector	10 days	Wed 9/2/15	Sat 9/12/15
29	25	VRU 4342	Producer	10 days	Sat 9/12/15	Tue 9/22/15
30	26	VRU 4262	Producer	8 days	Tue 9/22/15	Wed 9/30/15
31	27	TVIC 269RD1	Injector	8 days	Wed 9/30/15	Thu 10/8/15
32	28	TVIC 3264	Producer	10 days	Thu 10/8/15	Sun 10/18/15
33	31	LAI1 4684	Producer	10 days	Sun 10/18/15	Wed 10/28/15
34	32	VRU 4223	Producer	10 days	Wed 10/28/15	Sat 11/7/15
35	35	LAI1 5783	Injector	8 days	Sat 11/7/15	Sun 11/15/15
36	34	LAI1 4582	Producer	10 days	Sun 11/15/15	Wed 11/25/15
37	33	LAI1 4574	Injector	8 days	Wed 11/25/15	Thu 12/3/15
38	37	VIC1 4433	Producer	10 days	Thu 12/3/15	Sun 12/13/15
39	38	LAI1 5623	Injector	8 days	Sun 12/13/15	Mon 12/21/15
40	39	VIC1 4423	Injector	8 days	Mon 12/21/15	Tue 12/29/15
41	40	VIC1 4323	Producer	10 days	Tue 12/29/15	Fri 1/8/16
42		**Rig 2**		**122 days**	**Mon 8/31/15**	**Thu 12/31/15**
43	48	LAI1 6951	Injector	8 days	Sat 8/15/15	Sun 8/23/15
44	47	VRU 4374	Injector	8 days	Sun 8/23/15	Mon 8/31/15
45	46	LAI1 5633	Producer	10 days	Mon 8/31/15	Thu 9/10/15
46	43	VRU 4421	Producer	10 days	Thu 9/10/15	Sun 9/20/15
47	44	VRU 5452	Producer	10 days	Sun 9/20/15	Wed 9/30/15
48	50	BC-STK 2077	Producer	14 days	Wed 9/30/15	Wed 10/14/15
49	51	Marlow Burns 2079	Producer	14 days	Wed 10/14/15	Wed 10/28/15
50	45	VRU-LAI1 4462	Producer	10 days	Wed 10/28/15	Sat 11/7/15
51	42	LAI1 5661	Producer	10 days	Sat 11/7/15	Tue 11/17/15
52	41	LAI1 5463	Producer	10 days	Tue 11/17/15	Fri 11/27/15
53	49	LAI1 UB2	UB Producer	10 days	Fri 11/27/15	Mon 12/7/15
54	52	Marlow Burns 2578	Injector	12 days	Mon 12/7/15	Sat 12/19/15
55	53	LAI-COMM1 2678	Injector	12 days	Sat 12/19/15	Thu 12/31/15



ii. Approximate Location of All Wells Proposed to be Drilled or Re-drilled

Table 2 below provides X - Y coordinates for the 53 well locations included in the 2015 Plan year, including bottom hole and surface locations. The 53 drilled or re-drilled wells included in the 2015 Plan year include 34 producers and 19 injector wells. 1 of the injector wells would be a re-drill of existing well. Rectangles drawn to scale on the Attachment 1 location map represent the footprints (12' X 45') of conventional surface pumps and identify the 34 surface location candidates projected to be completed as producing wells. Squares drawn to scale on Attachment 1 represent the footprint (12' X 12') of conventional injection wells and indicate the surface locations of 19 wells proposed to be completed as injectors. The acronym "RD" within a well name reflects a well to be re-drilled.

Geographical location, visual impact, duration of drilling activities, relative distance to developed areas and other factors were the criteria used to avoid temporary overconcentration of drilling activities near any one developed area. Duration of drilling activities includes the mobilization of drilling rig equipment, actual drilling operations and demobilization of drilling equipment. The preceding Schedule 1, 2015 Proposed Drilling and Re-drilling Schedule, sets forth the duration of drilling activities for each individual well.

The entire field was reviewed for temporary overconcentration of drilling activities near developed areas including, without limitation, the surrounding parklands and recreational areas (including but not limited to Kenneth Hahn State Recreational Area, Culver City Park, Ladera Park, Baldwin Hills Sports Complex, etc.) and the residential communities of Windsor Hills, Ladera Heights, Blair Hills, Raintree Apartments, Culver Crest and West LA College. None of these areas would see the drilling of multiple wells in proximity to developed areas except for wells in close proximity to Windsor Hills. The wells in close proximity to Windsor Hills are BC-STK 6774 (#14), STK-BC 6783 (#19), STK-BC 2077 (#50), Marlow Burns 2079 (#51), Marlow Burns 2578 (#52),and LAI1-COMM1-2678 (#53), .

A review of Schedule 1 shows that these wells are drilled in 3 separate time periods of less than 30 days, after which period, the rig leaves the area in close proximity to Windsor Hills each time for a month or more, before returning. Therefore, the Plan removes any potential for over concentration for developed areas near Windsor Hills.

iii. The Production Zones Proposed for Development

The wells proposed in the 2015 plan will be used to develop various production zones within the oil field. These production zones include the Investment , Vickers-Rindge, and Moynier. All but 5 of the proposed wells would be drilled into the Vickers-Rindge production zone. In the field the Vickers-Rindge production zone ranges in depth from approximately 1,000 to 4,800 feet, and is considered a shallow depth zone for the purposes of the Settlement Agreement. One well will be drilled in the Investment zone, which lies above the Vickers-Rindge and is also considered to be shallow since it is less than 3,500' and shallower than the mid-zone. Four wells will be drilled in the Moynier zone, which is considered to be a mid-zone per the Settlement Agreement. Since the surface holes of the four Moynier wells are outside of the 800' setback from sensitive developed areas, the preparation of a Mid-Zone Supplement is not necessary per Term 1.b of the Settlement Agreement.

The Investment well will be drilled as a horizontal well since the Investment sand is not of sufficient thickness to justify a vertical well. A horizontal well will increase the amount of producing sand exposed to the wellbore, which will reduce the number of wells needed to obtain the same level of production. There is a common misconception that all horizontally drilled wells are hydraulically fractured. This horizontal well will not be hydraulically fractured.

The Vickers-Rindge wells have been designed to produce from multiple production zones, which means they are drilled as vertically as possible through the entire Vickers-Rindge interval. This serves to limit the number of new wells needed by maximizing production from each well. If each well was only designed to produce from one of the production zones then more wells would be needed to obtain the same level of production.

The Moynier wells are producing from a deeper horizon than the Vickers-Rindge, and are designed similarly to produce from multiple production zones over the life of the well. These wells are drilled as vertically as possible through the entire Moynier interval.

Table 2 lists the production zone for each proposed well.

Table 2 - 2015 Proposed Drilling and Re-drilling Location Table

2015 FM O&G Drilling and Re-drilling Proposed Locations 08-20-14												
			Bottom Hole Locations		Surface Locations							
Count	Well Name	TYPE	X (East)	Y (North)	x(East)	Y(North)	Estimated Total Vertical Depth @ Target Depth	Potential Target Production Zones	SHL[1] Within 800' of Sensitive Developed Area	Supplement Required	SHL Beyond 800' from Developed Area	Qualify to be Drilled as Bonus Well
1	BC 6621	Producer	4,177,466.00	4,112,888.00	4,177,442.97	4,112,978.43	2,500	Vickers-Rindge	Yes	No	No	No
2	LAI1 5664	Producer	4,176,402.00	4,112,138.00	4,176,189.14	4,112,108.21	3,100	Vickers-Rindge	Yes	No	No	No
3	LAI1 4483	Injector	4,174,808.00	4,114,324.00	4,174,741.16	4,114,565.57	3,300	Vickers-Rindge	No	No	Yes	Yes
4	LAI1 6863	Producer	4,178,282.00	4,110,344.00	4,178,071.78	4,110,524.28	3,300	Vickers-Rindge	Yes	No	No	No
5	VRU 4353	Injector	4,174,234.00	4,115,348.00	4,174,367.08	4,115,258.68	3,300	Vickers-Rindge	No	No	Yes	Yes
6	LAI1 6853	Producer	4,178,050.00	4,110,266.00	4,178,080.98	4,110,509.95	3,300	Vickers-Rindge	Yes	No	No	No
7	LAI1 4571	Injector	4,174,750.00	4,113,978.00	4,174,808.91	4,113,837.32	3,500	Vickers-Rindge	No	No	Yes	Yes
8	VIC1 4321	Producer	4,173,402.00	4,114,982.00	4,173,225.97	4,115,011.00	3,400	Vickers-Rindge	No	No	Yes	Yes
9	LAI1 4472	Injector	4,174,680.00	4,114,610.00	4,174,738.05	4,114,554.42	3,300	Vickers-Rindge	No	No	Yes	Yes
10	VRU 4451	Producer	4,174,086.00	4,114,718.00	4,174,132.80	4,114,628.88	3,300	Vickers-Rindge	No	No	Yes	Yes
11	VRU 4341	Producer	4,173,902.00	4,115,976.00	4,173,967.31	4,116,263.07	3,400	Vickers-Rindge	No	No	Yes	Yes

[1] SHL - Surface Hole Location

2015 FM O&G Drilling and Re-drilling Proposed Locations 08-20-14												
			Bottom Hole Locations		Surface Locations							
Count	Well Name	TYPE	X (East)	Y (North)	x(East)	Y(North)	Estimated Total Vertical Depth @ Target Depth	Potential Target Production Zones	SHL [1] Within 800' of Sensitive Developed Area	Supplement Required	SHL Beyond 800' from Developed Area	Qualify to be Drilled as Bonus Well
12	BC 6622	Injector	4,177,292.00	4,112,652.00	4,177,195.03	4,112,517.43	2,500	Vickers-Rindge	No	No	Yes	Yes
13	LAI1 5464	Producer	4,176,534.00	4,114,030.00	4,176,518.63	4,114,071.04	2,500	Vickers-Rindge	Yes	No	No	No
14	BC-STK 6774	Producer	4,178,608.00	4,111,050.00	4,178,458.93	4,111,234.80	2,600	Vickers-Rindge	Yes	No	No	No
15	BC 6634	Producer	4,177,648.00	4,112,236.00	4,177,693.21	4,111,994.39	2,400	Vickers-Rindge	No	No	Yes	Yes
16	VRU 4351	Injector	4,174,290.00	4,115,760.00	4,174,380.65	4,115,681.07	3,600	Vickers-Rindge	No	No	Yes	Yes
17	LAI1 5554	Producer	4,175,992.00	4,113,128.00	4,175,681.57	4,113,526.28	3,400	Vickers-Rindge	No	No	Yes	Yes
18	TVIC 3243	Producer	4,171,970.00	4,116,468.00	4,171,698.11	4,116,403.17	3,700	Vickers-Rindge	Yes	No	No	No
19	STK-BC 6783	Injector	4,178,908.00	4,111,042.00	4,178,583.01	4,110,693.93	2,700	Vickers-Rindge	Yes	No	No	No
20	LAI1 5621	Producer	4,175,376.00	4,112,880.00	4,175,225.24	4,112,668.54	3,100	Vickers-Rindge	No	No	No	No
21	BC 6623	Injector	4,177,472.00	4,112,332.00	4,177,686.30	4,112,017.28	2,400	Vickers-Rindge	No	No	Yes	Yes
22	LAI1 4583	Producer	4,174,772.00	4,113,326.00	4,174,866.53	4,113,366.99	3,200	Vickers-Rindge	No	No	Yes	Yes
23	LAI1 5622	Producer	4,175,316.00	4,112,680.00	4,175,219.96	4,112,674.10	3,000	Vickers-Rindge	No	No	No	No
24	VIC1 4434	Injector	4,173,672.00	4,114,036.00	4,173,604.88	4,114,066.30	3,200	Vickers-Rindge	No	No	Yes	Yes

2015 FM O&G Drilling and Re-drilling Proposed Locations 08-20-14												
			Bottom Hole Locations		Surface Locations							
Count	Well Name	TYPE	X (East)	Y (North)	x(East)	Y(North)	Estimated Total Vertical Depth @ Target Depth	Potential Target Production Zones	SHL[1] Within 800' of Sensitive Developed Area	Supplement Required	SHL Beyond 800' from Developed Area	Qualify to be Drilled as Bonus Well
25	VRU 4342	Producer	4,173,988.00	4,115,618.00	4,174,042.98	4,115,855.85	3,400	Vickers-Rindge	No	No	Yes	Yes
26	VRU 4262	Producer	4,174,310.00	4,116,476.00	4,174,037.59	4,116,573.77	3,000	Vickers-Rindge	Yes	No	No	No
27	TVIC 269RD1	Injector	4,171,896.00	4,116,298.00	4,172,007.10	4,116,152.50	3,220	Vickers-Rindge	No	No	Yes	Yes
28	TVIC 3264	Producer	4,172,496.00	4,116,220.00	4,172,657.94	4,116,258.44	3,700	Vickers-Rindge	No	No	Yes	Yes
29	BC 6753	Producer	4,178,048.00	4,111,436.00	4,178,275.64	4,111,312.46	3,000	Vickers-Rindge	No	No	No	No
30	LAI1 5641	Injector	4,175,770.00	4,112,858.00	4,175,690.16	4,113,536.31	3,300	Vickers-Rindge	No	No	Yes	Yes
31	LAI1 4684	Producer	4,174,950.00	4,112,610.00	4,174,971.99	4,112,627.93	3,000	Vickers-Rindge	No	No	No	No
32	VRU-4223	Producer	4,173,468.00	4,116,478.00	4,173,700.85	4,116,533.32	3,000	Vickers-Rindge	Yes	No	No	No
33	LAI1 4574	Injector	4,174,680.00	4,113,092.00	4,174,826.43	4,113,368.15	3,100	Vickers-Rindge	No	No	Yes	Yes
34	LAI1 4582	Producer	4,174,994.00	4,113,468.00	4,174,914.53	4,113,369.32	3,200	Vickers-Rindge	No	No	Yes	Yes
35	LAI1 5783	Injector	4,176,914.00	4,111,288.00	4,176,764.65	4,111,150.95	2,800	Vickers-Rindge	No	No	Yes	Yes
36	LAI1 6842	Producer	4,177,844.00	4,110,678.00	4,177,605.03	4,110,691.58	3,100	Vickers-Rindge	Yes	No	No	No
37	VIC1 4433	Producer	4,173,582.00	4,114,418.00	4,173,470.94	4,114,330.59	3,500	Vickers-Rindge	No	No	Yes	Yes
38	LAI1 5623	Injector	4,175,334.00	4,112,340.00	4,175,227.79	4,112,665.16	3,000	Vickers-Rindge	No	No	No	No

2015 FM O&G Drilling and Re-drilling Proposed Locations 08-20-14													
			Bottom Hole Locations		Surface Locations								
Count	Well Name	TYPE	X (East)	Y (North)	x(East)	Y(North)	Estimated Total Vertical Depth @ Target Depth	Potential Target Production Zones	SHL [1] Within 800' of Sensitive Developed Area	Supplement Required	SHL Beyond 800' from Developed Area	Qualify to be Drilled as Bonus Well
39	VIC1 4423	Injector	4,173,256.00	4,114,496.00	4,173,098.68	4,114,740.72	3,200	Vickers-Rindge	No	No	Yes	Yes
40	VIC1 4323	Producer	4,173,154.00	4,115,284.00	4,172,901.86	4,115,428.35	3,500	Vickers-Rindge	No	No	Yes	Yes
41	LAI1 5463	Producer	4,176,314.00	4,114,258.00	4,175,922.77	4,114,098.03	2,600	Vickers-Rindge	Yes	No	No	No
42	LAI1 5661	Producer	4,176,456.00	4,112,884.00	4,176,479.94	4,112,677.85	3,500	Vickers-Rindge	No	No	Yes	Yes
43	VRU 4421	Producer	4,173,422.00	4,115,952.00	4,173,593.45	4,116,030.95	3,500	Vickers-Rindge	No	No	Yes	Yes
44	VRU 5452	Producer	4,176,016.00	4,114,632.00	4,175,918.58	4,114,109.62	3,300	Vickers-Rindge	Yes	No	No	No
45	VRU-LAI1 4462	Producer	4,174,354.00	4,114,722.00	4,174,577.47	4,114,748.80	3,400	Vickers-Rindge	No	No	Yes	Yes
46	LAI1 5633	Producer	4,175,600.00	4,112,340.00	4,175,809.64	4,112,404.25	3,200	Vickers-Rindge	No	No	Yes	Yes
47	VRU 4374	Injector	4,174,736.00	4,115,068.00	4,174,607.86	4,115,210.33	3,300	Vickers-Rindge	No	No	Yes	Yes
48	LAI1 6951	Injector	4,178,278.00	4,110,010.00	4,177,918.22	4,110,391.60	3,000	Vickers-Rindge	Yes	No	No	No
49	LAI1-UB2	Producer	4,177,880.00	4,109,918.00	4,176,476.16	4,110,713.65	1,000	Investment	Yes	No	No	No
50	BC-STK 2077	Producer	4,179,117.00	4,111,161.00	4,178,155.02	4,111,277.03	5,700	Moynier	No	No	Yes	Yes
51	Marlow Burns 2079	Producer	4,180,360.00	4,109,690.00	4,178,484.49	4,110,766.56	6,400	Moynier	No	No	No	No

2015 FM O&G Drilling and Re-drilling Proposed Locations 08-20-14													
			Bottom Hole Locations		Surface Locations								
Count	Well Name	TYPE	X (East)	Y (North)	x(East)	Y(North)	Estimated Total Vertical Depth @ Target Depth	Potential Target Production Zones	SHL[1] Within 800' of Sensitive Developed Area	Supplement Required	SHL Beyond 800' from Developed Area	Qualify to be Drilled as Bonus Well
52	Marlow Burns 2578	Injector	4,179,656.00	4,110,878.00	4,178,145.98	4,111,272.87	6,000	Moynier	No	No	Yes	Yes
53	LAI-COMM1 2678	Injector	4,180,090.00	4,110,556.00	4,178,494.80	4,110,760.43	6,000	Moynier	No	No	No	No
	Coordinates in feet, NAD 1927, CA Plane, Zone 7; Depth in feet												

iv. Approximate Location of All New Well Pads, Including Size and Dimensions

There are no new drilling pads proposed for construction in the 2015 Drilling Plan.

v. Estimated Target Depth of All Proposed Wells and Their Estimated Bottom Hole Locations

Anticipated bottom hole locations for the 53 2015 Plan wells are noted on the location map, Attachment 1 and provided in Table 2. Approximate vertical depths at target depths for each of the wells are noted on Table 2.

vi. A Discussion of the Steps That Have Been Taken to Maximize Use of Existing Wells Pads, Maximize Use of Re-drilled Wells, and Maximize the Consolidation of Wells

To maximize the use of existing pads, FM O&G first identified the target production zones and bottom hole locations for each well. FM O&G then projected a maximum horizontal reach radius (i.e., the horizontal distance from the surface location to the bottom hole location) from each location to an available and suitable surface location that would support respective facilities for the type of well proposed (production or injection). The horizontal reach radius was based upon the shallowest target production zone for each well. FM O&G prioritized the use of available existing pads to the maximum degree possible.

Idle wells were utilized by FM O&G for new wells whenever possible (re-drills). Table 3 identifies all idle wells evaluated as potential re-drill candidates. As shown in this Table, 1 of the proposed 2015 wells would be re-drills.

The criteria evaluated to identify the suitability of an idle well for a re-drill candidate were as follows:

1. The horizontal reach of a well is limited by the shallowest target production zone for each well, and the fact that the wells need to be completed vertically through the target production zones to maximize the effectiveness of the well. The maximum horizontal reach radius for the Vickers-Rindge wells in the 2015 plan is approximately 300 feet (from the surface location) for both producers and injectors. The maximum horizontal reach for the Moynier wells in the 2015 plan is approximately 1,800 feet since it will be not be possible to recomplete these wells to the shallower Vickers Rindge in the future (if the Moynier wells were able to be recompleted to the Vickers Rindge, the maximum reach would be 300 feet). These wells cannot be recompleted to the Vickers Rindge in the future due to existing, surface constraints.
2. DOGGR 2007 Field Rules for Inglewood require that the production casing be cemented back to surface. For a producing well, the required casing in the perforated section must be 9 5/8”, with a corresponding 13 3/8” casing at surface. For a re-drill injector, the minimum production casing size at the injection interval is 7” with a corresponding minimum casing size at surface of 9 5/8”;
3. The existing orientation (inclination and deviation direction) of the idle well may also preclude its use because it may be impossible for the drill bit to follow a path to the intended target;

4. The re-drill candidate must have excellent casing integrity; the casing cannot be damaged;
5. The use of an idle well can trigger an offset well obligation according to the provisions of an adjacent lease. An “offset obligation” requires a second and adjacent well to be drilled on the adjacent lease to protect that lessor from drainage. In this case, the idle well would be rejected to minimize new wells and maximize consolidation and efficiency;
6. In some cases, it is more economically feasible to drill a new well rather than re-drill an existing idle well. Idle wells with potential mechanical integrity issues could experience problems during the re-drilling process, rendering the well uneconomical or dramatically increasing the drilling time associated with the well.
7. The path or route of the well to be drilled from the idle well candidate must navigate around existing production and injection wells. It may be technically or economically unfeasible to reach the target location if these obstructions cannot be avoided.

There is 1 well in the 2015 Plan which met the criteria and can be re-drilled. All proposed surface well locations were consolidated to the maximum extent possible.

Table 3 –Idle Wells within Approximately 300’ of 2015 Proposed Vickers Rindge Well Locations or within 1,800’ of 2015 Proposed Moynier Well Locations[2]

2015 FM O&G Idle Wells within 300 feet of Drilling and Re-drilling Proposed Vickers Rindge Locations or within 1,800’ of 2015 Proposed Moynier Well Locations					
No.	**Proposed Well**	**Type**	**Idle Well(s) within 300 feet**	**Possible Re-drill Candidate?**	**Comments**
1	BC 6621	Producer	BC 621	N	RTP candidate
2	LAI1 5664	Producer	N/A	N/A	
3	LAI1 4483	Injector	N/A	N/A	
4	LAI1 6863	Producer	LAI1 287	N	7" casing diameter too small
5	VRU 4353	Injector	N/A	N/A	
6	LAI1 6853	Producer	LAI1 287	N	7" casing diameter too small
7	LAI1 4571	Injector	N/A	N/A	
8	VIC1 4321	Producer	N/A	N/A	
9	LAI1 4472	Injector	N/A	N/A	
10	VRU 4451	Producer	N/A	N/A	
11	VRU 4341	Producer	N/A	N/A	
12	BC 6622	Injector	N/A	N/A	
13	LAI1 5464	Producer	LAI-BC 403	N	Surface location within 400 foot CSD setback

[2] Wells inside of the 800’ boundary from sensitive developed areas were not evaluated.

2015 FM O&G Idle Wells within 300 feet of Drilling and Re-drilling Proposed Vickers Rindge Locations or within 1,800' of 2015 Proposed Moynier Well Locations

No.	Proposed Well	Type	Idle Well(s) within 300 feet	Possible Re-drill Candidate?	Comments
14	BC-STK 6774	Producer	N/A	N/A	
15	BC 6634	Producer	N/A	N	
16	VRU 4351	Injector	N/A	N/A	
17	LAI1 5554	Producer	N/A	N/A	
18	TVIC 3243	Producer	TVIC 16 TVIC 71	N N	7" casing diameter too small 7" casing diameter too small
19	STK-BC 6783	Injector	N/A	N/A	
20	LAI1 5621	Producer	N/A	N/A	
21	BC 6623	Injector	N/A	N/A	
22	LAI1 4583	Producer	N/A	N/A	
23	LAI1 5622	Producer	N/A	N/A	
24	VIC1 4434	Injector	N/A	N/A	
25	VRU 4342	Producer	N/A	N/A	
26	VRU 4262	Producer	VRU-257	N	10 ¾" casing diameter too small
27	TVIC 269RD1	Injector	Re-drill Injector	Y	
28	TVIC 3264	Producer	TVIC-61	N	7" casing diameter too small
29	BC 6753	Producer	BC-50RD	N	10 3/4" casing diameter too small

2015 FM O&G Idle Wells within 300 feet of Drilling and Re-drilling Proposed Vickers Rindge Locations or within 1,800' of 2015 Proposed Moynier Well Locations					
No.	**Proposed Well**	**Type**	**Idle Well(s) within 300 feet**	**Possible Re-drill Candidate?**	**Comments**
30	LAI1 5641	Injector	LAI1-206	N	8 5/8" casing diameter too small
31	LAI1 4684	Producer	LAI1-186	N	7" casing diameter too small
32	VRU 4223	Producer	N/A	N/A	
33	LAI1 4574	Injector	LAI1-VIC1-3	N	7" casing diameter too small
34	LAI1 4582	Producer	N/A	N/A	
35	LAI1 5783	Injector	LAI1-BC-406	N	Well re-completion candidate
36	LAI1 6842	Producer	N/A	N/A	
37	VIC1 4433	Producer	VIC1-75A	N	5-1/2" casing diameter too small
38	LAI1 5623	Injector	N/A	N/A	
39	VIC1 4423	Injector	N/A	N/A	
40	VIC1 4323	Producer	N/A	N/A	
41	LAI1 5463	Producer	LAI-BC-403	N	Surface location within 400 foot CSD setback
42	LAI1 5661	Producer	N/A	N	
43	VRU 4421	Producer	VRU-144RD	N	7" casing diameter too small
44	VRU 5452	Producer	LAI1-VRU-2	N	7" casing diameter too small
45	VRU-LAI1 4462	Producer	VRU-LAI1-206 LAI1-1044	N N	9 5/8" casing diameter too small 9 5/8" casing diameter too small

2015 FM O&G Idle Wells within 300 feet of Drilling and Re-drilling Proposed Vickers Rindge Locations or within 1,800' of 2015 Proposed Moynier Well Locations					
No.	**Proposed Well**	**Type**	**Idle Well(s) within 300 feet**	**Possible Re-drill Candidate?**	**Comments**
46	LAI1 5633	Producer	N/A	N/A	
47	VRU 4374	Injector	N/A	N/A	
48	LAI1 6951	Injector	N/A	N/A	
49	LAI1 UB2	Producer	N/A	N/A	
50	BC-STK 2077	Producer	BC-332 BC-442 BC-233	N N N	5-1/2" casing diameter too small 8-5/8" casing diameter too small 9-5/8" casing diameter too small
51	Marlow Burns 2079	Producer	BC-332 BC-442	N N	5-1/2" casing diameter too small 8-5/8" casing diameter too small
52	Marlow Burns 2578	Injector	BC-332 BC-442 BC-233	N N N	5-1/2" casing diameter too small 8-5/8" casing diameter too small 9-5/8" casing diameter too small
53	LAI-COMM1-2678	Injector	BC-332 BC-442	N N	5-1/2" casing diameter too small 8-5/8" casing diameter too small

Note: "N/A" in above table 3 means no offset idle well within 300 feet from proposed Vickers Rindge wells or within 1,800 feet of proposed Moynier wells.
"RTP" means return to production

vii. Location of All Proposed Well Abandonments, if known, in accordance with DOGGR Integrity Testing Program of Idle Wells

FM O&G currently has 22 wells identified for plugging and abandonment consideration in 2015. Five of these wells fall within 800 feet of developed areas, and would qualify for generating "bonus wells". Please see Attachment 3, labeled CSD Plugged and Abandoned Wells as of June 30, 2014, and Table 4 for identification of abandoned wells and their respective locations. More candidates for plugging and abandonment may be identified and work performed in 2015 as deemed appropriate by DOGGR and FM O&G. All abandonments will be conducted in accordance with DOGGR regulations and the requirements specified in Section 10 of the Settlement Agreement.

Well abandonment is defined as *the permanent plugging of a well, in accordance with state law as set forth in Division 3, Chapter 1 of the California Public Resources Code and pursuant to requirements of DOGGR, found in Title 14 of the California Code of Regulations, sections 1723-1723.9, or in accordance with subsequently enacted applicable state laws or regulations regarding well abandonment*.

In addition to plugging and abandonment requirements contained in the CSD, there are other factors that determine when wells will be abandoned. Oil field economics and crude oil and gas prices determine whether wells remain viable future candidates as either producers or injectors. Wells that are mechanically sound and pass idle well testing requirements retain potential for economic production or injection consideration.

Additionally, in the course of day to day well operations, economically prohibitive repairs of mechanical problems encountered on marginally productive wells may also dictate plugging and abandonment.

Sections 4.c. – d. of the Settlement Agreement provide a process for FM O&G to generate "Bonus Wells" that allow additional drilling in each calendar year. "Bonus Wells" generated under the Settlement Agreement are tied to well abandonments that occur within 800' of a developed area (see Map Attachment 3 labeled "CSD Plugged and Abandoned Wells as of June 30, 2014"). Table 5 identifies that 40 "Bonus Wells" have been generated from inception of the CSD to June 30, 2014 to apply towards future drilling activities. 5 Bonus Wells were used in the 2011 Drilling Plan Year; leaving 35 Bonus Well credits to apply towards future drilling activities.

Table 4 - 2015 Proposed Well Abandonment Locations

Master Well Name	API Number	Surf. Loc X (East)	Surf. Loc Y (North)	W/IN 800'	Estimated Abandonment Start
LAI1-83a	037-08240	4,174,682	4,113,993	No	15-Jan
LAI1-375	037-25075	4,174,861	4,174,861	No	30-Jan
TVIC-24	037-09112	4,172,450	4,116,575	No	15-Feb
LAI-133a	037-08038	4,176,192	4,112,092	Yes	28-Feb
VRU-162	037-22988	4,174,188	4,114,996	No	15-Mar
TVIC-97	037-22988	4,172,604	4,116,166	No	30-Mar
VIC1-122	037-20498	4,173,585	4,114,036	No	15-Apr
VIC1-120	037-20386	4,173,253	4,114,969	No	30-Apr
VRU-LAI-206	037-21041	4,174,159	4,115,459	No	15-May
VRU LAI 204	037-21041	4,174,724	4,114,516	No	30-May
VRU-LAI-207	037-09076	4,173,889	4,114,656	No	15-Jun
VRU-256	037-22758	4,173,854	4,115,894	No	15-Jul
STOCKER-25	037-08329	4,178,819	4,110,093	Yes	15-Aug
LAI1-305	037-00229	4,175,377	4,113,590	No	15-Sep
VRU-LAI1-201	037-21038	4,175,376	4,114,665	Yes	15-Oct
BC-201	037-23381	4,177,465	4,112,379	No	15-Nov
Stocker BC-23	037-08308	4,178,887	4,111,015	Yes	30-June
WRZU-300	037-07794	4,173,405	4,116,028	No	30-July
VRU-284	04037-25221	4,173,793	4,116,805	Yes	30-August
LAI1-267	04037-07825	4,175,879	4,113,046	No	30-Sept
BC-LAI1-17	04037-23058	4,176,826	4,112,580	No	30-Oct

VRU-160a	04037-78960	4174713	4115078	No	30-Nov

Table 5 includes a year to date (YTD) cumulative summary of wells that have been plugged and abandoned commencing with the 2009 Plan. Attachment 3 provides a map showing the location of the cumulative wells that have been plugged and abandoned commencing with the 2009 Plan.

Table 5 – Cumulative Status Summary – Wells Plugged and Abandoned (as of June 30, 2014)

Cumulative Status Summary – Wells Plugged and Abandoned (as of June 30, 2013)							
Well Name	**TYPE**	**X (East)**	**Y (North)**	**W/IN 800'**	**Bonus Wells Earned**	**Bonus Wells Used**	**Year Plugged & Abandoned**
LAI1 101A	Oil	4,175,753.55	4,112,494.73	No	0	0	2009
LAI1 250	Oil	4,176,455.38	4,111,503.82	Yes	2	2	2009
VIC2 20	Oil	4,170,919.74	4,116,259.40	Yes	2	2	2009
WRZU 311	Oil	4,174,705.43	4,114,901.78	No	0	0	2009
WRZU 353	Oil	4,175,731.73	4,113,960.31	Yes	2	1	2009
BC 341	Oil	4,177,788.00	4,111,518.00	No	0	0	2009
TVIC 49	Oil	4,171,701.00	4,116,510.00	Yes	2	0	2009
TVIC 204	Water Injector	4,171,677.00	4,115,684.00	No	0	0	2009
VIC1 83	Oil	4,172,476.00	4,110,868.00	No	0	0	2009
VIC 2 22	Oil	4,171,276.00	4,115,079.00	Yes	2	0	2010
STK-BC-LAI1 LW 21	Oil	4,178,474.00	4,110,856.00	Yes	2	0	2009
Buckler-Comm 1A	Oil	4,178,825.00	4,108,751.00	Yes	2	0	2010
LAI1-BC- 12	Oil	4,176,442.86	4,113,352.43	No	0	0	2011
TVIC 58	Oil	4,172,435.59	4,115,797.46	No	0	0	2011
LAI1-STK LW-4	Oil	4,178,286.87	4,110,732.91	Yes	2	0	2011

Vickers 2-24	Water Injector	4,171,591.00	4,114,692.00	Yes	2	0	2011
TVIC-50	Oil	4,172,930.00	4,116,040.00	No	0	0	2012
VIC1-106	Oil	4,173,881	4,112,954	Yes	2	0	2012
BC-172	Oil	4,179,065	4,111,666	Yes	2	0	2012
TVIC-67	Oil	4,172,123	4,114,713	Yes	2	0	2012
LAI1-347	Injector	4,178,347	4,110,542	Yes	2	0	2013
LAI1-340	Oil	4,175,679	4,113,534	No	0	0	2013
BC-135		4,177,746	4,113,300	Yes	2	0	2013
BC-203		4,177,709	4,112,519	Yes	2	0	2013
BC-234		4,177,828	4,112,646	Yes	2	0	2013
BC-236		4,177,628	4,113,628	Yes	2	0	2013
BC-303		4,178,090	4,111,981	Yes	2	0	2013
STOCKER-504		4,179,074	4,110,386	Yes	2	0	2013
LAI1-313		4,175,407	4,112,353	Yes	2	0	2014
LAI1-315A		4,175,803	4,112,432	No	0	0	2014
LAI1-188A		4175,332	4,113,592	No	0	0	2014
LAI1VIC1-LW11		4,174,100	4,114,381	No	0	0	2014
Totals as of 6/30/14					**40**	**5**	

viii. Location of All Well Pads Proposed to be Abandoned and Restored

At the time of submittal, there are no well pads identified as part of the 2015 Plan to be abandoned and restored. To maximize future consolidation, minimize future grading and soil disturbance, and avoid encroachment on undisturbed areas, FM O&G's goal is to consolidate new wells onto existing pads whenever possible. Well pad abandonment candidates are therefore very rare. In addition, due to Southern California's dry climatic conditions and concern about fire safety, FM O&G endeavors to maintain buffer zones between equipment and trees and undergrowth. FM O&G will continue to evaluate well pads for restoration consideration.

In order for a well pad to be a candidate for abandonment and restoration it must meet three criteria. First there must be no active wells on the pad. Secondly there must be no idle wells on the pad that could be a future candidate for re-drilling or reworking; and third, the pad would not be useful in the future for potential new wells. A survey of the existing pads found that none of the pads met these three criteria, so no pads are proposed for abandonment and restoration in the 2015 plan.

ix. A Proposed Schedule and Phasing of the Drilling, Re-drilling, Well Abandonment, Well Pad Abandonment and Restoration Activities

The planned drilling and re-drilling period for 2015, following Plan approval by Los Angeles County, commences on approximately January 1, 2015, through approximately December 31, 2015. No individual well drilling or re-drilling activities will commence until respective DOGGR permit application approvals have been obtained for a well or wells. Furthermore, no well drilling or re-drilling activities will commence until respective Site Plan Review Application approvals have been obtained from the County of Los Angeles for an individual well or wells. Said Site Plan Review applications will evidence pre-approval of the current drilling plan by County of Los Angeles and shall adhere to the provisions of the CSD.

Well plugging and abandonment activities will occur over the course of the 2015 calendar year after approval of the Plan by the Director and upon permit approval for plugging and abandonment from DOGGR.

For the 2015 Drilling Plan, 1 of the 53 proposed wells will be a re-drill. All of the other proposed new wells will be consolidated onto existing pads. FM O&G will also schedule drilling and re-drilling activities to avoid a temporary over concentration of those activities in any one area if they are located near a developed area. This will be accomplished by rotating operational activities among the various Plan locations.

x. A Discussion of the Latest Equipment and Techniques that are Proposed for Use as Part of the Drilling and Re-drilling Program to Reduce Environmental Impacts

FM O&G utilizes technologies that minimize potential adverse effects of drilling and re-drilling activities and maintains compliance with CSD requirements, as well as state and federal regulations. Furthermore, Section 6 of the Settlement Agreement commits FM O&G to consider reasonable and feasible technological improvements which are capable of reducing the environmental impacts of drilling and re-drilling. Specific evaluation of the feasibility of utilizing natural gas-powered drill rigs is discussed in the

Settlement Agreement. As part of the preparation of the 2015 Plan, the following evaluations were conducted pursuant to Section 6 and existing CSD requirements.

Following is a list of the latest equipment and techniques that will be used as part of the 2015 drilling and re-drilling program.

1. A gas buster and portable flare, approved by the SCAQMD, will be available for immediate use to remove any gas encountered during drilling operations from drilling mud being sent to the shaker table, and to redirect such gas to the portable flare for combustion. While not required by the CSD, FM O&G's predecessor installed and maintained a gas buster and portable flare on all wells drilled during the 2012 program. FM O&G anticipates continuing this practice for the wells planned in the 2015 drilling program.

2. An odor suppressant spray system will be used on the mud shaker tables for all drilling and re-drilling operations to minimize any potential odors.

3. All drilling and re-drilling rigs shall utilize CARB/EPA Certified Tier II or better diesel engines to help reduce NOx emissions and heavy duty diesel catalysts to help reduce hydrocarbons and particulate matter. The drilling rig FM O&G anticipates using in the 2015 Drilling Plan execution has 2 of the 7 rig engines upgraded to Interim Tier IV, which are considered best available.

4. All off-road diesel construction equipment engines will utilize Tier III or better diesel engines plus Level 3 CARB verified diesel catalysts during drill pad construction. This is designed to reduce NOx, hydrocarbon and particulate matter emissions.

5. The following setbacks apply within the oil field for drilling and re-drilling activities:

   a. At least 400 feet from developed areas
   b. At least 20 feet from any public road

6. All drilling and re-drilling in the oil field between the hours of 6:00pm and 8:00am will be conducted in conformity with the Quiet Mode Drilling Plan and Section 2 of the Settlement Agreement. The Quiet Mode Drilling Plan minimizes potential noise impacts and includes the following mitigation measures:

   a. Cover V-door with rubber matting, and ensure the rubber matting stays on when handling pipe.
   b. Cover rig floor with rubber matting or wood.
   c. Place rubber matting or wood on the pipe racks and catwalk when rolling pipe off the pipe racks onto the catwalk.
   d. Use hydraulic tongs, instead of chain or pneumatic tongs.
   e. Wrap hammer wrenches with rags.
   f. Install sound barrier on the derrick at the "monkey board".
   g. Install soundproofing blankets around draw-works, rig floor, mud pumps and substructure.
   h. Install temporary sound wall at the perimeter of the drill pad between the rig and sensitive receptors.
   i. Minimize any banging of pipe on the catwalk by careful use of the forklift.
   j. Disable all audible mobile equipment and truck backup alarms.

7. Air monitoring equipment will be installed at the well locations for all drilling and re-drilling operations to monitor for total hydrocarbons and hydrogen sulfide.

Other technology that has been considered as part of the 2015 Plan is discussed below.

Electric Drilling Rigs: As part of the clean technology assessment contemplated in Section 6 of the Settlement Agreement, FM O&G continued to evaluate the use of electric drilling rigs for future drilling activity. Previous evaluations were conducted in preparation of the 2010 through 2014 drilling plans as well as again for the 2015 drilling plan. Currently, the use of electric drilling rigs remains infeasible as explained below in more detail.

Electric drill rigs require 3.5 – 4.5 MVA of power. The electrical distribution system at the Inglewood Field is not designed or constructed to handle incremental 3.5 – 4.5 MVA spot loads. Further, the field's existing electrical distribution system has a 12 kV backbone supplying a 4160v distribution system. Any spot loads such as the 3.5 - 4.5 MVA for the electric rigs would need to be fed by the 12kV system. This system only covers a very small area of the oil field. Upgrading the 12kV system to aerially cover FM O&G's drilling needs in the foreseeable future will approximately double the electrical distribution infrastructure necessary to serve the field. The visual impact of such an upgrade would be significant.

The remaining alternative for utilization of an electric rig would be to generate power for the rig within the field. In this scenario, large capacity diesel, Compressed Natural Gas (CNG) or Liquid natural Gas (LNG) generators would have to be located in the field, not always in proximity to the drilling rig, thus requiring utilization of special cables laid on the ground surface. FM O&G believes such an operation would be impractical and unsafe for the size of this oil field. Furthermore, the cables could not be laid across emergency service and public roadways due to heavy vehicle traffic and safety concerns, further limiting the distance of the temporary electrical generation equipment to the electric rigs.

Generation of onsite electrical power would produce air emissions, similar to the onsite drilling emissions incorporating CSD requirements. Air emissions associated with drilling would not be eliminated, just transferred to the source of the power generation facilities. The community has previously opposed remote power generation facilities at the oil field.

A final item of note is the fact that the footprint of electric rigs is larger than the footprint of conventional rigs. The larger footprint will require additional grading and in some areas fewer wells per pad. This additional disturbance runs counter to other CSD mitigation measures.

Coil Tubing Drilling Rigs: FM O&G has also continued to evaluate the use of coil tubing drilling rig technology, commonly known as CTDU. CTDU's are limited to slim-hole, 6 1/2" and smaller bit size with drilling operations and through tubing limited to 4 1/2". The casing exits are typically limited to 7 5/8" and smaller. Inglewood Oilfield wells require large 17 1/2" holes and13 3/8" surface casing, 12 1/4" hole and 9 5/8" production casing that exceed CTDU specifications. Furthermore, the ratio of hole size to coiled tubing outer diameter ranges from 6:1 to 5:1, thus removal of cuttings from well bores would be dramatically constrained due to significant reduction of annular drilling fluid velocity. Adoption of current CTDU technology at Inglewood remains infeasible.

Diesel – Electric Drilling Rigs: The general specifications for this type of rig are as follows: Depth Rating – 10,000'; Mast Height – 135'; Rig Floor Height – 14'; Power Generation – 2 diesel engines and 3 electric motors rated at a total of 5400 hp; and Well Pad Size Requirement – 360' x 165'.

FM O&G has evaluated the potential use of a diesel-electric drilling rig. By analyzing the general specifications of this rig, it is apparent the rig is taller, leading to a greater visual impact during drilling. Also, the footprint to accommodate the rig is 2.4 times larger than what is required for the currently used rig. Potential impacts for a size increase of this magnitude would translate into increased grading and surface disturbance, in addition to increased potential vegetation removal. Use of these rigs would also translate into more new drilling pads and greater expansion of existing pads, therefore resulting in expansion rather than consolidation of the oilfield.

Due to the larger location required to accommodate these types of rigs and the taller masts associated with the rig, FM O&G believes the use of this type of technology would create more, not less, undesirable impacts on the surrounding community (e.g. expanded rather than consolidated well drilling). Diesel electric rigs use similar Tier II engines as the drill rig FM O&G used in 2014 and FM O&G is proposing to use in 2015. The diesel engines on the combination diesel/electric rigs are used to drive an electrical generator that powers all of the rig equipment. The rig used by FM O&G has a total diesel horsepower rating of 3,200 for all of the engines. This compares with 5,400 hp for the diesel electric rig. As such the air emission factors would be the same for both types of rigs on a pounds per hour basis. Therefore, use of diesel-electric rigs would not result in any air quality benefits over the rig FM O&G currently uses.

Natural Gas – Electric Drilling Rigs: The general specifications for this type of rig are as follows: Depth Rating – 15,000'; Mast Height – 146'; Rig Floor Height – 24'6"; Power Generation – 3 natural gas engines and 5 electric motors rated at a total of 9500 hp; and Well Pad Size Requirement – 315' x 122'.

FM O&G previously evaluated the use of a potentially available natural gas-powered rig for drilling all planned wells at Inglewood. FM O&G re-surveyed 9 California drilling companies and identified only 2 natural gas powered rigs that are permitted and available for California operations. Both of these drilling rigs are currently under long term contract, one to Southern California Gas Company and the second to Occidental Petroleum.

The natural gas – electric rig is rated to drill to deeper depths than the conventional diesel – mechanical rigs used by FM O&G and proposed for use in 2015. Specifically the natural gas – electric rig is rated to drill to depths of 15,000', and the conventional diesel – mechanical rigs are rated to drill to depths of 12,000 feet (which would accommodate all wells proposed in this 2015 Drilling Plan). Because the natural gas – electric rig can drill deeper, it is larger in size than the conventional rigs currently utilized for use in the shallow Vickers Rindge development drilling program. The footprint to accommodate the natural gas – electric rig is 1.5 times larger than what is required for the current rig used and proposed in the 2015 Drilling Program. Using the natural gas – electric rig for all planned 2015 wells would require increased grading and surface disturbance, in addition to increased potential vegetation removal. The impacts would also translate into more new drilling pads and greater expansion of existing pads, therefore resulting in expansion rather than consolidation of the oilfield. Air emissions benefits gained by using the natural gas – electric rig are negligible as compared to using the conventional rigs when the CSD mandated mitigation and control technologies are implemented.

The drilling emissions for the drill rig that FM O&G has been using and proposes to use in 2015 has daily emissions of 0.34 lbs. VOCs, 11.5 lbs of CO, 76.9 lbs. of NO_x, and 0.15 lbs. of PM_{10}. A similar sized natural gas rig would be expected to have higher daily VOC and NOx emissions, but slightly less daily PM_{10} emissions. As such, the air emissions benefits gained by using the natural gas – electric rig are negligible as compared to using the conventional rigs when the CSD mandated mitigation and control technologies are implemented.

The use of new Tier IV engines, which is proposed for the 2015 drilling program, on the draw works would reduce the daily NOx emissions from drilling by about 16 percent. While this engine change would also reduce daily VOC and PM_{10} emissions, the requirement for a 90 percent control of these emissions from drilling engines specified in the CSD negates most of this additional reduction.

The rig mast height for the natural gas rig is approximately 146', compared to the 103' mast height for the smaller conventional rig. Collectively, the size of the drilling pad, height of the rig mast and required size and height of sound attenuation equipment and sound walls, would impose a more significant visual impact on the surrounding community.

Because of these factors, FM O&G believes at this time that use of a natural gas – electric drilling rig is not feasible or advisable for use in the 2015 drilling program.

xi. A Topographic Vertical Profile Showing Proposed Location of New Wells that Reflects Local Terrain Conditions and that Addresses the Potential Visibility of Existing and Proposed Well and Other Production Facilities from Residential and Recreation Areas

The topographic vertical profile for the 2015 Plan is intended to provide a visual representation of the potential visibility impact of a surface well pumping unit within the Inglewood Oil Field, as observed from the surrounding residential and recreational areas (receptors) at a viewing height of 5 feet. The topographic vertical profiles included in the Plan assumes: no physical barriers (e.g. structures, vegetation); "worst case", and 40 ft. pumping unit height. For the 2015 Drilling Plan we are showing all 53 wells locations as producers, since a producer reflects the highest degree of visual impact (19 injectors and 34 producers presently make up the proposed 53 wells). The profiles are shown on Attachment 4. No other facilities are required in support of the proposed producers and injectors after completion that would prompt a visual impact.

The white to grey shading labeled on each of the profiles as "Surface Model Elevation" represents the altitude above sea level (topography) of the region. The lighter shaded areas are higher in elevation whereas darker shaded areas are lower in elevation. Blue shading indicates areas of potential visibility of the respective pumping unit noted on the profile. A circle with a radius of 1 mile surrounding each well pumping unit facility provides a representation of distance as discussed later in this section. Areas outside the analysis area are white on the profiles as topographical data for these areas were not obtained.

Although injector wells have no surface equipment (i.e. pumping unit), the analyses was done as though they were producers for all 53 prospective well sites. The analyses were done at 40 feet above ground level at the locations of the identified production well sites, representing the maximum possible height of the pumping unit during operation and assuming the largest conventional well pump that could be located at the respective site. The data used for the profile is precise to within 5 feet.

Existing baseline conditions and distance to new facilities are considered in the evaluation of visual impacts to receptor sites. The Inglewood Oil Field represents the baseline visual condition and the proposed new pumping units represent the new facilities potentially impacting visibility. A circle of 1 mile radius has been placed on each of the profiles (Attachment 4) to illustrate any receptor areas up to 1 mile from the respective new pumping unit. As the distance from the facility increases, though the visibility of the facility remains possible, the visual impact will become negligible at the 1 mile distance. [3]

19 of the 53 Plan wells are proposed as injector wells. These planned injector wells project a minimal visual impact (respective equipment and fencing is less than five feet in height) but as a worst case have been analyzed the same as producers in the topographic vertical profile analyses by assuming a 40 ft. maximum height.

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[3] *The term "visual impact" is subjective and contains two primary elements. The first is the visibility of the proposed development. The second is the sensitivity of the viewer. Visual impact is a combination of the two elements and is typically assessed by level of significance, from very high, to low, or insignificant. The Scottish Good Practice Guide for Wind Farms defines visual impact as follows; "Visual effects relate to the changes that arise in the composition of available views as a result of changes to the landscape, to people's responses to the changes, and to the overall effects with respect to visual amenity." There are two representations on the 2015 Plan topographic profiles to assist the reviewer in assessing the visual impacts of the proposed rod pump units. The first is the Zone of Theoretical Visibility (ZTV), which is covered by the entire map and describes the area over which the proposed wells pumps (rod pump units) could be theoretically visible (the distances of the ZTV were based on a review of distances analyzed in conjunction to topography). The second is the area demarked by the 1 mile radius and corresponds to the ratio of height to distance of the reviewed analyses where the visual impact of the proposed rod pump unit was deemed low or insignificant.*

The analyses reviewed were consistent as to the direct relationship between object height and distance at which it was visible; that is, the shorter the structure, the closer the viewer had to be to see the object. All structures of approximately 100 feet in height were consistently not considered visually "impactful" beyond 2 km. (1.25 mi.); not easily visible or recognizable. Based on the aforementioned analyses as to 40' maximum height of the rod pump units for the wells proposed under the 2015 Plan, the corresponding "impactful" distance would cease at beyond .8 km., or ½ mi. The Plan has introduced an extremely conservative 1 mile (1.6 km.) radius around the proposed well locations shown on the vertical topographic profiles to further emphasize that the visual impact beyond the 1 mile distance would not be "impactful", as said visibility would be deemed low or insignificant.

Four observations as to visual impact are also relevant when addressing the 1 mile radius for the proposed rod pump units at the Inglewood Oil Field:

1) To be considered visible, an object needs to be "easily and comfortably visible". At 1 mile or greater, a maximum 40' tall rod pumping unit appears as a fraction of an inch in relative size to the visual surroundings. Wells beyond this distance will not stand out, and in most instances, are not recognizable. Furthermore, due to natural terrain contours, several of the units will either be partially or not visible (not within direct line of sight) or at less than the maximum height as the unit operates at less than full vertical extension.

2) Unless the unit is silhouetted against the sky, unlikely for most of the proposed view shed wells and those beyond a 1 mile distance, there is negligible visual impact on natural lines and contours within the oil field.

3) Due to the diverse tones and textures of vegetation in the oil field as well as field development (existing facilities), the addition of new rod pumps in most will not be noticeable against the complex visual texture baseline of the oil field beyond 1 mile, as further development is not anticipated to yield any significant change in the visual quality of the site.

4) As part of the visual mitigation strategy for the oil field, existing oil field facilities are painted, or due to be painted, utilizing a liquorish (dark) color selected by Los Angeles County. The color selected further minimizes visual impact of the proposed facilities beyond 1 mile by matching tones to blend with the texture of the field.

An example of the negligible visibility beyond 1 mile is made apparent on photo location 7B. The photo representation of proposed well LAI1 279RD1, depicting a rod pump unit to be located approximately one quarter of a mile from the photo viewpoint, would be unidentifiable but for the addition of lines and text identifying the proposed well location.

The following is a list of residential and recreational receptor areas surrounding the oil field included in the topographic vertical profile analysis.

- West Los Angeles College
- Culver City Park
- Baldwin Hills Scenic Overlook
- Kenneth Hahn State Recreation Area
- Fairfax Ballparks
- Holy Cross Cemetery
- Blair Hills
- Baldwin Hills
- Windsor Hills
- Ladera Heights
- Fox Hills
- Culver Crest

In FM O&G's attempt to further provide potential visual impact representation of the proposed new pumping units for the 2015 Plan wells, this plan includes examples of the same by utilizing baseline oil field photographs taken from receptor locations identified during the CEQA analysis that led to the preparation of the CSD (Attachment 5). The baseline photographs reflect all existing production facilities as of June, 2012. The baseline photographs were retaken in 2014 for the 2015 Drilling Plan to reflect current existing production facilities at the field. The selected examples of the potential receptor areas are shown below. The photo ID's following each of the locations listed correspond to the selected photographs contained in the CEQA analysis document.

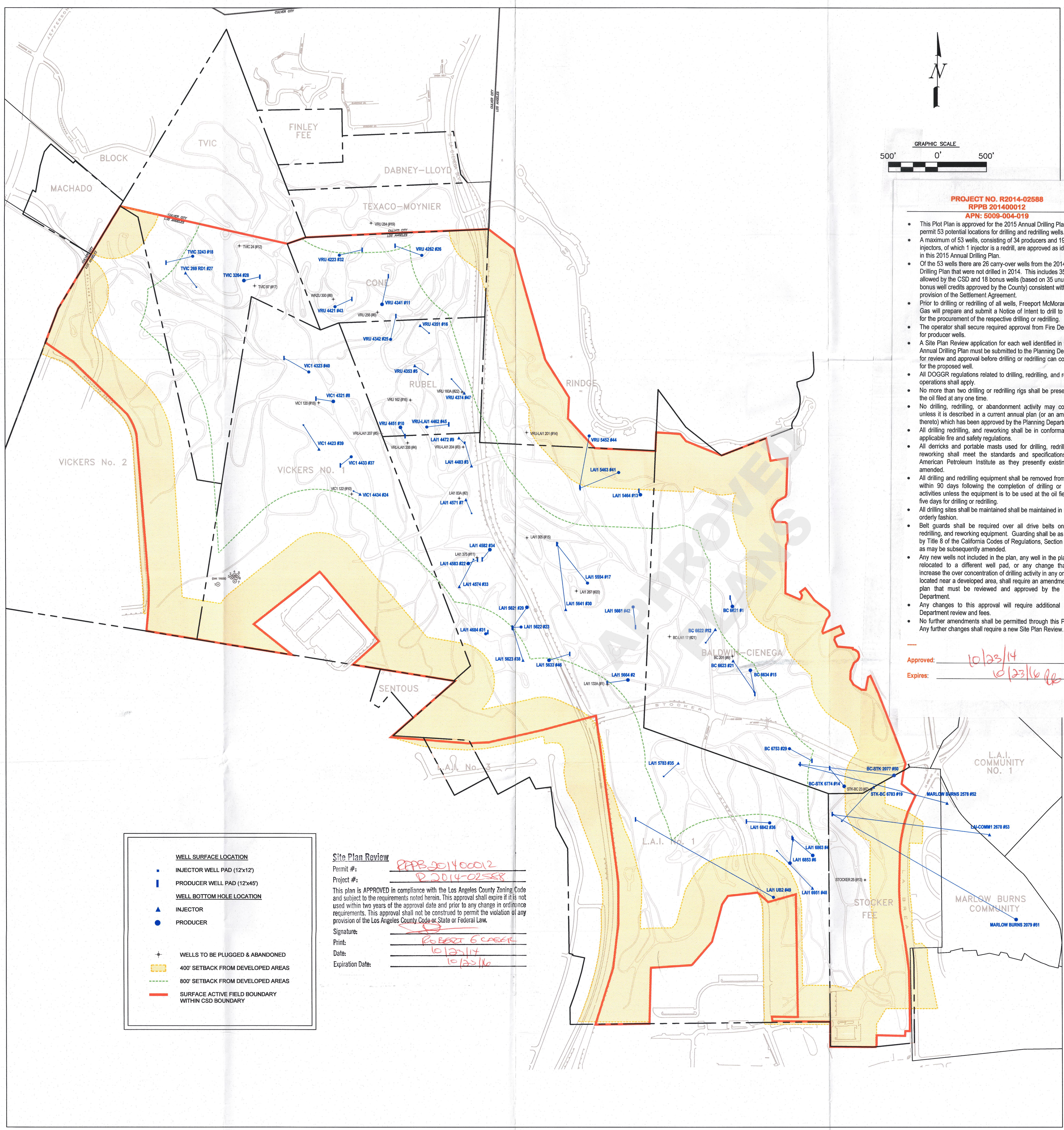
- Kenneth Hahn State Recreation area (2A)
- Culver City Park (3C)
- Ladera Heights (6C)
- Windsor Hills (7B)
- West LA College (8A & 8B)

Visual representations of respective new producing pumping facilities (to scale) were superimposed on the photographs as applicable. As with the topographic vertical profiles discussed above, we assumed surface equipment with a maximum height of 40' for all of the proposed facilities. Attachment 5 therefore illustrates the estimated visual impacts of new well facilities (if applicable) resulting from the 34 producers and the 19 injectors (treated as producers in the photographs) proposed for the 2015 Drilling Plan year[2]. If a receptor location (utilized for Attachment 5) lies within the 1 mile radius shown on any of the topographic visual profiles (Attachment 4) and the well may be visible from that location, the location ID is so noted on the profile.

[2] Artificial lift technology selection is highly dependent on the conditions of the wellbore and the specific application parameters of a given well. The specific lift system to be employed is not selected until after the well has been drilled and logged, and perforation intervals finalized. Engineers then estimate the gross production volume from the well, select, and size the lift system accordingly.

In FM O&G's Inglewood Oil field, the two primary artificial lift systems used in producing wells are (above ground) rod pump units and (subsurface) electrical submersible pumps (ESP's). Rod lift systems (the most common form of artificial lift) use sucker rods to bring fluid to the surface and are used primarily in wells with production rates less than 1,800 barrels per day (bpd) and wells which produce fluids with higher gas content, sand, and crude oil which is lower gravity and higher viscosity. Many of these conditions exist in the wells at Inglewood which makes rod pump systems the primary artificial lift choice at the field. The maximum height *of the rod pump units at full vertical extension is 40 feet.*

ESP systems employing centrifugal pumps are the preferred artificial lift technology for wells with flow rates greater than 1,800 bpd and in wells where deviations in the wellbore may cause unacceptable mechanical wear between the sucker rods and the production tubing. ESP systems are much less efficient than rod pump systems and power demands are much greater as well. ESP's are not recommended in wells that produce fluids with higher gas content, sand, and/or low gravity (higher viscosity) crude oil.



PROJECT NO. R2014-02588
RPPB 201400012
APN: 5009-004-019

- This Plot Plan is approved for the 2015 Annual Drilling Plan to permit 53 potential locations for drilling and redrilling wells.
- A maximum of 53 wells, consisting of 34 producers and 19 injectors, of which 1 injector is a redrill, are approved as identified in this 2015 Annual Drilling Plan.
- Of the 53 wells there are 26 carry-over wells from the 2014 Annual Drilling Plan that were not drilled in 2014. This includes 35 wells allowed by the CSD and 18 bonus wells (based on 35 unused bonus well credits approved by the County) consistent with the provision of the Settlement Agreement.
- Prior to drilling or redrilling of all wells, Freeport McMoran Oil and Gas will prepare and submit a Notice of Intent to drill to DOGGR for the procurement of the respective drilling or redrilling.
- The operator shall secure required approval from Fire Department for producer wells.
- A Site Plan Review application for each well identified in the 2015 Annual Drilling Plan must be submitted to the Planning Department for review and approval before drilling or redrilling can commence for the proposed well.
- All DOGGR regulations related to drilling, redrilling, and reworking operations shall apply.
- No more than two drilling or redrilling rigs shall be present within the oil filed at any one time.
- No drilling, redrilling, or abandonment activity may commence unless it is described in a current annual plan (or an amendment thereto) which has been approved by the Planning Department.
- All drilling redrilling, and reworking shall be in conformance with applicable fire and safety regulations.
- All derricks and portable masts used for drilling, redrilling, and reworking shall meet the standards and specifications of the American Petroleum Institute as they presently existing or as amended.
- All drilling and redrilling equipment shall be removed from the site within 90 days following the completion of drilling or redrilling activities unless the equipment is to be used at the oil field within five days for drilling or redrilling.
- All drilling sites shall be maintained shall be maintained in neat and orderly fashion.
- Belt guards shall be required over all drive belts on drilling, redrilling, and reworking equipment. Guarding shall be as required by Title 8 of the California Codes of Regulations, Section 6622, or as may be subsequently amended.
- Any new wells not included in the plan, any well in the plan that is relocated to a different well pad, or any change that would increase the over concentration of drilling activity in any one area if located near a developed area, shall require an amendment to the plan that must be reviewed and approved by the Planning Department.
- Any changes to this approval will require additional Planning Department review and fees.
- No further amendments shall be permitted through this Plot Plan. Any further changes shall require a new Site Plan Review.

Approved: 10/23/14
Expires: 10/23/16 RG

WELL SURFACE LOCATION
INJECTOR WELL PAD (12'x12')
PRODUCER WELL PAD (12'x45')
WELL BOTTOM HOLE LOCATION
INJECTOR
PRODUCER
WELLS TO BE PLUGGED & ABANDONED
400' SETBACK FROM DEVELOPED AREAS
800' SETBACK FROM DEVELOPED AREAS
SURFACE ACTIVE FIELD BOUNDARY WITHIN CSD BOUNDARY

Site Plan Review

Permit #: RPPB 201400012
Project #: R2014-02588

This plan is APPROVED in compliance with the Los Angeles County Zoning Code and subject to the requirements noted herein. This approval shall expire if it is not used within two years of the approval date and prior to any change in ordinance requirements. This approval shall not be construed to permit the violation of any provision of the Los Angeles County Code or State or Federal Law.

Signature:
Print: ROBERT G CASER
Date: 10/23/14
Expiration Date: 10/23/16

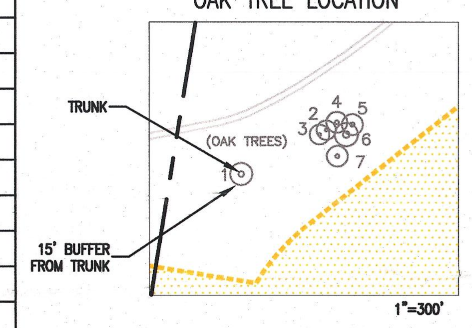
2015 DRILLING & RE-DRILLING PLAN WELLS

COUNT	TYPE	WELL NAME
1	PRODUCER	BC 6621
2	PRODUCER	LAI1 5664
3	INJECTOR	LAI1 4483
4	PRODUCER	LAI1 6863
5	INJECTOR	VRU 4353
6	PRODUCER	LAI1 6853
7	INJECTOR	LAI1 4571
8	PRODUCER	VIC1 4321
9	INJECTOR	LAI1 4472
10	PRODUCER	VRU 4451
11	PRODUCER	VRU 4341
12	INJECTOR	BC 6622
13	PRODUCER	LAI1 5464
14	PRODUCER	BC-STK 6774
15	PRODUCER	BC 6634
16	INJECTOR	VRU 4351
17	PRODUCER	LAI1 5554
18	PRODUCER	TVIC 3243
19	INJECTOR	STK-BC 6783
20	PRODUCER	LAI1 5621
21	INJECTOR	BC 6623
22	PRODUCER	LAI1 4583
23	PRODUCER	LAI1 5622
24	INJECTOR	VIC1 4434
25	PRODUCER	VRU 4342
26	PRODUCER	VRU 4262
27	INJECTOR	TVIC 269RD1
28	PRODUCER	TVIC 3264
29	PRODUCER	BC 6753
30	INJECTOR	LAI1 5641
31	PRODUCER	LAI1 4684
32	PRODUCER	VRU 4223
33	INJECTOR	LAI1 4574
34	PRODUCER	LAI1 4582
35	INJECTOR	LAI1 5783
36	PRODUCER	LAI1 6842
37	PRODUCER	VIC1 4433
38	INJECTOR	LAI1 5623
39	INJECTOR	VIC1 4423
40	PRODUCER	VIC1 4323
41	PRODUCER	LAI1 5463
42	PRODUCER	LAI1 5661
43	PRODUCER	VRU 4421
44	PRODUCER	VRU 5452
45	PRODUCER	VRU-LAI1 4462
46	PRODUCER	LAI1 5633
47	INJECTOR	VRU 4374
48	INJECTOR	LAI1 6951
49	PRODUCER	LAI1-UB2
50	PRODUCER	BC-STK 2077
51	PRODUCER	MARLOW BURNS 2079
52	INJECTOR	MARLOW BURNS 2578
53	INJECTOR	LAI-COMM1 2678

2015 WELL ABANDONMENTS

COUNT	WELL NAME
1	LAI1 133A
2	LAI1 83A
3	VRU-LAI1 204
4	VRU-LAI1 206
5	VRU-LAI1 207
6	VRU 256
7	STK-BC 23
8	WRZU 300
9	BC 201
10	VIC1 122
11	LAI1 375
12	TVIC 24
13	STOCKER 25
14	VRU-LAI1 201
15	LAI1 305
16	VRU 162
17	TVIC 97
18	VIC1 120
19	VRU 284
20	LAI1 267
21	BC-LAI1 17
22	VRU 160A

OAK TREE LOCATION



OAK TREE INVENTORY

OAK TREE #	# OF TRUNKS	CUM. DBH
1	1	10.0000
2	1	5.00
3	1	5.40
4	1	7.60
5	1	7.90
6	2	12.10
7	1	7.50

FREEPORT-MCMORAN OIL & GAS

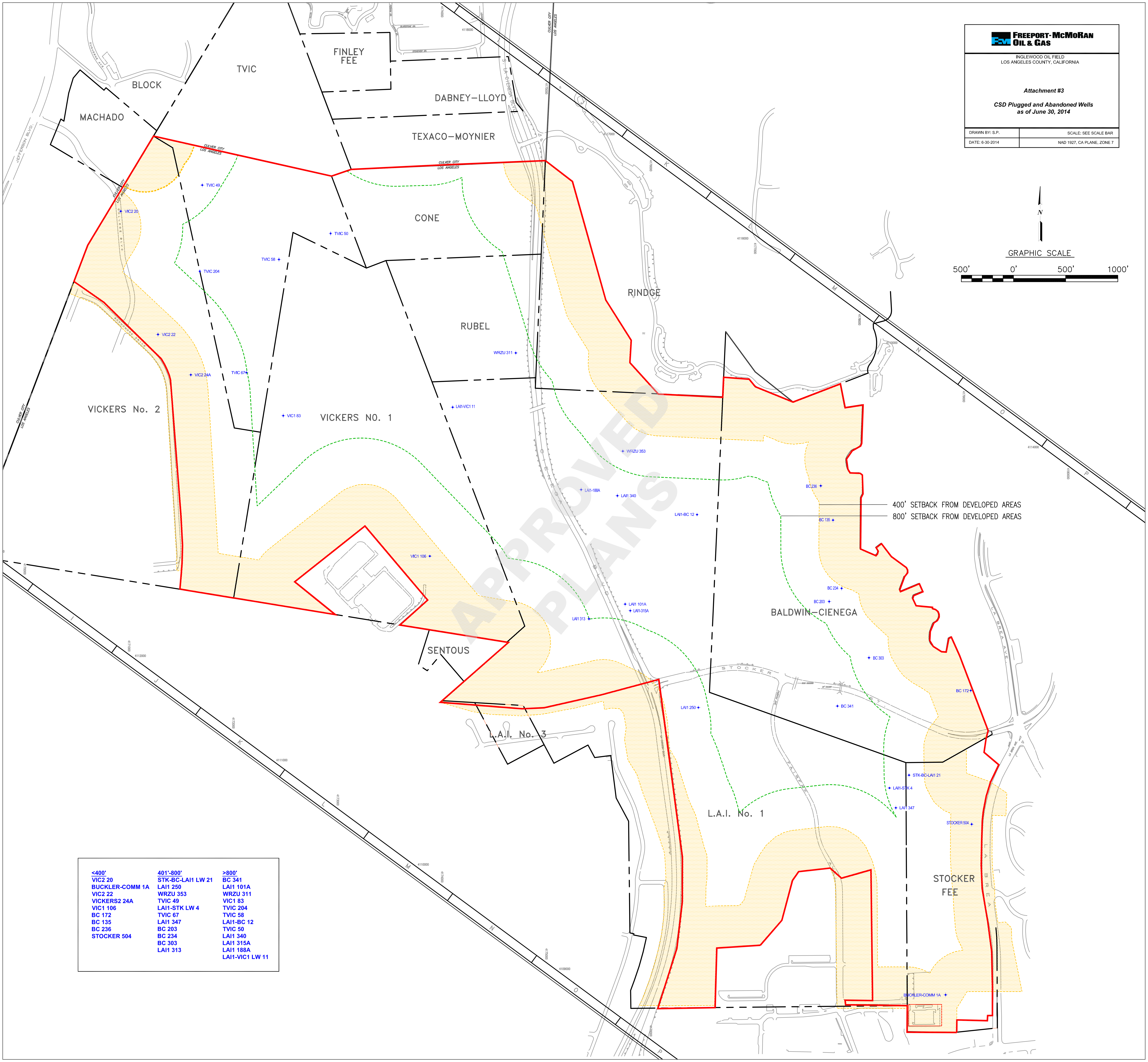
INGLEWOOD OIL FIELD
LOS ANGELES COUNTY, CALIFORNIA

APPLICANT'S COPY

Attachment #1

2015 Drilling, Re-drilling and Well Abandonment Map

DRAWN BY: S.P.	SCALE: SEE SCALE BAR
DATE: 8-21-2014	NAD 1927, CA PLANE, ZONE 7



<400'	401'-800'	>800'
VIC2 20	STK-BC-LAI1 LW 21	BC 341
BUCKLER-COMM 1A	LAI1 250	LAI1 101A
VIC2 22	WRZU 353	WRZU 311
VICKERS2 24A	TVIC 49	VIC1 83
VIC1 106	LAI1-STK LW 4	TVIC 204
BC 172	TVIC 67	TVIC 58
BC 135	LAI1 347	LAI1-BC 12
BC 236	BC 203	TVIC 50
STOCKER 504	BC 234	LAI1 340
	BC 303	LAI1 315A
	LAI1 313	LAI1 188A
		LAI1-VIC1 LW 11