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Ms. Mary Nichols
Chairperson
California Air Resources Board
1001 "I" Street
P.O. Box 2815
Sacramento, CA 95812

Comments of Occidental Petroleum on the Air Resources Board Rulemaking to Consider the Adoption of a Proposed California and Trade Program for Greenhouse Gas Emissions

Dear Ms. Nichols,

Occidental Petroleum Corporation ("Occidental") respectfully submits the following comments on the California Air Resources Board ("ARB") proposed regulation to implement a California greenhouse gas emissions cap-and-trade program, which will be considered by the Board on December 16, 2010.

Occidental is a Los Angeles-based oil and gas exploration and production company with operations in the United States, the Middle East, North Africa and Latin America. Occidental is the No. 1 natural gas producer and second-largest oil producer in California, where net daily production averaged 135,000 barrels of oil equivalent in 2009. Occidental's significant equity interests in California include:

- Occidental of Elk Hills, Inc. (OEHI) – the majority owner and operator of the Elk Hills field, which produces oil and associated natural gas from the former U.S. Naval Petroleum Reserve located in Kern County;
- THUMS Long Beach Company and Tidelands Oil Production Company – serving as the contract operator for the City of Long Beach of oil and gas fields owned primarily by the State of California;
- Vintage Production Company, LLC – operating properties that produce oil and gas from more than 50 fields primarily located in the Ventura, San Joaquin and Sacramento basins; and
- Elk Hills Power, LLC – currently a co-owner with Sempra Generation of a 550-MW gas-fired power generation plant, located in western Kern County, Occidental on December 10th announced it is purchasing Sempra Generation's 50 percent interest.

<u>Oil and Gas Production Sector – Allocation</u>

ARB staff recognized the imperative of maintaining the competitiveness of California businesses in Energy-Intensive Trade-Exposed ("EITE") sectors and Occidental acknowledges the efforts staff

has made to consider the potential impacts on upstream oil and gas production. Occidental concurs that the upstream oil and gas sector is an EITE sector and should receive an Assistance Factor of 1.0 for all compliance periods. Without such EITE classification, inclusion of the upstream sector in a cap-and-trade program will create a disadvantage for California oil and gas production facilities relative to out-of-state (or out-of-country) competitors that do not face similar requirements. The development of California's significant in-state hydrocarbon resources is vital for California's economy. Increased development of California hydrocarbons will also reduce U.S. dependence on foreign oil imports. To facilitate this ongoing development, it is essential to maintain an Assistance Factor of at least 1.0 for the upstream oil and gas sector.

Oil and Gas Production Sector – Benchmarking

Occidental, as a member of the Western States Petroleum Association ("WSPA"), continues to work with ARB staff on an appropriate and equitable upstream sector product-based benchmarking methodology for incorporation into the cap-and-trade regulations. We recognize the three-part methodology for the upstream sector that was developed with input from WSPA is a credible first step, acknowledging important differences between thermal enhanced recovery, non-thermal production and dry gas production operations. However, Occidental believes the three-part approach does not incorporate other important factors inherent in non-thermal production operations.

Each oil and gas reservoir is unique, the product of natural forces acting over geologic timescales. Commercial development of hydrocarbon resources is a complex endeavor determined by reservoir characteristics, technology and economics. Accordingly, a final benchmarking approach must embody this complexity, which the single benchmark for non-thermal operations does not capture. There are many important factors that would allow appropriate definition of the non-thermal category and benchmark(s):

- Maturity of production operations: Generally, the longer a reservoir has been in production, the more energy it takes to recover the next barrel of oil or cubic foot of gas. Consideration should be made for adjusting benchmarks over time to accommodate the natural decline curve of oil and gas reservoirs, which increases emission intensities.

- The use of non-thermal enhanced recovery methods: Gas injection, waterflooding, or other enhanced recovery operations, such as nitrogen, polymer or carbon dioxide injection, extend and enhance the productivity of the reservoir. All of these techniques require additional energy over primary recovery operations.

- Special operating conditions: The THUMS and Tidelands operations for the City of Long Beach and the State of California are mature waterfloods with water cuts of 98-percent or higher. These operations are subject to unique state and local subsidence regulations that require 105-percent replacement of gross production with injected fluids. These additional requirements burden the operations with significant and unique energy demands.

- The extent of gas production and processing: The energy demand and consequent emissions profile of recovering and processing associated gas can be significant. Not all upstream operations produce and/or recover associated gas. According to the Division of Oil, Gas, & Geothermal Resources Preliminary 2009 Annual Report, OEHI's associated gas production at Elk Hills is more than eight times the amount produced by the next largest California producer of associated gas. Also, the energy demand and emissions profile of processing Natural Gas Liquids ("NGLs") can be much higher than simple gas processing operations. Some facilities, like OEHI, produce significant quantities of NGLs, which has an important bearing on GHG emissions intensity per barrel of oil equivalent.

- The type of downhole fluid lifting technology used: The technology used to lift fluids, which is determined, in part, by the characteristics of the reservoir, the produced fluids, well type and design, surface spacing constraints, etc., has an impact on GHG emissions intensity. For example, there is a significant difference in the emission profile of a rod pump driven by an in-field internal combustion engine generator versus an electric submersible pump running off of electricity supplied by a public utility.

- The degree to which other operations at a facility are integrated with oil production operations: In addition to oil production and processing activities, OEHI operates gas plants with the largest aggregate capacity west of the Rockies, two combined heat and power ("CHP") cogeneration facilities, and sizable NGL production, storage, and transportation facilities. Each of these activities generates GHG emissions. Considering the spectrum of operations and end products, multiple benchmarks for GHG emissions intensity may be more appropriate than just one that is based on barrels of oil produced.

- The source of electricity for the facility's operations: Facilities that self-generate electricity or make use of on-site CHP cogeneration have made significant investments in generation technology (and emissions control equipment) that have helped remove load from the grid, avoid electrical transmission losses and avoid gas transmission compression costs. The GHG emissions from these long-term investments must not create a benchmark penalty for co-located upstream oil and gas operations.

- The GHG emissions profile for a facility's electricity: Allowance allocations for EITE facilities should consider the relative GHG emissions associated with actual electricity sources and reasonable alternatives. Operations at Elk Hills and THUMS are electric intensive and make use of on-site generated electricity. If these on-site generation units were shuttered, the replacement utility-sourced electricity would likely be generated by a gas fired combustion turbine having a much higher GHG emissions intensity than the utility's system-wide average GHG basis. Consequently, allowances allocated to facility self-generation or CHP units should reflect the emissions that would otherwise be created by a utility's incremental (or marginal) generating unit.

The factors noted above are among those that dictate the capital investments and affect the GHG emissions intensity of an upstream production operation, especially those in the non-thermal sub-sector. A benchmarking approach that does not consider these factors would significantly disadvantage certain upstream producers. It is imperative that the final methodology incorporate all relevant factors to allow for fair and equitable treatment of upstream operators.

Oil and Gas Production Sector – Cap Adjustment Factor

Notwithstanding the issues related to development of appropriate benchmarks for allocating allowances, the matter of reducing GHG emissions is a complex technical and economic challenge. Potential GHG reduction measures for the upstream sector could include: repowering, retrofitting, replacing or repairing existing equipment; installing new CHP facilities; electrifying equipment; using monitoring equipment to detect leaks; and possibly employing carbon dioxide injection to enhance oil recovery. As discussed below, many of these approaches have already been implemented, and none are simple or inexpensive.

Considering the maturity of California fields, most opportunities for equipment replacement or other efforts to improve operational and energy efficiency have been implemented. For example, Occidental has already aggressively pursued electrification of equipment, including the widespread use of electric pumps for its production wells. Moreover, GHG emissions from our oil and gas production equipment are already very low because of our efforts to lower other emissions, such as NOx. In addition, as an active participant in U.S. EPA's Natural Gas Star program, Occidental understands the environmental and economic benefits of voluntarily reducing methane emissions from its oil and gas operations. Occidental's California operations have reduced fugitive emissions by modifying facilities and installing capture technology, submitted verified energy efficiency and GHG emission reports as members of the California Climate Action Registry, and since 1990, prevented release of an estimated 13 billion cubic feet of methane (equivalent to about 6 million metric tons of CO2 equivalent emissions) when compared to past operation of the same fields. The proposed GHG cap and trade program does not appropriately recognize the results attained by early movers, like Occidental, that proactively reduced GHG emissions before implementation of AB32.

It is difficult to imagine additional timely and cost-effective equipment replacements or other operational and energy efficiency measures that could achieve a significant reduction in GHG emissions from the upstream sector in general, or Occidental's operations in particular. Accordingly, Occidental strongly urges the inclusion of a mechanism to reduce the initial rate of decline in the Cap Adjustment Factor for the upstream sector to avoid undue burdens on the competitiveness of affected California operations.

Oil and Gas Production Sector – Electricity and Steam

Occidental operates two CHP facilities with nameplate capacity of over 100 MW at oil and gas production operations in California. In addition, Occidental relies on other CHP facilities to provide steam for its heavy oil production operations in Kern County. CHP plays an important role

in the State's energy infrastructure and has the potential to be an even more significant contributor in achieving the State's GHG emission reduction goals. However, there are many challenging market barriers (e.g., departing load charges, lack of contracts, and resistance from utilities) faced by CHP operators and developers that limit the State from realizing the emission reduction potential of CHP. Occidental believes there are several important questions regarding CHP under the proposed cap-and-trade regulation. In this regard, Occidental references its earlier comments (submitted on November 15) and supports the comments of the Energy Producers and Users Coalition in its November 19, 2010 letter.

Respectfully,

Carl Wirdak

Carl Wirdak
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