Appendix for Chapter 3

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APPENDIX 3.1 ALTERNATIVE 2: ONSHORE DISPOSAL OF MUD AND CUTTINGS

Alternative 2 requires that all mud and cuttings be barged to shore for onshore disposal at an approved disposal site. This operation would entail storing the mud and cuttings in bins, transporting the bins to shore via workboat, and trucking the bins to an approved disposal site.

Since the type and size of the semi-submersible is unknown, the onboard storage capacity for mud and cuttings can not be estimated. For the Sedco 712, the onboard storage capacity for liquid mud is 900 bbls. There will likely be space to store cuttings on the semi-submersible until the transport boat arrives at the rig to take the cuttings to shore for disposal. Based on past experience in the Pacific OCS Region, a workboat will transport the mud and cuttings to shore. It is assumed that the 180-foot class workboat described in the Project Description would be used. The cuttings and mud would be transferred to a workboat in U. S. Coast Guard approved storage bins, via crane. These bins must be covered in order to fulfill regulatory requirements for travel over water (DOT) and to prevent emissions from ventilating into the atmosphere.

The rate and number of workboat trips to port depends on the volume and rate cuttings are produced when drilling each well. Typically, the rate cuttings are circulated to the rig floor is greater when drilling the upper portion of the well because of the faster drilling rate and the larger diameter hole. The number of bins that can be placed on the workboat is dependent on weather, safety, available space, and other factors. Costly rig downtime and raised serious health and safety concerns are associated with offloading bins during poor weather conditions. In consultation with Port Hueneme, it is estimated that under good weather conditions between 9 to 15 bins could be transported by a 180-foot workboat. An average of 12 bins per trip was assumed for this analysis.

There are few facilities in California that can take offshore-generated oil field wastes. The closest facility capable of accepting oil field waste is located near Bakersfield, approximately 150 miles from Port Hueneme. In order ensure compliance with DOT regulations, a maximum load weight (not including the truck weight) of 20,000 lbs. should be utilized. In consulting with trucking companies, depending on the weight of the material, up to 8 or 9 cubic yards (38 to 42 bbls) could be transported per truckload.

Table 3.1-1 summarizes the estimated volumes of mud and cuttings for each well, the approximate number of bins, estimated number of trips to shore, estimated miles from the unit to port, and estimated number of tank trucks to transport the cuttings to an approved disposal site. The table is based on the following assumptions:

- The operational storage capacity for the U. S. Coast Guard approved storage bins is 35 bbls
- The estimated number of trips to port is calculated based on transporting 12 bins per trip
- The estimated round trip mileage from the Unit to port is calculated based on taking drilling mud and cuttings to Port Hueneme
- The estimated number of truck trips is calculated based on a tank truck volume of 35 bbls.

APPENDIX 3.2 ALTERNATIVE EMPLOYING DIFFERENT DRILLING LOCATIONS

Overview

A "reasonable alternative" to the proposed action, under NEPA guidelines, requires that the alternative be both technologically and economically feasible. The proposed action under consideration is the drilling of wells from a mobile drilling unit (MODU). Two alternatives are proposed to the use of a MODU. These are (1) drilling extended-reach wells from an onshore location to the proposed target locations, and; (2) drilling extended-reach wells from existing platforms to the proposed target locations. These alternatives would completely mitigate the potential for "hard bottom" damage caused by the use of a MODU.

Table 3.1-1. Estimated volumes of mud and cuttings for each well, the approximate number of bins, estimated number of trips to shore, estimated round trip miles from the unit to port, estimated number of tank trucks trips.

Well	Mud Volume (bbls)	Cuttings Volume (bbls)	No. bins [1]	No. of Trips to Shore [2]	Miles to Port Hueneme [3]	No. of tank trucks [4]
Bonito (well 1)	3000	1,805	140	12	204 miles	140
Bonito (well 2)	3000	1,805	140	12	204 miles	140
Purisima Point	12,250	2,112	410	35	240 miles	410
Point Sal	12,250	2,112	410	35	240 miles	410
Gato Canyon	3000	4,270	210	20	100 miles	210

[1] The operational storage capacity for the bins is 35 bbls (<20,000 lbs)
[2] The estimated number of trips to port was calculated based on transporting 12 bins per trip
[3] The estimated mileage from the Unit to port is calculated based on round trip to Port Hueneme
[4] The estimated number of truck trips was calculated based on a standard tank truck volume of 35 bbls

In the Pacific OCS Region, the longest extended-reach well is *OCS-P 0193 SA-2*. This well was drilled by ExxonMobil to a total measured depth of approximately 24,660 feet, with a lateral offset ("stepout") of approximately 21,276 feet, at a true vertical depth of approximately 6,543 feet. This well was drilled in 103 days, from an existing offshore platform, and the estimated drilling costs exceeded $10 million.

The extended-reach well with greatest lateral offset was drilled in 1999 at the Wytch Farm oil field in the United Kingdom. BP Amoco drilled this well, known as *1M-16 SPZ*, to a total measured depth of 37,001 feet, with a stepout of 35,196 feet, at a true vertical depth of 5,371 feet. *1M-16 SPZ* was drilled in 123 days (Schlumberger, 1999a). The drilling cost for this well is not known, but was most probably much more than the cost of *OCS-P 0193 SA-2*.

The extended-reach wells in the Wytch Farm oil field are drilled from an onshore well site to an offshore location. The estimated field size of over 300 million barrels, and high productivity of individual wells, justifies the high cost of this type of well.

In the Tierra del Fuego region of Argentina, similar extended-reach wells have been drilled. Total Austral drilled oil well *Cullen Norte #1* in 128 days to a total measured depth of 36,693 feet, with a stepout of 34,728 feet, at a true vertical depth of 5,436 feet. This well was drilled from an onshore site to an offshore location. Wells in this field are documented to have produced up to 17,000 barrels per day (Schlumberger, 1999b).

Offshore Santa Maria Basin

Two existing platforms are considered as possible locations for drilling extended-reach wells. These platforms are Irene on lease OCS-P 0441 and Hidalgo on lease OCS-P 0450 (Figure 3.2-1.).

The proposed well locations in the Bonito Unit are unreachable from any onshore well site.

The four proposed Bonito Unit well sites are beyond the 21,000-foot lateral offset radius from either platform. Three of the four proposed well sites fall within the 35,000-foot radius from Platform Irene. The well site on lease OCS-P 0446 is within the 35,000-foot radius from Platform Hidalgo.

The four proposed Purisima Point Unit well sites are unreachable from any existing platform. They are also beyond a 21,000-foot radius drawn from the closest landfall, at Purisima Point. The two southernmost locations, in lease OCS-P 0432, are within the 35,000-foot radius.

The three proposed Point Sal well sites are also beyond the reach of any existing platform. Only the proposed site on lease OCS-P 416 is within the 35,000-foot radius drawn from the nearest landfall, at Point Sal.

In the offshore Santa Maria Basin, oil and gas have been produced from three fields (Point Arguello oil field, Point Pedernales oil field, and Tranquillion Ridge oil field). The best well in the Point Arguello field produced at sustained rates (over a three-month

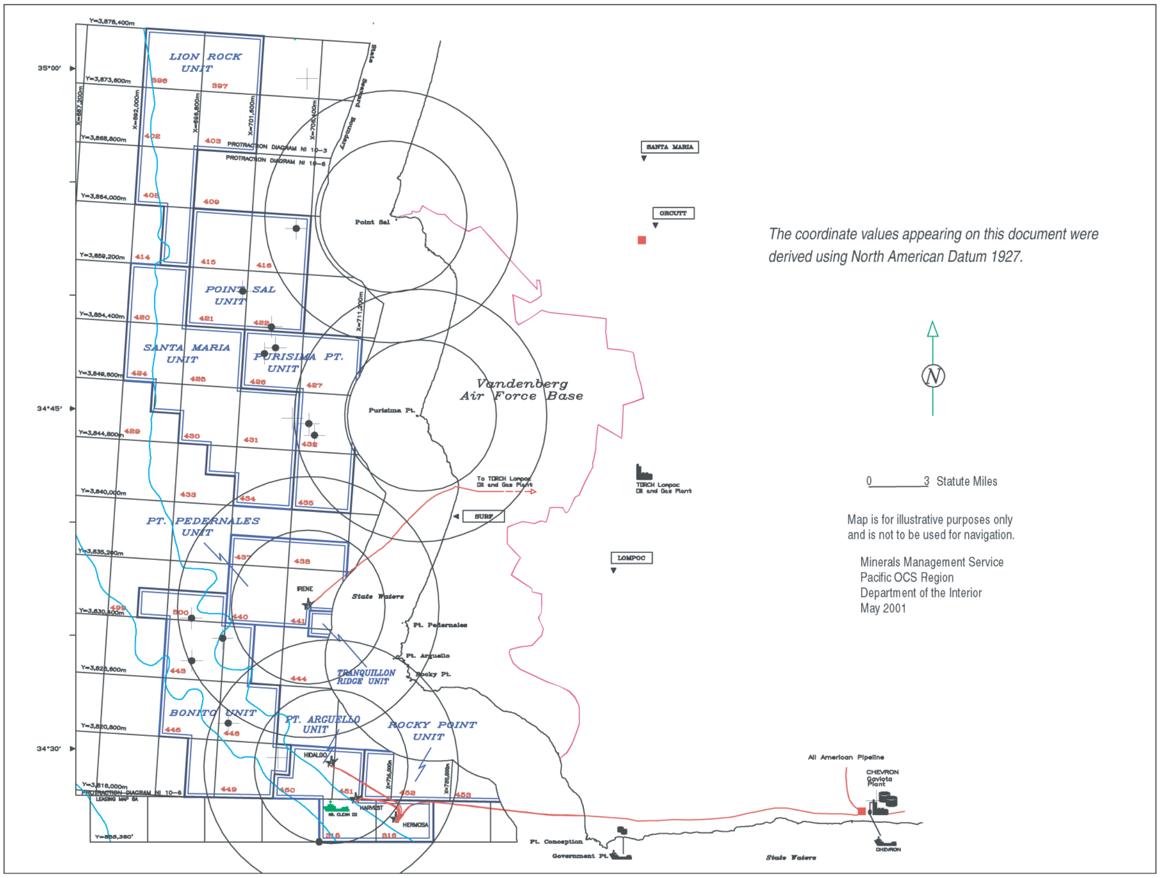

Figure 3.2-1. Santa Maria Basin proposed exploratory well (showing 21,000 and 35,000 offset radii from hypothetical alternative drill sites)

period) of over 10,000 barrel per day. The best well at Point Pedernales oil field produced at sustained rates of over 8,000 barrels per day

Santa Barbara Channel

The proposed well site on the Gato Canyon unit is beyond the 21,000 lateral offset radius from both Platform Hondo (on Lease OCS-P 0181) and Platform Holly (on State Parcel 3242). The well objectives are also beyond the 35,000-foot radius from Platform Hondo, but fall within that radius from Platform Holly (Figure 3.2-2.).

Platform Holly is currently 100% utilized in the development of the South Ellwood Offshore Oil field. The platform is adjacent to two undeveloped oilfields in State tidelands. It is not anticipated that this platform will be available for the potential development of the Gato Unit.

The closest landfall to the target area of the proposed Gato Canyon well is in the Naples area. Under current Santa Barbara County ordinance and regulation, a well site at this hypothetical location would be impermissible without an affirmative vote of the populace. A well drilled from an onshore site in the Naples area would be able to reach the target within the 21,000-foot lateral offset radius.

The nearest oil fields to the Gato Canyon Unit are the Hondo oil field (in the Federal OCS) and the South Ellwood oil field (in the State tidelands). At the Hondo oil field the best well produced at sustained rates of over 7,000 barrels per day. Drill stem test of oil well *OCS-P 0460-2*, the discovery well for the Gato Canyon oil field, indicated that this well could be capable of production rates in excess of 4,000 barrels per day.

Extended-reach wells

The alternative use of extended-reach wells would modify the potential impacts of the proposal. These modifications include emissions, materials, and costs as scaled to the increased drilling time. Any extended-reach well drilled from an existing platform would also risk affecting on-going operations.

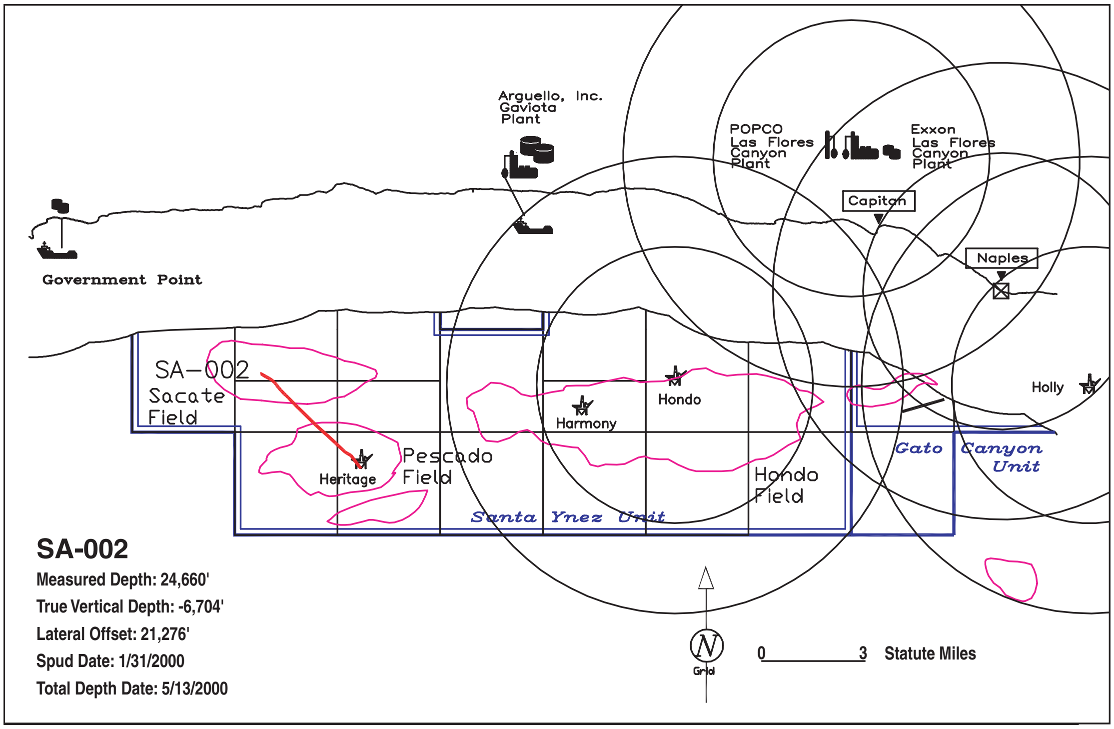

Figure 3.2-2. Santa Barbara Channel proposed exploratory well (showing 21,000 and 35,000 offset radii from hypotheticalalternative drill sites).

Extended-reach wells are costly. Data on drilling costs are proprietary; however, total costs averaging in excess of $100,000 per day, and $10,000,000 per well, are not uncommon. Large oil fields (such as the Wytch Farm in the United Kingdom), with proven, highly productive reservoirs, justify large expenditures in drilling costs because these costs will ultimately be recovered in production profits. Conversely, very expensive extended-reach wells are not often utilized in the exploration or delineation phase of a drilling program because of the geologic and economic risks involved. Furthermore, the extended-reach production wells cited above have been drilled by major, multinational oil corporations (such as BP Amoco, Total, and ExxonMobil) that are better able to absorb the cost of a drilling failure.

Any well drilled from an alternative location inside of the 21,000-foot radius would be technologically feasible and may be economically feasible. Any exploration well drilled beyond the 21,000-foot radius may be technologically feasible, but would probably be economically infeasible. Any well drilled beyond the 35,000-foot radius would likely be technologically and economically infeasible. We conclude that, under NEPA guidelines, the drilling of the proposed wells from alternative locations utilizing extended reach technology is not reasonable.

References

Schlumberger Press Release, 1999a, "Schlumberger Breaks Own Extended-reach World Records at BP Amoco Wytch Farm Field," July 27, 1999, 2 pages

Schlumberger Press Release, 1999b, "Schlumberger Breaks Extended-reach World Records at Tierra del Fuego Ara Field," April 16, 1999, 2 pages

APPENDIX 3.3 ALTERNATIVE TO USE A JACKUP MOBILE OFFSHORE DRILLING UNIT

In the scoping process, comments were submitted to the Region suggesting that the EIS include as a Project Alternative the use of a different Mobile Offshore Drilling Unit (MODU) that might minimize adverse impacts to the marine environment. One such MODU is a jackup rig.

The use of a jackup rig as opposed to the proposed use of a semi-submersible rig could minimize anchor impacts associated with the semi-submersible rig. However, the water depth limitation of jackup rigs makes this proposed alternative infeasible.

The water depth drilling capability of any existing jackup rig is approximately 450 feet when drilling in areas such as the Gulf of Mexico, or approximately 400 feet when drilling in harsh environment areas such as the North Sea or Canada. Although deeper water jackup rigs capable of drilling in up to 625 feet of water (492-foot depths in harsh environment areas) are under construction, it is unlikely that they will be ready and available for the timeframe that the drilling activities are planned. With three of the five proposed wells located in water depths greater than 450 feet, it is not technologically possible for a jackup rig to drill all five wells. Therefore, the mobilization of a second MODU, most likely a semi-submersible rig, would be required to drill the three deeper water well sites.

Requiring the use of a second MODU brings up several issues. First, obtaining an ultra-deepwater jackup rig may be difficult given the current and projected demand for these rigs worldwide. Second, requiring the mobilizing of an additional MODU to the Pacific OCS Region will increase the cumulative impacts of the four drilling projects and increase the costs of the proposed drilling activity for all the operators.

At the present time, worldwide jackup utilization has reached 90%. As the demand for gas continues to grow with rising electricity demand, analysts are predicting that the demand for jackup rigs, especially the ultra-deepwater rigs, will continue to grow (Maksoud 2001). Given this demand, acquiring one in the timeframe the drilling activities are planned will be unlikely.

If a jackup rig could be obtained, requiring a second MODU to mobilize to the POCSR will nullify efforts by the operators to reduce the cumulative impacts of the four drilling projects. To minimize cumulative air emissions and facilitate phasing the four drilling projects, the operators have been working towards contracting a single MODU for the planned drilling activities. The operators have agreed to share the costs and responsibility associated with the MODU mobilization and demobilization operations while retaining independent authority over each of their drilling programs. A second MODU will translate into a substantial increase for each operator due to the additional individual mobilization/demobilization costs associated with mobilizing a second rig.

In conclusion, a jackup rig would eliminate anchor impacts for two of the proposed five delineation wells. The water depth drilling capability limits jackup rigs from drilling all the proposed wells, requiring a semi-submersible rig to be mobilized to drill the remaining deeper water wells. Mobilizing a second MODU to the POCSR will increase the cumulative air emissions and operator costs. Given that proper analyses of well sites and anchor placement sites would effectively mitigate the anchor impacts, the overall environmental impacts would increase with the mobilization of a second rig to the POCSR, making this proposed alternative unreasonable.

References

Maksoud, Judy. 2001. "Harsh-Environment, Ultra-Premium Jackups Taking Advantage of U. S. Market Shifts." Offshore (February): 56.

APPENDIX 3.4 ALTERNATIVE TO REQUIRE DOWNHOLE DISPOSAL OF MUD AND CUTTINGS

In the scoping process, comments were submitted to the Region suggesting that the EIS include as a Project Alternative other methods for disposing of drilling mud and cuttings that might minimize adverse impacts to the marine environment. One such alternate disposal method is to slurry the mud and cuttings and inject them downhole.

Downhole disposal of mud and cuttings for these proposed delineation wells brings up several issues that make this alternative infeasible. Such issues include the relative absence of geologic information until after the well is drilled, a higher degree of uncertainty inherent to drilling exploration/delineation type wells, and the limitation in well design at the exploration stage.

When drilling a single well from a semi-submersible, the absence of geologic information make it impossible to confirm a well's ability to accept disposal material until the drilling is finished and the appropriate analyses and tests are completed and evaluated. This translates into additional time the semi-submersible would be on location and possibly additional environmental impacts, with no guarantee that downhole disposal could be performed. Therefore, the operator would need to have a contingency plan for the disposal of mud and cuttings in the event that it is determined that the well cannot receive the disposal material.

The criteria used to evaluate if a well is a good candidate for injection are that a formation is encountered with the necessary porosity and permeability to accept the material and that the integrity of the well bore and cap rock is sufficient to ensure that the near-surface formations would not be fractured. Fracturing could create conduits for transmitting hydrocarbons or other fluids. Time consuming injectivity tests would have to be performed to confirm the well's suitability for accepting material while the semi-submersible sits idle. Analyses to evaluate if these criterions exist could not be conducted until the well has been drilled.

In addition, there are limitations in the well design at the exploration/delineation stage that may make it unable to accommodate injection. The delineation wells proposed for this EIS are primarily designed to gather information about the size and extent of the hydrocarbon reservoir. It may not be possible to design these wells to accommodate other uses such as injection and still obtain the information the well is being drilled to collect in the first place. The differences in the design criteria for an injection well may include the use of thicker-walled casings to mitigate the effects of abrasion, larger volumes of premium cement to promote integrity at the casing shoes, and the use of special muds and flushing agents to reduce impediments to injection.

On development platforms in the Pacific OCS Region, downhole disposal of mud and cuttings that do not meet the requirements of the EPA NPDES permit has been done on a very limited number of development wells. Confirmed geologic information and confirmation by injectivity tests of the formation's suitability to receive injection material make this a practical option for development wells in some cases. However, for these proposed delineation wells, the lack of geologic information and the design limitations for these wells make this alternative infeasible for this drilling project.