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Shell OCS Beta Unit Development

December 1, 1978

Volume II

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SECTION 4.0
ENVIRONMENTAL IMPACT

4.1 GEOTECHNICAL CONSIDERATIONS

4.1.1 Platform Activities Related Impacts

Certain geologic conditions and processes must be recognized and considered in project design and construction in order to minimize any possibility of damage to the facilities, hazard to personnel, or a large oil spill. For example, uncontrolled reservoir fluid withdrawal could conceivably result in compaction of reservoir and caprock materials, possibly accompanied by ground subsidence and even fault rupture and induced seismicity. Increased reservoir pore pressures due to fluid injection have, in certain cases, induced fault movement and seismicity.

During well drilling, failure of the drilling mud system to keep deep formation gas and fluid from invading the borehole could result in a blowout and uncontrolled flow. However, stringent offshore drilling regulations and properly designed and maintained equipment make this occurrence unlikely. The careful planning of boreholes and accurate assessment of reservoir gas/oil ratios (GOR), pressures, and fracture gradients can significantly reduce any possibility of well blowout.

Relatively high seismicity can be expected in the Beta Unit area. The structures associated with oilfield development and production must be capable of withstanding these ground motions without significant damage, as such occurrences might result in an adverse environmental impact.

The following sections discuss the geotechnical factors which could conceivably cause or contribute to damage of the platforms, adversely affect personnel safety, or cause significant oil spills at the platforms. The environmental impacts are addressed. Mitigation measures are covered in Section 4.1.4.

4.1.1.1 Blowout and Caprock Rupture (Over-Pressurization)

A major oil spill emanating from a platform drilling operation could result from a well blowout which could not be quickly controlled. A blowout is usually the result of failure of the wellhead blowout prevention equipment or the drilling mud system which keeps formation gas and fluid from invading the well borehole. The inability to quickly control a blowout can usually be attributed to:

- Failure of the blowout prevention system (a series of powerful valves in series, which must all fail),

- Failure of the well casing to contain unanticipated high pressures, or

- Caprock rupture.

Because of low reservoir pressure, high oil viscosity, and low GOR, the likelihood of a significant oil spill resulting from a Beta Unit drilling well blowout is considered to be low. As discussed below, subsurface safety valves, as required by the Pacific Area OCS Orders promulgated by the U.S. Geological Survey on June 1, 1971, greatly reduce the potential for uncontrolled flow and a resultant oil spill during the producing life of a well. These subsurface safety valves placed in producing wells capable of flowing would prohibit upward movement of oil and gas in the event of damage to the wells or the platforms.

The geologic and other factors that have a direct bearing on such possible occurrences are:

- Depth to oil and gas reservoirs,

- Characteristics of the reservoir rock (fluid presure, porosities, and permeabilities),

- Nature and thickness of the caprock overlying the highest reservoir,

- Characteristics of nearby faults or other fractures,

- Well casing program.

The depth to the top of the highest known reservoir is about 2,700 feet (820 m) subsea (Shell, 1977) at the shallow- and deep-water platform sites. These producing zones are about at an average depth compared to other fields in the region.

The reservoir consists of a 2,000-foot (608 m) thickness of sandstone, shale, and siltstone, which is divided into seven zones by the thicker shale units. The sands are uncemented with relatively high porosities of 20 to 30 percent and intermediate permeabilities of 4 to 360 millidarcies. Tests indicate the reservoir fluid pressure are at typical hydrostatic levels (Shell, 1977).

The caprock consists predominantly of Pliocene and Pleistocene siltstone and shale with some thin, hard beds. In view of the age of these materials and the competence of the late Pleistocene units encountered during the foundation boring program, they are believed to be competent. The late Pleistocene units encountered at 450 to 500 feet (123 m to 152 m) below the mudline in test borings were uncemented, very stiff silt-clay mixtures (Section 3.1.1.5(1)).

The characteristics and location of the Palos Verdes fault zone and other nearby faults must be considered with respect to oil and gas seeps. The near-surface fault traces delineated by higher-resolution geophysical surveys are believed to be structurally continuous with the deeper fault systems which offset the reservoir sands (Mesa[2], 1977). Seafloor hydrocarbon seep areas, shown on Figure 3.1-9, closely align with fault traces F_1, F_2, and F_3 and occur adjacent to Fault F_4 and along the southeast projection of Fault F_5. This spatial association of hydrocarbon seep areas with fault traces is strongly suggestive of natural hydrocarbon migration along fault conduits, although not conclusive (State Lands Commission, 1975).

While the upward migration of hydrocarbons along faults is indicated, their source is unclear. The source of the hydrocarbon seeps may be the oil-bearing zones in the upper Miocene rocks, migration from much shallower depths, or some combination. Exploratory borings, soil test holes, and shallow seismic data showed no indication of shallow gas at the platform sites (Shell, 1977). No abnormally high pressure zones were reported during the coring and drilling of exploratory wells. Proper control of the pressure-maintenance program planned for the Beta Unit (Shell, 1977) should minimize any possibility of induced hydrocarbon seeps.

Test data indicated that the reservoir fluid pressure of the upper Miocene beds are at hydrostatic levels (Shell, 1977). Any significant increase of pressure in the reservoir beds by high-pressure water injection could potentially cause upward migration of oil and/or gas into the shallow upper fault planes. Over-pressurization of the reservoir beds by injection of fluids should be prevented by careful monitoring of water flood injection pressures.

In 1969, a major well blowout occurred on Platform A in the Dos Quadras offshore field near Santa Barbara, about 100 miles (160 km) northwest of the Beta Unit site. However, geologic conditions and well development procedures at the Beta Unit are significantly different than those which existed at the Dos Quadras Unit. Basically, the factors which contributed to the Dos Quadras offshore oil spill were the: (1) very shallow depth of the upper reservoirs; (2) high porosities, permeabilities, and fluid pressures in the reservoir rock; (3) a very thin (less than 240 feet - 73 m) capping strata of high porosity and permeability; and, (4) a short total cased interval of 238 feet (72 m) subsea depth (McCulloh, 1969). These conditions are compared to those at the Beta Unit site in Section 3, Table 3.1-2.

A greater thickness of capping strata, a deeper casing program, low-gravity oil, and hydrostatic reservoir pressures in the Beta Unit, coupled with revised rules and more stringent regulation of drilling operations, make the possibility of an oil spill related to loss of control of a well remote.

4.1.1.2 <u>Ground Subsidence</u>

Withdrawal of fluids from the oil zones, with the consequent lowering of reservoir fluid pressures, can cause reservoir compaction and eventual ground surface subsidence (Allen, 1973). Although certain geologic conditions set the stage for subsidence to occur (i.e. a thick, shallow, unconsolidated sand section, high porosities, interbedded fine-grained soils), the principal controlling factor is pore-fluid pressure. A significant reduction in the natural pore-fluid pressure, caused for example by oil and gas withdrawal, results in a transfer of load from the pore fluids to the intergranular skeleton, and compaction of the soils with accompanying subsidence can occur.

At the Beta Unit, pore-fluid pressure is planned to be controlled by a pressure maintenance program using water injection (Shell, 1977). This program will begin soon after the start of production and will continue throughout the life of the field. Accordingly, the potential for reservoir compaction and accompanying ground surface subsidence due to fluid withdrawal will be minimal if the planned pressure maintenance program is properly implemented and executed.

4.1.1.3 Ground Movement

Ground movement that possibly could damage wells, pipelines, or drilling platforms could be produced in several ways, including: (1) slumping or creep of unconsolidated sediments, either with or without the triggering action of seismic shaking; (2) sudden fault rupture or slow creep, with ground displacement sufficiently large to shear off well casings or pipelines.

(1) Shallow Gravity (Slope) Failure

Anomalous, shallow, subbottom features and topographic irregularities, which include shallow slumps and creep, are shown on Figure 3.1-9 and are discussed in Section 3.1.1.3(4). Topographic anomalies closest to the shallow-water platform sites are at least 700 feet (212 m) to the north and southwest, and are possibly associated with near-surface faulting and the paleo-shelf break (Mesa[2], 1977). Faults F_4 and F_5 bound the shallow-water platform sites on the west and east, respectively (Figure 3.1-15). Disrupted bedding associated with these fault traces is no closer than about 300 feet (91 m) to the platform locations.

Based on the detailed bathymetric and geophysical surveys and soil test borehole data provided to date, there is no evidence of shallow slumping, soil creep, or disturbed soils at the shallow-water platform sites indicated on Figure 3.1-15.

Shallow geophysical surveys have been made at the deep-water platform sites as reported in Mesa[2] (1977). This site is situated on the 700-foot (212 m) isobath, 300 feet (91 m) east of Fault F_{2A} and about 400 feet (122 m) west of Fault F_3 (Figure 3.1-6). These faults are within the Palos Verdes fault zone, and show evidence of displacing Holocene strata (Mesa[2], 1977). Although the faults were delineated by Mesa[2] (1977) in the deep-water platform area, detailed geologic hazards are not plotted; for example, the extent of disrupted bedding possibly associated with the faults, and surficial irregularities. In order to assess the deep-water platform site with respect to geologic hazards and the possible effects on the environment, more detailed geotechnical data for the site and site vicinity will be developed by Shell prior to the Eureka platform design approval.

A detailed review of the San Gabriel submarine canyon was made by Mesa[2] (1977) to assess the stability of the surficial units in an area of relatively steep slopes. Relief of the canyon walls ranges from 150 to nearly 200 feet (45 to 60 m), with slope angles as high as 30 degrees and averaging 15 degrees (Mesa[2], 1977). Even though high-resolution shallow geophysical data showed local daylighting of beds, the investigation found no unequivocal evidence of slumping or sliding within the area of the canyon studied. A slump block was identified, however, about two miles (3.2 km) east of the platform sites where canyon walls slope 10 degrees.

Surficial soils in the canyon, similar to those at the platform sites, were found to be relatively stable, even where daylighting at several degrees out of 20 to 30 degree canyon slopes (Mesa[2], 1977). Based on this comparison study, the likelihood of gravity-induced slumping or surficial soils creep at the platform sites, where seafloor gradients are less than four degrees, is remote.

(2) Near-Surface Fault Rupture

The possibility of sudden fault rupture or slow fault creep with ground displacement large enough to damage well casing or pipelines must also be considered. Although no near-surface faults have been found at the platform sites per se, the drilling platform locations are bounded by faults with evidence of displaced Holocene strata (Figure 3.1-6) and must be considered capable of movement during the life of the facilities.

Faults F_1 through F_4 are within the Palos Verdes fault zone (Mesa[2], 1977), which is considered capable of a Magnitude 6.5 to 7 earthquake, with a potential for strike-slip sense of displacement. Empirical relationships have been developed by Bonilla (1970) between earthquake magnitude and maximum amount of surface displacement. Based on a maximum of a 6.75 to 7 Magnitude event, as much as 4 to 7 feet (1.3-2.1 m) of lateral displacement could occur along any of Faults F_1 through F_4 within the Palos Verdes fault zone. Consequently, the possibility of well rupture must be considered where they cross these active faults. This fault rupture could take place either as sudden shearing associated with an earthquake or as slow seismic creep along a fault plane.

It is conceivable that wells which intercept faults within the Palos Verdes fault zone, including the Beta fault (Figure

3.1-7), could be damaged or sheared due to fault displacement. If casing in a flowing well was broken, communication could be established between the pressure of a deep reservoir and shallower strata, and flow of reservoir fluids through the shallow strata could result. There is no known instance of such an occurrence from natural ground movements, and such an accident seems extremely unlikely. Although casing rupture from fault displacement has been reported in several California oil fields, none has resulted in a blowout. Subsurface valves installed in accordance with OCS orders would normally serve to prevent a spill from even this type of accident. An appropriate siting of valves would likely reduce any spill to a very minor amount in the event of a break from such fault displacement.

4.1.1.4 Seismicity

(1) Vibratory Ground Motion

Because severe earthquakes could possibly occur in the Beta Platform site region, structures associated with oil field development and production should be designed to safely resist shaking from such events. For this purpose, the operator established design criteria for two levels of shaking: (1) the Strength Level Earthquake (SLE); and (2) the Ductility Level Earthquake (DLE). Typical design of important structures in seismically active areas requires that structures remain functional during the SLE and resist collapse during the DLE, such that there are no adverse environmental impacts.

Earthquake analyses and design for the two levels of shaking (Jones and Marshall, 1978) utilized response spectra and acceleration time histories scaled to a variety of peak accelerating levels. A summary of these analyses and the potential effects of significant earthquake ground shaking are discussed in Section 4.1.1.5.

(2) Induced Seismicity

Induced seismicity (earthquakes triggered by man's activities) has been associated with ground subsidence caused by hydrocarbon withdrawal during reservoir fluid pressure decreases as well as fluid injection and pressure increases. In the first case, severe ground subsidence in the nearby Wilmington Oil Field during the 1940's and 1950's generated several damaging shallow shocks with estimated magnitudes of 2.4 to 3.3 (Kovach, 1974). In the second case, fluid injection quantities at the Rangely, Colorado field were correlated with recorded seismicity patterns which ranged up to Richter Magnitude 3.4 (Gibbs *et al.*, 1973).

Both of these cases of induced seismicity in oil fields were triggered by significantly changing the virgin reservoir pore pressure. In the Wilmington Oil Field, the withdrawal of fluids from the producing zone, with the consequent lowering of reservoir fluid pressures, resulted in severe ground subsidence (Allen, 1973). This subsidence produced horizontal shear stresses relieved by sudden horizontal movements on very shallow slippage planes (Kovach, 1974). Water flooding of the Wilmington field since 1955 has reinstated reservoir pressures and effectively halted subsidence. No associated seismicity has been reported since 1961.

In the Rangely, Colorado field, reservoir pressure and production-rate declines instigated a water flooding program in 1957. By 1967, when induced seismicity was accurately located in the field, reservoir pressures were well above original, natural fluid pressures (Raleigh *et al.*, 1976).

Unlike rocks at the Beta Unit, the Rangely field contains a relatively hard brittle sandstone of low permeability. However, permeability along a fault in the Rangely field was sufficiently large that pressure increases at the wells was followed by fluid pressure increases in the fault plane. The increased fluid pressure in the fracture reduced frictional resistance to sliding, and slippage occurred which generated earthquakes (Raleigh *et al.*, 1976).

Even recognizing the differences in geologic conditions between the Beta Unit and other oil fields, maintenance of original fluid pressure at the Beta Unit is essential to minimize the possibility of induced seismicity. Proper implementation of the pressure maintenance program planned by Shell (1977) will alleviate the potential for induced seismicity.

4.1.1.5 Ground Instability: Shallow-Water Platforms

The Beta Unit shallow-water drilling and production platforms will be supported by eight and twelve steel piles, respectively, driven 200 feet (61 m) or more below the mudline. Any major failure or movement of the soil into which these piles are driven could alter the supporting capacity of the piles, which could in turn result in the collapse of the facility and consequential oil spills. Ground failure or movement could result from slope instabilities, from settlement or ground densification, or from loss in bearing capacity. The causes of these instabilities can generally be attributed either to gravity (or sustained) loading such as caused by the weight of structure, seismic loading such as caused by earthquakes, or fluid loading such as caused by ocean waves. The following three sections consider the potential for ground instability due to these three loading mechanisms.

(1) Gravity Loading

The shallow-water platform sites are believed to be stable from the standpoint of existing natural loading. Soils are normally consolidated to overconsolidated (Woodward-Clyde Consultants, 1978a) and, hence, no additional settlements are expected from dissipation of excess pore-water pressures, as might occur in an underconsolidated soil deposit. [Underconsolidated soils are characteristic of deltaic areas where rapid sediment accumulation occurs, such as near the mouth of the Mississippi River in the Gulf of Mexico. No similar source of sediment occurs in southern California.] Slopes are relatively flat (2° to a maximum of 4°) near the site and presently exhibit an ample margin of safety against sliding (Pyke, 1978). Seismic survey data also show no evidence of past slope movement at the platform sites (Section 3.1.1.3(4)).

The weights of the production and drilling platforms will result in net increases in load within the soils at the site. However, the nature of the platforms are such that loads will be transferred over depths of 200 feet (61 m) or more. The net change in load for any localized area or zone within the soil profile will, therefore, be small. As a result, little if any settlement is expected from platform loads. Similarly, loads from the platform are not expected to alter the potential for slope movement.

(2) Seismic Loading

The potential for significant earthquake-induced ground shaking is relatively high at the shallow-water platform sites because of the proximity of the active Palos Verdes and Newport-Inglewood fault zones. The consequences of earthquake-induced ground shaking can be liquefaction of cohesionless soils, densification of granular soils, post-shaking consolidation of cohesive soils, and failure of slopes.

- Liquefaction Potential

The potential for liquefaction of granular soils at the shallow-water platform sites was assessed by comparing strengths of soils obtained from consolidated-undrained triaxial tests to shearing stresses induced by earthquake ground shaking. Static strengths were reduced for likely degradation effects caused by pore-water pressure buildup. Ground shaking was simulated for five input motions using the computer program DCHARM (Doyle, 1978). Three of the input motions were artificial time histories. These records represented motions in rock caused by a Magnitude 6.75 earthquake on the Palos Verdes fault (scaled to 0.5 g), a Magnitude 7 event on the Newport-Inglewood fault (scaled to 0.35 g), and a Magnitude 8+ event on the San Andreas fault (scaled to 0.1 g). Analyses were also conducted using the Cholame-Shandon record of the 1966 Parkfield earthquake (scaled to 0.49 g) and the Pacoima Dam record for the 1971 San Fernando earthquake (scaled to 0.77 g). All records were input into the DCHARM analysis and resulted in mudline acceleration levels between 0.1 g and 0.4 g. Modulus and degradation soil properties used in the DCHARM analyses were determined by laboratory cyclic testing (strain-controlled) of nominally undisturbed soils (Woodward-Clyde Consultants, 1978a).

This assessment of liquefaction potential at the shallow-water site determined that an ample margin of safety exists against liquefaction of the upper zone of sandy and clayey silts (Layer A) and the intermediate zone of silty sand, sand, and gravels (Layer C). This limited analytical study is supported by published results of case studies which show that the probability of liquefaction is very small in deposits with geological ages similar to the ages of materials at the shallow-water site (Pyke, 1978). These results were obtained in a manner which is consistent with engineering practice; hence, liquefaction is not expected to be a significant hazard at the shallow-water site.

- <u>Dynamic Settlement</u>

Densification of granular soils can occur during earthquake-induced ground shaking. Such densification results from the tendency of granular soils to compact during cycles of shearing stress. Results of the field investigation for the shallow-water site (Woodward-Clyde Consultants, 1978a) indicate, however, that most cohesionless soils at the platform sites (Layer C) are very dense, *e.g.*, apparent relative densities are on the order of 100 percent. Furthermore, the results of dynamic response studies suggest that the maximum pore-water increase, as interpreted from the results of degradation studies, will be about 25 percent (Woodward-Clyde Consultants, 1977; Pyke, 1978). The combination of high apparent relative densities and low pore-water pressure increase suggests that the amount of vertical settlement will be small, perhaps less than 1.0 percent of the total of the layer thickness. For even this conservative assumption of settlement, it is probable that total earthquake-induced settlements will be less than one foot and differential settlements would be even less. This amount of settlement should not have an adverse effect on platform stability.

- <u>Post-Cyclic Consolidation</u>

Consolidation of cohesive soils may result as earthquake-induced excess pore-water pressures dissipate. Results of dynamic response studies for the shallow-water site (Pyke, 1978), when interpreted in terms of laboratory test data (Woodward-Clyde Consultants, 1978), suggest that the average pore-water increase in cohesive soils will be on the order of 10 percent of the effective confining pressure. Such pore-pressure increases will result in negligible consolidation; hence, settlement of cohesive soils will be small. No adverse effect on the platforms is expected from this phenomenon.

- <u>Dynamic Slope Stability</u>

The inertial effects of ground shaking may increase the potential for slope instabilities. A simple comparison was made between the undrained strength of the soil and the combined effects of earthquake ground shaking and gravity stresses (Pyke, 1978). This evaluation determined that at the shallow-water site the factor of safety against sliding will be adequate for levels of shaking scaled to maximum mudline accelerations of 1 to 0.41 g (Pyke, 1978). This conclusion was partly supported by the results of seismic profiling which showed that no evidence of past slope failures exist at the platform sites despite probable occurrence in the past of significant ground shaking (greater than 0.1 g) in proximity to the site. As procedures used in this analysis are consistent with present engineering practice, it is probable that the hazard associated with seismic-induced slope instabilities will be very small.

(3) Ocean Wave Loading

Ocean waves can cause significant increases in hydrostatic pressure on the seafloor. This increase in pressure has led to slope failures in soft underconsolidated cohesive soils and to liquefaction of cohesionless soils. The magnitude of the increase in shearing stress caused by a surface wave at the shallow-water platform site was estimated from the following equation:

$$\tau = \Delta P \quad \{ 2\pi^{h}/L \exp (-2\pi^{h}/L)\}$$

where ΔP is the change in bottom pressure, h is the depth below the seafloor, and L is the wave length (Pyke, 1978). The maximum shearing stresses induced by a design wave, 49 feet (14.9 m) in height with a 12-second period (the "200-year wave"), will be significantly less than the static undrained strength of the soil even when the static strength is reduced for degradation effects, as might occur after an earthquake. The total shearing stress is also less than the undrained soil strength when shearing stresses from the ocean wave are combined with gravity and earthquake stresses, thereby indicating that the site exhibits ample resistance to ocean-wave loading even when considered in combination with simultaneous effects of gravity and earthquake loading. These results suggest that the hazard associated with ocean-wave loading (e.g. slope failure or liquefaction) will be small and no adverse impacts will result.

4.1.1.6 Structural Instability: Shallow-Water Platform

The structural integrity of the platform must be maintained to preclude collapse of the structure and associated oil spills or loss of life. To assure structural stability, the platform was designed to support the weight of the superstructure and to withstand short-term loads caused by earthquakes and ocean waves. The following three sections review design methodologies used in evaluating the effects to the platforms of gravity, seismic, and ocean wave loading.

(1) Gravity Loading

Analyses were conducted to determine the axial and lateral capacities of piles during long-term loading. Details of these analyses are summarized in the following two subsections. The superstructure for the platform was designed in general accordance with guidelines set forth in API RP 2A (API, 1977). Details of these analyses are also reviewed.

- <u>Axial Pile Capacity</u>

Axial load capacities of piles were established by three distinct approaches: one involved the use of total stress concepts and two involved effective stress methods. The three approaches were used to obtain a more accurate prediction of the load-supporting capacities during various types or stages of pile loading.

The total stress approach involved use of the API Alpha Method, as described in Section 2.27 of API RP 2A (API, 1977). In determining the load supported by the piles, the value of alpha (α) was selected to represent a soil with an undrained strength greater than 1500 psf (72 kPa); the interface angle, δ, was selected on the basis of friction angles measured during drained triaxial tests; K_o was assumed to be 0.75. This methodology was used to establish axial load versus depth relationships for 42-, 48-, and 66-inch (107, 122 and 168 cm) piles loaded in compression and tension.

The first effective-stress methods involved use of the simplified Beta method (Woodward-Clyde Consultants, 1978a). This procedure employed the same basic equation for determining ultimate capacity as used in the Alpha method, but with the following modification for the unit skin friction:

$$f = \beta \sigma_v'$$

where σ_v' is the effective overburden pressure, and β is a factor given by the equation:

$$\beta = K \tan \delta$$

In this latter equation, K is a constant and δ is the interface angle. The value of K, which was assumed equal to the effective coëfficient of earth pressure at rest (K_o), was varied according to soil type and stress history. The interface angle was determined from laboratory tests. This effective-stress methodology was used to develop ultimate bearing capacity versus depth relationships for 42-, 48-, and 66-inch (107, 122 and 168 cm) diameter piles loaded in compression and tension.

The second effective-stress method involved use of critical-state soil mechanics (Woodward-Clyde Consultants, 1978b). This analysis also employed the same basic equation for determining ultimate capacity as used in the Alpha method, but with the unit skin friction now equal to:

$$f = \frac{1}{2} \, MP_f \cos \delta$$

where MP_f and δ were factors depending on the soil-pile interface angle and the mean state of effective stress. Ultimate pile capacity versus depth relationships were derived for immediate and long-term loading by varying the mean effective confining pressure according to the postulated state of pore-water pressure immediately after driving and after dissipation of porewater pressures.

As the three methods of predicting pile capacity defined different load capacity curves for the same pile diameters, an attempt was made to calibrate these methods in terms of effective behavior at the shallow-water platform sites for different stages of loading. A factor (c) was determined and applied to the pile capacity versus depth relationships to obtain an adjusted capacity curve for individual piles. The resulting sets of curves were then combined to define "best-estimates" of pile loading capacity for 42-, 48-, and 66-inch (107, 122, and 168 cm) diameter piles immediately after installation (short-term) and after complete dissipation of excess port-water pressure (long-term).

Of the two resulting sets of curves (short-term and long-term loading), the most critical design case was found to be immediately after installation. However, with time and associated dissipation of excess porewater pressures, the capacity of the piles increased. Complete pore-water dissipation was expected within a year of installation (Woodward-Clyde Consultants, 1978b). As production will not be initiated until approximately seven months after initial installation, the long-term axial capacity versus depth relationships were expected to govern. Piles designed in accordance with these final long-term curves will support loads imposed by the platform superstructure and, hence, should be adequate in terms of platform stability. Nevertheless, for conservatism, static design loads were increased by a factor of 2.0. [Ultimate capacities adjusted in this manner exceed those suggested by the standard API criteria (factor of safety would be about 1.3 for API)]. The approach used to establish axial pile capacity is consistent with the latest state-of-the-practice; hence, the hazard associated with axial pile failures is expected to be minimal and no adverse impacts will result.

- <u>Axial Load/Deformation Characteristics</u>

Piles will undergo axial displacements due to elastic shortening or elongation of the pile under compressive and tensile loads and due to deformation of soil at the soil-pile interface. Maximum shortening will occur during construction when structural dead loads are being imposed and before pore-water pressures dissipate (soils weaken). Load increases subsequent to platform installation will be significantly less than the total dead load. As a result, pile deformation during production is expected to be small and, therefore, will not have any effect on platform stability.

- Lateral Load/Deformation Characteristics

The shallow-water platforms will be subjected to lateral forces from winds, currents, and ocean waves. These lateral forces will cause the structure to deform laterally; therefore, the supporting foundation must be designed to resist lateral loads. To address this consideration, lateral load-deformational (p-y) characteristics of the soil were determined (Woodward-Clyde Consultants, 1978b). These analyses involved determining p-y curves in general accordance with Section 2.29 of API RP 2A (API, 1977). The following minor modifications were required in performing these analyses to account for the type and layering of soils at the platform site.

The p-y curves for soils were established by using the Matlock (1970) criterion for soft clay and the Reese *et al.* (1974) criterion for sands. The Matlock method was modified to incorporate the apparent dependence of pile displacement at one-half ultimate capacity (y_c) on pile diameter. The modified equation was defined as:

$$y_c = 8.9\ \varepsilon_{50}\ b^{0.5}$$

where b is the pile diameter and ε_{50} is the strain at one-half the maximum deviator stress. The modification to the Reese method involved incorporating the effects of soil layering (Woodward-Clyde Consultants, 1978b). The ultimate lateral resistance for the layered case was defined by the sum of the resistance in sand and the resistance of a wedge of soil in the overlying clay layers.

The modified Matlock and Reese methods were used to establish pseudostatic p-y curves for each layer encountered at the shallow-water platform site. Tabulated relationships were prepared for 42-, 48-, and 66-inch (107, 122 and 168 cm) diameter piles. These relationships were based on relatively fast field tests (Woodward-Clyde Consultants, 1978b) and, therefore, represented conditions during undrained loading such as might occur during a single wave or a gust of wind. It is believed that most lateral loads will be of short duration, and thus the short-term loading conditions will be representative. For longer-duration loading such as would occur from ocean currents, higher resisting capabilities should exist because of dissipation of excess pore-water pressures.

As these methods for determining lateral load capacity of the soil are consistent with the present state-of-the-practice, piles designed in accordance with these data and standard API criteria will withstand likely levels of lateral loading. As a result, the hazard associated with lateral pile failure or excessive lateral pile deformation is expected to be low and no adverse impacts are anticipated.

- Structural Stability (Static and Oceanographic)

The superstructure for each platform was designed to withstand environmental loads such as caused by wind, current, and wave forces, and loads from the weight of the structural members and equipment located on the platform deck (deck loads). Static analyses for deck loads and quasi-static analyses for wave loads were performed using a space-frame analysis computer program (Jones and Marshall, 1978). This program applied wave forces to the simulated structure [Section 4.1.1.6(3) provides additional comments on wave loading], combined these with specified wind and deck loads, self weight, and buoyancy, and computed detailed member stresses for AISC utilization ratio checks, as defined in API RP 2A Sections 2.18 and 2.19 (API, 1977). The program allowed a linear static-elastic analysis of the three-dimensional framed structure by the stiffness method. Computer input included specific geometry, member sizes, loading descriptions, and support conditions. Structural dead loads were not handled internally; but rather these loads were estimated and then included as extra loads.

At the foundation interface, the soil-pile interaction was simulated with appropriate spring matrices (Jones and Marshall, 1978). These matrices were determined on the basis of estimated gross shear load at the mudline, elastic settlements, rigid-body rotation of the jacket, pile makeup in the soil, and the previously described p-y curves [Section 4.1.1.6(1)] using a computer program (Jones and Marshall, 1978). Loads at the mudline were a function of both the "fixed head" deflection and the "relaxation" characteristics of the soil pile model. The axial component of the pile was simulated by an equivalent number which had the elastic property of the total pile makeup in the soil. This analysis method was used to establish forces and moments within all structural members, from which the adequacy of structural design could be checked.

Static analyses were conducted using loads increased by a factor of 2.0 for conservatism. As this general approach is consistent with API criteria (API, 1977) and because this method has been successfully employed in the static design of structures in the Gulf of Mexico, it is believed that the methodology will also be adequate for southern California. These results suggest that the platform has been adequately designed to resist long-term and short-term (non-seismic) loading. Hence, the hazard associated with structural failure is expected to be low and no adverse impacts are anticipated.

(2) Seismic Loading

Earthquake-induced ground shaking will have two potential effects which could influence the structural integrity of the platforms. The first effect is related to the inertial response of the structure. The inertial response will result in additional loads within tubular members, particularly cross-bracing. The second effect is the indirect consequence of these inertial loads. Inertial loads will be transferred through the pile-foundation system into the supporting soil. This load transfer will be cyclic in nature and could result in alteration of the supporting characteristics of the soil. In either case, detailed evaluations are required to assess the effects of earthquake loading on platform stability. The methodologies used to make these assessments during the study are reviewed in the following sections.

- Axial Capacity of Piles

The effects of earthquake loading on the axial capacity of piles were evaluated by using critical-state soil mechanics. Cyclic loading effects were accounted for by modifying the unit skin friction term in the equation used for estimating ultimate capacity on the basis of the potential excess pore-water pressures developed during undrained cyclic loading (Woodward-Clyde Consultants, 1978b). No modifications were made to account for potential benefits of rate-of-loading effects. It was assumed in the critical-state analysis that excess pore-water pressure would be sufficient to cause soil failure for the given loading condition. Such an assumption is believed to be conservative, in view of the potential for dissipation of excess pore-water pressures in proximity to the pile.

The results of this analysis show that the earthquake loading case is slightly more critical during design than the long-term static loading case. For conservatism the axial load capacity versus depth relationships were based on curves derived for earthquake loading conditions. As earthquake loading only occurs periodically in time, the factor of safety applied to loads was reduced from 2.0 for static loads to 1.2 for earthquake loading.

This approach for incorporating earthquake loading appears to account for the effects of cyclic pore-water pressure buildup developed during earthquakes, and thus incorporates the latest state-of-the-practice. Consequently, the axial capacity of piles during earthquake-induced ground shaking should be sufficient to support the platform. It is believed, therefore, that the hazard associated with axial pile failure under seismic loading is low and that adverse impacts will not result from implementation of the project.

- Lateral Load Capacity

Lateral load capacity curves were modified for earthquake loading by incorporating the effects of strain rate and cycles of load for free-field loading and for soil-pile interaction (Woodward-Clyde Consultants, 1978b). The form of this modification was a multiplication factor appropriate for different soil layers. The combined effect of dynamic (earthquake) and non-dynamic loading was obtained by multiplying the static p-y curves by the proposed multiplier. This methodology appears to incorporate the latest state-of-the-practice. It is believed, therefore, that the lateral load capacity of soil under earthquake loading is adequately incorporated within the design methodology. As a result, the hazard associated with loss in lateral pile-load capacity is expected to be low, thereby precluding the potential for significant adverse impact.

- <u>Structural Stability</u>

The previous two sections concentrated on the effects of earthquake on soil-pile response. Of equal importance in the overall stability problem is the response of the platform superstructure.

The response of the platform superstructure was evaluated in general accordance with recommendations given in API RP 2A (API, 1977). In this analysis, two levels of earthquake intensity were considered, the Strength Level Earthquake and the Ductility Level Earthquake. The Strength Level Earthquake required that the platform be adequately sized for strength and stiffness to maintain all nominal stresses within yield or buckling for the maximum level of earthquake activity which may be expected during the life of the structure. The Ductility Level Earthquake required that the platforms have sufficient ductility to prevent collapse during a maximum credible event. The maximum credible event is defined as having motions twice as large as those specified for the Strength Level Earthquake (API, 1977).

The elastic analysis (Strength Level Earthquake) employed both the API-spectra and time-history approaches for evaluating seismic response (Jones and Marshall, 1978). API Zone 4, Soil C spectra were scaled to the appropriate acceleration levels for three components of excitation. The maximum excitation (0.25 g maximum) was applied along the major structural axis. This excitation was combined with 0.66 of the major components applied in the orthogonal direction and 0.50 of the major component in the vertical direction. The three spectra were applied simultaneously: modal responses were combined by the Naval Research Laboratory method. In this method the absolute value of the maximum mode was taken with the square root of the sum of the squares of the other modes. This method is more conservative than that specified by API (Jones and Marshall, 1978).

To check and calibrate the spectral analysis, time-history analyses were performed (Jones and Marshall, 1978). This check was made using recorded acceleration-time histories from the 1953 Taft earthquake, the 1940 El Centro earthquake, the 1949 Olympia earthquake, and artificially generated time histories to match the API spectrum. The major component of each of these records were fit to the API spectrum by scaling maximum acceleration values at the ground surface to 0.25 g and adjusting time scales.

The time-history analysis for the Strength Level Earthquake involved use of a computer program (Jones and Marshall, 1978), which provided a three-dimensional simulation of the platform superstructure. Forces of structural members were calculated by the stiffness approach. The spring matrices for the structure support joints were determined with a computer program, in the same manner as described for obtaining spring matrices for the static space-frame analysis [Section 4.1.1.6(1)].

Given these soil-pile springs, analyses for earthquake loadings were made from which axial pile loads and actual pile-joint deflections were obtained. Deflections from the frame analysis were reimposed on the pile model, thus resulting in a bending movement in the pile.

Inelastic studies (Ductility Level Earthquake) were also performed using a computer program (Jones and Marshall, 1978). The two-dimensional finite element program included failure algorithms for beam column and cross-bracing elements. Masses which are concentrated at the nodes include contained water and the added mass effect of the surrounding water. Piles and soil supports were explicitly modeled, rather than using linearized matrices at the mudline. These supports reflected axial and lateral pile capacities described in Section 4.1.1.6(1).

Input motions to the program were obtained from the results of ground motion analyses performed using another computer program called DCHARM (Doyle, 1978). This program models upwardly propagating shear waves using the method of characteristics and nonlinear dynamic soil properties. Input motion for the DCHARM studies were at rock stratum. Dynamic soil properties were modeled using the results of cyclic laboratory tests (Woodward-Clyde Consultants, 1978a). Motion histories were obtained at various locations within the soil profile for five earthquakes: the San Andreas, Newport-Inglewood, and Palos Verdes records (Dames and Moore, 1978a), the 1966 Parkfield, Cholame Shandon No. 2 (N65E) record, and the 1971 San Fernando, Pacoima Dam (S16E) record. Bedrock accelerations input to DCHARM and the resulting mudline accelerations are summarized on the following table:

Earthquake Record	Bedrock Maximum Acceleration, a/g	Mudline Maximum Acceleration, a/g
Palos Verdes	0.50	0.23
Newport-Inglewood	0.35	0.17
Parkfield	0.49	0.33
Pacoima Dam	0.77	0.41
San Andreas	0.10	0.09

Inelastic-response analyses were performed using the input motions from the DCHARM analyses together with an overload analysis (Jones and Marshall, 1978). The overload method involved applying a very gradual ramp acceleration from which a picture of progressive failure and the formation of structural collapse mechanisms were observed. This overload method was analogous to the incremental quasistatic method described in API RP 2A (API, 1977).

Results of these analyses indicated that the production platform meets API overload requirements (Jones and Marshall, 1978). For the time history analyses of the Ductility Level Earthquake (which is estimated to have a recurrence interval of greater than 1,000 years) extensive damage is predicted; however, due to structural redundancy, collapse does not occur.

These studies, as summarized above, suggest that the dynamic response of the platform superstructures during earthquake shaking has been addressed in general accordance with the state-of-the-art. The platforms, therefore, should be stable during predicted levels of earthquake-induced ground shaking and no adverse impacts are anticipated.

- Deck Design

The survival of critical piping, equipment, and other components essential to continued operations and safety was also considered in the dynamic-response analyses of the structure (Jones and Marshall, 1978). Deck acceleration spectra were required as input to these analyses. It was determined from time history studies that peak deck accelerations would equal or exceed the input ground accelerations for elastic response. Design response spectra which envelop these results were developed. Equivalent static load analyses (based on enveloping the spectrum of deck joint values of 0.4 g and 0.27 g as lateral accelerations and 0.4-g vertical acceleration) were then used to obtain individual member forces. Three directions of excitation were combined using the Naval Research Laboratory method. This criterion exceeds that recommended by API (1977).

The approach described above appears to consider potential loading induced by an earthquake; hence, the deck system should be adequate during earthquake loading. The hazard associated with failure of the deck system is, therefore, believed to be low, precluding adverse impacts.

(3) Ocean-Wave Loading

Ocean waves will result in cyclic horizontal loading to the platform superstructure. The horizontal loads will consist of drag forces which are related to the kinetic energy of the water and inertial forces which are related to the acceleration of the water particle. These forces were considered in determining loads within the platform superstructure. Axial and lateral pile capacities were also adjusted for these forces.

Wave loads were incorporated in a manner consistent with API criteria (API, 1977). It is understood that the potential effects of structural fatigue from wave loading are also being evaluated. Damage calculations are being performed for four positions at each end of each primary structural member. According to Shell, the results will become available early enough in the fabrication program to make modifications to improve fatigue characteristics, if required.

The adjustment to axial pile capacity for ocean-wave loading was accomplished by using the same technique used for earthquake loading (Woodward-Clyde Consultants, 1978b). That method was based on critical-state soil mechanics. Design capacities for earthquake loading were, therefore, also considered appropriate for ocean-wave loading. The p-y curves during ocean-wave loading were adjusted to account for remolding of the soil and the associated reduction of lateral capacity (Woodward-Clyde Consultants, 1978b). These adjustments were applied only to Layers A and B, as deflections in deeper layers would not result in cyclic degradation. The methodology suggested by Matlock (1970) in API RP 2A was used to accomplish these adjustments. All loads caused by ocean-wave loading were increased by a factor of 1.5 for conservatism.

The approach for incorporating ocean-wave forces, as described above, is consistent with accepted design. As the effects of these wave forces have been considered in both structural and pile loading phases of design, it appears that the structures will be able to withstand likely wave loading during their lifespan. The hazard associated with wave-induced structural failure or soil-pile failure is, therefore, expected to be low, and no adverse impact will result from construction and operation of the facility.

4.1.1.7 Ground and Structural Instability: Deep-water Platform (Eureka)

The deep-water platform is tentatively planned for emplacement at a location approximately 8,000 feet (2,440 m) south-southeast of the shallow-water platform. The water depth at the deep-water platform site will be approximately 700 feet (213 m). The bottom slope at the deep-water site varies from 4 to 5 degrees. Steel piles will be used to support the platform.

Design of the deep-water platform is still in preliminary phases. Soil borings are being placed to determine the types and characteristics of soils at the site. Information from these studies will be available before design of the platform is completed. As the design of the platform is yet preliminary, design constraints can only be reviewed in a qualitative manner. A more detailed review by the U.S.G.S. will be performed once soil conditions are known and structural design is finalized.

The design constraints for the deep-water platform are, however, similar to those for the shallow-water platforms. From the standpoint of ground stability, any failure or movement of the soil into which piles are driven could alter the supporting capacity of the piles, which could in turn result in the collapse of the facility. Ground failure or movement could result from slope instabilities, from settlement or ground densification, or from loss in bearing capacity. The causes of these instabilities can generally be attributed either to gravity (or sustained) loading such as caused by the weight of the structure, or to short-term loading such as caused by earthquakes or ocean waves. From the standpoint of structural instability, the structural integrity of the platform must be maintained to preclude collapse of the structure and associated oil spills. To assure structural stability, the platform must be designed to support the weight of the superstructure and to withstand short-term loads caused by earthquakes and storm waves. The following paragraphs present a generic discussion of potential hazards and design methodologies used in evaluating the effects to the platforms of gravity, seismic, and ocean-wave loading.

The deep-water platform site appears to be stable under existing natural loads. Slopes are somewhat steeper than at the shallow-water site; however, they are still less than those which would be expected to involve instabilities. Soils are expected to be normally consolidated; hence no excessive settlements should be anticipated from dissipation of excess port-water pressures, as would occur if soils were underconsolidated. Furthermore, as noted in Section 4.1.1.5(1), platform weights are not expected to have any adverse effects on soil behavior. As long as piles and structural members are designed by using procedures similar to those cited in Section 4.1.1.6(1), the platform should be stable.

Earthquake loading to the soil and structure must be considered in design. Methodologies reviewed in Sections 4.1.1.5(2) and 4.1.1.6(2) should be sufficient when assessing soil stability and structural stability. These methodologies require detailed information about the behavior of soils under static and dynamic loading and the response of the structure under simulated earthquakes. This information is presently being collected by the applicant. That information was not available for review as part of this draft. However, based on the procedures used in design of the shallow-water facilities, it is not anticipated that any adverse impact will result from erection of the Eureka platform. The detailed design and soils data will be reviewed by the U.S.G.S. prior to issuance of the permit to proceed.

Ocean-wave loading will have a very small effect on the stability of soils at the site, because of the large water depth. However, ocean waves will result in cyclic horizontal loading to the platform, as discussed in Section 4.1.1.6(3). The deep-water platform should withstand ocean-wave loading as long as procedures similar to those used for shallow-water platforms are used in the design of the deep-water platform.

4.1.2 Impact of Pipelines

A subsea pipeline will be used to transport oil from the production platform to the onshore terminus. Pipelines will also be used to transport oil between the two shallow-water platforms and between the deep-water and shallow-water platforms. Failure of any of these pipelines could potentially result in significant oil spills. The following sections provide a discussion of the potential causes of pipeline failure.

4.1.2.1 Production Platform to Onshore Terminus

Oil will be transported from the production platform to an onshore terminus through a concrete-encased, steel pipeline. The pipeline will be located on the surface of the seafloor from the production platform to a point near the Long Beach Breakwater (Figure 2.4-16); from that point to shore, the pipeline will be buried approximately 4 feet (1.2 m). The proposed and alternate pipeline routes are shown in Figure 3.1-10. Section 4.6.3 discusses impacts related to marine operations interference with the pipeline.

During production, the offshore portion of the oil pipeline must remain intact to preclude the possibility of oil spills. Hazards related to ground subsidence, slumping, and fault movement must, therefore, be considered during design. To ensure the integrity of the pipeline, it is also necessary to consider the potential effects of gravity loads, seismic loads, and ocean-wave loads on the pipeline and the supporting foundation materials. To avoid oil spills along the onshore route, consideration must be given to hazards such as subsidence, ground movement, fault rupture, and ground instability. These considerations, along with structural design considerations, are addressed in the following paragraphs.

(1) Subsidence

The withdrawal of fluids from subsurface reservoirs during the development of an oil field can result in general ground subsidence. Such subsidence is caused by the compaction of subsurface rock as pore fluids are removed.

About 29 feet (9 m) of subsidence were recorded in the Long Beach-Wilmington area through the 1950's when a water reinjection program was initiated. If present trends continue, the pipeline in the area affected by past subsidence, mainly the Harbor area and about a mile beyond the breakwater, will not be impacted. Subsidence at the platform sites will also be negligible as long as effective injection methods are followed. It is probable that even if subsidence occurred, the affected area would be so broad that only small relative displacements would occur at the surface. Normal pipe design should be sufficient to tolerate such displacements.

Overpressurization could result in some rebound in certain situations. The magnitude of rebound would generally be extremely small and, thus, have no adverse effect on pipeline performance.

(2) Ground Movement

The results of subsea profiles indicate that seafloor slopes along the pipeline route are very gentle. Furthermore, no evidence of past non-seismic ground movement exists. In view of these conditions, the potential for subsea pipeline rupture due to ground movement (not associated with earthquakes or wave loading) appears low.

Slopes near or at the shoreline exceed those offshore; hence the potential for ground movement and pipeline rupture increases. However, these slopes are statically stable. As long as slope angles are not altered and as long as drainage conditions along the route remain the same, the potential for future ground movement (not associated with earthquake loading) appears to be low.

(3) Fault Movement and Ground Rupture

Ground displacement due to active faulting is a hazard that must be considered in the tectonically-active Long Beach/Los Angeles region. Surface rupture is most likely to occur along faults which display evidence of Holocene displacements.

Fault traces in the Palos Verdes and "unnamed" fault zones are located near the project pipeline route and display evidence of displaced Holocene-age deposits. However, faults F_1 through F_4, within the Palos Verdes fault zone, trend nearly parallel with the pipeline alignment and do not intersect it (Figure 3.1-12). Similarly, Faults F_5 through F_7 were not reported by Dames and Moor (1977b) to cross the pipeline corridor. Three faults are shown to cross the project pipeline route in the vicinity of the Long Beach breakwater (Figure 3.1-13). Two of these faults, designated F_A and F_B, may be associated with the "unnamed" fault zone of Junger and Wagner (1977) which forms the boundary of the Wilmington graben a few miles to the south (Figure 3.1-3). Faults within this zone are considered to be active in light of reported displacements of Holocene deposits (Greene *et al.*, 1975).

The "unnamed" fault zone forms a discontinuous series of faults, none of which can be traced for more than about 14 miles (22 km). If it is assumed that 50 percent of the total length [conservatively measured as 20 miles, or 32 km, based on Vedder *et al.*, (1974) map sheet 3] ruptures laterally during a single event, the earthquake magnitude associated with this length (Albee and Smith, 1966; Housner, 1970) would be in the range of 6.0 to 6.5. The average maximum ground surface displacement associated with a Magnitude 6.5 earthquake is approximately two feet (0.6 m) (Bonilla, 1970).

Any fault movement will cause either displacement of the pipeline or slippage of the pipeline relative to the seafloor. The amount of displacement along faults within the "unnamed" fault zone could vary from less than a few inches to several feet. Most displacement is expected to be lateral offset (strike-slip) rather than vertical (normal or reverse). These displacements could result in additional bending stresses in the pipe either during movement (relative slippage) or following fault movement (permanent offsets). If bending stresses are sufficiently large, pipeline rupture could occur.

The potential consequence of fault movements is currently under assessment by the applicant and will be incorporated in the design of the production platform to onshore pipeline. Preliminary information indicates that the above-ground motion of the pipeline will be capable of withstanding 3.0 feet (1.0 m) of vertical and horizontal displacement without reaching pipe yield. Thus postulated fault displacements of 2.0 feet (0.6 m) on the "unnamed" faults, F_A and F_B, would not cause pipe rupture. Final design information will be available by December 1, 1978. This date will be early enough to modify pipeline design, if final displacement limits prove to be unacceptable.

There are no mapped active or potentially active faults along the onshore portion of the Long Beach pipeline route. This does not preclude the possibility of future fault movement along this route, but the probability is very low. It is likely that any movements which might occur will be less than those which could be tolerated by a pipeline; hence, no impact would be expected.

The offshore sections of the Huntington Beach and Seal Beach alternate routes are imprecisely located at this time. An assessment of fault hazards should be made if either alternative is chosen over the proposed route.

(4) Bearing Failure and Ground Instability

Failure or movement of the ground beneath the pipeline could result in either loss of bearing support and subsequent pipeline rupture or horizontal movement of the pipe from its original location. Three potential causes of bearing failure and ground instability exist along the pipeline route: soil failure due to gravity loading, soil failure due to seismic loading, and soil failure due to ocean-wave loading.

- Gravity Loading

Soil samples have been obtained at 19 locations along the offshore portion of the pipeline routes (Dames and Moore, 1977b and 1978b). From these limited investigations, it appears that surficial sediments consist of fine sands, silty sands, and soft clays. Most soils will be fine sandy silts; deposits of cohesive soils exist near and within Long Beach Harbor. Onshore soils will vary from sands at the shoreline to silty sands and silty clays along the onshore route. Relatively loose hydraulic fills are found within Long Beach Harbor (Fugro, 1978).

The bearing capacity of offshore materials could vary from essentially 0 at the soil-water interface to 120 psf

(5.8 kPa) or more at a depth of 1 feet (0.3 m). As the bearing pressure of the pipeline under gravity loading will be about 80 psf (3.8 kPa), the pipeline is expected to sink into the seafloor. However, the maximum depth of settlement is expected to be less than 1 foot (0.3 km). For normal offshore pipeline design, no impact will result from such movement.

In offshore areas where rapid changes in sediment types occur (e.g. from sands to soft clays), large differential settlements could occur over short distances. At these locations larger bending stresses could develop in the pipeline. If bending stresses are sufficiently large, the pipe could rupture. However, along most of the pipeline route, the depositional environment has been relatively uniform in recent times, and the occurrence of rapid changes in sediment type is generally expected to be very limited. In these areas, it is believed that the hazard associated with differential movement under gravity loading at offshore sites is slight. At locations where buried channels exist (Dames and Moore, 1978b), larger differential settlements may occur. However, the widths of these existing channels are generally large; hence differential movement would probably be gentle . The applicant is presently evaluating the maximum acceptable pipe curvature, which in turn establishes maximum tolerable differential movements within a given distance. If differential movement appears likely and if these movements exceed tolerable levels, then mitigating measures such as modifying pipeline design or alignment could be taken to eliminate the hazard.

Soils along the onshore portion of the pipeline route are expected to be appreciably stronger than the offshore soils because effective confining pressures will generally be higher and because apparent overconsolidation from dessication will generally exist. As pipe bearing pressures will be less (concrete coating will be eliminated), ground stability under gravity loading will be better than that offshore. As a result, the hazards from bearing failures and settlement along the onshore route appear to be very low.

- <u>Seismic Loading</u>

Seismic loading is likely to occur during the lifespan of the pipeline. For high levels of acceleration, it is possible that surficial zones of cohesionless soil will liquefy at points along the offshore portion of the pipeline route. Due to the possibility of relatively thick [>10 feet (3 m)] loose deposits of hydraulic fill along some portions of the onshore pipeline route, a potential also exists for liquefaction at onshore sites.

Liquefaction would result in partial or complete loss of soil bearing capacity. In this situation the pipeline may sink into the liquefied sediment. The depth to which the pipeline sinks will depend upon the vertical and lateral extent of liquefaction, the duration of strong shaking (which defines the time during which the pipe can sink), and the buoyancy characteristics of the pipes. The primary danger to the pipeline will arise in areas where transitions in soil type occur, *e.g.*, from a clean, loose, cohesionless sand to a more compact clay, over short distances. In these locations, large differential settlements could occur which would, in turn, cause significant bending stresses in the pipeline.

The potential significance of bearing capacity loss under seismic-induced liquefaction is being assessed by the applicant as part of the pipeline seismic design review. The results of this analysis will be available prior to final pipeline design. Preliminary results of this study indicate that differential settlement due to sinking will be small (*e.g.*, less than 1 foot - 0.3 m), as the weight of the pipeline flowing full is only slightly greater than the buoyant weight of the liquefied soil. For conditions where the pipeline is only slightly heavier than the displaced weight of soil, the rate of settlement will be slow (*e.g.*, less than 1 foot/minute); hence settlements will be small as the duration that the soil remains liquefied would be short (*e.g.*, less than 1 minute). For normal design, the pipeline should be able to withstand such movements, even where relative movement occurs over short distances.

Another type of ground instability which is indirectly related to liquefaction of cohesionless soils is the flow slide. This slide is initiated by liquefaction of loose cohesionless deposits. Typically it occurs below submarine canyons. These low-density flows can move at relatively high velocities over considerable distances. Such flows could result in large horizontal loadings to a pipeline resting on the seafloor. As seismic profile data indicate no previous occurrences of flow slides, it is believed that the potential hazard of this phenomenon is very low.

- <u>Ocean-Wave Loading</u>

Ocean waves result in additional loading to a pipe and the supporting soil. This loading can result in loss of soil bearing support through liquefaction of cohesionless soil or through scour of material from beneath the pipeline which could, in turn, lead to pipeline rupture, as discussed previously. It is likely that the potential hazard associated with this phenomenon generally will increase towards shore, where wave-induced bottom pressures increase. Should liquefaction occur, settlement of the pipeline could take place. While the rate of sinking will be small due to the nearly buoyant condition of the pipeline, the duration of liquefaction could be appreciably greater than that for an earthquake. As a result, the pipeline could undergo greater settlements than would occur during an earthquake. The magnitude of settlement will depend on the duration of liquefaction (which will be determined by the duration of large wave-loading and soil permeability) and the tendency of the soil to compact or dilate during shear. It is expected that maximum settlements will not exceed several feet. Provided that differential settlements over short distances are not excessive, the pipeline should be able to withstand such movement. Where liquefaction appears probable, and if likely levels of pipeline differential movement exceed tolerable limits, various mitigating measures can be taken to reduce the potential hazard. These measures include burying the pipeline, rerouting to areas where soils are more compact, modifying pipe design, or altering pipeline alignment.

The second wave-associated hazard is caused by scour of materials beneath the pipeline. Currents in shallow waters may be sufficient to transport cohesionless soils, and such scour will result in loss of bearing support and, consequently, higher bending stresses in the pipeline. The potential occurrence and consequence of scour is unknown. However, it is expected that during large storms, horizontal wave particle velocity at the bottom will vary from about 6 feet per second (1.8 m/sec) in shallow water [less than 80 feet (24 m)] to less than 1 foot per second (0.3 m/sec) in deep water (platform deposits). A velocity of 6 feet per second (1.8 m/sec) is sufficient to transport coarse sands and fine gravels in a river (Sunborg, 1956). Loss of material from beneath the pipeline might, therefore, occur during the lifespan of the pipeline. The consequence of this loss in material will be gradual settlement of the pipeline. No adverse behavior is expected unless scour occurs in specific areas, resulting in the pipeline bridging scour pits. In this situation the bending stresses in the pipe will increase. The potential for a scour-related hazard can be established by determining the probable level of water particle velocities, the grain size and distribution of sediments, and the acceptable size of scour pockets (if they develop). Where scour pits appear likely to develop and if such pits cannot be tolerated, then various remedial measures can be taken to mitigate this potential hazard. These measures include modifying pipe design, altering pipeline alignment, or providing protective blankets (rock or fabrics) to preclude scour.

The third wave-related hazard involves the lateral stability of the pipeline during wave loading. Pipelines located on the seafloor are subjected to lateral loadings from current and wave forces. For the pipeline to remain in place during such loading, it is necessary for the frictional resistance developed at the soil-water interface to exceed the drag forces caused by wave or current action. These hydrodynamic effects have been considered at water depths between 40 and 300 feet (12.2 and 91 m) for the 100-year storm using the procedure suggested by Jones (1978). It was shown that a pipe with an outer diameter of 16-inches (41 cm) [total outside diameter of 18.3 inches (46.5 cm) with corrosion protection and concrete thickness] would withstand the largest predicted hydrodynamic loads (at the Long Beach Harbor breakwater). This approach appears to be consistent with state-of-the-art practice. As a result, the possibility of pipeline rupture due to lateral movement of the pipeline appears to be low.

(5) <u>Structural Integrity</u>

The pipeline will be 16-inches (41 cm) in outer diameter with a 0.5-inch (1.3 cm) wall thickness. A 0.156-inch (0.4

cm) corrosion-protection coating and a 1.0-inch (2.54 cm) concrete coating surround the pipe. The resulting total pipe diameter is 18.3 inches (46.5 cm). The submerged weight of the pipe will be 118 pounds per linear foot (16.5 kg/m). The pipe is designed for a maximum operating pressure of 1420 psi (9800 kPa), and can withstand external hydrostatic pressures with the pipeline void and with its absolute internal pressure equal to one atmosphere.

The oil pipeline has been designed in compliance with U.S.G.S., Conservation Division, Branch of Oil & Gas Operations, Pacific Region, OCS Order No. 9, dated June 1, 1971, ANSI B31.4-1974, "Liquid Petroleum Transportation Piping Systems," and Department of Transportation Regulation 49, Part 195, as amended August 18, 1976, "Transportation of Liquids by Pipeline." Portions of the pipeline routes are within the jurisdiction of the State of California The State will review the design for compliance with the preceeding codes and good engineering practice. In addition to the above, the pipeline design and operating procedures would follow API Recommended Practice RP 1111, Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines, March 1976, and the Department of Interior/Department of Transportation memorandum of understanding of June 11, 1976.

As these guidelines are consistent with state-of-the-art practice, it is believed that the pipeline will be adequate for normal operation.

4.1.2.2 Drilling Platform to Production Platform

A pipeline will be placed between the drilling and production platforms along a bridge connecting the two platforms. This pipeline is being statically designed in accordance with industry standards. Dynamic analyses also have been performed on this pipeline. Expansion loops have been incorporated to minimize pipeline buckling. As these design approaches are consistent with accepted and state-of-the-art practices, the pipeline is expected to be adequate during gravity and seismic loading.

4.1.2.3 Deep-Water Platform to Shallow-Water Platform

A steel pipeline is tentatively planned for transporting oil from the deep-water platform to the shallow-water platform. The route for this pipeline is shown in Figure 3.1-6. Water depths along the pipeline route vary from 260 to 700 feet (70 to 213 m); seabottom slopes range from 2° at the shallow-water platform site to about 4° at the deep-water site.

The hazards which could potentially affect pipeline integrity along this route include ground subsidence, ground movement, fault movement, bearing failure or ground instability, and structural failure. These factors are discussed in greater detail in the following paragraphs. This discussion will be qualitative in nature because sediment conditions along the route have not been established and because the design of the pipeline has not been finalized.

(1) Subsidence

Subsidence of the seabottom in areas of petroleum withdrawal is a design consideration, as discussed in Section 4.1.2.1(1). However, as long as proper reinjection procedures are used, this phenomenon will not create any hazard.

(2) Ground Movement

Slopes along this pipeline route exceed slopes shoreward of the shallow-water platforms. This increase in slope increases the potential for slope instabilities. However, data from geophysical surveys show that no significant submarine slides or slumps occur along the pipeline route. Two disturbed areas bordering the pipeline route are associated with surficial expressions of faults (Pyke, 1978).

As slopes are relatively small and no past evidence of slumping exists along the route, the potential for slumping under gravity loading and associated pipeline rupture appears to be low. However, if subsequent route studies determine that soils with low strengths exist along the route (thus increasing the potential for slumping), the hazard associated with slumping could be mitigated by realigning the pipeline to avoid hazardous areas or modifying pipe design to withstand ground movement.

(3) Fault Movement

The deep-water to shallow-water pipeline crosses two faults, F_3 and F_4. These faults are within the Palos Verdes fault zone (Mesa[2], 1977). A Magnitude 6.75 to 7.0 earthquake has been postulated as the maximum credible for these faults (Section 3.1.2.4) with a potential for strike-slip sense of displacement. This earthquake has a mean recurrence interval of greater than 1000 years. Empirical relationships have been developed by Bonilla (1970) between earthquake magnitude and maximum amount of surface displacement. Based on the assigned maximum 6.75 magnitude event, as much as 5 to 7 feet (1.5-2.1 m) of lateral displacement could occur along either fault. Consequently, the shallow-water to deep-water pipeline must be designed to withstand significant lateral displacements.

The ability of the pipeline to withstand displacements on the order of 5 to 7 feet (1.5-2.1 m) is being assessed by the applicant, as noted previously. If the pipeline cannot withstand such displacements, several measures can be taken to mitigate this potential hazard. These alternative measures could include modifying pipeline design to withstand larger displacements, altering the configuration of the route to increase the pipeline length per unit distance, or incorporating shutoff valves in areas where maximum displacements might occur.

(4) Bearing Failure and Ground Instability

As discussed in Section 4.1.2.1(4), an offshore pipeline supported on the seafloor can be damaged or ruptured in special situations if the bearing capacity of the supporting soil decreases or if ground instability occurs. The cause of bearing-capacity loss or ground instability can be gravity loading, seismic loading, or ocean-wave loading.

- Gravity Loading

Soils along the pipeline route have not been identified at the time of this review. However, they are expected to be similar to those found at the shallow-water platform site, perhaps with a higher percentage of fine-grained materials. The strength of this material is expected to be somewhat lower than would exist between the shallow-water platform and the onshore terminus. Consequently, greater settlement might be expected if the unit weight of the pipeline is the same as that used for the shallow-water-to-terminus route.

The effects of softer soils on pipeline behavior will be minimal except where differential settlement occurs. If differential settlement is expected, then larger deformation could occur within unit lengths of the pipeline. To mitigate this response, the design of the pipeline could be modified or alternate routes could be selected to avoid unsuitable zones.

- Seismic Loading

Seismic loading considerations will be similar to those cited in Section 4.1.2.1(4). As materials are expected to be more cohesive (fine-grained), the ability of the sediment to withstand liquefaction is expected to increase. The existence of submarine channels along the two faults, F_3 and F_4, increases the likelihood of liquefaction-induced sediment flows. However, geophysical records show no evidence of past flows along these channels. An evaluation of sediment types and layering in proximity to these channels could establish whether or not such flows have occurred in the past.

The extent of seismic-related hazards can be established by determining the type and characteristics of soils along the pipeline route. If conditions exist which suggest that liquefaction or liquefaction-induced flows could occur during the lifespan of the pipeline, several measures can be taken to mitigate their effect. These measures could include modifying the pipeline design or changing pipeline alignment.

- Ocean-Wave Loading

The importance of ocean-wave loading decreases as the water depth increases. For example, wave-induced shearing stresses will be less than 100 psf (4.8 kPa) in the upper 35 feet (10.7 m) of soil (Pyke, 1978) and water particle velocities will be less than 1 foot per second (30.5 cm/sec). It is unlikely that such wave-induced forces will have any appreciable effect on the pipeline or foundation soils along the pipeline route. The hazard associated with wave-induced loading to the soil or pipeline is, therefore, expected to be very low.

(5) Structural Stability

The pipeline will be designed in accordance with appropriate industry standards and government regulations. This should ensure adequate behavior during normal operations.

4.1.3 Hydrogen Sulfide

When sea water is used as reservoir injection fluid, a buildup of corrosion, scale, and adverse micro-biological effects is likely (Mitchell, 1978). This can lead to the formation of hydrogen sulfide gas. Therefore, an early monitoring program should be instigated which would identify hydrogen sulfide conditions so that they can be properly treated.

4.1.4 Mitigation

The following is a summary of mitigation measures which are recommended to reduce or eliminate potential adverse geotechnical impacts.

4.1.4.1 Well Blowout

Low reservoir pressures, high oil viscosity, and greater thickness of capping strata in the Beta field significantly reduce the likelihood of a well blowout. Compliance with Pacific area OCS orders promulgated by the U.S.G.S., particularly those aspects related to installation and maintenance of subsurface safety valves and the well casing program, should mitigate the potential for uncontrolled flow during the producing life of a well.

4.1.4.2 Over-Pressurization/Subsidence

The reservoir pressure maintenance program planned by Shell using water injection and careful monitoring of the pressure throughout the life of the project should mitigate any adverse impacts associated with either over-pressurization (induced oil seeps) or subsidence.

4.1.4.3 Fault Rupture

The possibility of well rupture due to near-surface fault rupture should be adequately mitigated by the proper installation and maintenance of subsurface safety valves as discussed in 4.1.4.1.

4.1.4.4 Induced Seismicity

Although geologic conditions at the Beta field reduce the possibility of induced seismic events, the reservoir pressure maintenance program by water injection should mitigate any potential for induced seismicity.

4.1.4.5 Platform Design

The impacts of ground instability and structural instability including gravity loading, seismic loading, and ocean wave loading on the shallow-water platforms appear to be adequately mitigated by the use of conservative design criteria and state-of-the-art design techniques. Moreover, the U.S.G.S. will conduct a complete design review of the platform designs prior to issuance of a permit. The deep-water platform design has not been completed, and further geotechnical studies are planned by Shell to complete this design. However, based on the procedures used in the design of the shallow-water facilities, no adverse impacts should result. Moreover, the U.S.G.S. will conduct a design review prior to final approval.

4.1.4.6 Pipeline Design

Failure of the pipeline transporting oil to shore could have adverse impacts, primarily oil-spill associated. Causes of failure might include subsidence, ground movement (not earthquake-associated), fault movement, bearing failure and ground instability, or structural failure. In some cases, the pipeline design to withstand these effects has not been finalized pending completion of technical studies by Shell. These studies should be completed in the near future, and will determine if any mitigation is required, particularly due to fault movement, bearing failure, or ground instability. The primary mitigation would be modifying the pipeline design or altering the alignment to withstand or avoid the effects. If wave-associated scour effects are predicted, mitigation can be provided by protective blankets. As in the case of the platform designs, the pipeline design will be reviewed by the U.S.G.S., and appropriate state and local agencies. Structural integrity of the pipeline should be assured by compliance with U.S.G.S., Department of Transportation, and API regulations (see 4.1.2.1).

Similar impacts can be anticipated from the deep-water platform to shallow-water platform pipelines, and can be mitigated by methods described for the onshore pipeline. In the case of these pipelines, the designs are less complete, and will be dependent on further geotechnical studies as the project proceeds.

4.2 ONSHORE HYDROLOGY

4.2.1 Environmental Impacts

4.2.1.1 Surface Water - Huntington Harbour Crew Launch

The proposed project's Surfside crew boat launch will not significantly alter surface hydrology in the area over the life of the project. The area is currently impervious to surface water; the demolition of the filling station and construction of parking facilities will not alter this condition. Surface water will continue to be channeled off-site into the adjacent waterway. Short-term impacts to surface hydrology and water quality may occur during construction of this portion of the proposed project. This impact could occur when bare ground is exposed during repaving of the facility. The impact would be in the form of increased silt loads in the runoff water from the site. This would only occur in the event of rainfall or water passing over the site from another source.

4.2.1.2 Groundwater - Huntington Harbour Crew Launch

The proposed project's Surfside crew boat launch facility will not alter groundwater conditions from their present status. Because of the impervious nature of the site, no water will percolate into underlying strata. This portion of the proposed project will have no effect on the already saline groundwater conditions prevailing in the area.

4.2.1.3 Surface Water - Port of Long Beach

Surface-water conditions at the proposed supply facility will not be appreciably affected as a result of the project's construction. Some minimal paving of the areas may be required, but the quantity will be so low as to not significantly alter runoff amounts or patterns. In contrast, the proposed project's surge tank and manifold facility, which is currently unpaved, will be partially paved, rendering it partially impervious. This will increase runoff quantities. However, the site will be diked to contain a possible oil spill. This diking will also contain runoff waters which have either passed through a sump and pump system or an oil and water separator to meet quality standards. In the former case, all runoff would be collected for disposal elsewhere, in effect, reducing runoff into harbor waters. In the latter case, all oily waters would be separated from the runoff water and then the water would be discharged into the harbor. If a separator system is used, there would be a small increase in runoff waters reaching the harbor over ambient levels. In either case, the impacts upon water quality are not considered to be significant.

4.2.1.4 Groundwater - Port of Long Beach

The proposed supply transfer facility will not affect groundwater quality in the Port of Long Beach. Some paving will reduce percolation of surface waters into groundwater-bearing strata, but because the groundwater is not a usable resource, this reduction is considered insignificant. Construction of the distribution facility will reduce the amount of surface water percolating to groundwater levels because part of the site will be paved. Likewise, this reduction of percolating water will not have an adverse effect upon the groundwater environment.

4.2.2 Mitigation Measures

4.2.2.1 Huntington Harbour Crew Launch

(1) Surface-Water Hydrology

No mitigation measures are needed for this portion of the proposed project, as no adverse surface hydrological impacts will occur. Proper attention to drainage patterns during the construction of the parking lot should ensure that adequate surface-water drainage is provided. Siltation control measures should also be taken during construction.

(2) Groundwater Hydrology

No mitigation measures are needed for groundwater impacts in the Huntington Harbour area, as no groundwater impacts are predicted.

4.2.2.2 Port of Long Beach

(1) Surface-Water Hydrology

Surface-water discharge control measures for the distribution facility portion of the proposed project include: (1) (1) diking of the facility to retain the capacity of the tank plus 25 percent; and (2) grading and paving of the facility so that surface runoff is drained to an oil and water separating system or to a sump pump, instead of being discharged directly into harbor waters.

No mitigation measures are needed for the materials storage facility, as no significant impacts will occur.

(2) Groundwater Hydrology

No mitigation measures for groundwater are proposed for either site involved in the proposed project within the Port of Long Beach. Groundwater losses resulting from the proposed project will be minimal, if noticeable at all; since groundwater in this vicinity is of poor quality and little value, no mitigation measures are proposed.

4.3 AIR QUALITY

4.3.1 Project Emission

4.3.1.1 Construction Emission

(1) Offshore Emissions

The air pollutant emissions associated with the construction phase operations for the offshore facilities were calculated by collecting relevant data on the offshore activities and applying accepted emission factors for each particular activity. These figures are based on the best available data at this time and may not necessarily reflect the exact emissions that will occur at project start-up.

For the offshore platform installation and construction, it was anticipated that approximately 120 individuals will be required as support staff. The major equipment involved includes a derrick barge, crew and supply boats, and tugs for moving and handling materials and personnel from the dock-side of the fabrication yard to the platform area. A small helicopter will probably be required to transport specialists, inspectors, and other officials to the work site. It was assumed that the crew boats and helicopter would make three to four round trips per day and two trips per week respectively to the platforms. The off shore construction emission factors summarized in Table 4.3-1 were obtained from emission factors and data given in Tables 4.3-2 through 4.3-5.

(2) Onshore Emissions

The last five months of the construction phase will include fabrication and installation of the pipeline to shore and an onshore facility. Although the final route and method of installation has not yet been established, it is likely that the onshore site will require approximately one acre of land in the Long Beach

TABLE 4.3-1

BETA PROJECT OFFSHORE AVERAGE DAILY CONSTRUCTION EMISSIONS

	Emissions (lbs./day) (2)				
Activity (1)	Particulates	CO	HC	SO_x	NO_x
Derrick Barge	39	675	111	102	1110
Crew Boats	19	61	28	15	149
Supply Boats	5	15	7	4	37
Tugs	7	--	5	11	154
Helicopters	1	23	2	0.5	2.5
Staff Autos (3)	Neg	71	3	Neg	11
Total	71	845	156	132.5	1463.5

(1) Estimates of equipment activity from a special report to the Governor of California (Shell, 1977).
(2) Emissions calculations based on emission factors in Tables 4.3-2 to 4.3-5.
(3) Assumes 120 vehicles @ 30 miles (round trip) traveled per vehicle.

TABLE 4.3-2

EMISSION FACTORS FOR DERRICK BARGE

Pollutant	Emission Factor (lbs./1000 gal.)
Particulate	13
CO	225
HC	37
SO_x	34 (1)
NO_x	370

(1) Sulfur content = 0.25%.
Reference: U.S. EPA - Compilations of Emission Factors, AP-42.

EMISSIONS FROM DERRICK BARGE

Pollutant	Emissions (lbs./day) (1)
Particulate	39
CO	675
HC	111
SO_x	102
NO_x	1110

(1) Based on diesel fuel consumption of 3000 gal./day.
Personal communication with G. Salzman of Alaska Constructors, diesel fuel consumption of Hugh W. Gordon derrick barge, August 25, 1978.

TABLE 4.3-3

EMISSION FACTORS FOR SUPPLY AND CREW BOAT

Pollutant	Emissions (lbs./gal.)
Particulate	0.035
SO_x	0.027
CO	0.11
HC	0.05
NO_x	0.27

Reference: U.S. EPA - Compilations of Emission Factors, AP-42.

EMISSIONS FROM CREW BOATS

Pollutant	Emissions (lbs./day) (1)
Particulate	19
SO_x	15
CO	61
HC	28
NO_x	149

(1) Emission calculations based on 552 gal./day fuel consumption.
Reference: U.S. EPA Compilations of Emission Factors, AP-42.
Assumptions:
- 1 boat makes 4 round trips/day
- 1 round trip = 30 nautical miles x 4 = 120 miles.
- 60 gal./hr. for work boats at 2/3 power (EPA, AP-42, 1975)
- Assume speed = 13 knots
- 2.3 hrs./trip x 60 gal./hr. = 138 gal./trip = 552 gal./day

EMISSIONS FROM SUPPLY BOAT

Pollutant	Emmissions (lbs./day) (1)
Particulate	5
SO_x	4
CO	15
HC	7
NO_x	37

(1) Emission calculations based on 138 gal./day fuel consumption.
Assumptions:
- Supply boat makes 1 round trip/day.
- Fuel consumption and travel time assumptions are the same as shown for crew boat.

TABLE 4.3-4

EMISSION FACTORS FOR TUG BOATS

Pollutant	Emissions (lbs./gal.)
SO_x (1)	0.039
NO_x	0.572
Particulate	0.025
HC	0.0185

(1) Sulfur content = 0.275% - Emissions calculations based on 270 gal./day

Reference: Supplement No. 3 to SCAQMD Staff Report, New Source Review of the Proposed Sohio Petroleum Terminal in Long Beach, California, October, 1977.

Assumptions:

3 tugs make 1 round trip/day
1 round trip = 30 nautical miles
30 gal./hr. per tug hr.
Assume speed = 10 knots
3 hrs./trip x 30 gal./ hr. x 3 tugs = 270 gal./day

EMISSIONS FROM TUG BOATS

Pollutant	Emissions (lbs./day)
SO_x	11
NO_x	154
Particulate	7
HC	5

TABLE 4.3-5

EMISSION FOR HELICOPTERS

Pollutant	Emission Factors (1) (lbs/engine)	Emissions (lbs/week)
Particulate	0.25	0.14
SO_x	0.18	0.07
CO	5.70	3.30
HC	0.52	0.29
NO_x	0.57	0.36

Reference: EPA Compilation of Emission Factors, AP-42.
(1) Emission factors per helicopter landing-takeoff cycle.

area. The onshore facilities will consist of a small, 10,000-barrel (1,590 m^3) surge tank, a scraper trap, and meters and pumps.

Site preparation, assembly of equipment, and excavation are anticipated to require up to a maximum of 120, but not more than 100, people at any given time from the Los Angeles/Orange area.

Air pollutant emissions from construction of the onshore facility will occur primarily during excavation and fabrication of the site. Transportation emissions associated with the workers' vehicles could also be significant if stop-and-go traffic conditions around the site persist during peak commuting hours.

Excavations and trenching from the onshore site will generate fugitive dust emissions. An approximate dust emission factor for construction operations is 1.2 tons per acre (0.43 mt per ha) of construction per month of activity (EPA, 1974). Assuming that the site is 1.0 acre (0.4 ha) in size, and is being worked upon daily for two months, there will be about 80 pounds (36 kg) per day of dust emissions.

A number of workers' vehicles will converge on the site during construction of the surge tank and support facilities. It is estimated that during the peak construction period the vehicle miles traveled per day generated by construction worker vehicles will be about 3,000 (30 mi (48 km)/day x 100 cars). Stop-and-go traffic conditions during the morning and afternoon rush hours could produce local "hot spots" of carbon monoxide. The air pollutant emissions associated with construction and workers' traffic are shown in Table 4.3-6.

TABLE 4.3-6

ONSHORE CONSTRUCTION PHASE EMISSIONS

	Emissions (lbs/day)				
Activity	Particulates	SOx	NOx	HC	CO
Construction(1) Dust	80	--	--	--	--
Vehicle Emissions(2)	Neg.	Neg.	10.0	3.0	59.0

(1) Assumes 1.2 tons/acre (0.43 mt per ha)/month, two months of construction.
(2) 1978 California Mix, 100 cars driven 30 miles round trip (48 km)/day.

4.3.1.2 Operations Phase Emissions

(1) Offshore Emissions - Platforms and Drilling Equipment

The primary pollutants which will be emitted by the proposed offshore facilities are NO_x, SO_2, CO, HC, and particulate matter. The major sources of these pollutants will be the turbines and diesel-powered engines installed, respectively, on the production platform and drilling rigs. Other potential sources of emissions include fugitive hydrocarbons associated with drilling and oil recovery operations, standby generators, and crew and supply boats. For purposes of this analysis, emissions from these sources were considered secondary or temporary emissions.

(a) Gas/Diesel Turbines

The Plan of Development for Shell calls for installation of a total of ten Solar Saturn and Centaur turbines. These turbines are the prime movers for the electric power generators and for the water injection pumps. All of the turbines will be located on Platform Elly, and will be sized to handle the production of crude oil from Platform Ellen and future Platform Eureka. It is proposed that these turbines will use both natural gas and diesel fuel. As noted in the Project Description (Section 2.0), these turbines will initially use diesel fuel until the Beta wells begin to produce natural gas, at which time the turbines will convert to the produced gas. Table 4.3-8 shows the fuel consumption for the Solar Saturn and the Centaur turbines by year and fuel type. These estimates are based on projected load data and horsepower requirements for the planned schedule of drilling and production operations (Table 4.3-9). The emission factors for these turbines are indicated by fuel type in Table 4.3-7.

TABLE 4.3-7

EMISSION FACTORS FOR GAS/DIESEL
ELECTRIC UTILITY TURBINES(1)

Pollutant	Oil Fuel $lb/10^3$ gal. oil	Gas Fuel $lb/10^6$ scf
NO_x	67.8	413
HC	5.57	42
CO	15.4	115
TSP	5.0	14
SO_2(2) until 1992	70.0	0
after 1992	14.0	0

(1) EPA AP-42 (3.3.1-2).
(2) Sulfur content of diesel fuel is assumed to be 0.25 percent by weight until 1992, and 0.10 percent thereafter. Gas fuel does not have any measureable amounts of sulfur compounds (Shell Oil Company, 1978).

TABLE 4.3-8

SHELL BETA PROJECT GAS DIESEL TURBINE FUEL CONSUMPTIONS

Year	Annual Fuel Consumption by Saturn Engines		Annual Fuel Consumption by Centaur Engines		Total Annual Fuel Consumption	
	Diesel 10^3 gal/y	Gas 10^6 scf/y	Diesel 10^3 gal/y	Gas 10^6 scf/y	Diesel 10^3 gal/y	Gas 10^6 scf/y
1980	0	0	1907.9	0	1907.9	0
1981	0	102.9	0	554.1	0	657.0
1982	0	244.2	0	571.9	0	816.1
1983	0	268.2	0	589.7	0	857.9
1984	0	296.6	0	643.0	0	939.6
1985	0	315.2	0	678.6	0	993.8
1986	0	317.3	0	866.8	0	1184.1
1987	0	416.0	0	893.4	0	1309.4
1988	0	495.7	0	902.3	0	1398.0
1989	0	505.2	0	920.1	0	1425.3
1990	0	512.0	0	937.9	0	1449.9
1991	0	517.6	0	946.8	0	1464.4
1992	0	521.9	0	955.7	0	1477.6
1993	2155.0	301.1	0	973.5	2155.0	1274.6
1994	4374.2	0	0	982.3	4374.2	982.3
1995	2945.7	200.9	2428.8	660.8	5374.5	861.7
1996	3704.3	100.3	2461.3	669.7	6165.6	770.0
1997	3728.8	100.1	2472.4	672.7	6201.2	772.8
1998	3752.8	99.9	2493.9	678.6	6246.7	778.5
1999	3775.0	99.7	4206.4	571.9	7981.4	671.6
2000	4519.0	0	4255.9	578.6	8774.9	578.6

Source: Based on operations and production characteristics provided by Shell Oil Company, 1978.

TABLE 4.3-9

SCHEDULE OF LOAD AND FUEL ASSIGNMENTS FOR THE GAS/DIESEL TURBINES OF THE BETA PROJECT

Year	Saturn Engines						Centaur Engines			
	Unit #1 hp	Unit #2 hp	Unit #3 hp	Unit #4 hp	Unit #5 hp	Unit #6 hp	Unit #1 KW	Unit #2 KW	Unit #3 KW	Unit #4 KW
1980	0	0	0	0	0	0	1600*	0	0	0
1	921	0	0	0	0	0	1800	1800	0	0
2	714	714	524	0	0	0	1900	1900	0	0
3	765	765	723	0	0	0	2000	2000	0	0
4	870	870	869	0	0	0	2300	2300	0	0
5	922	922	1000	0	0	0	2500	2500	0	0
6	935	935	1000	0	0	0	1930	1930	1930	0
7	930	930	939	939	0	0	2030	2030	2030	0
8	925	925	839	839	839	0	2067	2067	2067	0
9	919	919	883	883	883	0	2133	2133	2133	0
1990	912	912	916	916	916	0	2200	2200	2200	0
1	907	907	943	943	943	0	2233	2233	2233	0
2	902	902	964	964	964	0	2267	2267	2267	0
3	898	898	871	871*	871*	871*	2333	2333	2333	0
4	894*	894*	887*	887*	887*	887*	2367	2367	2367	0
5	890	890	902*	902*	902*	902*	2400	2400	2400*	0
6	888	888*	915*	915*	915*	915*	2450	2450	2450*	0
7	886	886*	926*	926*	926*	926*	2467	2467	2467*	0
8	883	883*	937*	937*	937*	937*	2500	2500	2500*	0
9	881	881*	947*	947*	947*	947*	1900	1900	1900*	1900*
2000	880*	880*	956*	956*	956*	956*	1938	1938	1938*	1938*

Notes: (1) Each engine runs on gas fuel unless a star (*) next to the load indicates that it runs on diesel fuel.
(2) Saturn engines #1 and #2 pump source water; the other four Saturn engines pump produced water.

Source: Shell Oil Company, 1978.

(b) Caterpillar 398 Diesel Engines

Caterpillar diesel engines will be used on the drilling platforms to power the drilling rigs. Each rig will be equipped with three of these engines (including the standby), complete with separate circuit aftercoolers.

The drilling rig schedules include the use of only two drilling rigs at any one time. They will be used for drilling and completing wells. There will be alternating well drilling on Platform Ellen from July 1, 1980 until January 1, 1983, and on Eureka from January 1, 1983 until July 1, 1986. One rig will be used at each platform for well servicing only after July 1, 1986. Well servicing after July 1, 1986 will be at one-third drilling power and used only 12 hours per day. Based on previous experience by Shell Oil Company, they have estimated that 461 hp average power is required per drilling rig while performing all operations required to drill a well. Shell also estimates that at least one engine would be running at all times while drilling. The operating engine would be running loaded 53 percent of the time and idling 47 percent of the time. Table 4.3-10 shows the distribution of the load factor for the 53 percent of the time the engine is operating.

The emission data displayed in Table 4.3-11 are based on emission factors obtained from manufacturers' test data and include all operations phases that the Caterpillar engines would experience (*i.e.*, tripping, drilling, waiting for cement, etc.).

(c) Primary Operating Emissions Summary

Based on the fuel consumption rates given in Table 4.3-8, the operating schedule of the drilling rigs, and Tables 4.3-10 and 4.3-11, the total offshore gas/diesel turbine and drilling rig emissions from the Shell Beta project are shown in Table 4.3-12. Based on this table, the highest NO_x, SO_x, CO, and particulates emissions will occur with the year 2000; the year 1999 is the highest for HC. However, Shell is planning to use 0.25 percent sulfur diesel fuel from the beginning of the project until they switch to 0.1 percent sulfur fuel in 1992. Shell anticipates burning production gas fuel of negligible sulfur content in the turbines.

The total fuel consumption for each category of engines was utilized to calculate the maximum annual and short-term (pounds per day) emissions from the offshore facilities. The worst year, 2000, was used for the impact analysis. The maximum discharge of emissions is a function of the operating capacity of the engines and the sulfur content of the fuel used. Maximum discharge of the engines for the Beta project will occur in the year 2000, when the turbines and diesel engines are using the maximum amount of diesel fuel.

TABLE 4.3-10

LOAD FACTOR FOR CAT D398 ENGINE WHEN USED FOR DRILLING(1)

Percent of Running Time (2)	Percent of Full Load (2)
30	100
15	75
30	50
25	25

(1) Source: Shell Oil Company, 1978.
(2) One diesel engine will be running loaded 53 percent of the time--these columns showing a distribution of the loaded time. The engine will be idling 47 percent of the time.

TABLE 4.3-11

EMISSION FACTORS FOR CATERPILLAR D398 DIESEL ENGINES(1)

	Load Factor (%)				
	100	75	50	25	Idle
Pollutant	Emissions lbs/hr				
SO_2(2)	3.45	2.01	1.34	0.67	0.14
HC	0.11	0.10	0.12	0.29	0.88
CO	2.43	1.98	1.98	3.31	4.85
NO_x	8.45	5.16	3.64	1.75	0.15
Particulate	0.17	0.11	0.10	0.10	0.09

(1) Data supplied by Caterpillar Tractor Company, 1978.
(2) Emission factors based on use of 0.5 percent sulfur diesel fuel.

TABLE 4.3-12

COMBINED TURBINE AND DIESEL ENGINE EMISSIONS
SHELL BETA PROJECT

YEAR	NO_x (tons/year)			HC (tons/year)			CO (tons/year)			PARTICULATE (tons/year)			SO_2* (tons/year)		
	Turb	D Eng	Total	Turb	D Eng	Total	Turb	D Eng	Total	Turb	D Eng	Total	Turb	D Eng	Total
1980	64.7	11.5	76.2	0.3	1.2	1.5	14.7	15.7	30.4	4.8	1.11	5.91	33.4	2.3	35.7
1981	135.7	23.1	158.8	13.8	2.3	16.1	37.8	31.3	69.1	4.6	2.22	6.82	0	4.6	4.6
1982	168.5	23.1	191.6	17.1	2.3	19.4	46.9	31.3	78.2	5.7	2.22	7.92	0	4.6	4.6
1983	177.2	23.1	200.3	18.0	2.3	20.3	49.3	31.3	80.6	6.0	2.22	8.22	0	4.6	4.6
1984	194.0	23.1	217.1	19.7	2.3	22.0	54.0	31.3	85.3	6.6	2.22	8.82	0	4.6	4.6
1985	205.2	13.4	218.6	20.9	1.4	22.3	57.1	18.3	75.4	7.0	1.31	8.31	0	2.6	2.6
1986	244.5	3.8	248.3	24.9	0.4	25.3	68.1	5.2	73.3	8.3	0.4	8.7	0	0.8	0.8
1987	270.4	3.8	274.2	27.5	0.4	27.9	75.3	5.2	80.5	9.2	0.4	9.6	0	0.8	0.8
1988	288.7	3.8	292.5	29.4	0.4	29.8	80.4	5.2	85.6	9.8	0.4	10.2	0	0.8	0.8
1989	294.3	3.8	298.1	29.9	0.4	30.3	82.0	5.2	87.2	10.0	0.4	10.4	0	0.8	0.8
1990	299.4	3.8	303.2	30.4	0.4	30.8	83.4	5.2	88.6	10.1	0.4	10.5	0	0.8	0.8
1991	302.4	3.8	306.2	30.8	0.4	31.2	84.2	5.2	89.4	10.3	0.4	10.7	0	0.8	0.8
1992	305.1	3.8	308.9	31.0	0.4	31.4	85.0	5.2	90.2	10.3	0.4	10.7	0	0.8	0.8
1993	336.3	3.8	340.1	32.8	0.4	33.2	89.9	5.2	95.1	14.3	0.4	14.7	15.1	0.3	15.4
1994	351.1	3.8	354.9	32.8	0.4	33.2	90.2	5.2	95.4	17.8	0.4	18.2	30.6	0.3	30.9
1995	360.1	3.8	363.9	33.1	0.4	33.5	90.9	5.2	96.1	19.5	0.4	19.9	37.6	0.3	37.9
1996	368.0	3.8	371.8	33.3	0.4	33.7	91.8	5.2	97.0	20.8	0.4	21.2	43.2	0.3	43.5
1997	369.8	3.8	373.6	33.5	0.4	33.9	92.2	5.2	97.4	20.9	0.4	21.3	43.4	0.3	43.7
1998	372.5	3.8	376.3	33.7	0.4	34.1	92.9	5.2	98.1	21.1	0.4	21.5	43.7	0.3	44.0
1999	409.3	3.8	413.1	36.3	0.4	36.7	100.1	5.2	105.3	24.7	0.4	25.1	55.9	0.3	56.2
2000	417.0	3.8	420.8	35.0	0.4	35.4	100.8	5.2	106.0	26.0	0.4	26.4	61.4	0.3	17.1

*Sulfur content of diesel fuel is assumed to be 0.25 percent by weight until 1992, and 0.10 percent thereafter. Gas fuel does not have any measurable amounts of sulfur compounds.

The annual average emissions from the turbines and diesel engines, for the lifetime of the project, are significantly lower than the worst year emissions. Table 4.3-13 lists the annual average and worst-case emissions for the turbines and the diesel engines.

TABLE 4.3-13

ANNUAL AVERAGE AND WORST-CASE TURBINE AND DIESEL ENGINE EMISSIONS

Pollutant	Annual Average Emissions (tons/year)	Worst-Case Emissions (tons/year)
NO_x	290.9	420.8
HC	27.7	36.7
CO	85.9	106.0
TSP	13.6	26.4
SO_2	18.8	61.7

(2) Offshore Emissions - Other Sources

Shell estimates that spillage of crude and lubricating oil on the platform will be extremely limited. This is based upon their experience with offshore operations and similar projects. A worst-case estimate of 100 barrels per year has been used in this analysis. Virtually all of this is expected to be recovered and injected into the processing system. The hydrocarbon emissions from a 100-barrel spill, assuming a two-percent vaporization, was less than 668 pounds (303 kg) per year (Swader and Mikolai, 1973).

Preliminary estimates by Shell for the early years of production show that two percent of the injected natural gas will have to be flared because of compressor malfunctions. This equates to a maximum of $31.5 \times 10^6 ft^3$/year ($8.9 \times 10^5 m^3$/year).

The amount of gas that is necessary to be flared will be reduced as the production of the gas from the field decreases. First priority for use of the gas is for fuel for the gas turbines. Secondary usage of the gas is for reinjection into the oil wells. The largest amount of gas to be flared, if there is a compressor malfunction, will be emitted from the high-pressure gas compressors that are used to pressurize the reinjection gas. Once there is no longer gas available for reinjection, the amount of gas flared will be significantly reduced. In addition, several compressors will be purged twice per week for maintenance. Shell estimates that 3,130 ft^3/year (88.6 m^3/year) of gas will be exhausted to the flare. Shell proposes to construct a smokeless type flare with an oil collection system at the bottom; any collected oil will be recycled. Pollutant emissions from gas flaring operations are summarized in Table 4.3-14.

TABLE 4.3-14

EMISSIONS FROM GAS FLARING

Pollutant	Emission Factor[(1)] pounds/10^6 scf	Emissions (Tons/Year) Maintenance Purging	Malfunctions	Total
NO_x	120.0	<0.01	2.0	2.0
HC	8.0	<0.01	0.13	0.13
CO	20.0	<0.01	0.32	0.32
Particulates	15.0	<0.01	0.2	0.2
SO_x	0.6	<0.01	0.1	0.1

(1) U.S. EPA Compilation of Emission Factors, AP-42, Table 1.4-1

Well servicing will take place up to four times per year per well. These operations will release small quantities of methane and some non-methane hydrocarbons (NMHC). A conservative estimate of NMHC released from each well is 200 pounds/year per well (90.7 kg/yr), or less than 12 tons per year (10.8 mt) with all 120 wells in production on both Platforms Ellen and Eureka.

An indirect air quality impact is the emission of pollutants associated with supply and crew boats. During the first three years of the project, Shell proposes to operate a 165-foot (50 m) supply boat, powered by a 1200-hp inboard diesel engine once a day between the platforms and the onshore facility (about 30 miles - 48 km - per round trip). After the first three years, the supply boat will operate once per week. A 40-foot (12 m), 800-hp diesel-powered crew boat will make a maximum of six round trips per day to and from the platforms.

The operations of both crew and supply boats will result in a total of about 49 trips per week during the first three years and about 43 trips per week thereafter. For calculation purposes, it was assumed that each boat traveled at an average speed of 13 knots (24 km/hr), and consumed 60 gallons/hour (227 l/hr) of diesel fuel. Emissions from crew and supply boats are shown in Table 3.4-15.

TABLE 4.3-15

CREW AND SUPPLY BOAT EMISIONS

Pollutant	Emissions (Tons/Year)(1) First 3 Years	Thereafter
NC_x	47.6	41.8
HC	8.8	7.7
CO	19.4	17.0
Particulates	6.2	5.4
SOx	4.8	4.2

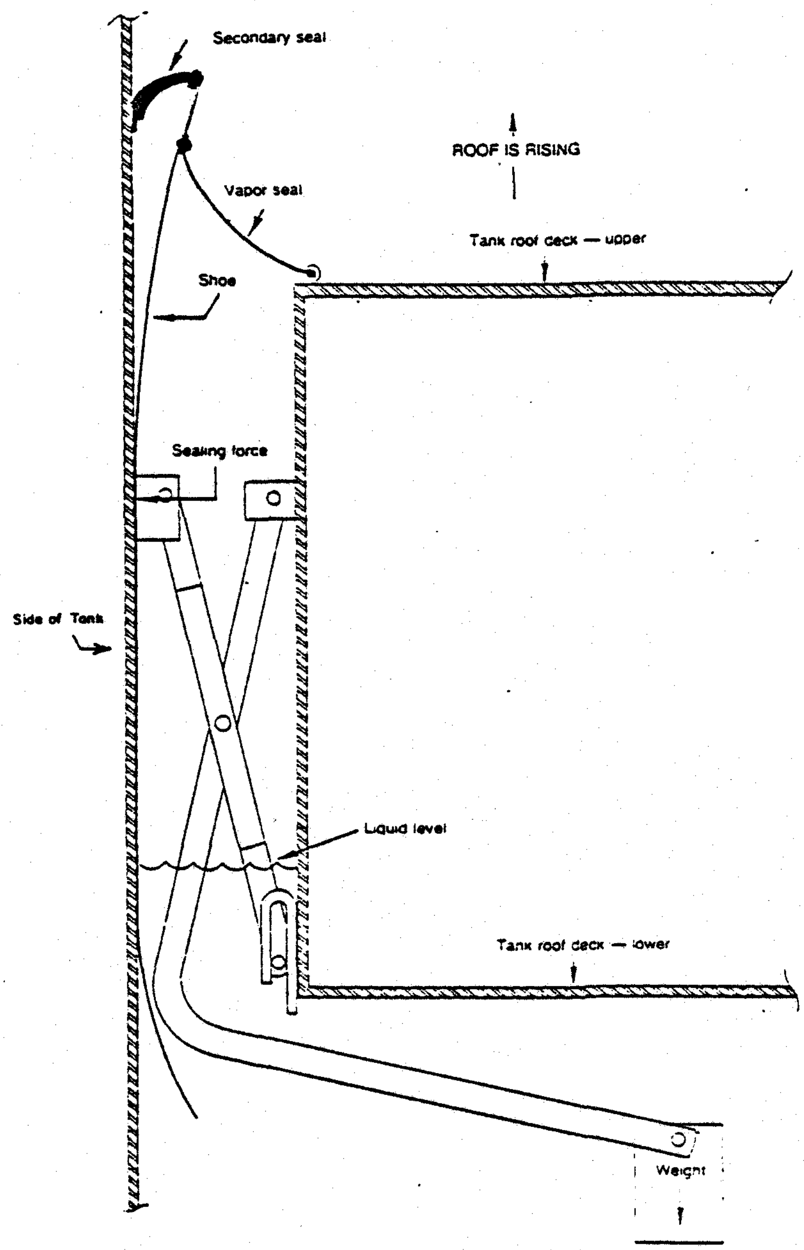
(1) Emission Factors from U.S. EPA Compilation of Emission Factors - AP-42, Table 4.3-3)

(3) Onshore Emissions

One 10,000-barrel (1,590 m^3) capacity crude oil surge tank will be constructed in the Port of Long Beach for this project. Shell proposes to install a tank equipped with a double-seal floating roof which will meet or exceed SCAQMD requirements, as outlined in Rule 463 for floating roof tanks (see Figure 4.3-1). Floating-roof tanks reduce evaporative storage losses by minimizing vapor spaces. The tank consists of a welded or riveted cylindrical steel wall, equipped with a deck or roof which is free to float on the surface of the stored liquid. The roof then rises and falls according to the depth of stored liquid. To ensure that the liquid surface is completely covered, the roof is equipped with a sliding seal which fits against the tank wall. Sliding seals are also provided at support columns and at all other points where tank appurtenances pass through the floating roof. Floating-roof tanks produce two types of hydrocarbon vapor emissions. A standing loss occurs when vapors escape from between the outer side of the sealing ring on the floating roof and the inner side of the tank wall. According to the SCAQMD, a double seal is the best available control technology, and results in emission reductions of greater than 90 percent. This technique will be used for the proposed surge tank.

A second type of hydrocarbon emission, known as "wetting loss," occurs when the floating roof moves toward the bottom of the tank during emptying. As the roof descends, a small quantity of crude oil is left on the walls of the tank and evaporates when exposed to the atmosphere.

Until recently, the only available and generally accepted method of estimating hydrocarbon emissions from floating roof tanks was that presented in American Petroleum Institute (API) Bulletin 2517 (1960). The calculation is based on an empirically-



Double Seal Floating Roof Storage Tank

4.3-1
Figure

derived technique developed from field data gathered during the 1930's and 1940's. This technique is now widely utilized throughout the industry and is generally accepted as the best available procedure for estimating emissions from storage tanks. However, API does stress the fact that these procedures can greatly overpredict emissions, and as a result, API and other groups are now beginning to reevaluate the procedures in an attempt to update them. Preliminary results of research programs (Chicago Bridge and Iron, 1976) lead to the following conclusions:

(a) Hydrocarbon emissions from floating roof tanks are dramatically lower than those estimated by API 2517.

(b) Research in the area of seal technology shows that emission losses can be further reduced by the use of secondary seals to the range of 10 to 15 percent of those predicted by API 2517.

The SCAQMD (October, 1977) selected a figure of 25 percent of API 2517 as the basis for calculating tankage emissions for the proposed SOHIO West Coast Terminal project. The SCAQMD utilized the 25 percent figure to compensate for any corrections or deviations in the Chicago Bridge and Iron research program. Storage tank emission calculations for the Beta project are presented as 100 and 25 percent of API 2517.

The following equation, from the EPA AP-42, Section 4.3.2.2, was utilized to calculate the 100-percent standing storage losses from the 10,000 barrel surge tank:

$$L_S = (9.21 \times 10^{-3})(M)\left(\frac{P}{14.7-P}\right)^{0.7} D^{1.5} V_W^{\;0.7} K_T K_S K_P K_C$$

L_S = Loss in pounds/day

M = Molecular weight of vapor = 71.5 lb/lb-mole at 113F (see Table 4.3-16)

P = True vapor pressure = 1.1 psia @ 65F

D = Tank Diameter = 40 feet (12.2 m)

V_W = Mean wind speed = 6 mi/hr (9.6 km/hr)

K_T = Tank type = 0.045 (Double seal pontoon roof)

K_S = Seal Factor = 1.00 (modern seal)

K_P = Paint Factor = 1.00 (light grey or aluminum)

K_C = Bulk liquid factor = 0.84 (crude oil)

L_S = 3.9 lb/day (1.76 kg/day)

Shell expects that all oil pumped through the pipeline from Platform Elly will be moved through the onshore pumps to

TABLE 4.3-16

ESTIMATED COMPOSITION OF SHELL BETA
CRUDE OIL VAPOR AT 113F

Components	% By Weight
Methane	0
Ethane	0.1
Propane	4.9
Iso-Butane	6.7
N-Butane	19.1
Iso-Pentane	18.6
N-Pentane	18.5
2,2-Dimethyl Butane	0.1
2,3-Dimethyl Butane	1.0
2-Methyl Pentane	7.6
Cyclo Pentane	2.8
3-Methyl Pentane	5.9
N-Hexane	5.0
2,4-Dimethyl Pentane	0.1
Methyl Cyclo Pentane	6.9
($6^{+}C$)	2.7

local refineries. The oil level in the surge tank will normally remain low and fairly constant, unless there is a malfunction of the onshore pumps. The oil in the pipeline normally does not go through the surge tanks. Therefore, as a very conservative estimate, it was assumed that the surge tank was completely filled and emptied once per month, which would result in a tank turnover of 120,000 barrels per year. From AP-42, Section 4.3.2.2., the wetting losses can be represented by the equation:

$$L_w = T\left(\frac{22.4\ d\ C_f}{D}\right)$$

L_w = Withdrawal loss in pounds/year

T = Throughput (120,000 barrels/year)

d = Density of crude (7.9 pounds/gallon @ 65°F)

C_f = Tank construction factor (0.02 for steel tanks)

D = Tank Diameter - 40 feet (12.2 m)

L_w = 446 pounds/year (202 kg/year)

The total standing storage and wetting losses are summarized by API and SCAQMD methods in Table 4.3-17.

TABLE 4.3-17

ESTIMATED ONSHORE SURGE TANK LOSSES

	Emissions in pounds/year (kg/year)	
	API	SCAQMD (25% of API)
Standing Storage Losses	1423 (642)	356 (160)
Wetting Losses	446 (202)	112 (51)
Annual Losses	1869 (844)	468 (211)

The platform-to-shore pipeline will be cleaned and serviced once per month using a device called a "pig." This process will release approximately five barrels (0.8 m^3) of crude oil into an open 20-barrel (3.2 m^3) "pig" catcher each time the pipeline is cleaned. Such operations will produce a negligible amount of fugitive hydrocarbons.

Woffinden (1976) measured fugitive heavy hydrocarbon leak rates of 0.34 lb (0.15 kg) per day from the 4,000 barrel per day ARCO Elwood facility. In addition, he estimated that only 0.35 lb (0.16 kg) per day would be lost from a proposed 20,000 barrel facility. Thus, fugitive emissions from pumps, seals, and valves are anticipated to produce a negligible amount of hydrocarbons.

Emissions from additional onshore commercial electric power generation used to provide power to operate the pumps at the distribution facility are difficult to quantify due to the interconnected nature of the electrical generation network. However, the SCAQMD (1977) has addressed a method to estimate the emissions due to the power requirement of the pumps. The power requirement is an additional 9.6 MW hours per day based on the demand of the onshore pumps (estimated to be 400 KW). Fuel burned is assumed to be 0.25 percent sulfur fuel oil. The emission factors for the power plant emissions are listed in Table 4.3-18.

TABLE 4.3-18

RELATED POWER PLANT EMISSION FACTORS FOR BETA ONSHORE ELECTRIC POWER REQUIREMENTS

Pollutant	Emission Factor lbs/MW Hour
NO_x	2.5
SO_x	2.61
Particulate Matter	0.5
HC	0.2

SOURCE: SCAQMD (1977)

The total annual emissions associated with all offshore and onshore operations of the Beta project are summarized in Table 4.3-19.

4.3.2 Air Quality Impacts

4.3.2.1 Attainment Areas

In the previous sections, information was presented to describe the air quality environmental setting of the project and the project itself. The impacts of the project depend on the existing air quality in the area, the emissions generated to the atmosphere from the project, and the amount of dilution and dispersion afforded the emissions before they reach a receptor. One additional factor considered in this analysis is the question of which agency has jurisdiction over the project's offshore emissions, since factors used in determining levels of impact (and permitting requirements) vary from agency to agency. The purpose of any of the agencies is to protect the public health through improvement of air quality. A detailed discussion of effects of air pollutants on health can be found in the Final Revised Air Quality Appendix to the

TABLE 4.3-19

OPERATIONS PHASE

EMISSIONS SUMMARY TONS/YEAR (lbs/day)

Activity	Total Hydrocarbons	Sulfur Oxides	Particulate Matter	Nitrogen Oxides	Carbon Monoxide
Production[1][2] Platform	37.0 (203) 27.7	61.7 (338) 18.8	26.4 (145) 13.6	420.8 (2306) 290.9	106.0 (581) 35.9
Gas Flaring	0.13 (0.72)	0.01 (0.06)	0.2 (1.1)	2.0 (11.0)	0.32 (1.8)
Well Servicing	6.0 (32.8)	--	--	--	--
Platform Oil Spill	0.33 (1.8)	--	--	--	--
Crew/Supply[3] Boats	8.8 (48.2)	4.8 (26.3)	6.2 (33.9)	47.6 (260.8)	19.4 (106)
Employee Vehicles	0.5 (2.7)	Negl.	Negl.	2.0 (11.0)	12.6 (9.1)
Onshore Tankage	0.9 (4.9)	--	--	--	--
Onshore Electric Power Generation	0.3 (1.6)	4.6 (25.2)	0.9 (4.9)	4.4 (24.1)	--
Totals[1][2]	53.9 (295.7) 44.7	71.1 (389.6) 28.2	33.7 (184.9) 20.9	476.8 (2612.9) 346.9	138.3 (758.2) 118.2

(1) Maximum yearly emissions per Table 4.3-12.
(2) Second row of numbers represents annual average emissions per Table 4.3-13 expressed in tons/year.
(3) Maximum during first three years.

SOHIO West Coast to Mid-Continent Pipeline EIR, Port of Long Beach, 1977. In summary, the effects on health of ozone at certain concentrations include breakdowns in membranes, and breathing difficulties. Exposure to high ambient concentrations can cause a kind of suffocation stemming from oxygen deficiency, but the effect is less than one cigarette. High SO_2 concentrations can cause respiratory diseases in children, lung irritation, chest spasms, and lack of oxygen. Nitrogen dioxide can cause leaf browning, and affects the lining of the lung and lung cells. Long-term continued exposure to high levels of particulates may be associated with increases in chronic respiratory diseases. Exposure to particulates in conjunction with sulfur dioxide may produce acute illnesses.

Existing air quality, nine miles (14.4 km) offshore, is anticipated to meet both federal and California ambient air quality standards (Table 3.3-16). However, within the SCAQMD land area, air quality standards are violated for all air contaminants for which there are standards. Where the transition zone between attainment and non-attainment occurs is subject to speculation and undoubtedly occurs at different locations with differing meteorological conditions.

The emissions generated by the project and the associated meteorology which provides the transport, dilution, dispersion, and oxidation are later considered by pollutant for the maximum day and annual average situation using EPA-approved dispersion models.

Concerning the jurisdiction questions, these analyses simplify the approach by first assuming that the offshore platforms are either located in an attainment area or that they are located in a non-attainment area, regardless of jurisdiction. If the platforms are located in an attainment area, where existing air quality is cleaner than the EPA standards, then a major new project must comply with EPA's Prevention of Significant Deterioration (PSD) guidelines, which are described later. If the project is located in a non-attainment area, then it must comply with New Source Review air quality analyses and offset requirements. In the case of the Shell Beta project, its location in the ocean outside the three-mile limit of state authority may mean that none of the environmental agencies (EPA, CARB, or SCAQMD) has jurisdiction. Instead, the Department of Interior may have sole jurisdiction for the Outer Continental Shelf (OCS). Each of the agencies is described below in terms of its authority and the consequent relationship to the Shell Beta project.

(1) <u>U.S. Environmental Protection Agency (EPA)</u>

In 1970, the U.S. EPA designated Air Quality Control Regions (AQCR) encompassing the entire United States and its territories. However, the Outer Continental Shelf beyond the three-mile limit of state jurisdiction was not included in the AQCR designations. More recently, on April 13, 1978, EPA made a Notice of Determination that the Clean Air Act, as amended, and the regulations promulgated thereunder, does apply to activities on the OCS, when such activities could affect the air quality of an adjacent state.

(2) U.S. Department of Interior

On September 18, 1978, the amendments to the OCS Act gave to the Secretary of the Interior the power to promulgate regulations for compliance with National Ambient Air Quality Standards (NAAQS) of the Clean Air Act to the extent that the activities under the OCS Act significantly affect the air quality of a state. The amendments to the OCS Act state the following:

> "By their adoption of requirements for regulations for compliance with air quality standards it is not intended to supersede the Clean Air Act or the responsibilities of the EPA Administrator. There is no intent to affect, extend, or reduce whatever present authority the EPA has in applying and enforcing the Clean Air Act, including the use of EPA's permitting authority."

(3) California Air Resources Board (CARB)

The CARB was empowered by the State Legislature to adopt rules, under specified conditions, and to maintain jurisdiction for local air pollution control districts. Generally, the CARB follows a procedure which includes workshops and/or public hearings on model rules. After a hearing on a model rule, the CARB may "suggest" that the model rule or equivalent be adopted within 60 days by a local district of districts. If action is not taken by the local district or districts on the CARB "suggestion," the CARB may itself adopt that rule for the local district or districts. Such was the case when the CARB adopted Rule 213 for the South Coast Air Quality Management District (SCAQMD) pertaining to required review procedures for major new source applicants. The CARB assumes an overseer position on the SCAQMD construction permits and in some cases, under Rule 213, both EPA and the CARB must approve the SCAQMD determinations. Jursidiction over the Shell Beta project may be reached directly by the CARB's presumed authority over facilities affecting the coastal waters which were defined by CARB to extend 60 miles offshore from the SCAQMD (CARB, 1977).

(4) South Coast Air Quality Management District (SCAQMD)

This agency was created by the California General Assembly to administer a local air pollution control program for several counties in the Los Angeles Basin. The SCAQMD clearly has jurisdiction over the onshore tankage portion of the Shell Beta project. Since a pipeline connects the onshore and offshore project, SCAQMD jurisdiction may extend to the offshore facility. Also, since emissions from the offshore facility may affect the SCAQMD air quality, authority for some control may be claimed by SCAQMD.

Regardless of agency jurisdiction, the Clean Air Act, as amended in August 1977, provides the fundamental legal authority under which air emissions are controlled in the United States. Certain authorities are delegated to other federal, state, or local

TABLE 4.3-20

EPA INCREMENTS FOR PREVENTION OF SIGNIFICANT DETERIORATION

Pollutant	Maximum Allowable Increase (micrograms per cubic meter)
CLASS I	
Particulate matter:	
Annual geometric mean	5
24-hr. maximum	10
Sulfur dioxide:	
Annual arithmetic mean	2
24-hr. maximum	5
3-hr. maximum	25
CLASS II	
Particulate matter:	
Annual geometric mean	19
24-hr. maximum	37
Sulfur dioxide:	
Annual arithmetic mean	20
24-hr. maximum	91
3-hr. maximum	512
CLASS III	
Particulate matter:	
Annual geometric mean	37
24-hr. maximum	75
Sulfur dioxide:	
Annual arithmetic mean	40
24-hr. maximum	182
3-hr. maximum	700

agencies, but EPA maintains some level of control regardless of such delegation.

For the entire nation, EPA has promulgated rules to protect those areas which are cleaner than ambient air quality standards; these rules are entitled "Prevention of Significant Deterioration" (PSD).

EPA established, on June 19, 1978, increments shown in Table 4.3-20 as maximum increases in air quality levels which can be allowed from a major new source in a clean air area. In addition, EPA has established levels that represent the minimum amount of ambient impact that is significant for sources in an attainment area but affecting a non-attainment area. These are shown in Table 4.3-21. Class I areas are those where pristine air quality is desired; Class II areas are those where some development may occur; Class III areas are those which already exceed ambient air quality standards. The modelling which follows compares the projected impacts with the various EPA requirements described above.

TABLE 4.3-21

EPA AIR QUALITY LEVELS REPRESENTING THE MINIMUM AMOUNT OF AMBIENT IMPACT THAT IS CONSIDERED SIGNIFICANT

		Averaging Time			
Pollutant	Annual	24-Hour	8-Hour	3-Hour	1-Hour
SO_2	1 $\mu g/m^3$	5 $\mu g/m^3$		25 $\mu g/m^3$	
TSP	1 $\mu g/m^3$	5 $\mu g/m^3$			
NO_x	1 $\mu g/m^3$				
CO			0.5 mg/m^3		2 mg/m^3

SOURCE: "Prevention of Significant Air Quality Deterioration, State Implementation Plan Requirements," EPA, June 19, 1978

The initial step for determining the degree of air quality impact of the Beta project was to compile a comprehensive emission inventory. The inventory is categorized by modes of operation (*i.e.*, indirect or direct emissions), the rate and schedule of emission, and, in some cases, the probability of an emission-producing activity.

After the emission sources have been categorized, projections of expected air quality impacts are made using appropriate mathematical dispersion models that relate emissions to air quality concentrations under adverse meteorological conditions. The degree of analysis of impact is directly related to the significance of the impact (and, in turn, the quantity of emissions). The most thorough analysis was made for the turbine and diesel engines, since they are the major source of pollutants from the project.

(1) Construction Phase Impacts

(a) Offshore Impacts

The installation and outfitting of the offshore platforms will cause temporary intermittent air quality impacts. These impacts will be insignificant due to the relatively small quantities of emissions and the intermittency of the activity.

Nitrogen oxides are the pollutant emitted in the largest quantity during installation and outfitting of the offshore platforms. The majority of these emissions will occur from the derrick barge. The principal cause of NO_x emissions is the use of heavy-duty diesel engines on the derrick barge, tug, and crew boats. The impact of these emissions is an increase in NO_x emissions of about 0.01 percent over current emissions (see Table 3.3-12 and Figure 3.3-11) in Los Angeles County. This increase is small when compared with regional emissions for nitrogen oxides.

These vessel-related emissions essentially will be a non-continuous line source from Long Beach to the platforms. Due to the relatively small amount of pollutants emitted over a large distance (approximately 15 miles (24 km)), impacts of these emissions are likely to be insignificant.

(b) Onshore Impacts

Fugitive dust emissions from excavation of the onshore distribution site will temporarily increase dust levels. In this instance, the impacts will be minimal and will be mitigated by the usual dust control method (a water spray).

Exhaust from the workers' automobiles will be the prime source of carbon monoxide, nitrogen oxides, and hydrocarbons. Approximately 220 vehicles will converge on the site during a typical work day, and these emissions could create localized short-term "hot-spots" around the site during peak commuter hours. Other studies of large-scale construction activities in the Port of Long Beach showed a negligible increase in CO levels by the workers' commuting traffic.

(2) Operations Phase Impacts

The pollutants NO_2, SO_2, and TSP were modeled as non-reactive pollutants using computerized air quality dispersion models. The concentrations of these pollutants were determined using the Texas Air Control Board's Texas Episodic Model (TEM) and the EPA's AQDM. The Texas Model is used for calculating short-term impacts (one to twenty-four hours), and the AQDM was used for the annual average calculations. These models are both recommended for air quality impact analyses in the EPA's guideline document on air quality modeling (EPA, 1977). Both models assume a steady-state Gaussian plume formula. The vertical (σz) and horizontal (σy) dispersion coefficients are assumed to be Gaussian and the rates of spreading are determined from the Pasquill-Gifford coefficients.

To use the models, it was necessary to describe the meteorological conditions that would produce reasonable worst-case estimates of the impact from the project. For the platforms, the maximum plume centerline concentrations occur under neutral to stable stability conditions, and low wind speeds and mixing heights. This meteorology is representative of the southern California coastline and offshore waters. The wind directions used to model short-term impacts were selected to produce the shortest path to the coastline. In this case, a wind direction of 235° was input into the models. For annual averages, the meteorology was determined using joint frequency distributions from the STAR data for Long Beach, which was the only data in close proximity to the project site that incorporates stability data with wind speeds and directions.

All calculations in this analysis were performed assuming conservation of pollutants (i.e., the pollutants were assumed to be chemically inert). In addition, no pollutant deposition or removal was credited for SOx and NOx over the oceans, even though deposition will occur. A conservative assumption of 100 percent NO to NO_2 conversion was also utilized in this analysis. These assumptions will result in conservative (i.e., higher than actual) values for the impact of the Beta project. As noted in the Environmental Setting, the percentage of wind directions that could transport pollutants into the SCAB occurred about 65 percent of the time on an annual basis.

(a) Nitrogen Dioxide Emission Impact

Nitrogen dioxide exhause from the turbines and diesel engines will be the major source of emissions from the platforms and drilling rigs. The emissions for each case are summarized in Table 4.3-22. The annual average and short-term models were utilized to calculate the NO_2 impacts at the shoreline and the three-mile limit. Crew and supply boat emissions were considered to be intermittent in nature, and were eliminated from the modeling analysis. All sources modeled (*i.e.*, the Saturn and Centaur turbines and the Cat D-398 diesel) were assumed to be point sources. Exhaust stack characteristics of these sources are presented in Table 4.3-23.

The maximum increases in ambient NO_2 will occur well out at sea. The model results based on the AQDM model indicate an annual maximum NO_2 value of 0.46 $\mu g/m^3$ approximately two miles (3.2 km) downwind of the platforms. The TEM model indicates a worst-case 1-hour maximum of NO_2 of 12 $\mu g/m^3$ approximately four miles (6.4 km) downwind of the platforms. The results are shown in Table 4.3-24.

TABLE 4.3- 22

TURBINE AND DRILLING RIG EMISSIONS

Source Identification	Emissions[1] tons/day (kilograms/day)			
	SO_x	NO_x	CO	Particulate
Saturn Turbines	0.06 (81.8)	0.42 (381.0)	0.10 (90.7)	0.03 (27.2)
Centaur Turbines	0.08 (72.7)	0.72 (653.2)	0.17 (154.2)	0.05 (45.4)
CAT D-398 Diesels	0.001 (0.9)	0.01 (9.5)	0.01 (9.1)	0.001 (1.0)

SOURCE: Based on production characteristics supplied by Shell Oil Company, 1978, and emission factors in Tables 4.3-9 and 4.3-11.

TABLE 4.3-23

STACK PARAMETERS FOR TURBINES AND DIESEL ENGINES

Source	Height (M)	Diameter (M)	Velocity ($MSec^{-1}$)	Temperature (°C)
Saturn Turbines	29.0	0.87	55.1	399.0
Centaur Turbines	29.0	2.79	19.8	177.0
Cat D-398 Diesel	29.0	0.3	5.0	100.0

TABLE 4.3-24

INCREASE IN NO_x CONCENTRATIONS FROM BETA PROJECT

Regulation/Standard	Averaging Time	Maximum Allowable Concentration $\mu g/m^3$	Calculated Maximum Increase In Concentration[1] $\mu g/m^3$
EPA Significance	Annual	1	0.05
Federal NAAQS	Annual	100	0.05
California AAQS	1-Hour	470	11.0

(1) Three-mile territorial limit

Onshore and three-mile impacts were predicted to be minimal. The worst-case one-hour NO_2 concentrations at the three-mile limit and shoreline were 11 $\mu g/m^3$ and 8 $\mu g/m^3$, respectively. These modeling results are conservative for the reasons previously discussed, and using the assumption of an undirectional wind. If the 11 $\mu g/m^3$ predicted concentration were to occur, the state one-hour NO_2 standard of 470 $\mu g/m^3$ would not be approached. Similarly, the annual average dispersion calculations showed minimal impacts at the three-mile limit and shoreline of 0.05 $\mu g/m^3$ and 0.03 $\mu g/m^3$, respectively. These concentrations are considerably less than the EPA significance level of 1 $\mu g/m^3$ annual average for NO_2.

In summary, it can be assumed from the modeling that NO_x emissions from the platforms and drilling rigs will have a minimal impact on air quality in the Los Angeles Basin.

(b) Sulfur Dioxide Emission Impact

The impact of SO_2 emissions in the vicinity of the project was determined using the Gaussian plume models. The operational cases modeled were the same as defined earlier for NO_2. The sulfur dioxide emissions and operational data for the engines are summarized in Tables 4.3-22 and 4.3-23. The SO_2 emissions were examined under a number of meteorological conditions and averaging times.

The ambient air quality standards for SO_2 are prescribed for 1 hour, 3 hours, and 24 hours, as well as for an annual standard. In addition to these, EPA has defined significance levels for SO_2 concentrations on a 3 hour, 24 hour, and annual basis. Table 4.3-25 shows the predicted increase in ambient SO_2 concentrations resulting from the project.

TABLE 4.3-25

INCREASE IN SO_2 CONCENTRATIONS FROM BETA PROJECT

Regulation/Standard	Averaging Time	Maximum Allowable Concentration $\mu g/m^3$	Calculated Maximum Increase In Concentration[1] $\mu g/m^3$
EPA Significance	3 hour	25.0	2.0
EPA Significance	24 hour	5.0	1.0
Federal NAAQS	24 hour	365.0	1.0
EPA Significance	Annual	1.0	0.01
Federal NAAQS	Annual	80.0	0.01
California AAQS	1 hour	1310.0	2.0

(1) Three-mile territorial limit

The maximum concentration of SO_2 will also occur well out to sea. The worst-case 1 hour, 3 hour, and 24 hour concentrations were modeled by the TEM and were as follows: the 1 hour maximum of 2 $\mu g/m^3$ was four miles (6.4 km) downwind, the 3 hour maximum of 1 $\mu g/m^3$ was six miles (9.6 km) downwind, and the 24 hour maximum of 1 $\mu g/m^3$ was four miles (6.4 km) downwind. The annual maximum of 0.06 $\mu g/m^3$ was two miles (3.2 km) downwind. Further, if any of the maximum concentrations were to reach the coastline, neither the federal or state standards would be approached. It may, therefore, be assumed that the platform and drilling rig SO_2 emissions will have a minimal effect on air quality in the South Coast Air Basin.

The Beta project's sulfur dioxide emissions may contribute somewhat to the formation of sulfate in the Basin. Based on the SO_2 modeling results, it would be expected that these impacts would be minimal.

Sulfates are of primary concern because of their effects on health and visibility reduction. The high sulfate concentrations found in the South Coast Air Basin are caused by the area's climatology and geography. During the summer months, photochemical activity is at its peak, and these processes can cause rapid conversion of SO_2 to sulfate if the proper combination of meteorological factors is attained. Research studies indicate that an SO_2 conversion rate to sulfate is in excess of 10 percent per hour.

No accepted modeling technique is available to calculate any sulfate formation caused by the project's emissions of sulfur dioxide. However, the project emissions of SO_2 will be minimized, to the greatest extent possible, by burning low sulfur diesel fuel.

It is also likely that a high percentage of the SO_2 emissions would be absorbed by their interaction with the ocean surface as the plume travels toward the South Coast Air Basin, thus further reducing the impact of these emissions.

(c) Particulate, Carbon Monoxide, and Hydrocarbon Impacts

The ambient air quality standards (Table 3.3-16) for particulate include the California standard for a 24 hour period (100 $\mu g/m^3$) as well as the state annual geometric mean standard (60 $\mu g/m^3$). EPA has promulgated significance levels for particulate (Table 4.3-20) on a 24-hour averaging time (5.0 $\mu g/m^3$) and annually (1.0 $\mu g/m^3$). Modeling the particulate emissions with the short-term and annual Gaussian dispersion equations, and worst-case meteorology, yielded negligible ground level concentrations at the three-mile limit and the shoreline.

The carbon monoxide impacts at the three-mile limit and coastline were insignificant. A one-hour significance level of 2 $\mu g/m^3$ for CO was selected by EPA and the modeling indicated maximum concentrations of only 0.003 $\mu g/m^3$ and 0.002 $\mu g/m^3$ at the three-mile limit and shoreline, respectively. Operational emissions of carbon monoxide and particulate will have negligible impacts on coastal air quality.

The project turbines and diesels running at their maximum load will emit only 200 pounds per day of hydrocarbons and thus are expected to have little or no impact. The hydrocarbon emissions from the onshore 10,000 barrel (1,590 m^3) surge tank are about 5 pounds per day. This assumes that Shell utilizes the best available control technology - BACT (floating roof with double seals) - to control hydrocarbons.

4.3.2.2 Non-Attainment Areas

Assuming that the Shell Beta project is either in a non-attainment area or that one of the agencies exercises jurisdiction over the project as if it were within the South Coast Air Quality Control Region, then a different set of impact analyses and requirements must be met.

In December 1976, with statutory dates for attainment of the National Ambient Air Quality Standards (NAAQS) either past or pending, EPA addressed the question of how to treat applications for construction of new or modified sources in those areas of the country that had still not attained the standards. The ruling was entitled "Interpretative Ruling for Implementation of the Requirements of 40CFR51.18," and contained the following statement in the introduction:

> "Briefly stated, the Ruling reflects EPA's judgement that the Clean Air Act does not prohibit major new or expanded sources in areas that exceed a NAAQS, provided that the net effect of the new emissions, together with reductions from existing facilities beyond that required by the SIP, does not exacerbate current primary (health) standard violation, but instead contributes to reasonable progress in attaining such standards."

At the heart of this Interpretative Ruling was the offset or trade-off policy. In addition, amendments to the 1977 Clean Air Act and the SCAQMD New Source Review Rule 213[1] further refined the basis for assessment of impact in non-attainment areas. The SCAQMD Rule 213 provides that any new source or expansion of an existing source that emits more than 15 pounds/hour, or 150 pounds/day for any pollutant must incorporate BACT. If the source emits more than 25 pounds/hour or 250 pounds/day of any pollutant, then the source will be subjected to an air quality impact analysis, and may require emission offsets for all pollutants. The goal is to achieve a net air quality benefit wthin the non-attainment area. As noted in subsequent discussion (Table 4.3-29), the Shell Beta project will

[1] Rule 213 was adopted for the District by the California Air Resources Board on October 8, 1976.

exceed the 250 pounds/day "cut off" in terms of HC, SO_2, and NO_x, and will, therefore, be subject to an air quality impact analysis and possible provision of appropriate emission offsets.

To aid in compliance with Rule 213, the SCAQMD has issued guidelines for projects to meet the following offset (trade-off) criteria established under Rule 213:

(1) The total annual emission reductions achieved by trade-offs must exceed the total annual average project emissions by a factor of 2.0 or more for each pollutant (SO_x, NO_x, PM, and ORG). This ratio is known as the Project Benefit Ratio; and

(2) The daily emission reductions achieved by trade-offs must exceed the expected daily project emissions at the maximum operational level by a factor of 1.2 or more. This factor is known as the Safety Factor.

SCAQMD has verbally (at public forums and meetings) indicated the following guidelines on offsets:

(1) Intra-pollutant trade-offs only;

(2) Hydrocarbon trade-offs may be basinwide (South Coast Air Basin):

(3) NO_x, SO_x, and TSP trade-offs in near vicinity (3.2-8.0 km (2-5 miles)). If not enough trade-offs are available in the near vicinity, a larger trade-off area may be acceptable. SCAQMD may also consider dispersion modeling to determine location of NO_x, SO_x, and TSP trade-offs;

(4) Intra-company trade-offs (same location) on a 1:1 basis;

(5) Intra-company trade-offs at different locations must satisfy the Project Benefit Ration and the Safety Factor (preceeding paragraph);

(6) Carbon monoxide (CO) may be excluded from trade-offs;

(7) Emission reductions as a result of installing and placing into operation air pollution control equipment prior to December 31, 1979 on a trade-off candidate will result in full offset credit. In addition, the SCAQMD has stated control equipment placed into operation after December 31, 1979 will be allowed offset credits only for the amount of reductions in excess of those required as a part of the SIP revisions. (Written confirmation is pending.)

(8) Subsection (b) maintains that the Air Pollution Control Officer (APCO) will deny an authority-to-construct permit for a new source that will emit more

than 15 pounds/hour (6.8 kg/hour) or 150 pounds/day (68 kg/day) of nitrogen oxides or organic gases unless the best available control technology will be utilized by the new source;

(9) The APCO may exempt from the provisions of subsection (c) of Rule 213 any new stationary source that utilizes unique and innovative control technology which will result in a significantly lower emission rate from the stationary source than would have occurred with the use of previously known best available control technology, and which will likely serve as a model for technology, to be applied to similar stationary sources within the state.

In addition to the model rules mentioned in the preceeding section, the SCAQMD has under consideration amendments to its solvent usage rule, service station vapor recovery rule, and sulfur content of fuels rule. The SCAQMD also is considering new rules on iron ore sintering operations, nitrogen oxides from water heaters, emission standards for asbestos, lightering vessel operations, and flanges and valves.

In addition to the efforts of the SCAQMD, over the past two years the CARB has conducted many workshops and hearings on model rules for a variety of sources and operations emitting sulfur compounds, nitrogen compounds, and/or organic compounds. These rules, and their suggested emission limits, are summarized in Tables 4.3-26, 4.3-27. and 4.3-28.

Many of the model and proposed rules have been undergoing review and/or have not progressed to the stage where the CARB has deemed it advisable to request their adoption by the SCAQMD. Some may even have been tabled indefinitely as a result of rules adopted by the SCAQMD. At the present time, there are only two rules that have been forwarded to the SCAQMD by the CARB for adoption which have not yet been acted upon. One is a rule for reducing nitrogen oxides (NO_x) from residential furnaces, and the other is a rule for reducing volatile organic compounds (VOC) from automobile coating operations.

A subjective evaluation only can be given of the impact of these model and proposed rules on available offsets. New terms and units have been introduced for the emission limits of the model and proposed rules which are not directly comparable to the terms and units in present rules. Also, adoption of the model and proposed rules in their present form, if adopted at all, is uncertain.

4.3.3 Mitigation

In response to the possibility that Rule 213 may be applied, potential offsets available within the South Coast Air Basin as the means of mitigating the Beta project emissions have been identified and are presented within the following sections.

TABLE 4.3-26

CARB PROPOSED OR MODEL RULES FOR CONTROL OF SO_2 EMISSIONS IN SCAQMD

Source to be Controlled	Suggested Emission Limits
1. Sulfur contents of fuels.	(a) 0.1 sulfur by weight in liquid fuels. (b) Equivalent of 0.1% sulfur converted to lbs. per 10^6 btu for solid fuels.
2. Sulfur contents of fuels for non-electric generating units.	(a) 0.25% sulfur by weight for liquid and solid fuels. (b) 240 ppm H_2S for natural gas (15 gr. per 100 ft.^{3}). (c) 800 ppm H_2S for industrial gas (50 gr. per 100 ft.^{3}).
3. Sulfur contents of fuels for boats, ships and vessels towing barges (pleasure craft exempted)	(a) 0.1% sulfur by weight for liquid fuels burned in South Coast Air Basin (SCAB) waters, or (b) 0.5% sulfur by weight if this type fuel is burned at all locations which impact SCAB.
4. Sulfur recovery and sulfuric acid plants.	(a) 150 ppm SO_2 in effluent.
5. All stationary SO_2 sources.	(a) 150 ppm SO_2 in effluent.
6. Lightering vessels.	(a) 0.5% sulfur by weight in fuel.
7. Petroleum coke calcining.	(a) 750 grams SO_2 per metric ton (1.5 lbs. per ton) and 25 kg. SO_2 per hour for existing calciners. (b) 450 grams SO_2 per metric ton and 20 kg. SO_2 per hour for new calciners.

TABLE 4.3-26 (Cont'd.)

CARB PROPOSED OR MODEL RULES FOR CONTROL OF SO_2 EMISSIONS IN SCAQMD

Source to be Controlled	Suggested Emission Limits
8. Fluid catalytic cracking units.	(a) 750 ppm SO_2 (dry basis), and (b) 200 kg. SO_2 per 10^3 bbls. of feed (when adopted). (c) 120 kg. SO_2 per 10^3 bbls. of feed (two years later). (d) 20 kg. SO_2 per 10^3 bbls. of feed (five years later).
9. Steam generators for electric power - 2000 net MW or larger.	(a) 30 ppm SO_2 at 3% O_2.
10. Steam generators - medium.	(a) 60 ppm SO_2 at 3% O_2.
11. Marine vessels (commercial).	(a) Low sulfur fuels (hearing not yet held - October 26, 1978).
12. Stationary sources.	(a) Not defined in Notice (hearing not yet held - December 13, 1978).

TABLE 4.3-27

CARB PROPOSED OR MODEL RULES FOR CONTROL OF NO_x EMISSIONS IN SCAQMD

Source to be Controlled	Suggested Emission Limits
1. Steam and gas turbine units for generating electricity.	(a) 100, 125 and 150 ppm NO_x at 3% O_2 for existing gas-fired steam units with burners tangential, opposed or face positioned, respectively. (b) 175, 200 and 225 ppm NO_x at 3% O_2 for existing liquid or solid fuel-fired steam units with burners tangential, opposed or face positioned, respectively. (c) 75 and 150 ppm NO_x at 3% O_2 for new gas-fired and liquid or solid fuel-fired steam units, respectively. (d) 75 and 100 ppm NO_x at 3% O_2 for existing gas-fired and liquid-fired gas turbine units, respectively. (e) 50 and 75 ppm NO_x at 3% O_2 for new gas-fired and liquid-fired gas turbine units, respectively.
2. Boilers and process heaters not used for generating electricity. (Small units - < 2.5 x 10^6 K cal/hr. or 10 x 10^6 Btu/hr. - excluded.)	(a) 100 and 150 ppm NO_x for existing horizontally-fired heaters with forced draft on gas and liquid or solid fuels, respectively. (b) 125 and 150 ppm NO_x for existing natural or induced draft units on gas and liquid or solid fuel, respectively. (c) 100 and 150 ppm NO_x for new units on gas and liquid or solid fuel, respectively.

TABLE 4.3-27(Cont'd.)

CARB PROPOSED OR MODEL RULES FOR CONTROL OF NO_x EMISSIONS IN SCAQMD

Source to be Controlled	Suggested Emission Limits
3. New Gas-fired fan type central furnaces.	(a) 60 nanograms NO_x/joule of heat delivered to heated space, decreasing to 40 nanograms/joule and eventually to 12 nanograms/joule in the latter half of the eighties.
4. Stationary internal combustion engines[1].	(a) 50% reduction depending upon type of engine, fuel used and load characteristics.
5. Glass melting furnaces[1].	(a) 20% reduction by 1978.
6. Industrial boilers and heaters[1].	(a) 50 to 90% reduction.

[1] Model rule not located.

TABLE 4.3-28

CARB PROPOSED OR MODEL RULES FOR CONTROL OF VOC EMISSIONS IN SCAQMD

Source to be Controlled	Suggested Emission Limits
1. Lightering vessels.	(a) 95% control of non-methane HC vapors displaced during filling.
2. Transfer of gasoline into stationary storage containers.	(a) 95% control of HC vapors displaced during filling.
3. Transfer of gasoline into vehicle fuel tanks.	(a) 95% control of HC vapors displaced during filling from facilities dispensing 50,000 gallons per month or more.
4. Transfer of gasoline into tank trucks.	(a) 0.6 lbs. per 1000 gallons of gasoline transferred.
5. Marine coating operations.	(a) 295 grams VOC per liter of coating (minus water). (b) Other limits for high performance coatings depending on generic type.
6. Metal parts and product coating (formerly metal furniture and fixtures). (See No. 11.)	(a) 275 grams VOC per liter of coating (minus water) for baked coating and 340 grams VOC per liter of coating (minus water) for air-dried coatings. (b) 180 grams VOC per liter of coating (minus water) for new sources utilizing baked coatings after January 1, 1982.

TABLE 4.3-28 (Cont'd.)

CARB PROPOSED OR MODEL RULES FOR CONTROL OF VOC EMISSIONS IN SCAQMD

Source to be Controlled	Suggested Emission Limits
6. (Cont'd.)	(c) Electrostatic application or other techniques to provide at least 65% transfer efficiency. (d) Excludes automobiles, light-duty trucks, aircraft, aerospace vehicles, marine vessels, cans, coils and magnetic wire.
7. Can coating.	(a) 180 grams VOC per liter of coating (minus water) for sheet base coat (exterior and interior) and overvarnish. (b) 250 grams VOC per liter of coating (minus water) for two-piece can exterior base coat and over-varnish. (c) 510 grams VOC per liter of coating (minus water) for two and three-piece can interior body spray and two-piece can exterior end spray or rollcoat. (d) 660 grams VOC per liter of coating (minus water) for three-piece can side seam spray. (e) 440 grams VOC per liter of coating (minus water) for end sealing compound. (f) Appropriate control measures (such as afterburners) instead of low solvent coatings.

TABLE 4.3-28 (Cont'd)

CARB PROPOSED OR MODEL RULES FOR CONTROL OF VOC[1] EMISSIONS IN SCAQMD

Source to be Controlled	Suggested Emission Limits
8. Coil coating.	(a) 180 grams VOC per liter of coating (minus water for prime and top coat in single coating operations. (b) Appropriate control measures (such as afterburners) instead of low solvent coatings.
9. Paper and fabric coating.	(a) 120 grams VOC per liter of coating (minus water) when heating ovens are used. Exemption for coatings where less than 256 grams VOC per liter (minus water) are applied.
10. Organic solvent degreasing.	(a) Specified good practices and design for closed top degreasers. (b) 85% control (by weight) for open top degreasers.
11. Metal furniture coating (may have been superseded by No. 6).	(a) Low solvent coatings (either water-borne, high solids or powder) for oven-baked coatings by January 1, 1982. (b) Powder coatings or equivalent emission control measures for oven-baked coatings by January 1, 1987.

[1] Volatile organic compounds (Hydrocarbon)

Since the Beta project location is approximately 9 miles (14.4 km) southwest of Huntington Beach, the 2-to-5 mile (3.2-8.0 km) trade-off area, as suggested in item No. 3 of Section 4.3.2.2, cannot be met. An area of 20 miles (32 km) in radius from Huntington Beach was utilized to identify point sources of TSP, SO_2, and NO_x as potential trade-offs. The entire South Coast Air Basin was utilized for HC sources for potential trade-offs. The basic source of data was the SCAQMD EIS Trade-Off Report, published August 16, 1978. Emissions data contained within this report were for the year 1977.

The EIS Trade-Off Report was analyzed to identify potential trade-offs in one of two general categories: internal trade-offs within the Shell Oil Company and third party trade-offs. In addition to the data within the EIS Trade-Off Report, numerous candidates were personally contacted to delineate additional sources of potential trade-offs.

In addition to the area breakdown of source classifications, potential candidates were delineated by the following emission categories for specific pollutants: hydrocarbons, sources greater than 22.7 metric tons (25 tons) per year; particulates, nitrogen oxides, and sulfur dioxide sources greater than 9.1 metric tons (10 tons) per year. A cut-off point of 9.1 metric tons (10 tons) per year was chosen for TSP, SO_2, and NO_x, due to insufficient large sources in the area of study.

Table 4.3-29 shows the total emissions from the primary and secondary sources for both the offshore and the onshore facilities of the Beta project, as previously summarized in Table 4.3-19. Both the maximum daily emissions and the maximum annual emissions are presented. As previously indicated, the maximum emissions for the project occur during the year 2000. The analysis of the project emissions was provided in Section 4.3.1.2(1).

As noted earlier under Rule 213, all pollutants from the Beta project must be traded off, with the exception of CO. Using the SCAQMD values, Table 4.3-30 presents a comparison of the Project Benefit Ratio (2.0 times the annual emissions) and the Safety Factor (1.2 times the maximum daily emissions.[1] In this case, it is shown that the Project Benefit Ratio is the governing factor for trade-offs for the Beta project.

If EPA regulations are considered as the governing trade-off policy, only the pollutant emissions that exceed 100 tons per year would have to be offset. As shown in Table 4.3-29, only NO_x would be required to be offset.

With the current revisions in the California Statewide Implement Plan (SIP), it is doubtful if any trade-offs will remain

[1]The Project Benefit Ratio and the Safety Factor are suggested methodologies from the District, and are used in this analysis as the best available guidelines. It is possible that upon completion of the SCAQMD Air Quality Impact Analysis of the project that these ratios may change.

TABLE 4.3-29

BETA UNIT TOTAL PROJECT EMISSIONS[(1)]

Pollutant	Maximum Daily Emissions (pounds per day)	Annual Average Emissions (tons per year)
HC	293	44.7
TSP	185	20.9
SO_2	389	28.2
NC	2,602	346.9

(1) Emissions based on operational characteristics furnished by Shell Oil Company. Maximum emissions occur during the year 2000. Employee vehicles emissions rates excluded.

TABLE 4.3-30

RULE 213 OFFSET VALUES[(1)]

Pollutant	Project Safety Factor 1.2 Times Maximum Daily Emissions (pounds per day)	Project Benefit Ratio 2.0 Times Annual Emissions (tons per year)
HC	352	89.4
TSP	178	41.8
SO_2	479	56.4
NO_x	3,164	693.8

(1) It should be noted that the actual offset ratios could differ from this presentation, based on completion of the SCAQMD impact analysis.

TABLE 4.3- 31

EMISSION REDUCTION CONTROL TECHNOLOGY

PARTICULATES

Source Category	Emission Reduction Measures	Estimated Percent Reduction Available
Power Plants	Scrubbers, filters	75
Surface Coaters	Filter collectors	50
Sand and Gravel Crushing	Wetting systems, dust collectors for conveyor and transfer points	50
Asphaltic Concrete Batching	Baghouses, dust collectors at transfer points	80(1)
Chemical Manufacturing	Filter collectors	50
Mineral Processing	Baghouses, scrubbers(1)	50(2)

(1) Information based on "Emissions Inventory and Offset Study, Potential Sites and Alternatives to Sundesert Project", Engineering-Science, November 8, 1977.

(2) Ten percent for facilities with existing controls.

TABLE 4.3-32

EMISSION REDUCTION CONTROL TECHNOLOGY

HYDROCARBONS

Source Category	Emission Reduction Measures	Estimated Percent Reduction Available
Petroleum Production	Improved maintenance, improved pump packings and seals, floating roof tanks, vapor recovery systems	5
Petroleum Refining	Floating roof tanks, vapor recovery	5
Petroleum Marketing	Floating roof tanks, vapor recovery	10
Manufacturing and Miscellaneous	Controls are process specific	10 to 50

TABLE 4.3-33

EMISSION REDUCTION CONTROL TECHNOLOGY

SULFUR DIOXIDE

Source Category	Emission Reduction Measures	Estimated Percent Reduction Available
Power Plants	Flue gas scrubbers	90
Fuel Consumption	Hydrosulfurization of fuel oil to 0.03% sulfur(1)	30
Chemical Manufacturing	Absorption, scrubbers, lower sulfur content fuel oil	50
Mineral Processing	Scrubbers, absorption	50

(1) Based on Alaska Petrofining Corporation information.

by the end of 1979. Section 4.3.2.2 indicates that the full credit for offsets could possibly be obtained if the air pollution control equipment has been installed and is operating by January 1, 1980. Provisions for growth after January 1, 1980 are incorporated into the SIP revisions.

The following discussion analyses various trade-off possibilities that could be used to meet the Rule 213 requirements.

4.3.3.1 Emission Reduction Control Technology

In order to evaluate the potential offsets available for the Beta project, it is necessary to discuss the various means of controlling pollutant emissions. The techniques discussed in this section were applied to the emissions listed in the succeeding sections. Emission reduction control technology and the most probable amount of emission reductions to be gained by the use of the technology for various source categories are presented in Tables 4.3-31, 4.3-32, 4.3-33, and 4.3-34.

TABLE 4.3-34

EMISSION REDUCTION CONTROL TECHNOLOGY
OXIDES OF NITROGEN

Source Category	Emission Reduction Measures	Estimated Percent Reducation Available
Gypsum Processing	Substitution of coal as the fuel used in the kiln process	33
Internal Combustion Engines (stationary)	Ammonia injection, catalytic converters	60
Power Plants	Ammonia injection	40
Industrial Boilers	Ammonia injection, catalytic converters	20

(1) Hydrocarbons

- Petroleum Production. Improved packing and seals around pump rod assemblies and improved maintenance procedures on existing packing can be used to reduce emissions. Technology exists to control emissions from storage tanks in the form of floating roofs and vapor recovery systems. Available reduction is estimated at 5 percent.

- Petroleum Refining: Floating roofs and vapor recovery systems can be used to reduce emissions from storage facilities: estimated reduction is 5 percent.

- <u>Petroleum Marketing</u>: The larger gasoline bulk plants' loading racks usually are controlled by vapor recovery or vapor balance systems. Where vapor balance is used, there are possibilities for additional hydrocarbon emission reductions if vapor recovery systems (compression-condensation or compression-adsorption) are installed. Smaller bulk plants with lower throughputs usually use submerged fill as the only means of control. Additional hydrocarbon emission reductions can be obtained by adding vapor recovery or vapor balance systems to the smaller plants' systems. Estimated percent emission reduction available is 10 percent.

- <u>Manufacturing and Miscellaneous</u>: Processes which are uncommon are generally excluded from SIP control measures. An example would be paper processing. For these various sources, estimated emission reductions are 10 percent.

(2) <u>Particulates</u>

- <u>Power Plants</u>: Scrubbers, bag filters, or precipitators could reduce particulate matter by 75 percent.

- <u>Surface Coaters</u>: Surface coating operations emit particulate matter which could be controlled by the application of filter collectors. Estimated percent reduction is 10 percent.

- <u>Sand and Gravel Processing</u>: Emissions from sand and gravel plants are mainly from operations similar to asphaltic concrete plants - drying, screening, and conveying. The potential for reducing emissions may lie in dust control measures for fugitive emissions from storage piles and roadways or additional control of some screening operations. Conceivable offsets might be obtained from improved containment of emissions or control measures for quarrying operations which could achieve a 50 percent reduction.

- <u>Asphaltic Concrete Batching Plants</u>: Emissions from batching plants occur principally from dryers, screens, and mixers. All of the larger sources and many of the smaller sources may be controlled by scrubbers and baghouses. Emissions from a controlled plant are relatively low and, except for fugitive emissions, little return in emission reduction would be achieved by the effort of control. For uncontrolled sources, emission reduction is estimated at 80 percent. For controlled sources, emission reduction is estimated at 10 percent.

- <u>Chemical Manufacturing</u>: Chemical manufacturing particulate emissions could be controlled by filter collectors. Uncontrolled source emission reduction is estimated at 50 percent. Controlled source emission reduction is estimated at 10 percent.

- <u>Mineral Processing</u>: This category would include such industries as carbon and borax manufacturing. Baghouse and scrubber controls may offer potential offsets on the order of 50 percent of existing emissions.

• Fugitive Dust: Fugitive dust is evolved from construction/demolition operations and from unpaved roads and unimproved land. Considerable dust is evolved during windy days. It is sometimes possible to use better "housekeeping" and maintenance to reduce dust emissions from industrial sites and to pave dust-emitting roads and work areas. Also, aggregate storage piles can be enclosed to reduce emissions. No estimates are offered at this time for percent reduction achievable for fugitive dust emissions.

(3) Sulfur Dioxide

• Power Plants: Flue gas scrubbers could reduce SO_2 emissions by 95 percent.

• Fuel Combustion: Hydrodesulfurization of fuel oil down to 0.03 percent sulfur could reduce emissions 30 percent further than the projected SIP requirement of reducing fuel oil sulfur content to 0.1 percent.

• Mineral and Chemical Processing: SO_2 emissions originate from the ore and/or from the fuels used. Reductions could be achieved by using a lower sulfur fuel or by using scrubbers. Percent reduction is estimated at 50 percent.

(4) Oxides of Nitrogen

• Gypsum Processing Plants: Emission reductions of 33 percent are estimated by using coal as the fuel in the kiln process.

• Internal Combustion Engines (Stationary): NO_x emissions could be reduced (60 percent estimated) by the application of ammonia injection and catalytic converters on new installations. Zero percent reduction is estimated for existing units with high excess air.

• Power Plants: Ammonia injection is reported to provide 40 percent reduction of NO_x in large boilers.

• Industrial Boilers, Commercial, and Institutional Boilers and Heaters: Ammonia injection might be applied to these processes. However, emission reductions available would be less than for large power plants; 20 percent was utilized. Emissions could also be reduced by application of 0.03 percent fuel oil.

4.3.3.2 Trade-Off Analyses

In an effort to determine potential courses of action in terms of emission offsets, three major areas were investigated: (1) offsets available within the South Coast Air Basin (SCAB) from sources internal to Shell Oil; (2) offsets available outside the SCAB from sources internal to Shell Oil; and (3) offsets available within the SCAB from third party sources external to Shell Oil.

(1) Internal Offsets Within SCAB

The SCAQMD EIS Trade-Off Report was analyzed to determine potential trade-offs internal to the Shell Oil Company. Table 4.3-35 presents the emissions of particulates, hydrocarbons, sulfur dioxide, and nitrogen oxides for Shell Oil Company sources within the SCAB. The appropriate emission control factors, as discussed in the preceeding section, were applied to the listed emissions to obtain the potential emission offsets. A comparison of Tables 4.3-35 and 4.3-29 indicates the Shell Oil Company has enough internal trade-offs within the Basin to offset the effect of the Beta project.

(2) Internal Offsets Outside SCAB

In addition to the possible Shell Oil Company trade-offs within the SCAB, Shell has proposed that NO_x emission reductions from their Ventura County Oil Field be used as offsets for the NO_x emissions from the Beta project. Ventura is located in the southern half of the South Central Coast Air Basin (SCCAB).

Although the classical pattern has been to disallow interbasin trade-offs as a means of mitigating a project's emissions, there are sound reasons, based on the meteorology of southern California, that indicate interbasin trade-offs between SCCAB and SCAB should be considered as a viable means of mitigating the Beta project emissions.

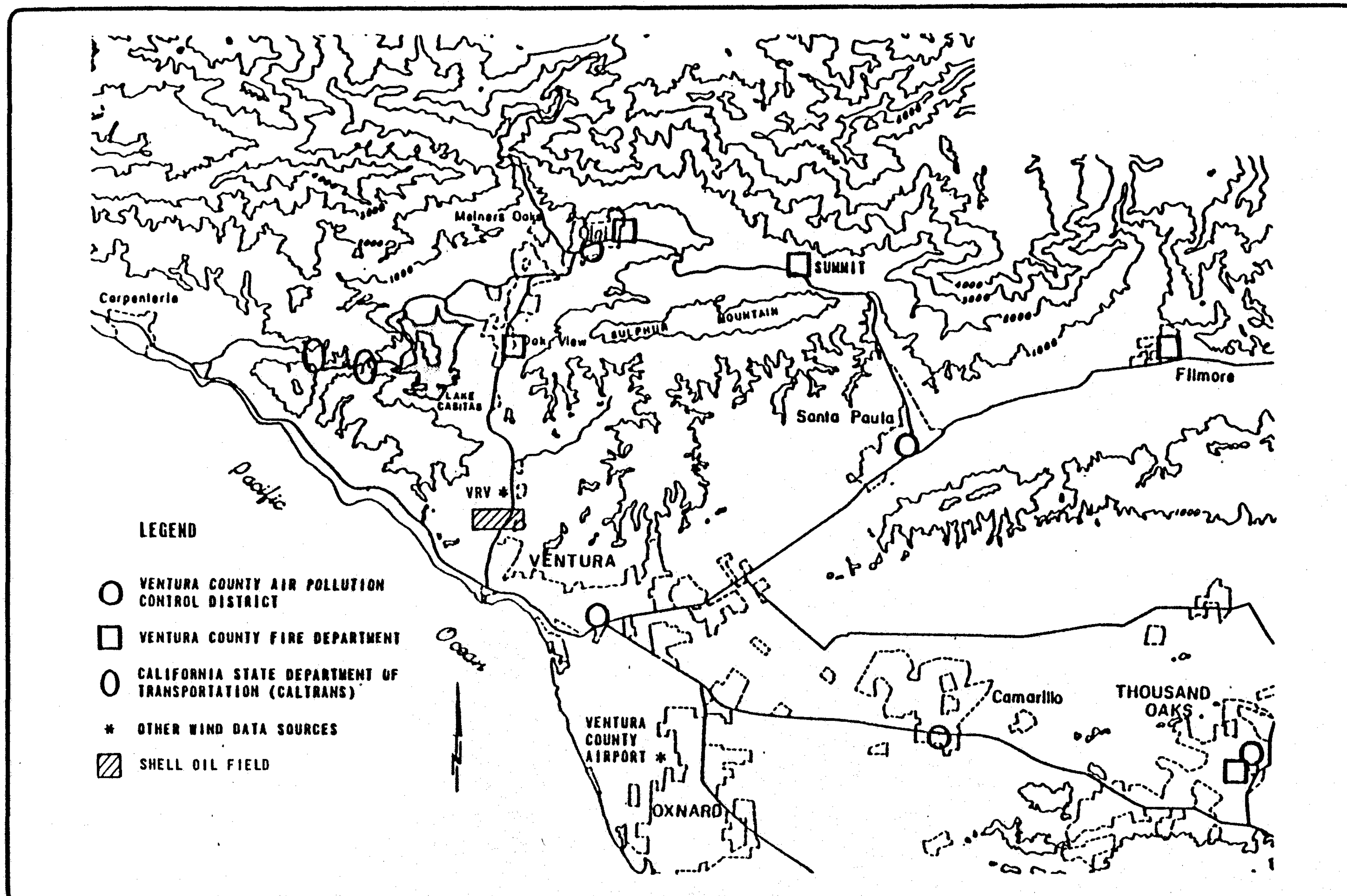
Basically, wind flow, that is, the movement of air, transports pollutants from a source to a receptor. If the wind does not flow, the pollutants are not transported away from the source. The effects of meteorology on transport, dispersion, and stability have been discussed previously (Section 3.3). When a new emitter (source of pollution) is added to an area, any location downwind of the source will improve when the source, through some means of control technology, decreases the amount of pollutants being emitted into the air. Air movement (wind flow) does not respect, nor is it governed by, political boundaries. Therefore, it is reasonable to conclude that if emissions from a source of pollutants in Ventura County are reduced, and this cleaner air is transported into the SCAB, the SCAB will benefit because some of the air entering the Basin is now cleaner than it had been prior to the emission reductions. This section discusses how much of the improved air will find its way into the SCAB and, in turn, suggests what percentage of the reduced emissions could be used as viable trade-offs for the Beta project.

The Shell Oil Company currently operates production and storage facilities located near Ventura, California. The operation utilizes numerous natural gas-fueled engines and compressors. The compressors, which are spread throughout the Shell Ventura Oil Field, are operated almost continuously. Shell has already reduced some of the emissions, and has proposed to further reduce emissions by converting the compressors to operate on purchased electrical power. If possible, enough of the compressors will be converted to

TABLE 4.3-35

SHELL OIL COMPANY EMISSIONS AND POTENTIAL EMISSION OFFSETS WITH SCAB

Source Category	Emissions Tons/Year	Potential Emission Offsets Tons/Year
PARTICULATES		
1. Petroleum Production	0	0
2. Petroleum Refining	301	30
3. Petroleum Marketing	37	0
	338	30
HYDROCARBONS		
1. Petroleum Production	37	0
2. Petroleum Refining	3,778	200
3. Petroleum Marketing	295	0
	4,110	200
SULFUR DIOXIDE		
1. Petroleum Production	0	0
2. Petroleum Refining	3,231	500
3. Petroleum Marketing	38	0
	3,269	500
NITROGEN OXIDES		
1. Petroleum Production	1	0
2. Petroleum Refining	2,018	500
3. Petroleum Marketing	462	0
	2,481	500



Location of Wind Data in Ventura Vicinity

4.3-2
Figure

electrical power to offset the Beta project NO_x emissions. Although the proposed electrification of the compressors and engines within the oil field will reduce the onsite emissions, it should be noted there will be indirect emissions associated with the required power generation. However, due to the interconnected nature of the electrical generation network, it is extremely difficult to quantify the emissions and to identify the location of the emissions. The Ventura Oil Field currently produces 1,553.1 tons per year of NO_x and 823.5 tons per year of hydrocarbons (Sheridan, Rappolt, 1977).

Figure 4.3-2 shows the approximate location of the Shell Ventura Oil Field and most of the locations of meteorological stations that were used to evaluate the air flow regimes that would govern the transport of pollutants from the oil field.

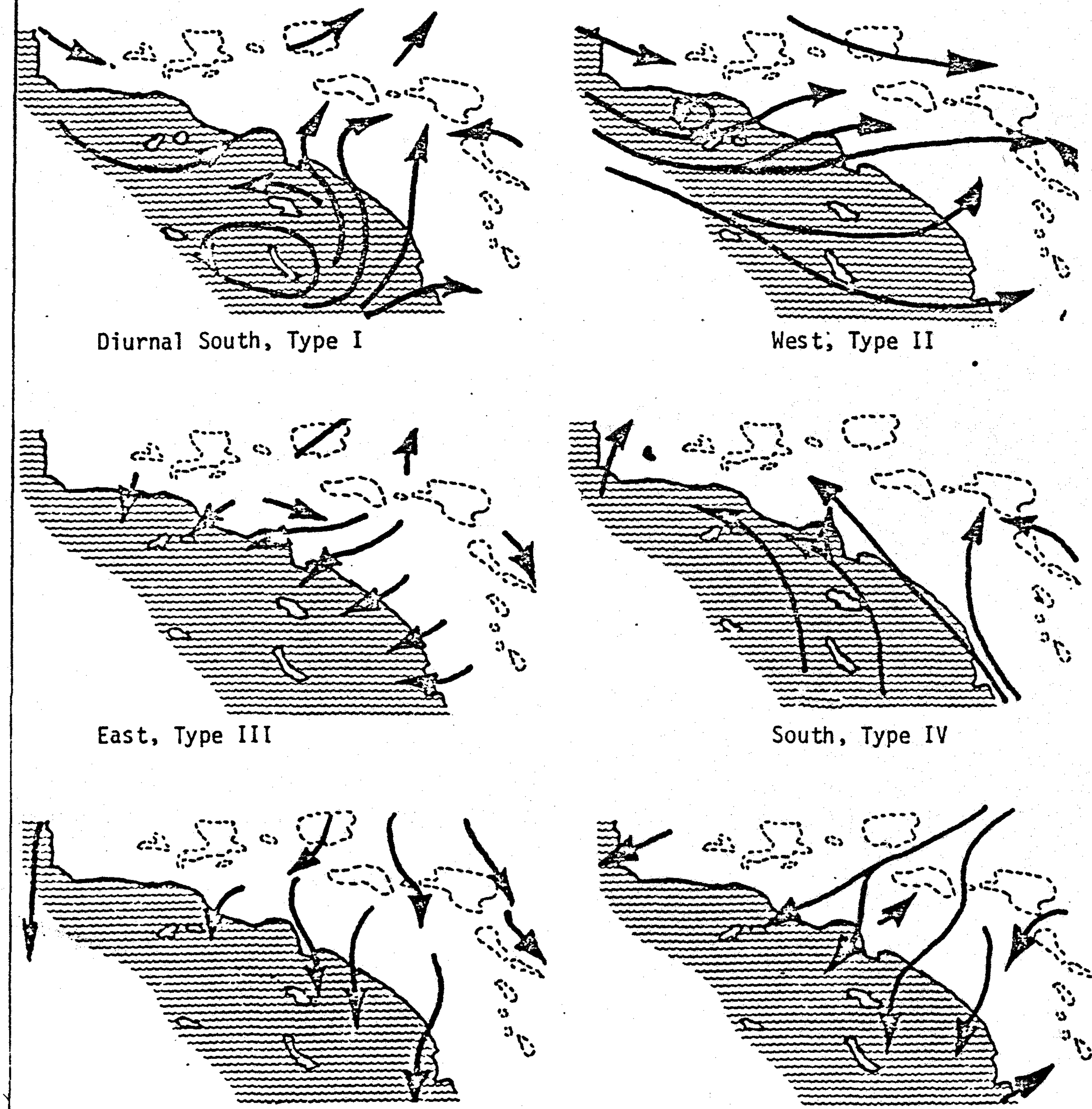
(a) Regional Climatology

The general factors governing regional weather patterns, including those of Ventura County, have been discussed in Section 3.3.1. Figures 3.3-1, 3.3-2, 3.3-3, and 3.3-4 show the general prevailing air flows during the daytime and nighttime for the months of April, July, October, and January. The nighttime drainage winds (Figures 3.3-1 and 3.3-2) flow down the Ventura River Valley, Santa Clara River Valley, and Simi-Santa Susana Valley into the Oxnard Plain and offshore into the Santa Barbara Channel. The drainage flow, upon entering the Santa Barbara Channel, merges with the prevailing air flow off the southern California coast and appears to be transported toward the SCAB, or, with the onset of the daily sea breeze, will be brought back into the Ventura-Oxnard area. The daytime flow (Figures 3.3-3 and 3.3-4) exhibits the predominant sea breeze characteristics and flows up the Ventura River Valley, Santa Clara River Valley, and the Simi-Santa Susana Valley. In the area of Point Mugu the Santa Monica mountains split the sea breeze. Some of the flow enters the Oxnard Plain, while part of the flow travels along the coast toward the SCAB. During the winter months, the nighttime drainage flow becomes stronger and persists for a longer time period. These factors cause the drainage flow to penetrate further offshore. During the summer, the combination of the sea breeze and the Eastern Pacific High combine to strengthen the daytime onshore flow. Often, during the summer, the nighttime drainage flow will be weak or not developed at all.

(b) Interbasin Air Exchanges

Many studies have been conducted on the occurrence of interbasin air (and air pollutant) exchanges between the SCAB and the SCCAB. Primarily, these studies have discussed the exchanges between Ventura County (the Oxnard Plain) and Los Angeles County.

In 1975, the CARB presented a classification of Surface Airflow Patterns that affect southern California from Point Conception to San Diego. These weather types were based on 1974-75 data. Figure 4.3-3 presents the eight types of surface air flow. The data were taken from the meteorological maps that are prepared by CARB four times daily (4 am, 10 am, 4 pm, 10 pm). Table 4.3-36 presents the percent occurrence of airflow types by season and time of day for the maps shown in Figure 4.3-3.



Diurnal South, Type I

West, Type II

East, Type III

South, Type IV

North, Type V

Santa Ana, Type VI

Calm, Type VII

Miscellaneous, Type VIII

South Coast Airflow Types

Figure 4.3-3

TABLE 4.3-36

PERCENT OCCURRENCE[1] OF AIRFLOW TYPES
BY SEASON AND TIME OF DAY, SOUTH COAST AIR BASIN (1974-75 DATA)

Type	I Diurnal South	II West	III East	IV South	V North	VI Santa Ana	VII Calm	VIII Miscl.
Jan-Mar								
4 am	11%	15%	37%	0%	4%	3%	9%	21%
10 am	17	17	27	1	2	5	6	26
4 pm	24	50	4	1	0	1	0	19
10 pm	12	28	24	1	3	2	6	25
All times	16	28	23	1	2	3	5	23
Apr-June								
4 am	15	35	37	0	0	1	4	7
10 am	44	32	2	0	0	1	0	22
4 pm	25	68	1	0	0	0	0	6
10 pm	30	60	4	0	0	1	0	5
All times	29	49	11	0	0	1	1	10
July-Sep								
4 am	19	44	19	0	1	0	11	7
10 am	38	43	3	1	1	0	0	16
4 pm	13	83	0	0	0	0	0	5
10 pm	28	62	5	0	0	0	1	4
All times	24	58	7	0	0	0	3	8
Oct-Dec								
4 am	5	20	44	1	3	0	11	14
10 am	14	16	26	0	8	2	9	25
4 pm	10	47	2	1	0	1	0	40
10 pm	3	27	35	1	2	0	5	27
All times	8	28	27	1	3	1	6	26
Yearly								
4 am	13	28	35	0	2	1	9	12
10 am	28	27	14	0	2	2	4	22
4 pm	18	62	2	0	0	1	0	18
10 pm	13	47	18	0	1	1	3	16
All times	18	41	17	0	1	1	4	17

[1]Within a seasonal grouping, each entry represents the percent occurrence of that type for the stated time of day. The percents add to near 100% horizontally.
Source: CARB, 1975.

The predominant type that occurred was the West, Type II, with an annual occurrence of 41 percent. As expected, this type occurred most frequently during the July-September period, with the least number of occurrences during the October-March period. The West, Type II category would transport air from the Oxnard Plain into the SCAB.

The East, Type III is the normal drainage wind and, as expected, occurred most frequently during the October-March period. This type is most frequent during the morning hours, as reflected by the percentages at 4 am. This type, by itself, will not provide air exchanges between the two Basins.

The Diurnal South, Type I occurs on an annual basis of 18 percent. It appears most frequently during the April-June period. Figure 4.3-2 shows that the only air exchange between the two basins would occur from Ventura County into the northwest corner of the SCAB. Figure 4.3-2 also shows what appears to be a Catalina eddy offshore. It is anticipated that the general flow around this eddy would block the air flow from Ventura County from being transported toward Los Angeles. If the center of the eddy is displaced farther to the west or north, the resultant wind flow would transport air from the SCAB to the Oxnard area where it would be redirected to onshore. However, if the center of the eddy is displaced to the south or east, the resultant wind flow would transport air along the coastline from the Oxnard Plain into the Los Angeles area.

The South, Type IV only occurs a small percentage of the time, during the October-March time period. This type would provide air transport from the SCAB into Ventura County.

These data indicate that, a minimum of 41 percent of the time, air transport is from Ventura County into the SCAB. However, this can be expanded, because the East, Type III is usually followed by the West, Type II category during the same day. The typical scenario would be the occurrence of the East, Type III during the nighttime hours followed by the West, Type II during the mid-morning and afternoon hours. When the East, Type III air flow is followed by the West, Type II, the air that has traveled from the Oxnard Plain to offshore will be redirected towards the shoreline. Part of this air will enter the SCAB. The combination of these two types of flows would indicate an exchange of air from the Oxnard Plain area to the SCAB of approximately 60 percent of the time on an annual basis.

Another analysis (Lorenzen, 1975) of air exchanges between the two air basins was conducted by the CARB. The analysis was based on the CARB's Air Flow Charts (drawn every six hours: 4 am, 10 am, 4 pm, 10 pm) during June through September, 1974. This analysis was conducted during the period when the occurrence of the West, Type II is most frequent. Table 4.3-38 presents the analysis. The table was based on 484 air flow charts during the June-September period. The results from this study indicate only 12 percent of the time the air from Ventura County is transported to Los Angeles County. This is the time of year that the previous study indicated

TABLE 4.3-37

FREQUENCY OF AIR EXCHANGE BETWEEN SCCAB AND SCAB

(Based on 484 ARB Air Flow Charts)

	From Los Angeles County to Ventura County			From Ventura County to Los Angeles County			Little Evidence of Air Exchange
	Over Land	Over Water	Total	Over Land	Over Water	Total	
June 1974							
0400 PST	12	0	12	4	4	8	10
1000 PST	6	1	7	1	1	2	21
1600 PST	0	0	0	4	2	6	24
2200 PST	18	0	18	4	1	5	7
June Total	36	1	37	13	8	21	62
July 1974*							
0400 PST	12	0	12	0	1	1	17
1000 PST	4	1	5	0	0	0	25
1600 PST	1	0	1	2	0	2	27
2200 PST	20	0	20	3	1	4	6
July Total	37	1	38	5	2	7	75
August 1974							
0400 PST	11	0	11	2	3	5	15
1000 PST	3	0	3	2	0	2	26
1600 PST	3	0	3	0	0	0	28
2200 PST	16	0	16	1	6	7	8
August Total	33	0	33	5	9	14	77
September 1974							
0400 PST	5	1	6	5	0	5	19
1000 PST	6	0	6	0	1	1	23
1600 PST	0	0	0	5	0	5	25
2200 PST	14	0	14	2	3	5	11
September Total	25	1	26	12	4	16	78
TOTALS			134			58	292
PERCENT			28			12	60

* 1 day missing

a maximum air exchange from Ventura to the SCAB. It was also concluded that 60 percent of the time, there was little evidence of air exchange between the two basins.

Another analysis of air exchanges between the two basins was presented by Cover (1978). The study examined the characteristic wind flow patterns around the Los Angeles and Ventura County Air Basins. The intent of the study was to quantify the degree of pollutant interaction between the two air basins. The data used for the study included the streamline charts that were presented in Figures 3.3-1 through 3.3-4; surface winds from meteorological buoys in the Pacific Ocean; surface wind roses from Los Angeles International Airport, Los Alamitos Naval Air Station, Long Beach, Oxnard Air Force Base, and the Point Mugu Naval Air Station; stability array data from Long Beach; stability array data from Oxnard AFB; and mean mixing depths from Santa Monica. The report concluded that, during sea breeze conditions, the air entering the Ventura County Air Basin has two possible exits. It would either exit to the northeast through the Santa Clara River Valley or along the Simi-Santa Susana Valley. This is expected to occur on nearly 100 percent of the late-morning-to-early-evening periods on an annual basis. The air flow of this type represents nearly 50 percent of the total annual period. Another part of the conclusion stated that approximately 25 percent of the annual period, the offshore flow from the Ventura County Basin is turned by the prevailing northwesterly winds over the ocean, and is directed into the Santa Monica Bay. Therefore, it was concluded that direct interaction between the Los Angeles and the Ventura County Air Basin occurred a minimum of 75 percent of the annual period.

In 1975, Keuper and Niemann, during a ten-day period in June and July, conducted a program to detect the flow of photochemical pollutants aloft from the coastal edge of the Los Angeles Basin to the Ventura County coast. The previous studies discussed concentrated primarily on surface transport. This study used an instrumented light aircraft that flew between Los Angeles and Ventura Counties. Concurrent with the aircraft flights, wind aloft measurements were made at three locations. Measurements were made six times per 24-hour day. The winds aloft measurements were used to construct trajectories of air parcels. The trajectories represented a history of the air, and gave evidence of the origin of the parcel. The most persistent layer of ozone was found just above the base of the characteristic southern California summer subsidence inversion layer. The study shows that air transport aloft, above the marine inversion, occurs on a regular basis from the SCAB to the Oxnard Plain.

A specific study designed to measure quantitatively the transport from the Ormond Beach Generating Station (OBGS) at Point Hueneme is reported by Lamb *et al.* (1977). Atmospheric tracer experiments were conducted to determine the transport and dispersion associated with pollutants emitted from the OBGS. Sulfur hexaflouride (SF_6) tracer was released from 3:00 am to 5:00 pm on September 21, 1975, and from 3:00 am to 11:40 am on September 22, 1975. Air samples were collected along ten automobile traverses during September 21 and along three automobile traverses during

September 22. Hourly averaged air samples were collected at each of eight fixed stations, continuously from midnight September 20 until noon September 24. The results clearly showed pollutant transport occurs from the Oxnard Plain along the Malibu coast into the Los Angeles Basin and along an inland route into the San Fernando Valley as far east as Burbank. Air parcel trajectories were computed from meteorological data and were found to be consistent with the tracer data. The trajectory data indicated that transport along the coast also moves pollutants into the Burbank region. The pollutants released from the OBGS were found to be diluted by approximately 10^5 upon reaching Burbank or the Santa Monica area. Hourly winds were plotted as streamlines. The hourly streamlines and the wind vectors were used to develop air parcel surface trajectories. The important results of the trajectory analysis were: all trajectories, no matter at what time they were started, ended in the Ontario area. Some of the OBGS releases wandered about in the San Fernando Valley for many hours before exiting and continuing on to the Ontario area. Some of the releases left the San Fernando Valley, were entrained in the land breeze and were transported offshore, where they were later brought back onshore by the seabreeze and transported toward Ontario. Other trajectories showed a transport over the ocean into the Los Angeles area on their way to Ontario.

Table 4.3-38 summarizes the discussions and studies mentioned above, and presents, on an annual basis, the percentages of air that flows from the Oxnard Plain into the SCAB.

TABLE 4.3-38

SUMMARY OF AIR EXCHANGE FREQUENCIES FROM SCCAB TO SCAB

Source	Percentage
CARB (1975)[1]	60
Lorenzen (1975)[2]	12
Cover (1978)[3]	75
Kauper, Nieman (1975)[4]	--
Lamb (1977)[5]	--

1. Based on 1974-75 data.
2. Data covers period of June through September 1974.
3. Based on long-term climatological data.
4. Data was taken for winds aloft and air flow from SCAB into SCCAB.
5. Data based on SF_6 Tracer releases during a two-day period in September 1975. It is not appropriate to extend this limited data to an annual percentage.

The data studies based on long periods of data (CARB, 1975; Cover, 1978) indicated there was generally a transport of 60 to 75 percent of the surface air flow from the Oxnard Plain area to the SCAB. The tracer study (Lamb *et al.*, 1977) was conducted during period of East, Type III surface flow at night and

West, Type II flow during the daytime, and indicated definite transport from the Oxnard Plain area into the SCAB. Lorenzen (1975) covered only a period of four months, and did not discuss whether the data that were taken were for a year that was considered to be normal.

(c) Transport As Affected by the Ventura River Valley

The preceeding discussions indicate there is generally transport of air from the Oxnard Plain area of Ventura County into the SCAB. The common routes of transport are: air flows from the plain to offshore, where the usual seabreeze will carry the air into the SCAB. The air is carried either into the Santa Monica area or across the eastern end of the Santa Monica mountains into the San Fernando Valley. The other most common paths are along Highway 101 or through the Simi-Santa Susana Valley into the San Fernando Valley. At this point, little attention has been focused on air flow in the specific area of the Shell Ventura Oil Field. As shown in Figure 4.3-2, the oil field is located north of Ventura and extends in an east-west orientation across the Ventura River Valley.

The emissions from Shell's Ventura Oil Field will occur in the lower layer of the atmosphere, which means that the transport of pollutants will be governed by the surface wind flows. Since the oil field lies across the Ventura River Valley, the pollutant transport will be governed by the surface flow along the river valley. The preceeding discussions concerned surface air flow over the Oxnard Plain, and are not representative of the Ventura River Valley flow. Because of the topographic constraints, the air flow along the river valley will be primarily either up-valley or down-valley. Up-valley flow will occur during the daytime, and will carry air from the ocean across the oil field in a northerly direction toward the Ojai Valley area. Down-valley flow will occur primarily at night and early morning, and will carry air from the Ojai Valley area down the river valley, past the oil field, and into the Santa Barbara Channel. To determine the amount of air flow that passes through the Ventura Oil Field on an annual basis and is later transported into the SCAB, it was necessary to determine the frequency distribution of up- and down-valley air flow along the Ventura River Valley.

Representative data for the Ventura River Valley in the vicinity of the Shell Oil Field was available from a private commercial source. One year of data was summarized in the form of a wind rose (Table 4.3-39). As expected along a river valley, a distinct bimodal distribution was evident in the wind direction frequencies with down-valley flow (NW, N, NE, E, and W directions) accounting for 54 percent (approximately 13 hours per day) of all wind directions, while up-valley flow (SE-W-SW directions) accounted for approximately 46 percent, or 11 hours per day.

The small percentages of east and west winds (5 percent) were included in the down-valley total. Westerly winds would usually transport materials across the foothills into the Santa Clara River Valley. Easterly winds would transport emissions

TABLE 4.3- 39

ANNUAL WIND ROSE - VENTURA RIVER VALLEY (VRV)
MARCH 1975 - FEBRUARY 1976
(Percent)

Wind Direction	Wind Speed (mph) 0-3	4-6	7-10	11-16	17-21	>21	Total
N	6.4	6.0	12.0	6.3	0.6	<0.1	31.3
NE	2.7	2.1	1.5	0.5	0.1	0.0	6.9
E	1.0	0.8	0.7	0.1	0.1	0.0	2.6
SE	0.9	1.1	1.8	1.1	<0.1	0.0	4.9
S	5.7	5.8	10.2	7.9	0.3	<0.1	29.9
SW	0.6	2.5	5.9	2.0	<0.1	<0.1	11.0
W	0.2	0.4	1.0	0.8	<0.1	<0.1	2.4
NW	2.9	2.9	3.0	1.7	0.2	<0.1	10.7
Total	20.4	21.6	36.1	20.4	1.2	<0.1	

across the oil field to the ocean west of Ventura. Wind speeds were variable to 16 miles per hour, with the seven-to-ten-mile-per-hour bracket recording the highest percentage, at 36.1 percent of all observations.

An additional analysis, based on a short-term meteorological measurement program in the Canada Larga Canyon (north and east of the oil field), indicated that 15 percent of the up-valley air flow will be diverted up the Canada Larga Canyon.

The remainder of the up-valley winds will transport emissions from the Shell Oil Field into the Ojai Valley. Wind data from the Upper Ojai Valley at Summit (Ventura County Fire Department) indicated a predominantly easterly flow (into the Ojai Valley) during the entire day. Once in the Ojai Valley, the opposing flows either weaken to a point of stagnation or set up an area of weak convergence, usually in the eastern part of the valley. Some of the air will exist from the Ojai Valley to the north past Meiners Oaks.

The down-valley flow, along the Ventura River, past the Shell Oil Field begins earlier in the evening and continues longer in the morning than the usual drainage wind in the rest of the Oxnard Plain area. During these times of the day (early evening and late morning), the air that is transported offshore from the Ventura River Valley will be blown back onshore by the existing sea breeze. When these conditions occur, the air returning onshore will be transported up the Santa Clara River Valley. Approximately one-third of the annual down-valley flow along the Ventura River Valley (an average of four hours per day) will be advected up the Santa Clara Valley. The usual section of the SCAB that will be impacted by this air is the northwest corner, northwest of the Saugus-Newhall area.

The remainder of the down-valley flow, 9-10 hours per day, will be carried far enough offshore that it will either re-enter the Oxnard Plain, due to the prevailing westerlies or the onset of the sea breeze, and be transported toward the SCAB through the Highway 101 or Simi-Santa Susana Valley routes, or it will be transported along the coast and enter the SCAB in the Santa Monica area. Since an average of 9-10 hours per day, on an annual basis, of air that travels down the Ventura River Valley past the Shell Ventura Oil Field will be transported into the SCAB, a figure of 40 percent can be used as the appropriate percentage for the air exchange from Shell's Ventura County Oil Field to the SCAB.

The Shell proposed trade-offs of nitrogen oxides from their Ventura Oil Field for the Beta project should be adjusted by the 40 percent air exchange factor. Since the total emissions of nitrogen oxides are 1,553.1 tons per year, there would be a maximum of 621.2 tons per year available as trade-offs for the Beta project.

(3) <u>Third Party Offsets within SCAB</u>

SCAQMD EIS Trade-Off Report was analyzed to determine third party potential trade-offs that could be used to mitigate the effect of the Beta project emissions. An area of 20 miles (36 km) radius from Huntington Beach was utilized to identify stationary point sources of TSP, NO_x, and SO_2. The entire SCAB was utilized to identify HC sources. The results of this analysis are shown in Tables 4.3-40, 4.3-41, 4.3-42, and 4.3-43.

(a) Particulates

The largest source of potential offsets within the area of interest is from the electrical power generation sources. These sources can be controlled by the addition of scrubbers, bag filters, or precipitators, and would provide an average of 75 percent control. However, most probably the easiest and most economical sources to control would be the chemical industry sources. These can be controlled by the use of filter collectors.

As shown in Table 4.3-40, the potential offsets for particulates are more than adequate to mitigate the effects of the Beta project emissions.

(b) Hydrocarbons

Although, as shown on Table 4.3-41, the petroleum industry and electrical power generation are two of the largest sources of emissions of hydrocarbons, it is doubtful if any of these emissions would be available for potential offsets. The petroleum industry category does not include any sources from Shell Oil Company or the other participants in the Beta project. It is doubtful if current control technology would reduce any of the emissions from the power generation sources. Any reductions from this category would be extremely uneconomical. The emissions from the petroleum industry could be controlled by several methods, such as the addition of floating roof tanks, vapor recovery systems to storage facilities, and improved packing and seals around pump rod assemblies and improved maintenance procedures on existing packing. It is usual for the petroleum industry to reserve their potential trade-offs to be used for their own growth.

The chemical industry, manufacturing, and all other sources would be the most readily available and most economical of hydrocarbon emission source.

(c) Sulfur Dioxide

As Table 4.3-42 shows, the largest source of SO_2 emissions is electrical power generation. SO_2 can be controlled by the addition of flue gas scrubbers. The addition of these controls to power generating stations are extremely expensive, as demonstrated by the addition of the scrubber to the Southern California Edison generation plant at Los Alamitos for a SOHIO trade-off.

Probably the most economical sources to control would be the chemical industry. These emissions can be controlled by the use of lower sulfur fuel or by the addition of scrubbers.

TABLE 4.3-4C

EXISTING PARTICULATE EMISSIONS AND POTENTIAL OFFSETS[1]

Source Category	Emissions Tons/Year	Potential Offsets Tons/Year
1. Petroleum Industry	1,675	168
2. Power Generation (Electrical)	26,000	20,000
3. Metallurgical Operations	240	120
4. Chemical Industry and Handling	910	450
5. Mineral Processing	165	80
6. Manufacturing and All Others	390	195

(1) An area of 20 miles in radius from Huntington Beach was utilized to identify point sources of TSP, SO_x and NO_x. The entire SCAB was utilized for HC sources. The data were generated from the SCAQMD EIS Trade-off Report published August 16, 1978.

TABLE 4.3-41

EXISTING HYDROCARBON EMISSIONS AND POTENTIAL OFFSETS[1]

Source Category	Emissions Tons/Year	Potential Offsets Tons/Year
1. Petroleum Industry	19,400	970
2. Power Generation (Electrical)	12,800	0
3. Metallurgical Operations	1,000	250
4. Chemical Industry and Handling	3,550	1,065
5. Mineral Processing	------	-----
6. Manufacturing and All Others	21,000	5,250

(1) An area of 20 miles in radius from Huntington Beach was utilized to identify point sources of TSP, SO_x and NO_x. The entire SCAB was utilized for HC sources. The data were generated from the SCAQMD EIS Trade-off Report published August 16, 1978.

TABLE 4.3-42

EXISTING SULFUR DIOXIDE EMISSIONS AND POTENTIAL OFFSETS(1)

Source Category	Emissions Tons/Year	Potential Offsets Tons/Year
1. Petroleum Industry	13,900	1,400
2. Power Generation (Electrical)	61,000	55,000
3. Metallurgical Operations	200	100
4. Chemical Industry and Handling	6,100	3,000
5. Mineral Processing	50	25
6. Manufacturing and All Others	660	330

(1) An area of 20 miles in radius from Huntington Beach was utilized to identify point sources of TSP, SO_X and NO_X. The entire SCAB was utilized for HC sources. The data were generated from the SCAQMD EIS Trade-off Report published August 16, 1978.

The potential offsets for this category are more than enough to mitigate the effects of the Beta project.

(d) Oxides of Nitrogen

As shown on Table 4.3-43, the largest source of NO_x emissions is electrical power generation. Ammonia injection is reported to provide NO_x reduction in large boilers. The addition of control technology to the boilers can easily provide more than enough offsets for the Beta project. These additions are extremely expensive, as demonstrated by the recent Southern California Edison and SOHIO agreement for the Southern California Edison Los Alamitos generating station.

Other sources could be used, such as the addition of ammonia injection and catalytic converters on installations of stationary internal combustion engines.

4.3.3.3 Additional Third Party Trade-Offs within the SCAB

In addition to the sources of potential offsets for the Beta project that are listed in the District EIS Trade-Off Report, numerous other possibilities were personally contacted as part of this study and evaluated in order to delineate additional sources of potential trade-offs. An area of 20 miles (32 km) in radius from Huntington Beach was utilized to identify sources of TSP, SO_2, NO_x, and HC. Enough sources were evaluated to more than mitigate the emissions of the Beta project.

(1) Particulates

The sources of particulate matter which are suggested as possibilities for emission offsets are fugitive dust sources. No proposed or model rules by CARB for this source have been noted.

The area of interest was searched for appropriate locations that would contribute to the particulate emissions. Several locations have been found that are appropriate candidates for emission offsets. Some of the sources have indicated their willingness to participate as a third party trade-off. Because of the unavailability of the owners, the remaining sources will be recontacted to determine their possible willingness to participate as a trade-off candidate. Control technologies available would be chemical stabilization of soil or mechanical covering of soil. More than enough trade-offs are currently available to mitigate the Beta project emissions.

(2) Hydrocarbons

The sources of HC which are promising candidates for emission offsets are associated with surface coating and/or printing operations. These operations use organic solvents in their processes.

TABLE 4.3-43

EXISTING OXIDES OF NITROGEN EMISSIONS AND POTENTIAL OFFSETS[(1)]

Source Category	Emissions Tons/Year	Potential Offsets Tons/Year
1. Petroleum Industry	19,700	4,000
2. Power Generation (Electrical)	101,000	40,000
3. Metallurgical Operations	360	0
4. Chemical Industry and Handling	1,700	510
5. Mineral Processing	630	160
6. Manufacturing and All Others	3,450	860

(1) An area of 20 miles in radius from Huntington Beach was utilized to identify point sources of TSP, SO_x and NO_x. The entire SCAB was utilized for HC sources. The data were generated from the SCAQMD EIS Trade-off Report published August 16, 1978.

The sources that have been investigated could provide up to 400 tons per year as trade-offs with the installation of appropriate control technology. Control technologies available, at an economical cost per pound of trade-offs, are activated carbon adsorption, vapor recovery and distillation units, and low-solvent or powder coatings.

(3) Sulfur Dioxide

The sources of SO_2 which are promising candidates for emission offsets are associated with the combustion of waste gas. The sources that have been investigated could supply large quantities of SO_2 for trade-off. Present rules allow 80 ppm of H_2S for material gas and 800 ppm H_2S for refinery process gas. No proposed or model rules were noted which would change these. Control technology exists for lowering H_2S contents of fuel gases to quite low values.

(4) Oxides of Nitrogen

The sources of NO_x which are promising candidates for emission offsets are associated with the combustion of natural gas and diesel fuel in stationary internal combustion engines. According to a CARB survey, the emissions from stationary internal combustion engines in the SCAB during 1977 were as follows: reciprocating engines, 80 tons per day; turbine engines, 10 tons per day. The CARB conducted a workshop of October 5, 1978 to gather information to develop a model rule to limit emissions of NO_x from stationary internal combustion engines. The rule would effect a reduction in excess of 90 percent for NO_x emissions from the stationary internal combustion engines. Even if this is the case, the proposed control technology of ammonia injection should provide enough offsets to meet the Project Benefit Ratio.

4.3.3.4 Supplemental Mitigation Measures

As an additional mitigation measure, Shell is considering controlling nitrogen oxide emissions from the turbines by means of water or steam injection into the combustion chambers. The manufacturer, Solar Turbine International, anticipates a NO_x emission reduction 65 to 75 percent of the uncontrolled emissions, although little supporting test data are available utilizing this technique. Shell is presently proceeding with a testing program to secure this data. Should Shell install these controls, total NO_x emissions from the turbines could be reduced by 65 percent (271 tons per year), and NO_2 air quality impacts would be reduced proportionally by 65 percent.

It should be mentioned that the annual air quality impact and offset analyses were based on 100 percent of the platform emissions reaching the South Coast Air Basin. As was discussed in the Environmental Setting, the percentage of wind directions that could likely transport emissions into the SCAB occurred 65 percent of the time on an annual basis. Therefore, based on these data, only 65 percent of the platform emissions would end up in the SCAB during the year.

The impact analyses and offset studies clearly show that if, as an extreme worst-case, 100 percent transport into the SCAB is assumed, the air quality effects are minimal and the necessary trade-off emissions can be met from Shell's own facilities.

4.3.4 Air Quality Impacts from Oil Spills

The principal air quality impact of an oil spill will be the potential production of ozone resulting from the hydrocarbon vapors in the presence of oxides of nitrogen and solar radiation. Presently, photochemical smog models used to predict ambient ozone from stationary and mobile emission sources are not suitable for most oil spill scenario analyses. The air quality impacts of a spill will depend upon the quantity of oil spilled and other important factors such as wind direction, wind speed, concentrations of oxides of nitrogen, and adequate sunlight to produce the photochemical reactions.

To qualitatively estimate the potential air quality impacts of oil spills, information was obtained from the U.S. Coast Guard's Pollution Incident Reporting System on all oil spills greater than 50,000 gallons (7,950 bbls) in the United States for the years 1973 through 1977. The historical spill data were analyzed and correlated with ambient ozone data nearest to the spill. This analysis attempted to provide a reasonable estimate of measured ozone or hydrocrabon vapor, if any, due to actual major oil spills throughout the United States. The air quality impacts from an oil spill at the platforms or from the pipeline could be viewed as similar to the past oil spills.

A total of 61 spills of crude oil were available for study from the Coast Guard list. Of that 61, only spills in or around port and harbor loading or storage facilities were examined. Onshore pipeline spill data were utilized only if the spill was in conjunction with a port or harbor loading or storage facility. After deciding on spills with potential correlation to a port or harbor facility, data on ambient air monitoring and wind direction for the spill area was obtained. Less than 20 spills from the Coast Guard list met the requirements, and data were available for only 12 of the spill sites.[1] All the spill sites with data were in the Gulf Coast area. Ambient monitoring data were not available for the big Santa Barbara spill of 1969. Of the 12 spills that had wind and ambient monitoring data, three had instrument malfunctions or calibration testing the day of the spills. Five of the spills were located too far (10 miles or greater) from the ambient monitors, and another two spills had no wind correlation between the spill location and monitoring location.

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[1] The spills ranged in size from 51,156 gallons to 1,961,795 gallons.

The remaining two spills were acceptable for study. One spill was in the Corpus Christi, Texas area (51,156 gallons - 1,200 bbls), the other was in the Texas City, Texas area (75,600 gallons - 1,800 bbls). Both were within five miles of an ambient monitoring station; the Corpus Christi spill was less than two miles from an ambient monitoring station. The wind flow was from the spill toward the monitoring station and the sampling equipment at the monitoring stations was operating. The parameters measured were: total hydrocarbons, ozone, non-methane hydrocarbons, wind speed, wind direction, and ambient temperature. No significant increases in the levels of any pollutant was observed to have occurred as a result of either spill.

This analysis is certainly not conclusive regarding the air quality impact of oil spills. It is important to note that no actual data can be found that would support a statement that oil spills have represented a significant air pollution problem.

However, to provide a worst-case analysis, a theoretical analysis was made of the potential 80,000-barrel (12,720 m^3) spill discussed earlier. Few published analyses exist of hydrocarbon vapors released from oil slicks on water. Studies conducted by Mikolaj *et al.* (1973) have shown evaporative losses from natural seep oil in Santa Barbara of up to 21 percent in two to six hours. The rate of evaporation depends upon oil composition, amount of exposed surface area, spill thickness, and meteorological factors. For this analysis, all volatile fractions (about 20 percent by weight) are assumed to vaporize in 24 hours. A spill of 80,000 barrels (12,720 m^3) would then produce approximately 2,650 pounds per day of hydrocarbons (80,000 barrels x 42 gal/barrel x 7.9 lb/gal x 0.2).

The primary air quality impact of hydrocarbon emissions in the presence of nitrogen oxides and sunlight will be the production of ozone. The present photochemical models used to predict ambient ozone levels are not suitable for dealing with such a large area source of emissions. Some researchers have utilized photochemical models to qualitatively estimate the impacts on air quality of a massive spill of oil in the Santa Barbara Channel (Taylor, 1977). A spill of approximately 6,600 barrels (1,050 m^3) resulted in an increase in ozone concentrations of 17 pphm (approximately twice the federal 1-hour ozone standard). Other studies have shown ozone levels in excess of 0.6 ppm (California Stage 3 Episode level) from a spill of the same magnitude (Port of Long Beach, 1977).

It was considered reasonable, then, to assume that a spill of 80,000 barrels (12,720 m^3) would produce ozone levels much greater than the federal 1-hour 0.08 ppm level.

The exact air quality impacts of a major spill are unknown, since the specific circumstances surrounding a spill are not defined. Important meteorological factors such as temperature, cloud cover, wind speed, and the quantity of nitrogen oxides in the air must be determined. The impacts discussed should be viewed as an approximation until more sophisticated techniques are developed.

4.4 OCEANOGRAPHIC/WATER QUALITY

4.4.1 Oceanographic Impacts

Insignificant environmental impacts on oceanographic parameters are expected as a result of project construction, routine well drilling, and production operations at the Shell Beta platforms. Adverse impacts could, however, occur as a result of oceanographic conditions, such as ocean storms.

The physical behavior of currents, tides, and waves in the platform area will not be affected, except on a very small and highly localized scale, by the project. These effects are insignificant. The occurrence of very high waves could, however, affect drilling and production operations and contribute to potential accidental oil spills, as discussed in Section 4.4.3.

The platforms have been designed for severe ocean storms having less than a one percent chance of exceedance in any given year. The design wave, wind, current, and tide criteria for the site are as follows:

- Wave

Maximum height (crest-trough)	45 feet (13.7 m)
Period of maximum wave	9 to 15 seconds

- Wind (5-second average; assumed in the wave direction; measured at +30 feet elevation) — 64 knots (118.4 km/hr)

- Current (assumed in the wave direction)

Surface	2.8 fps (0.9 mps)
Mid-depth	1.6 fps (0.5 mps)
Bottom	0.6 fps (0.2 mps)

- Tide (including storm surge) — 6.0 feet (1.8 m) (above MLLW)

These oceanographic design criteria, derived from a study by Evans Hamilton, Inc. (1976), are in agreement with data found in both the BLM and Oceanographic Services reports, and are considered conservative for the study area (BLM 1975; Oceanographic Services 1977). Because the platform design criteria are conservative, no mitigation is considered necessary for the platform oceanographic design criteria.

Calculations of wave run-up indicate that a 100-year tsunami event, with a tidal condition above approximately mean high water (4.71 feet above mean low low water) would sustain overtopping of the bulkhead and inundation of various areas within the Port. It is anticipated that the distribution facility and storage yard would be inundated; however, no significant structural damage would be realized.

4.4.2 Water Quality Impacts

Factors associated with the construction, drilling, production, and conveyance of oil from the proposed platforms which may affect water quality include: introduction of drilling muds and cuttings into the water column, dredging, thermal discharges, sanitary and domestic wastes, platform drainage, corrosion control, and injection waters. The possible effects of each of these factors on water quality are discussed below.

4.4.2.1 Construction

The initial platform-jacket placement and assembly, which will be completed within five days after initiation, is expected to have only a temporary impact on water quality at the platform site and, as such, will not be discussed in detail or considered as potentially detrimental.

4.4.2.2 Muds and Cuttings

Drilling muds are preparations of lime, sodium hydroxide, polyphosphates, barium sulfate, silicates, iron, and aluminum oxides and tannins. The primary ingredients are barite for weight and clay (bentonite) for viscosity. Mud compositions are determined by the requirements of individual drilling operations. Most drilling muds are water-based, with water providing a continuous liquid phase in which certain materials are either suspended or dissolved. The muds are carefully compounded to provide controlled characteristics of density, viscosity, thixotropic properties, and water retention.

Drilling fluids lubricate and cool the bit, lift cuttings from the hole, control well pressure, control borehole wall properties, and minimize corrosion in the protective casing and the drill string. The mud is pumped down the drill shaft during drilling, recovered, and treated for recirculation. Normally, muds are not disposed of until drilling is complete and, by OCS Order No. 7, they are free from oil, if discharged.

Environmental concern has been focused on those elements and additives used to modify the properties of drilling fluids. Commercial clays are seldom sufficient to meet all drilling requirements without the use of additives to enhance drilling and mud properties. The available additives range from expensively mined barite and complex chemical components to substances as common and readily available as sawdust.

Drilled cuttings are composed of shattered and pulverized sediment and underlying rock. These cuttings will be brought to the surface, cleaned, and then discharged at the site.

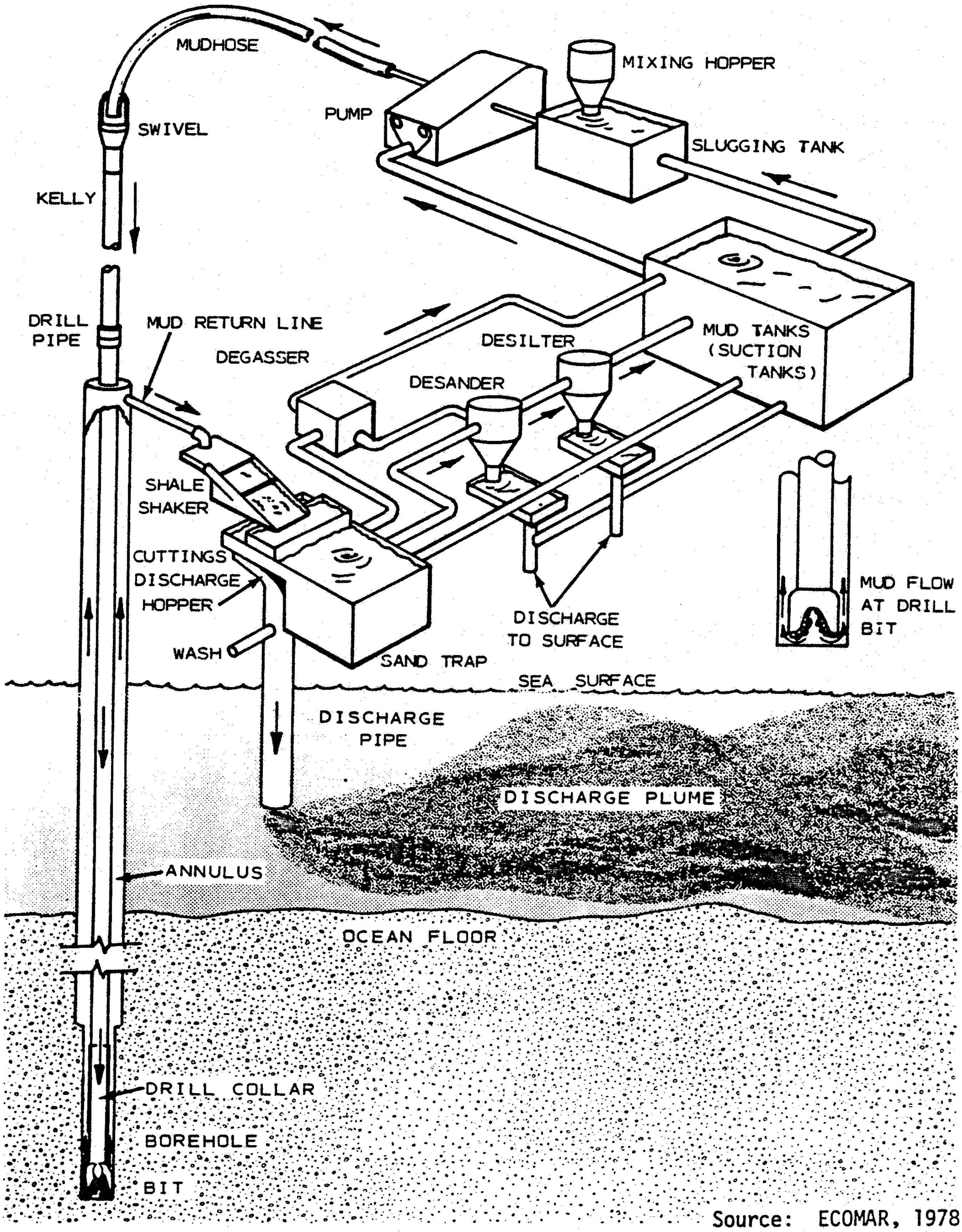
The Shell Beta drilling platforms will utilize two drilling rigs on each platform. Drilling on the first platform is expected to be completed before commencing on the second platform. Each drilling rig will be equipped with separate mud tanks. A 1,200-barrel (192 m^3) completion fluid tank will be shared by both rigs. A low-solids, gas-free mud will be maintained using high-speed shale shakers, desanders, desilters, and degassers (Figure 4.4-1). The shale shakers will be equipped with cuttings-recovery systems to handle any oil-contaminated cuttings for disposal. Cuttings that cannot be adequately cleaned will be diverted to a waste-cuttings holding tank to be hauled ashore for disposal.

Excess drilling mud is to be discharged over a one-hour period every two weeks at a depth of 100 feet (30 m). The amount of drilling mud per discharge is estimated to be 27,000 gallons (102,600 liters), with all oil or emulsion-based drilling fluids removed. There will be no discharge of emulsified free oil. The daily average discharge for both muds and cuttings is anticipated to be 4,000 gallons (15,200 liters) each.

Objections to the disposal of drilling fluids often center on the argument that certain additives may alter the chemical balance in surrounding sea water, proving toxic to local animal and plant life. Solid additives may cause excessive turbidity or, by settling over bottom sediments or reefs, leave them uninhabitable. Recent field studies have been conducted by Shell and ARCO to determine the fate and potential effect of mud and cuttings discharges (ECOMAR, 1978). The results of these studies indicate several important facts. As the cuttings were discharged, the material separated, upon entering the water, in two phases. First, the cuttings fell rapidly to the bottom. Second, most of the mud that adhered to the cuttings (usually 1 to 5 percent by volume) was washed off and spread horizontally to form a surface plume. Even under conditions of maximum discharge (750 bbl/hr or 120 m^3/hr), dilutions of 400 to 1000:1 were reached within 330 feet (100 m) of the discharge point. Maximum suspended solids content within the plume did not exceed 25 ppm. When cuttings were discharged from a depth of 43 feet (13 m), the plume spread vertially to a depth of 86 feet (26 m) within 3,300 feet (1000 m) downstream of the plume. This suggests that in most OCS areas mud plumes will have reached background levels of suspended solids and heavy metals prior to reaching the bottom (Ray, 1978).

The study on drilling-mud cuttings showed that measurable quantities of particulates and associated trace metals (barium, chromium, lead) were collected in sediment traps near the drilling operations. The quantities showed a direct relationship to predominant current flow. The sediment grab samples showed only minor accumulations of the trace metals (Ba, Cr, Pb) at the completion of the two-month drilling operation.

Chromium in the drilling mud is found as the organic



Source: ECOMAR, 1978

Drilling Fluid Circulation Path

4.4-1
Figure

A low-solids, gas-free mud will be maintained using high-speed shale shakers, desanders, desilters, and degassers (Figure 4.4-1). The shale shakers will be equipped with cuttings-recovery systems to handle any oil-contaminated cuttings for disposal. Cuttings that cannot be adequately cleaned will be diverted to a waste-cuttings holding tank to be hauled ashore for disposal.

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Chromium in the drilling mud is found as the organic complex, ferrochrome lignosulfonate. Because ferrochrome lignosulfonate, an emulsifier, contains three-percent chromium, it is one of the more toxic constituents of drilling mud. Chromium is present in drilling mud at a concentration of approximately 12 parts per thousand. The required sea-water additions to the mud concentrations will reduce this value to less than four parts per thousand. The dilution-dispersion effects in Pacific waters are considerable. Recent work suggests that ferrochrome lignosulfonate complex, ferrochrome lignosulfonate. Because ferrochrome lignosulfonate, an emulsifier, contains three-percent chromium, it is one of the more toxic constituents of drilling mud. Chromium is present in drilling mud at a concentration of approximately 12 parts per thousand. The required sea-water additions to the mud concentrations will reduce this value to less than four parts per thousand. The dilution-dispersion effects in Pacific waters are considerable. Recent work suggests that ferrochrome lignosulfonate with moderate dilution is relatively harmless (BLM, 1975). Of the three trace metals examined during the study, chromium was most rapidly dispersed.

Concentration of barium in barite is approximately 55 percent by weight. Barium as the compound $BaSO_4$ in drilling mud is relatively insoluble, and appears to be inert in the marine environment, with no apparent toxic effects on marine species (ECOMAR, 1978). The barium content of southern California coastal waters has been estimated to range from 11 to 22 micrograms per kilogram of sea water (Chow, 1976). It has been proposed that barium could provide an excellent tracer for drilling-related contamination because of its consistent content in ocean waters.

Lead, the heavy-metal contaminant resulting from drilling discharge, is known to be toxic to marine species; however, the precise toxic concentrations are not available. Concentrations of lead in California coastal waters were reported by ECOMAR (1978)as 0.35 micrograms per liter.

The various materials used to construct drilling fluids may temporarily increase chemical oxygen demand (COD), lowering the dissolved oxygen content in waters influenced by the discharged materials. Flocculents (salt, lime, etc.) and thinners (lignites, lignosulfonates, and phosphates) could modify both the salinity and pH of the discharge-affected waters.

Temperature, pH, dissolved oxygen, and salinity measurements, at or near the mud-and-cuttings discharge, were reported to be relatively unchanged in the receiving waters even very near the discharge pipe (Table 4.4-1).

TABLE 4.4-1

SELECTED SAMPLINGS RESULTS FROM MUD-AND-CUTTINGS DISCHARGE

Distance from Discharge Source:	8 Meters	60 Meters	75 Meters	Average Control Value
Parameters				
% Transmittance	26.0	75.0	15.0	93.0
Depth (meters)	3.2	1.9	1.8	1.6
Temperature (°C)	14.6	14.8	14.7	14.7
Dissolved Oxygen (mg/l)	8.82	8.56	7.49	9.26
Salinity (0/00)	33.9	34.1	33.9	33.8
pH	8.17	8.19	8.18	8.17

NOTE: Samples taken at predetermined depths from moored support as discharge passed.

Source: ECOMAR, 1978.

Percent light transmittance (%T), a measure of turbidity, was the most sensitive measure of plume presence and density in the water column. It was shown that within the most concentrated areas of the plume, background levels of suspended solids were reached within 650 feet (200 m) of the source. Calculations indicated that between 70 and 90 percent of the materials settling to the bottom from the mud-and-cuttings discharge were transported and/or dispersed beyond detection limits.

4.4.2.3 Dredging

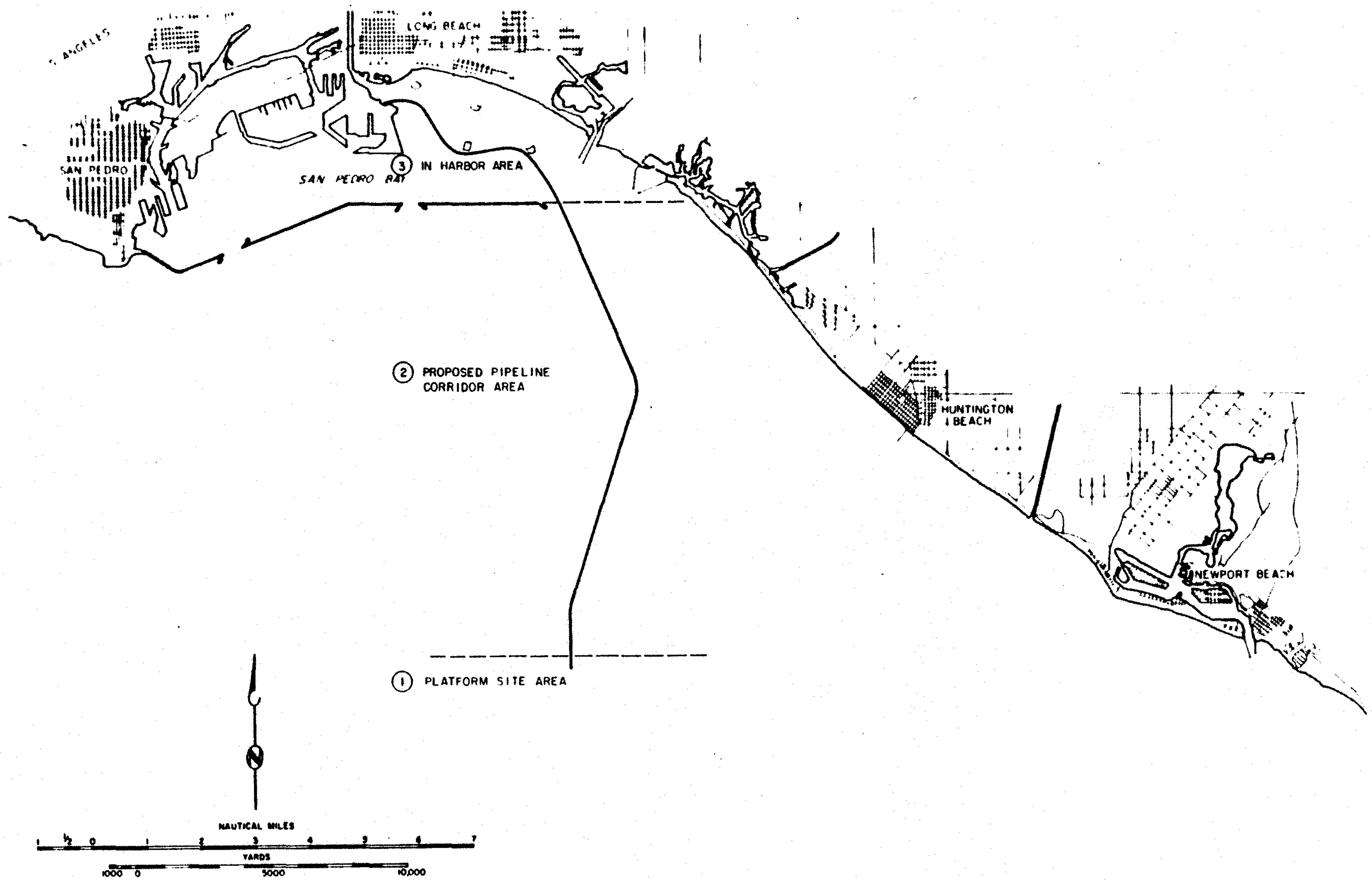
The Shell Beta project plan of development calls for a single 16-inch (0.4 m) oil pipeline to be installed from the production platform site (Elly) to the shore site within Long Beach Harbor (Figure 4.4-2). All of the pipeline from the Long Beach breakwater to landfall will be dredged and buried with at least four feet (1.2 m) of cover. Trenching will include the use of a dipper type dredge, casting aside the spoil for subsequent backfill. The dredged sediments are to be moved in a manner to minimize turbidity and resuspension.

During pipeline dredging, a large volume of sediment is disrupted and resuspended for a short time in the overlying waters. Even small dredging operations can increase chemical concentrations and increase turbidity in the dredging zone. Generally, pipeline dredging and burial can cause:

- Resuspension of pollutants.
- Temporary destruction of benthic biotic communities.
- Dredge-spoils smothering of burrowing and attached benthic animals.
- Increased turbidity, reducing light and clogging respiratory organs and filter feeding mechanisms.
- Temporary displacement of marine life due to machinery and noise.

It is impossible to accurately calculate the volume of material that will be reworked because the width of the trench varies with compactness and the fluidization point of the sediment.

The amount of turbidity and resuspension of pollutants is expected to be minimal because of the method of dredging and pipeline burial. Core samples collected by Dames and Moore (1975b) close to the proposed Beta project pipeline route were analyzed for mercury, cadmium, zinc, lead, oil, and grease. This study concluded that the concentrations of pollutants in the samples analyzed were below the maximum allowable concentrations required by the EPA for the dredging and replacement of material in the pipeline trenches. Additional sediment samples were collected as part of the field



Major Study Area Boundaries

4.4-2
Figure

study for this report. The results from those analyses, as presented in the Technical Appendix, are in general agreement with the Dames and Moore results.

The effects from pipeline dredging and burial will cause minor and transient modifications in the water quality along the pipeline route. Any detrimental conditions are expected to be of a temporary nature, and no special handling of the excavated material is deemed necessary.

4.4.2.4 Thermal Discharges

There are two primary sources for thermal additions connected with the Shell Beta project: (1) cooling water discharge and (2) pipeline heat dissipation. It is estimated that the drilling platform (Ellen) will require an average of one million gallons of cooling water a day. The water intake pipe will be located 60 feet (18 m) below the surface, with the discharge at a depth of approximately 10 to 20 feet (3 to 6 m). This discharge results from circulating seawater through internal-combustion-engine cooling-system heat exchangers. There is to be no process contact made.

Based on an energy balance on the platform's cooling circuit, the daily temperature difference (ΔT) between the intake water and the discharge water can vary between a minimum of 3.4F (1.9C) and a maximum of 21.6F (12.0C)(Shell Oil, 1978).

The concern for thermal additions to receiving waters is not directly related to the difference between the intake and discharge temperatures, but rather to the difference between the discharge and receiving water temperatures. The temperature of the discharged cooling water will vary depending on the number of diesel generator units operating and the amount of heat rejected from each diesel engine. The difference between the discharge and the receiving water temperature will fluctuate daily and seasonally, in response to natural warming and cooling trends.

During summer months, when a strong thermocline has developed, there is a natural temperature difference between the surface water and water below the thermocline. This difference aids in reducing the impact of thermal additions by providing cooler intake water relative to the surface receiving water.

Temperature data collected at the platform site during the July 1978 field study (Technical Appendix) showed a temperature difference of 5.4 to 10.8F (3.0 to 6.0C) between the proposed depths of intake and discharge. This natural difference would reduce the potential maximum ΔT between discharge and receiving water temperatures to a range of 10.6 to 16.2F (6.0 to 9.0C).

In winter, the thermocline is greatly reduced or absent, leaving a natural temperature gradient of only 5.0F (2.8C) from the surface to a depth of 200 feet (61 m)(Hancock, 1965). Because of the relative depths of the intake and discharge structures, the discharge to receiving water ΔT during winter could reach the maximum of 21.6F (12.0C).

The Environmental Protection Agency policy for federal waters presently allows for a maximum receiving water ΔT of 20.0F (11.1C)(EPA, 1978). The Shell Beta drilling platform cooling water discharge system would comply with EPA policy during periods when the ΔT between the intake temperature and the receiving water temperature equaled or exceeded 5.0F (2.8C). This situation would be common during summer months, as previously discussed. Under the present plan of development, cooling water effluent could exceed EPA policy limits during winter periods of reduced temperature gradient and maximum energy load.

During the transfer of processed oil from the production platform (ELLY) to the onshore terminal, heat is dissipated from the oil through the pipeline to the surrounding receiving waters. To ensure the smooth flow of oil through the pipeline, the processed oil is heated to approximately 110F (43C) before it leaves the production site. As the oil travels through the pipeline it cools off, dissipating the heat to the receiving waters. The amount of heat lost depends on the amount of internal pipe coating and the number of barrels being transferred, i.e. the greater the amount of oil being transferred, the less heat loss. The pipeline design calls for oil to be pumped at even 12,000 barrel (1,900 m^3) per day increments. A 12,000 bbl (1,900 m^3) per day transfer would account for a 43F (23.9C) loss from platform to onshore terminal; a 30,000 bbl (4,800 m^3) per day transfer would only drop 24F (13.3C). The majority of heat is lost within the first few miles.

Dames and Moore (1973) state that in nearshore waters, it is unlikely that a pipeline skin temperature even as high as 19F (5.6C) above ambient would prevent the growth of sessile organisms (e.g., barnacles, tubeworms, and bivalves). The amount of heat lost to receiving waters through pipeline operations should have little effect on any other physical or chemical parameters.

4.4.2.5 Thermal Mitigation

In order to insure complete compliance with existing EPA policy, the following mitigating measures can be taken:

(1) The Shell Plan of Development can be amended to extend the intake pipe to a depth of 200 feet (61 m) so as to take advantage of the natural year-round temperature gradient at that depth, thus reducing the discharge to receiving water ΔT to within the 20.0F (11.1C) limit.

(2) Shell can evaluate the possibility of discharging the cooling water through a multiport diffuser system.

Such a system would increase the initial dilution and enhance the dispersion of the cooling water, thus minimizing the imapct.

(3) Increase the cooling water flow rate, thus decreasing the discharge ΔT.

4.4.2.6 Sanitary and Domestic Waste

The treatment of sanitary and domestic wastes will be accomplished at the production site. Discharges from toilets on the drilling platforms will be mascerated, oxygenated by rolling with air, chlorinated to 1 mg/l residual chlorine, and retained for 30 minutes. After the retention period has elapsed, all waste will be discharged through a pipe 40 feet (12 m) below the surface. Galley discharges will pass through grease traps and then be combined with untreated discharges from laundry, washrooms, showers, and urinals for ultimate ocean disposal. The average discharge is anticipated to be 5,500 gallons (20,817 l) per day with an average daily chlorine residual of 1.5 mg/l. Discharge from one toilet and urinal(s) on the production platform, where there are no living quarters and typically less than ten people at any time, will be mascerated, chlorinated, and discharged to the ocean through a pipe 40 feet (12 m) below the surface.

The site area is typical of offshore water within the Southern California Bight, having naturally small or negligible coliform bacteria concentrations. Due to the distance of the site from shoreline and the dilution factors involved, no detrimental effects to water quality are anticipated. The effluent from the Shell Beta unit will comply with EPA requirements as shown below:

Far Offshore Category

Water Source	Oil and Grease (mg/l)		Residual Chlorine (mg/l)
	Maximum for any One Day	Average Daily Values for thirty consecutive days	
Produced Water	72	48	NA
Deck Drainage Drill Cuttings Produced Sand	No discharge of free oil to the surface waters		NA
Sanitary Waste	NA	NA	1.0 Minimum
Domestic Waste	NA	NA	NA

NA = Not applicable

4.4.2.7 Platform Drainage

In order to prevent spills of oil or other pollutant material from reaching the ocean, both the drilling platform and the production platform will be equipped with drainage collection systems in all areas where spills are likely to occur. These "drip pans" collect the spilled material and route it to a water sump. Oil is collected in an oil sump and pumped back into the oil-handling system. Water is collected in a drain-water surge tank and pumped back into the produced water-cleanup system. Under normal operations (i.e., routine cleanup and washdown of small spills) no discharge of either oil or water into the ocean will occur.

Should the capacity of the pumping system be exceeded (*e.g.*, during a heavy rainstorm or when fire-water is being used), the excess water which cannot be pumped back into the produced water system will discharge into an emergency sump or skim pile which has a capacity of 220 bbls (35 m^3). In the unlikely event that any oil carries over into the skim pile, provisions are included to recover the oil.

The drilling platform will be divided into two drainage systems for separate handling. Drainage from the top deck, from drip pans in the rig substructure, and from the rig floor will gravitate to a "waste tank" located on the lower deck. Drainage from the lower deck areas will drain to a sump tank below the lower deck, from which the liquids will be pumped into the waste tank. Wash water from the cuttings washer will also gravitate to the waste tank. Oily waste water from the waste tank will be sent to the production platform for treatment. Washed cuttings and oil-free sediments from the waste tank will gravitate to the skim pile for disposal.

The pollutant concentrations in ocean discharges will be within the limits prescribed by EPA in their Interim Final NPDES Effluent Guidelines with one exception; deck drainage will achieve "discharge of no free oil to the surface waters." This deck drainage requirement was stipulated by EPA and the industry in API versus EPA, Ninth Circuit Court of Appeals, 76-3588.

4.4.2.8 Corrosion Control

The essence of successful cathodic protection is to ensure that the correct amount of electric current arrives on the surface of the steel so that it will generate the electrochemical conditions required to passivate the metal at that point. The actual amount of current required to passivate varies according to the interrelationship of a number of environmental factors, such as temperature, dissolved oxygen, and water velocity (French-Muller, 1978). The life expectation of the anode is then a function of the volume of metal, its surface area and shape, and the resistivity of the water.

Cathodic protection below the mean water level for the Shell Beta project will consist of aluminum and zinc anodes. One million pounds (454,000 kg) of aluminum will be located uniformly throughout the platform structures as a function of the structures' surface area and projected life. Given a 30-year life expectancy, the daily aluminum input to receiving waters from anode deterioration will be approximately 90 pounds (40.9 kg). The EPA has not, to date, established aluminum discharge criteria for federal waters; however, due to the quantity of receiving water and the circulation through the area, no harmful effects are anticipated.

The pipeline will be protected by zinc anodes dispersed along the length of the corridor. Approximately 315 pounds (143 kg) of zinc will be deployed per 1000 feet (305 m) of pipeline. With 14 miles (22.5 km) of pipeline and an anode life expectancy of 30 years, anticipated input to receiving waters from zinc will be approximately two pounds (0.9 kg) per day. Although zinc is a potentially toxic metal, the small quantities anticipated from cathodic protection should not cause detrimental effects within the study area.

4.4.2.9 Injection Waters

Subsidence due to reservoir fluid withdrawal will be negligible in connection with Shell Beta drilling operations. A pressure maintenance program will begin soon after the start of production and reservoir pressure maintenance will be accomplished by injecting the produced water and by injecting a source water. Unless a suitable subsurface aquifer can be found (not likely), sea water will be used for the source water.

Prior to injection of produced water, it will be treated to remove suspended solids and oil. EPA requirements allow overboard discharge of these solids provided no free oil is present. The Plan of Development prepared by Shell indicates that all free oil will be removed. Provisions have been made for the collection of the solids for barging to shore for disposal if necessary. Under normal operation, all produced water will be injected, although at times it may become necessary to discharge overboard. When this occurs, the water so discharged will be sufficiently clean to meet EPA requirements. Little or no reduction of pore pressure is anticipated; accordingly, no compensating settlement of overburden is expected (Fugro, 1978).

4.4.3 Oil Spills

Some of the most significant impacts that could occur as a result of the Shell Beta project are those associated with accidental oil spills. The following discussion examines the possible causes of spills, the potential movement and fate of these spills, and the significant environmental impacts that could result from them.

4.4.3.1 Background

The worldwide input of oil to the ocean from offshore drilling and production operations is estimated at 0.08 million metric tons per annum (National Academy of Science, 1975). The majority of oil spills are less than 50 barrels (8 m^3); however, the small number of large spills account for the majority of the spill volume. The U.S. Coast Guard (1974) reported that in 1973-1974 about 76 percent of the number of oil spills was less than 2.4 bbl (0.4 m^3). These spills accounted for approximately 1 percent of the total volume spilled. In contrast, less than 2 percent of the spills of 2,400 bbl (385 m^3) or greater accounted for over 60 percent of the spill volume.

During drilling and production, oil spills can occur from blowouts, fires, pipeline leaks or ruptures, pump failures, ship collisions, and operating equipment failures. The Bureau of Land Management reports that the primary cause of major oil spills is the result of equipment inadequacies and operator errors (BLM, 1975). A blowout is the most likely cause of a major oil spill; however, it is not the most likely cause of any spill. In general, leaks, ruptures, and equipment failures are the most common causes of oil spills from offshore facilities.

Accidental oil spills during offshore operations account for only a small portion (7.5 percent) of the total oil spillage in OCS California, but locally they can be very significant; their frequency and magnitude and the fate and effects of the oil are important factors in OCS development decisions (BLM, 1975). Although oil wells must be considered as potential sources of pollution, data supplied by the U.S.G.S. for the period of 1964-1974 indicate there has been only one spill incident connected with federal OCS oil and gas operations in California involving greater than 50 bbl (8 m^3) of oil (BLM, 1975).

Oil spills from pipeline ruptures or breaks comprise a significant portion of the total spill volume. During OCS operations, more oil has been spilled from pipeline accidents than from all other sources combined. A large portion of the volume of pipeline oil spilled results from anchor-dragging-related incidents (BLM, 1975). New safety regulations and the oil industry's determination to decrease the high volume of spillage per accident and to keep the frequency of recurrence low, has led to the development of new techniques and equipment. Pipeline burial, corrosion protection, continuous metering systems, and automatic high-pressure shutdowns have all helped to decrease the spillage rate.

Prior to the new regulations concerning pipelines, the spillage rate was 0.0125 percent of the total production. Since 1970, with the regulations in effect, the spillage rate has been 0.001 percent, about an order of magnitude less (BLM, 1975).

Marine operations impacts are addressed in Section 4.6.3.

The estimated average produced gravity for Platform Ellen is 16°API, while Platform Eureka is expected to produce an average of 13° to 14°API oil. The estimated peak production rate from both drilling platforms will be 24,000 b/d (3816 m^3) of 14-16°API (specific gravity 0.96) oil by 1986. The working specific gravity within the pipeline is expected to be 0.94, the production oil being less dense than the receiving water.

The project area is comprised of three major subdivisions for oil spill analysis: (1) the offshore shallow-water platform site area; (2) the proposed pipeline route between the production platform (Elly) and the Long Beach breakwater, and (3) the three-mile (4.8 km) pipeline route between the Long Beach breakwater and the onshore facility (Figure 4.4-2).

The fate of an oil spill within the study area depends on the spreading motion of the oil and the translation of the slick by winds, and by the surface water currents. If both of these mechanisms are well enough understood, then approximate oil spill movement predictions can be made.

4.4.3.2 Dispersion of Oil

When petroleum is spilled into the ocean, it immediately begins to undergo physical and chemical changes which alter its composition and area. The rate of change depends upon many complex factors including evaporation, solution, spreading, emulsification, air-sea interchange, biological degradation and uptake, and sedimentation. Spreading, drift, and other natural reducing phenomena are the primary processes that describe oil spill dispersion.

(1) Spreading. To properly assess the behavior of petroleum spills at the air-sea interface, its area of coverage, thickness, and physical conditions must be determined as a function of time. Fay (1969), considering the spread of oil on a calm sea, concluded that gravitational effects controlled spreading characteristics as the oil layer thins. The most important assumption underlying the analysis for oil spreading is the absence of any effects of wind, tidal currents, and waves. It is expected that the drifting motion caused by winds and tidal currents would simply be superimposed on the spreading motion to be experienced on calm, stationary water.

The spread of an oil film on surface waters will pass through several stages as time progresses; in each stage, one spreading force will be balanced by one retarding force. Although there are four such possible combinations for large scale slicks, only three regimes are important: (1) the gravity-inertia regime (called "inertial spread"), (2) the gravity-viscous regime (called "viscous spread"), and (3) the surface-tension-viscous regime (called "surface-tension spread"). As time progresses, a large spill will pass through these three regimes in succession. A very small spill will generally behave as a surface-tension spread (Fay, 1971).

The spreading laws for each regime have been determined, to within an unknown constant, and are presented in the Technical Appendix. These laws give the linear extent of the slick as a function of time, the volume of the oil spill, and the physical properties of the oil and water.

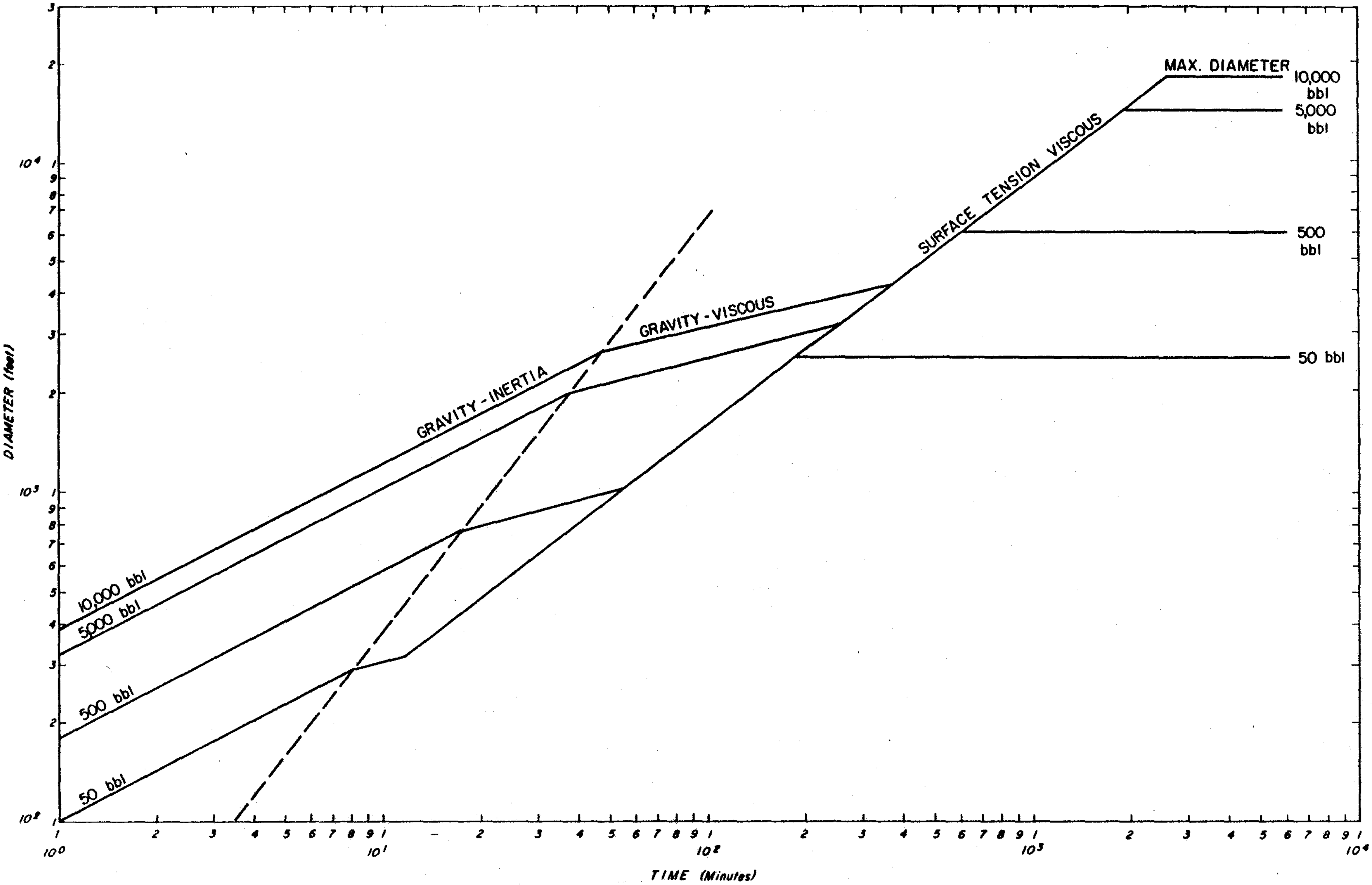
The force of gravity, acting downward, causes a sidewise spreading motion of a floating oil film by creating an unbalanced pressure distribution in the pool of oil and the surrounding water. This force on an element of oil film acts in the direction of decreasing film thickness and is proportional to the thickness, its gradient, and the difference in density between oil and water. As the oil film spreads and becomes thinner, the gravity force diminishes.

The initial inertia of an element of the oil layer decreases along with its thickness as time progresses and the film spreads, but the inertia of the viscous layer of water below the oil increases with time as its thickness grows. Consequently, the viscous retardation will eventually outweigh the inertial resistance of the oil layer itself.

At the front edge of the expanding slick, an imbalance exists between the surface tension at the water-air interface and the sum of the surface tensions at the oil-air and oil-water interfaces. The net difference, called the spreading coefficient, is a force which acts at the edge of the film pulling it outward. This spreading force does not depend upon film thickness as does the gravity force, and will not decrease as the oil film thins out. Eventually the surface tension force will predominate as the spreading force until the spill reaches its maximum area. In almost all cases, the final film thickness is much greater than that of a monomolecular layer, being about 10^{-2} to 10^{-3} cm (Fay, 1971). The three regimes and their effects were incorporated in the calculation for oil spill diameter versus time presented in Figure 4.4-3.

(2) <u>Wind and Current Patterns</u>. Surface currents driven by wind, waves, and convectional cells determine the shape and direction of movement of the spill; wind being the most influential external factor (Blokker, 1964). Wind patterns within the Southern California Bight, during all seasons of the year, are primarily from the west-northwest with secondary wind directions from the west and southwest. On an annual basis, winds are from westerly through northwesterly directions 57.1 percent of the time (Oceanographic Services, Inc., 1978). Wherever the shore trends more or less east and west, there is a change in winds from the prevailing northwest direction to those blowing from the southwest or west (Allan Hancock, 1965a).

Wind speeds less than 15 knots (27.8 km/hr) occur 89.3 percent of the time. Of this percentage, 39 percent are in the 6 to 10 knot (11 to 18.5 km/hr) range and 29.7 percent are between 0 and



Brown and Caldwell, Consulting Engineers.

Oil Spill Diameter Versus Time

4.4-3
Figure

5 knots (0 to 9.3 km/hr). The highest reported wind speeds during the 10-year period (1965 through 1974) were between 46 and 50 knots (85 to 92.5 km/hr) and occurred less than 0.05 percent of the time (Oceanographic Services, Inc., 1978).

Current speeds and directions, as previously discussed, are more or less seasonal. In the fall and winter, currents flow toward the southeast and northwest at an average speed of 0.2 knots (0.4 km/hr). In the spring, the average speed increases to 0.4 knots (0.7 km/hr) with the current flow shifting more toward the east and northwest. Summer conditions remain similar to those found in the spring for current direction; however, the average speed is slightly reduced to 0.3 knots (0.6 km/hr).

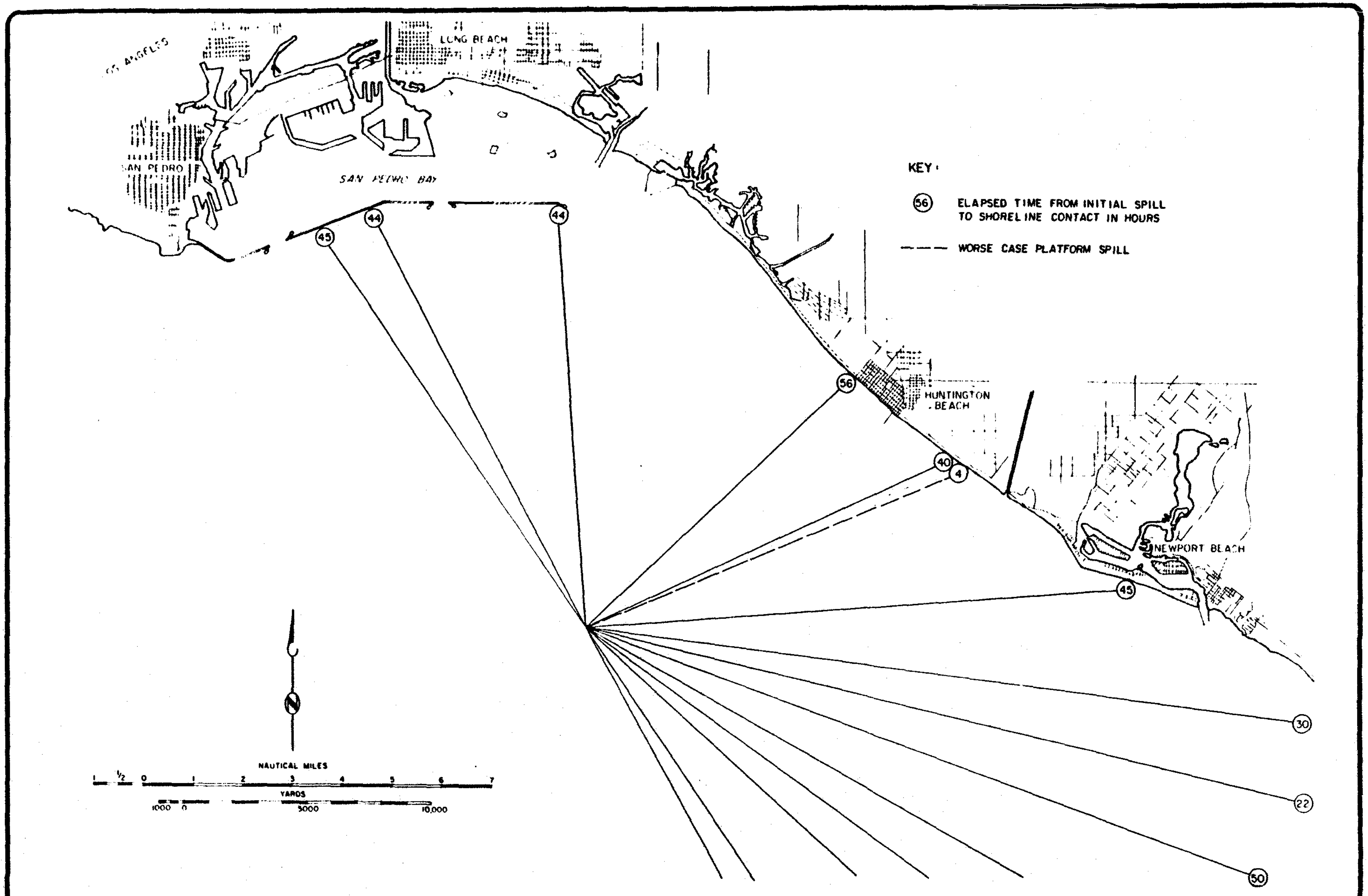
Based on these most frequent occurrences of wind and current speeds and directions, a table presenting a vector analysis was prepared (Table 4.4-2). The vector analyses were performed using equations of Fay (1971) and Premack and Brown (1973)(presented in the Technical Appendix) to provide the most probable oil spill trajectories for offshore spills.

Figures 4.4-4 and 4.4-5 represent the probable area of influence of a potential oil spill and were constructed from the results presented in Table 4.4-2. Given the dominant currents and winds, it is anticipated that an oil spill in the vicinity of the platform site or along the pipeline will travel in one of the vector directions indicated. In interpreting the figures, it should be noted that they represent calculations made for only the conditions presented in Table 4.4-2 and reflect the path of an unaltered spill. The circled numbers at the end of each vector indicate the elapsed time of travel from the spill site to shoreline contact.

The harbor area within Long Beach/Los Angeles breakwater presents a complex and varied pattern of currents. Figures 4.4-6 through 4.4-9 represent typical current patterns within the harbor area. Oil spill movements within the harbor depend primarily on the location of the initial discharge. Because of the close proximity of land in all directions, it is anticipated that the oil would reach some shoreline in the harbor within only a few hours.

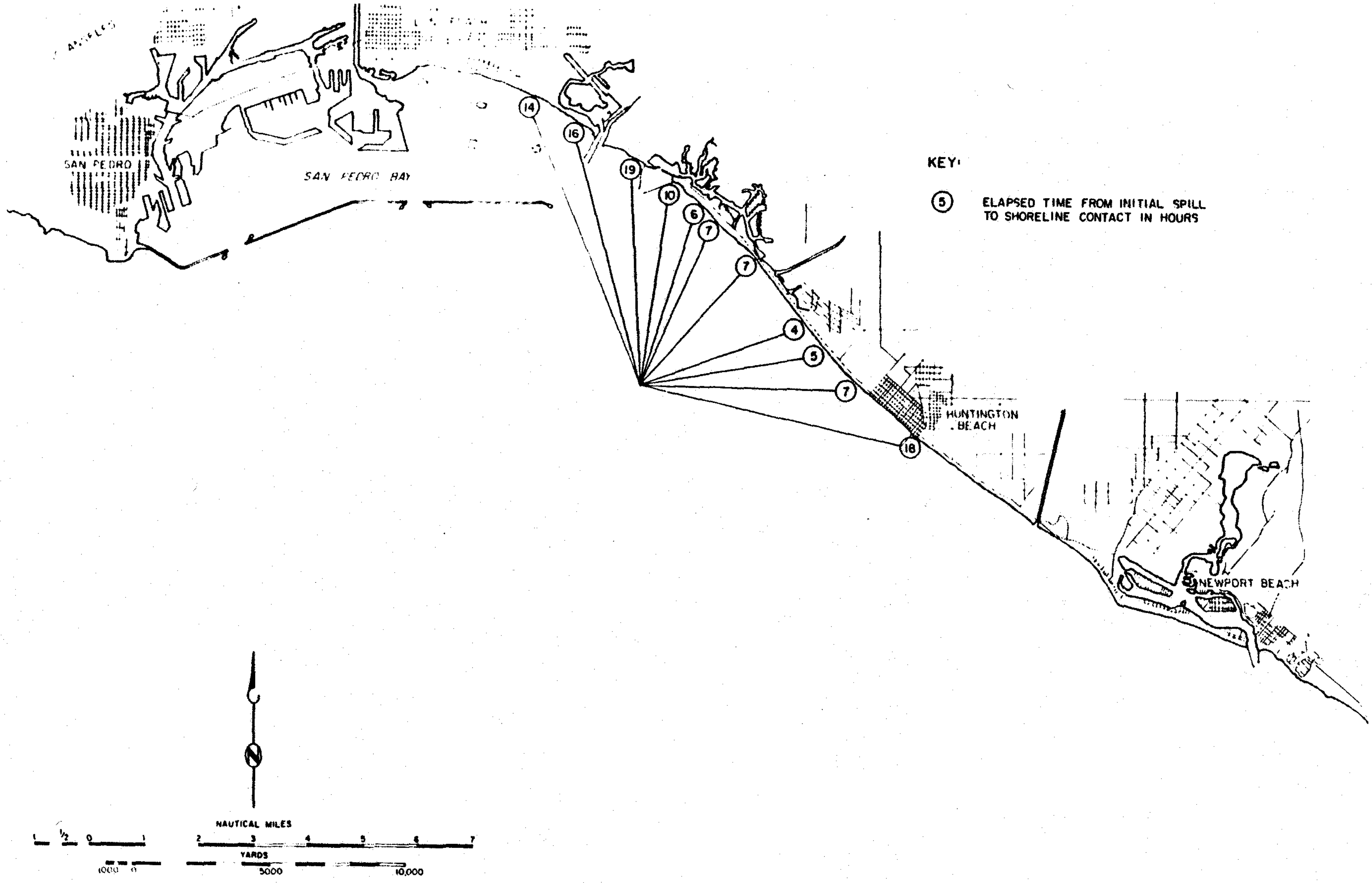
4.4.3.3 Natural Reducing Phenomena

In addition to the movement of an oil slick, it is important to know the ultimate disposition of the spilled oil. Weathering processes immediately begin to alter the slick that spreads out over the surface of the ocean. The composition of petroleum and characteristics of the environment such as temperature, concentrations of bacteria and nutrients, and sea state determine the rate at which petroleum is altered. Evaporation, emulsification, dissolution, sedimentation, and biological dispersion all contribute to the natural reduction of oil slick mass.



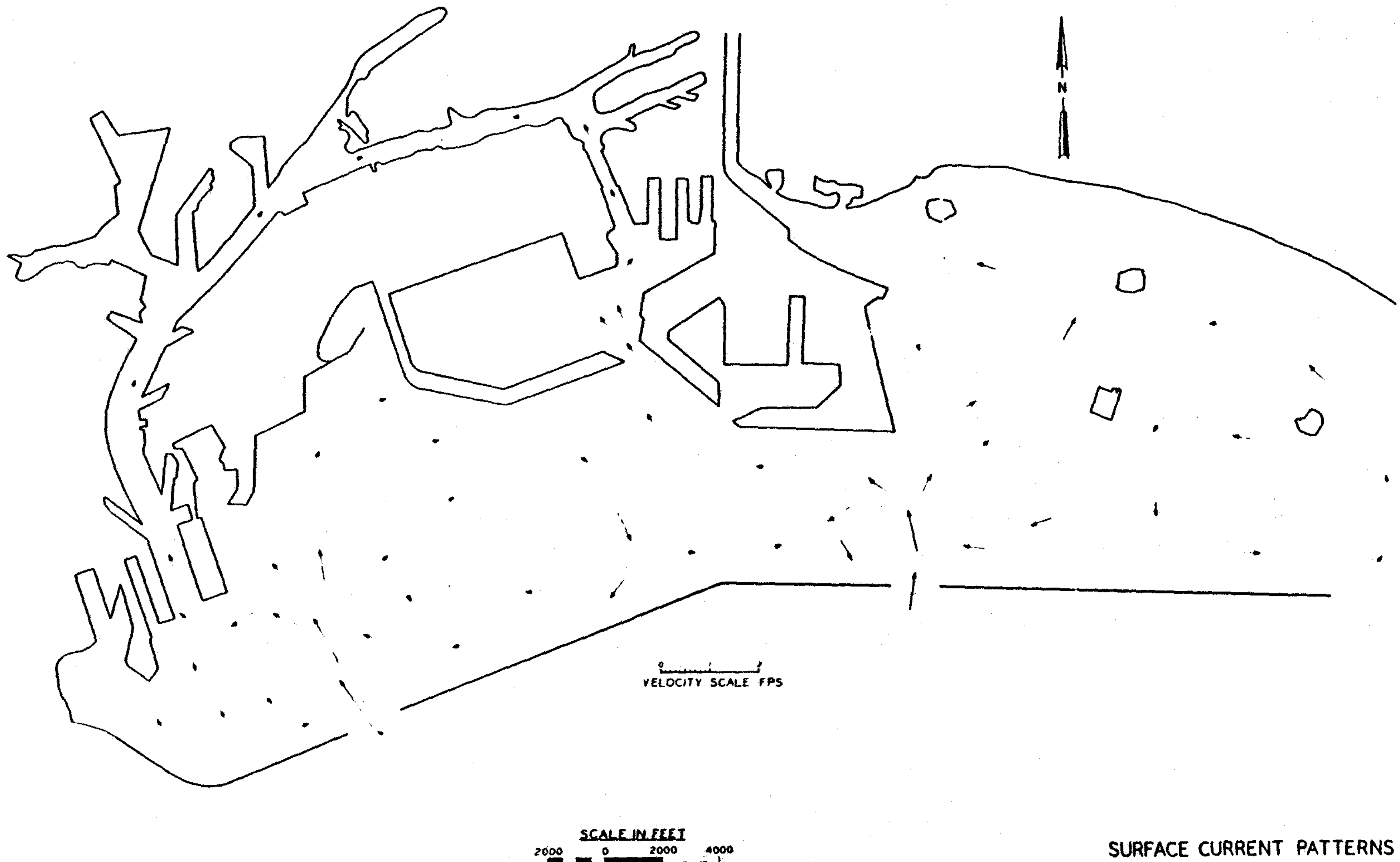
Probable Area of Influence from a Platform Site Oil Spill

4.4-4
Figure



Probable Area of Influence from a Pipeline Oil Spill

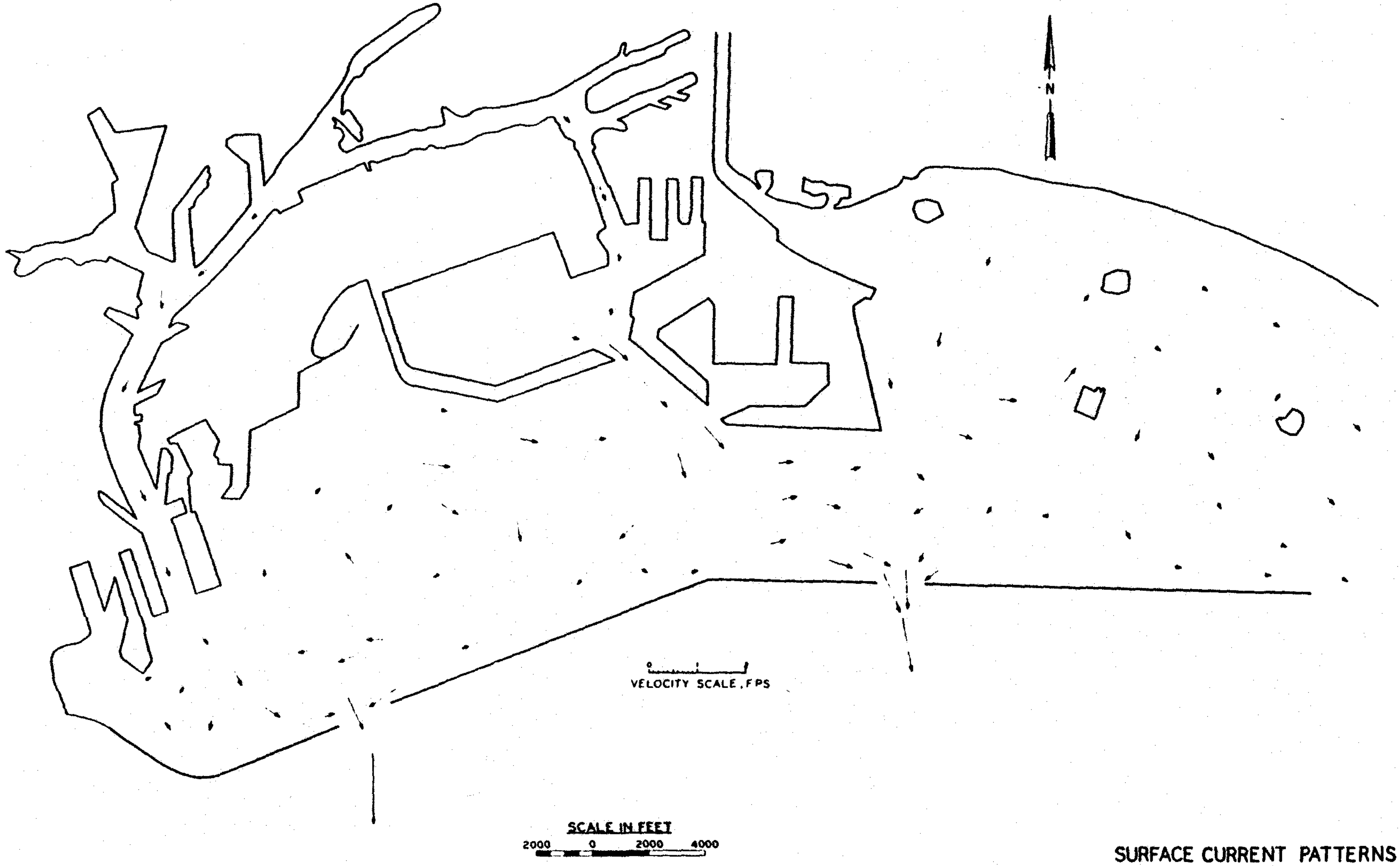
4.4-5
Figure



Source: U.S. Army Engineers, 1975

Harbor Current Patterns for a Spring Tide

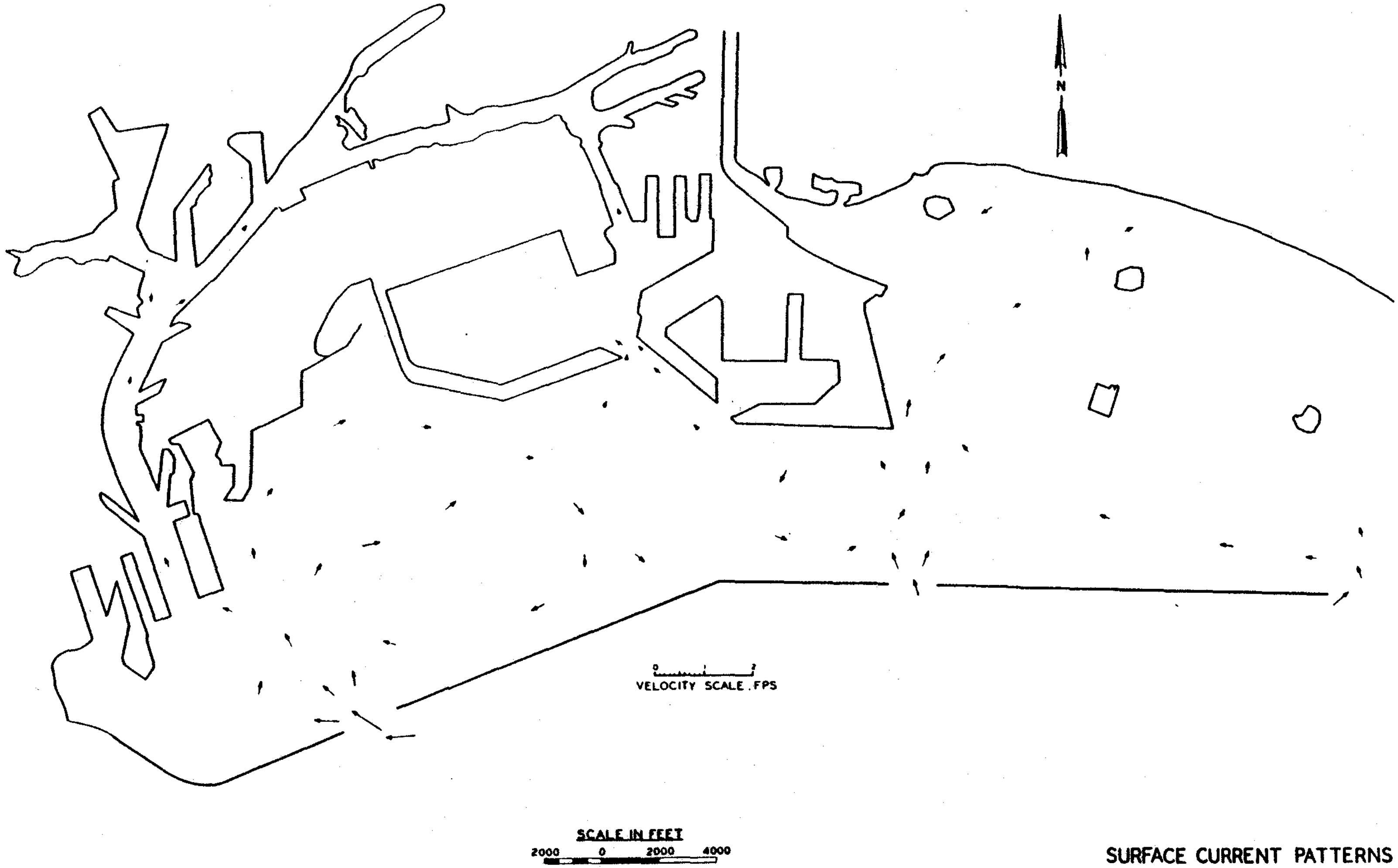
4.4-6
Figure



Source: U.S. Army Engineers, 1975

Harbor Current Patterns for a Spring Tide

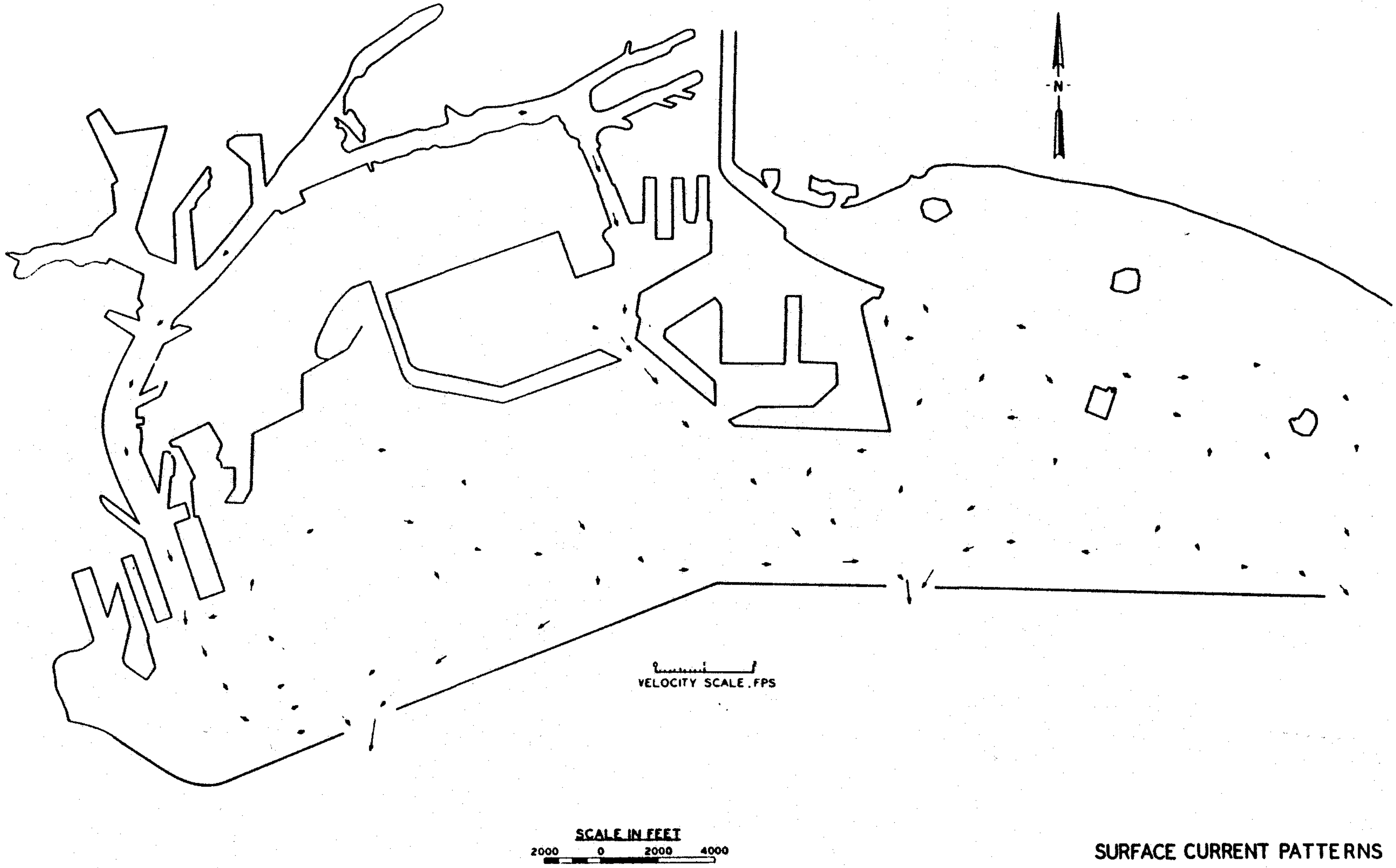
4.4-7
Figure



Source: U.S. Army Engineers, 1975

Harbor Current Patterns for a Neap Tide

4.4-8
Figure



Source: U.S. Army Engineers, 1975

Harbor Current Patterns for a Neap Tide

4.4-9
Figure

Table 4.4-2

SIMULATED OIL SPILL DATA

WIND	CURRENTS 0.2 kts SE	0.2 kts NW	0.3 kts E	0.3 kts NW	0.4 kts E	0.4 kts NW
WNW						
5 kts	0.35[a] / 125	0.10 / 356	0.44 / 098	0.21 / 332	0.52 / 097	0.32 / 326
10 kts	0.51 / 121	0.17 / 086	0.61 / 102	0.13 / 047	0.70 / 100	0.19 / 356
15 kts	0.68 / 119	0.33 / 099	0.77 / 104	0.25 / 086	0.87 / 103	0.20 / 065
WSW						
5 kts	0.28 / 102	0.22 / 358	0.44 / 082	0.31 / 345	0.52 / 083	0.40 / 338
10 kts	0.44 / 091	0.32 / 026	0.61 / 078	0.38 / 009	0.70 / 080	0.45 / 358
15 kts	0.66 / 091	0.46 / 043	0.77 / 076	0.49 / 025	0.87 / 077	0.54 / 013

Average Conditions

Fall/Winter Conditions	Spring Conditions	Summer Conditions
0.2 kts	0.4 kts	0.3 kts
SE/NW	E/NW	E/NW

[a] $\frac{\text{Speed}}{\text{Dir.}} = \frac{\text{Kts}}{^{\circ}\text{T}}$

(1) Evaporation

The lighter fractions of crude and other volatile fractions will evaporate to the air at a rate primarily dependent on vapor pressure of the oil. Physical conditions such as high winds and rough seas will increase the rate of evaporation. In general, the more toxic fractions evaporate faster, leaving a less toxic, more viscous, and denser residue in the surface slick. However, the BLM (1975) stated that if an oil slick 3 to 4 miles (5-6 km) offshore reached land in less than 3.5 to 4 hours, then very little of the toxic fraction would have been reduced by evaporation.

(2) Emulsification

Emulsification, the dispersing of a liquid in an immiscible liquid, takes place as either oil-in-water or water-in-oil. In general, the lighter fractions will go into an oil-in-water emulsification more easily than heavier fractions; however, vigorous agitation and/or solvent emulsifier mixtures are usually required for any significant emulsification of the lighter fraction to occur (Nelson-Smith, 1973). As the hydrocarbon molecular weight increases, the emulsions become water-in-oil. These tend to form naturally and easily, especially with some wind and wave agitation, and they are quite stable (Woodward-Clyde, 1976).

(3) Dissolution

Pure hydrocarbons separate into component parts in sea water. For a given class of hydrocarbons, dissolution or solubility in water decreases with increasing molecular weight; however, even under ideal conditions, relatively little oil is dispersed by dissolution as compared to the amount dispersed by other physical-chemical parameters.

(4) Sedimentation

The presence of suspended sediments in the water column provide an excellent surface for oil adsorption. The oil adheres to the particulate matter and the heavier particles settle to the bottom or are transported away from the initial spill area. During a period of heavy sediment input, the slick will be diminished and oil settlement will be maximum. As much as 30 percent of the oil could settle to the bottom in nearshore waters through this process (BLM, 1975).

(5) Biodegradation

The size of an oil slick can be reduced through various biological activities. Hydrocarbons are synthesized by living organisms through ingestion and oxidized by bacteria through microbial action. Along the California coast, oil-oxidizing bacteria range from essentially none to greater than 10 per milliliter of mud, with the largest populations being found in San Pedro Bay and Long Beach Harbor (Woodward-Clyde, 1976). Microbial degradation appears to be most efficient in removing relatively low concentrations of oil such as thin films. Biodegradation is a relatively slow process and of little significance in the short term compared with the other parameters mentioned.

4.4.3.4 Oil Spill Scenarios

In providing scenarios representative of possible oil spills from Shell Beta drilling and production operations, each of the three major study areas (platform, pipeline, and harbor) were considered separately. A simplified most probable approach was taken in the preparation of the scenarios to provide a very conservative analysis. The oil spills discussed are presented as unaltered spills, discounting natural physical and chemical dispersion factors such as evaporation, sedimentation, etc., and any oil-spill containment operations. The analyses are based primarily on the influences of natural spreading and the dominant wind and current vectors.

For the first two cases, outside of the breakwater, values were selected which would reflect average conditions in the study area during any given season. A constant 10-knot (18.5 km/hr) west-northwest wind factor for the platform site and a 10-knot (18.5 km/hr) west-southwest wind factor for the pipeline site were selected as those which reflect dominant wind patterns at the locations given. A current factor was added for a 0.3-knot (0.5 km/hr) northwest flow. The resultant transport vector direction under the conditions provided would produce oil slicks traveling from the platform site along a course of 047°T at a speed of 0.13 knots (0.24 km/hr) and from the pipeline along a course of 009°T at a speed of 0.38 knots (0.7 km/hr) (Table 2.2-4). These two cases do not attempt to predict the ultimate fate of all potential oil spills, however, they do reflect two probable occurrences under typical study area conditions. The third case presents a short discussion of oil spill conditions within the harbor area while case four has been included to reflect a worst- case situation for a platform catastrophe.

(1) Scenario 1. A 5,000-bbl (795 m^3) oil spill occurs at the offshore platform site, either by blowout during drilling operations on the drilling platform (Ellen), by rupture of gathering lines, pump failures, fire, ship collision, or by operating equipment error on the production platform (Elly). This spill is of reasonable expected size, as a maximum storage reservoir capacity of 10,000 bbl (1590 m^3) of processed oil is available on Platform Elly, with 5,000 bbl (795 m^3) an average working capacity. There is a steady west-northwest wind blowing at 10 knot (18.5 km/hr), and the average surface current is toward the northwest at 0.3 knots (0.55

km/hr). The oil moves onshore in the direction of Huntington Beach (047°T) at a speed of 0.13 knots (0.24 km/hr).

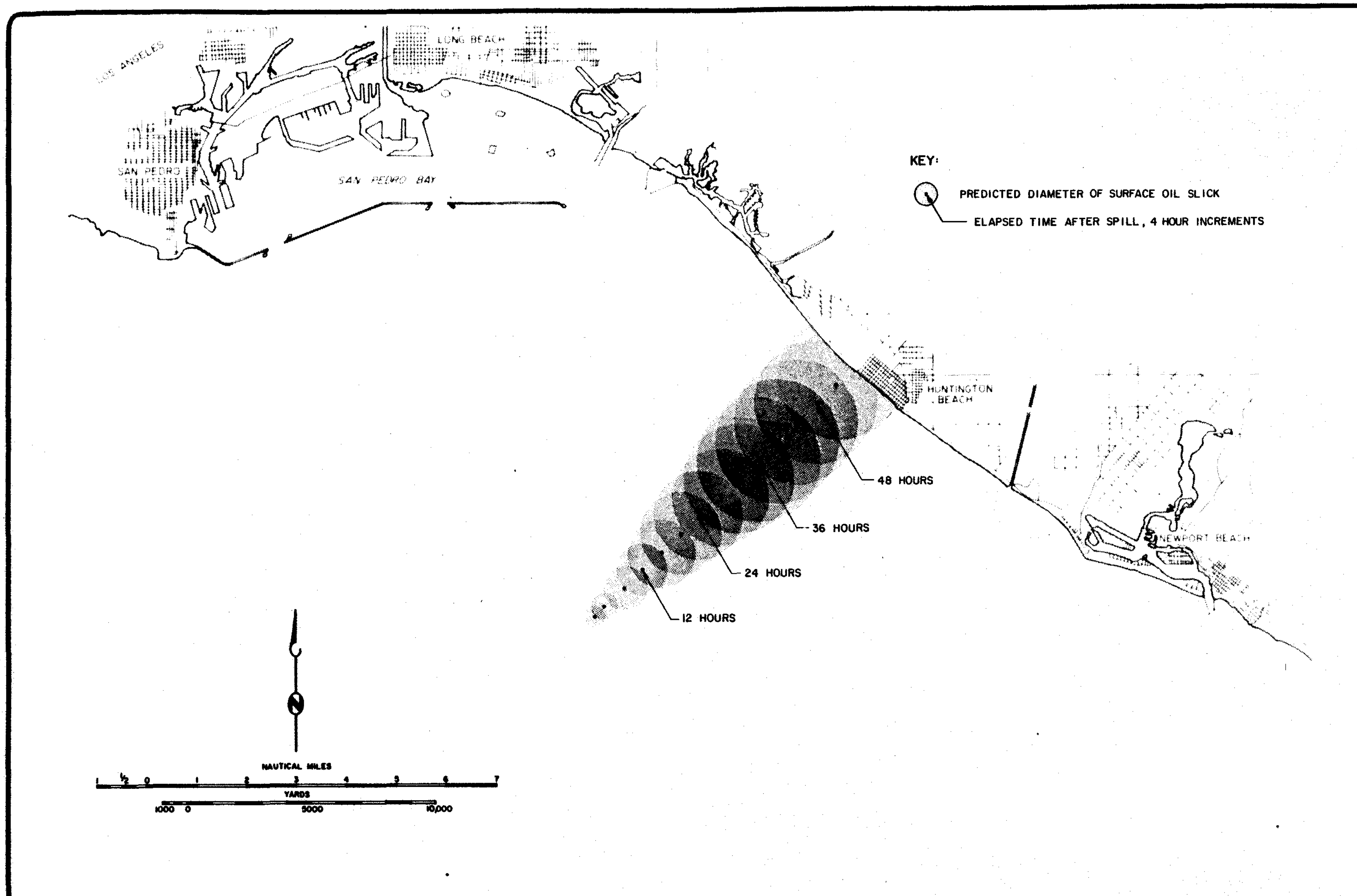
Assuming the oil spreads radially, the area covered by a 5,000-bbl (795 m^3) spill will be:

Time	Diameter
4 hrs.	3,200 ft. (976 m)
8 hrs.	5,400 ft. (1647 m)
12 hrs.	6,800 ft. (2074 m)
16 hrs.	8,600 ft. (2623 m)
20 hrs.	10,000 ft. (3050 m)
24 hrs.	11,500 ft. (3508 m)
28 hrs.	13,000 ft. (3965 m)
32 hrs.	14,250 ft. (4346 m) (Maximum Size)

A maximum diameter of 14,250 feet (4346 m) is achieved 32 hours after the initial spill, and covers 1.59×10^8 ft^2 (3660 acres or 1482 hectares). Initial contact with shore would occur about 48 hours after the spill, and the center of the slick would reach Huntington Beach in 56 hours as represented in Figure 4.4-10.

Variations in wind and current patterns will naturally occur as the oil path moves closer to shore. Wind patterns shift from the dominant west-northwest to a west-southwest duration in response to the east-west Palos Verdes land orientation. Tidal influences become a more dominant factor, shifting the oil pattern north and south depending on the tidal phase. Any number of physical parameters can cause the oil to vary in course, altering the ultimate disposition site shown in Figure 4.4-10. These localized influences, under the conditions given, would tend to rotate the slick path in a more northerly direction. Under differing conditions the ultimate path could assume any number of directions as shown in Figure 4.4-4.

(2) Scenario 2. A 50-bbl (8 m^3) oil spill occurs along the pipeline route, approximately three miles (4.8 km) offshore between Platform Elly and the Long Beach breakwater. This size pipeline spill is a reasonable estimate of the sensitivity of the oil pipeline leak detection system and would represent an undetected operational spill. There is west-southwest wind which moves the oil onshore (009°T) at a speed of 0.38 kts (0.7 km/hr). The area covered by such a spill would reach a maximum diameter of 2,550 ft (778 m) within four hours, and cover an area of $5.11 \times 10^6 ft^2$ (117



Case 1—Platform Oil Spill, 5000 bbl

4.4-10
Figure

acres or 471 hectares). The spill would reach the Alamitos Bay area within about 10 hours (Figure 4.4-11).

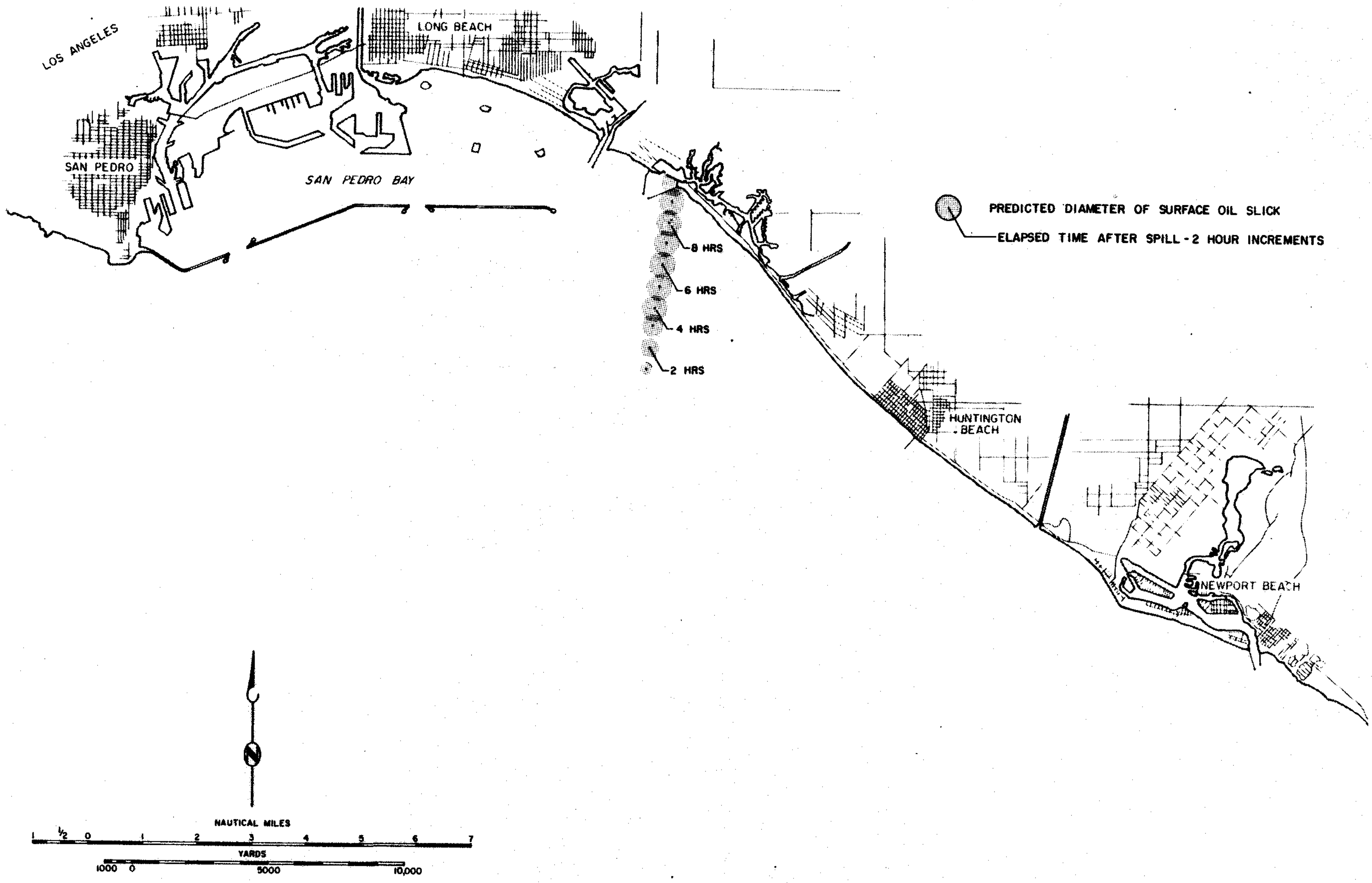
(3) Scenario 3. A 50-bbl (8 m^3) oil spill occurs along the pipeline route inside Long Beach breakwater. Surface currents inside the Long Beach Harbor are complex, exhibit tidal peridocity, and are influenced by factors such as bottom topography, proximity to harbor inlets, and proximity to natural and man-made land structures. An oil spill from any point within Long Beach Harbor would most likely reach land within a few hours. No graphic predictions are presented for this type of spill, although a representation may be visualized using Figures 4.4-6 through 4.4-9.

(4) Scenario 4. A worst-case scenario was constructed to reflect the following catastrophic conditions:

- A summer storm producing a 35-knot (65 km/hr) wind from the southwest is in progress;
- There is a 1.0-knot (1.85 km/hr) easterly current flow, which added to existing wind conditions produces a resultant 1.96-knot (3.6 km/hr) 006°T transport vector;
- Because of the adverse storm conditions, an oil tanker collides with the production platform spilling 68,000 bbl (10,800 m^3) of oil from ruptured tanks;
- The production platform is destroyed in the collision and storage tanks are at maximum capacity - an additional 10,000 bbl (1,590 m^3) are lost; and
- As a result of the collision, the pipeline valves and safety systems are destroyed at the platform location, allowing for a loss of 2,000 bbl (318 m^3).

Assuming all these conditions are present, which is an extremely remote possibility (perhaps once in 80,000 years or less often), a major oil spill (80,000 bbl - 12720 m^3) could reach the shoreline within four hours (Figure 4.4-4). The vector shown in Figure 4.4-4 reflects the general direction of such a catastrophic spill. Under the physical conditions noted, a volume of this size would be scattered and dispersed through wave and wind processes over a much broader area. The oil would divide into large patches, spreading and moving both upcoast and downcoast of the projected land contact point. The resultant impact could adversely cover a major portion of the study area (60,000 acres - 24,240 ha). No graphic prediction is provided for this scenario.

The degree of impact from the spills described in these scenarios is discussed within the following sections:



Case 2—Pipeline Oil Spill, 50 bbl

4.4-11
Figure

- Water Quality (4.4.3.5)
- Air Quality (4.3.4)
- Marine/Terrestrial Biology (4.5)
- Recreation (4.6)

The potential mitigation of these impacts is also discussed within those sections. In general, mitigation of oil spill impacts is limited to effective spill containment plans. Shell has provided a spill contingency plan, and the plan is analyzed in Section 4.4.3.7 and appropriate mitigation has been recommended to improve the effectiveness of that plan.

4.4.3.5 Oil Spill Impacts on Water Quality

Based upon observations of previous moderate to large oil spills, the quality of the seawater should not be significantly affected by a moderate or even large discharge of crude oil. If water quality should be affected, the effects would be generally of short duration. Probably the most important effect would be the physical presence of a floating oil slick. Oil coming ashore would be aesthetically objectionable and would interfere with recreational activities (McAuliffe, 1973).

Water quality parameters which may potentially be altered by the presence of an oil slick include biochemical oxygen demand, dissolved oxygen, nutrients, odor, and light transmittance.

(1) Biochemical Oxygen Demand (BOD) and Dissolved Oxygen. In small amounts that produce a film on the surface of the water, petroleum is a barrier that inhibits gaseous exchange between the water and the atmosphere. The dissolved oxygen content in seawater is reduced and the BOD and oxidizability are increased as petroleum concentration rises (Alyakrinskaya, 1966).

A rise in BOD in near-surface waters should not have significant effects because the surface layer is the most oxygen enriched layer and has sufficient capacity to satisfy the biochemical oxygen demand (McAuliffe, 1973). In general, the BOD requirement of spilled oil would be spread over a relatively large area and concentrated in the upper layers of water. Oxygen levels would be replenished by aeration, photosynthesis, and mixing by waves and currents.

Observations by the U.S. Fish and Wildlife Service (1969) during the Santa Barbara oil spill showed small dissolved oxygen reductions under thin slicks as compared with associated uncontaminated water. Kolpack, *et al.* (1971) also detected decreased dissolved oxygen concentration in the upper 30 meters under an oil slick. These reductions, probably associated with increased biochemical oxygen demand, were insufficient to cause any biological damage, because resultant oxygen levels remained well above saturation levels.

A biologically significant reduction in dissolved oxygen is not expected to occur unless one or more of the following conditions occur:

- A continuous, thick layer of oil covers a very large area (on the order of hundreds of acres).
- Surface conditions remain calm and currents are minimal for several days. Both conditions would reduce mixing under the slick.
- Large populations of zooplanktonic and nektonic organisms (which use dissolved oxygen for metabolic processes and excrete wastes with relatively high BOD) are present, and phytoplanktonic populations (which produce oxygen through photosynthesis) are low.
- Activity levels of oleophilic bacteria are low.

(2) Nutrients. The U.S. Fish and Wildlife Service (1969) measured near surface nutrient levels (NO_2, NO_3, PO_4, SiO_2) in areas contaminated by an oil slick. No significant variations were observed during or after the spill. Kolpack, *et al.* (1971) were not able to demonstrate any significant variations in these same nutrients attributable to the Santa Barbara oil spill.

(3) Odor. Beginning with a petroleum concentration of 5 ml/liter, polluted seawater covered by an oil film retains the smell for two to three weeks. Under these conditions, petroleum may be taken to be a stable contaminant of the water (Alyakrinskaya, 1966). The persistence of such an odor is a function of duration and extent of the slick, constituent hydrocarbons present in the spilled oil, and temperature. As temperature increases, the rapidity with which the odor disappears also increases. Odor can persist from one to three days after dispersal of the slick, and from 1 to 25 days when oil films are present.

(4) Light Transmission. Light transmission may be affected by oil slicks. The extent of this effect will depend on the nature of the oil and its thickness. Slicks of moderate thickness may be expected to reduce light penetration, but reduction of light transmission is, at most, a transient situation and should have minimal biological effect (McAuliffe, 1973).

Oil remaining on the water surface tends to develop into thicker rope-like configurations surrounded by a thin sheen. Therefore, only a small portion of the total spill area surface is significantly affected. Only under extremely calm sea surface conditions, which are rare, does oil tend to form a continuous slick (McAuliffe, 1973).

Measurements of photosynthetic activity (light required) measured under slicks at Santa Barbara showed no reduction in photosynthetic activity (Oguri and Kanter, 1971).

4.4.3.6 Water Quality Oil Spill Mitigation

Oil-spill cleanup activities are partially effective in removing spilled oil from the environment and thus reducing the adverse effects of the oil spill. However, the cleanup procedure itself can have adverse effects (Smith, 1968; Lonningan and Hagstrom, 1976). The implementation of cleanup activities should consider these potential impacts and employ those which result in the least overall adverse impacts of both oil-spill and cleanup.

The preferred approach to oil-spill cleanup is physical containment and removal, and major strides have been made in the development of equipment for this purpose (Coit, 1977). Such methods involve the use of floating booms and skimmers or absorbents. In all major marine oil producing areas of the United States, the petroleum industry has formed, financed, and operated oil-spill cooperatives. The technology and expertise assimilated through these cooperatives has resulted in the development of a better-trained, more highly-organized oil-spill containment task force. Within the southern California area, there are several organizations capable of supplying the manpower and expertise necessary to properly contain and clean up an oil spill. A listing of these organizations is provided in the Shell Oil-Spill Contingency Plan.

Although oil-spill cleanup organizations have developed sophisticated and effective equipment, this equipment becomes less efficient as sea states increase (Coit, 1977). In protected waters, recovery can be quite effective, and booms are one of the most efficient methods available if conditions are favorable for their use.

The Oil-Spill Contingency Plan for the Beta Unit (Shell, 1977) provides for the use of booms as the primary method of spill containment. An assessment of this plan is provided in Section 4.4.4.2. Once contained, the oil would be removed by skimmers or absorbent materials. During containment operations, for very small, thin slicks (<10 bbl - 1.6 m^3), the use of Oil Herder^R may be employed to consolidate the slick for mechanical cleanup. Oil Herder^R is a surface-tension modifier which, when properly applied, inhibits spreading of oil spills. Oil Herder^R dissipates rapidly, and any effects on water quality would be of short duration and less harmful than the oil itself.

The use of chemical dispersants may be employed for oil spills larger than 5 to 10 gallons (19-38 l), as described in the

Oil-Spill Contingency Plan. Dispersants are surface-active chemicals which penetrate an oil slick and break it into tiny droplets. The most important advantage gained by using dispersants is rapid oil dilution. Dispersed oil mixes downward in near-surface waters, removing the oil from most of the wind's influence (Coit, 1977; Smith and Holliday, 1978). As the oil is dispersed, increased surface area is available to natural mechanisms such as evaporation, solubilization, and biodegradation. Thus, the use of dispersants is one way to eliminate the most visible evidence of petroleum spills and prevent concentrated oil from reaching the shoreline (National Academy of Science, 1975).

Dispersants vary in effectiveness according to the type of oil, weather conditions, and method of application (Smith and Holliday, 1978). Choice of chemical and method of treatment are of primary importance (Coit, 1977). The use of oil-spill dispersants is a debatable countermeasure in the effort to minimize or eliminate the biological impact of oil pollution (Hidce, 1975; Hagstrom and Lonning, 1977; Sekerah and Fay, 1978). The difference in the ecological effects of an oil and an oil/dispersant mixture must be of determinative importance when a decision is to be made on whether chemical dispersants should be used in a cleanup situation (Linden, 1975). There is substantial worldwide difference in the level of acceptance and concern regarding their use. In the United States, the use of dispersants has historically (1967) been discouraged by federal regulation, due primarily to early concern over the use of some toxic dispersants (Coit, 1977). Governmental restrictions control the use of dispersants, and they may only be employed with the approval of the United States Coast Guard and/or the Environmental Protection Agency.

Although the controversy regarding the merits and shortcomings of chemically dispersing oil spills is far from resolved, substantial progress has been made since the Torrey Canyon incident of 1967. Dispersants have been developed which are less toxic than the earlier detergent types (Canevari and Lindblom, 1976). According to Coit (1977), the use of low toxicity dispersants to control oil spills may be a sound control approach in offshore areas, particularly when an oil spill is approaching a sensitive coastline. A more detailed discussion of potential dispersant toxicity can be found in the biological section (4.5.2.1).

A list of those dispersants acceptable by the federal government (EPA) and those licensed by the State of California include:

Federal	State
COREXIT 9527	COREXIT 9527
Atlantic-Pacific Oil Dispersant	COREXIT 7664
NOSCOM	ECO/+
Sea Master, NS-555	Atlantic-Pacific Oil Dispersant
Gold Crew Dispersant	
Cold Clean	
BP 110 X	
BP 11 WD	

The Shell Oil Spill Contingency Plan specifies the use of only one dispersant, COREXIT 9527.

In summary, the use of booms, absorbents, and the Shell Oil Herder[R] as mitigation should reduce adverse impacts on water quality from oil spills. The use of chemical dispersants as a mitigation, however, is debatable and could create secondary impacts if not properly applied. The spill contingency plan does indicate that permission to use chemical dispersants must be received from the U.S. Coast Guard, and that the U.S. Coast Guard will supervise its application. In addition, dispersants will be distributed on the slick by trained technicians who are familiar with the products and their application, and not by unskilled volunteers or outside recruited help (Holliday, 1978).

4.4.4 Spill Contingency Plans

4.4.4.1 Federal

The national legal and administrative framework for oil spill response procedures is provided by the Federal Water Pollution Control Act of 1970 (PL 92-500), as amended in 1971 and 1972. PL 92-500 established that the spiller would be liable for cleanup costs and all penalties, the only defenses being acts of God, acts of war, negligence on the part of the U.S. Government, or acts or omissions on the part of third parties. This act required the formation of a new contingency plan and delegated responsibility for its development to the Council on Environmental Quality. Pursuant to Section 311(c)(2) of the act, a National Oil and Hazardous Substances Pollution Contingency Plan (NCP) was established in 1973 and amended in 1975 (Federal Register, 40 (28): 6282-6302).

The NCP provides for: (1) assignment of cleanup responsibilities to various federal agencies in coordination with state and local entities; (2) establishment of a national center for coordination and direction of operations; and (3) establishment of strike and task forces to carry out the plan. The body with overall responsibility for implementation of the plan is the National Response Team (NRT), composed of representatives of several cognizant government agencies such as the Departments of Defense, Interior, Commerce, and Transportation, and the Environmental Protection Agency. The lead agency for spill cleanup in inland waters of the United States is designated as the Environmental Protection Agency; the U.S. Coast Guard is responsible for coastal waters and the Great Lakes and for ports and harbors (Section 1510.36). The U.S. Geological Survey is responsible for measures to abate the source of pollution from offshore wells.

The U.S. Coast Guard has established three national strike teams to provide this protection. The southern California coastal area is the responsibility of the Pacific Strike Team, which is based in San Francisco. The strike team is staffed with trained personnel and supplied with sophisticated containment and removal equipment. They can provide direct assistance in major emergencies, as well as furnish consultation and equipment on request for less serious spills. However, basic implementation of the NCP rests on the regional concept: each of the Standard Federal Regions (EPA, HUD, and HEW regions) is directed by the NCP to develop a Regional Contingency Plan establishing a Regional Response Team (RRT) with overall responsibility for coordinating spill response within the region.

The governing plan for the southern California coastal region is the Region IX Multi-Agency Oil and Hazardous Materials Pollution Contingency Plan, Subregional Plan for Zone One, Southern California, dated December 1971. Zone One is contained within the 11th Coast Guard District, whose coastal boundaries are the northern limit of Santa Barbara County and the Mexican border. The Commander of the 11th Coast Guard District serves as the on-scene coordinator (OSC) for all spills, and as such, is the key federal official onsite. It is the OSC, together with other federal, state, and local agency representatives, who coordinates cleanup efforts and, if necessary, actually directs those efforts when the spiller's response is judged inadequate. As such, the 11th Coast Guard District has a very detailed containment plan, which provides policy and direction for spill containment within the Shell Beta project area.

4.4.4.2 State

State response to pollution incidents is governed by the State of California Oil Spill Contingency Plan of March 1974, developed in accordance with California Government Code 8574.1. This plan (1) provides for a coordinated response to oil spills by various state agencies, and (2) furnishes a procedure for keeping local governments and the public informed regarding a spill and its probable effects. The state plan creates a State Agency Coordinator, with responsibility for directing on-scene operations of all state agencies engaged in combating a pollution incident. The state plan also establishes a support team to provide technical advisory and supervisory advise in response to an actual spill.

While the state plan provides direction in a spill situation, it does encourage local agencies to prepare plans to handle the specific needs of individual localities. However, based on discussions with local officials and with the possible exceptions of the Port of Los Angeles, City of Laguna Beach, and Orange County, little effort has been expended by local governments in this region to establish local plans.

4.4.4.3 Shell Oil Spill Contingency Plan

In keeping with the 1972 amendments to PL 92-500, which fixes liability with the spiller, both federal and state contingency plans urge industry to plan for and commit resources towards oil spill containment and removal operations. Thus Shell, as part of this project, prepared in 1976 a Spill Contingency Plan for the Beta project. It is Shell's intent to update the Plan in 1979 prior to U.S.G.S. approval of the Beta project. The following paragraphs describe the Plan as it presently exists.

The purpose of this Plan is to direct Shell Oil Company personnel in their response to an oil spill emergency. The Plan provides for the use of the containment and cleanup capabilities of the Southern California Petroleum Contingency Organization (SC-PCO), Clean Seas Incorporated, and Clean Coastal Waters. In addition to Shell's plan, each of these cooperatives have their own contingency plans for dealing with spills.

(1) Plan Description

The Shell Oil Spill Contingency Plan divides responses into two categories, small spill and large spill, and outlines the procedures to be followed for each case.

(a) Small Spill Plan. It is proposed that small spills of less than 400 gallons 1.5 m^3) be handled by platform personnel and materials/equipment stored aboard the platforms. The plan provides job descriptions for various key individuals. Platform staff receive training on spill containment procedures, and are drilled monthly to provide required readiness. A list of equipment available aboard the platforms is shown in Table 4.4-3.

(b) Large Spill Plan. In the case of large spills [greater than 400 gallons 1.5 m^3)], it is anticipated that assistance will be required from shore. Platform personnel using on-board equipment (see Table 4.4-3) will initiate constraint procedures pending arrival of assistance. Shell's drilling foreman will initiate control measures and notify Shell's offshore drilling superintendent, who will contact appropriate governmental agencies and the onshore assistance groups.

Shell belongs to the SC-PCO cooperative. This organization will provide a large portion of the equipment which would be required to contain a large spill. This equipment is stored in San Pedro and on Santa Catalina Island. The Shell Oil Spill Containment Plan provides a listing of SC-PCO equipment and its locations. The plan also provides listings of commercial firms within the Los Angeles-Long Beach Harbor area who can provide additional equipment or manpower as required.

The plan indicates that containment efforts will be supervised by Shell's infield supervisors and corporate management. Management support and technical advice will be provided by SC-PCO.

Job descriptions are provided for Shell Oil Company personnel who might be required in an oil spill emergency. Job responsibilities are listed for personnel on levels ranging from

TABLE 4.4-3

EQUIPMENT ABOARD BETA PLATFORMS

- All blowout prevention equipment listed in the Final OCS Order No. 2, Drilling Procedure, effective May 1, 1976, U.S. Geological Survey
- Curbs, gutters, drains, and drip pans will be placed to collect contaminants from the deck areas and prevent them from discharging into ocean waters.
- A Vikoma Seapack fast deployment containment system with 1,600 feet of boom.
- A Vikoma Komara Miniskimmer, complete with fuel, hose, and connections, capable of recovering 70 barrels per hour of crude or 14 barrels per hour of diesel oil.
- A crew/supply boat.
- Ten bales of 3M type 156 Sorbent Pads 12" x 18".
- Ten bales of 3M type 1070 Sorbent Boom (five 8-foot booms per bale).
- Ten 5-gallon containers of Shell Oil Herder(R) collecting agent.
- Two 55-gallon drums of COREXIT 9527 dispersant.
- Spray application equipment.
- Two pillow tanks, 1,200 gallons each, Sea Containers.
- Rope, pitchforks.
- Communications equipment.

company management to working supervisors. Tasks envisioned are detailed in job descriptions, and they include management, notification, immediate- and longer-term responses and actions, liaison with government agencies on all levels, public and media relations and dissemination of information, protection and cleanup activities ashore, wildlife and environmental concerns, legal affairs, the employment of non-company personnel as required, and monitoring and assessment. The plan calls for in-company training of personnel and familiarization with equipment and materials to be used.

(2) Plan Enhancement

Recognizing that Shell's contingency Plan was prepared in 1976 and that Shell will update the plan and submit it to U.S.G.S. in 1979 prior to commencement of Beta operations, the following are recommendations to enhance its effectiveness as it presently exists.

(a) Updated and Expanded Plan. The plan should be updated to include current key personnel contacts, equipment inventories (both SC-PCO and commercial), and personnel responsibilities. Depending on the spill magnitude, Shell plans to use in-company, SC-PCO, and commercial resources to handle cleanup. Even though SC-PCO plans incorporate commercial resources, and some are listed in Shell's current plan, it may be appropriate to incorporate specific commitments from other commercial firms with call-up priorities for specific services such as additional experienced personnel, booms, tugs, and food catering when the requirements of a major spill dictate such support. Overall plan effectiveness is, of course, dependent on periodic and timely updating which U.S.G.S. requires. An additional important aspect of this updating is to allow periodic incorporation of new or improved technology.

The key personnel assignments and training program described in the present plan can be augmented by a more specific set of detail procedures (both immediate and continuing actions) by individual assignments to avoid uncertainties in time of emergency.

Shell plans to use approved dispersants to prevent a slick from reaching shore. In this respect, the plan can be enhanced by detailing procedures for the use and application of dispersants to prevent misuse and accompanying adverse environmental effects.

(b) Spill Containment. The Coast Guard and U.S.G.S. policy is to contain a spill onsite as opposed to dealing with it on or near shore. Shell has indicated a similar policy as regards the Beta Unit, and this presumably will be reflected in the updated plan.

There are varying professional opinions as regards the effectiveness and practicality of storing large containment booms on a platform to deal promptly with large spills.

Despite the limitations imposed by a given set of circumstances (including platform damage or weather), provision of additional rubber spillbooms on the platform might enhance on-site containment efforts until other resources can be applied. Such a system should be evaluated for the Beta project as a part of the continuing evolution of oil spill containment technology. One possible suggestion is to relocate one of the existing SC-PCO Vikoma seapacks to the platform. This would provide up to 3000 feet of open-sea boom for immediate deployment in conjunction with the seapack already proposed for the platform.

(c) Pipeline Monitoring. The installed pipeline leak detection system should warn of any leaks exceeding 50 barrels (8 m^3), and should this occur, the pipeline will be shut down. As part of the plan update, procedures for handling a pipeline leak should be incorporated, at least those elements dealing with the more unique aspects such as leak source location. These would include aerial and surface surveillance techniques. Platform service boats can also run the pipeline route periodically to check for leakage during their normal operations.

(d) Shore Protection. A detailed report was prepared for SC-PCO by Ultrasystems (undated) specifying locations of sensitive bays and estuaries and plans for protection of these areas during an oil spill. The updating of the Shell Plan should incorporate appropriate measures from, and references to, this report. Measures should include provision for booming of certain harbors, bays, and estuaries in the event of a major spill. Spillbooms should be readily available for prompt deployment across entrances, as follows:

	Location	Boom Footages/Size
(1)	Alamitos Bay (between end of east and west jetties	750 ft (228 m)/8 in (20 cm)
(2)	Newport Beach Harbor	1000 ft (305 m)/8 in (20 cm)
(3)	Anaheim Bay (between end of east and west jetties)	750 ft (228 m)/8 in (20 cm)
(4)	San Gabriel and Santa Ana River mouths	750 ft (228 m)/8 in (20 cm)

Staggered boom deployment across bay and harbor entrances may be necessary to ensure adequate protection. There are 5,000 feet (1,525 m) of boom at Aminoil (Huntington Beach) and over 10 miles (16 km) of boom in harbor areas (U.S.G.S., 1978). Local agencies, such as harbor masters, should be assigned the responsibility for boom deployment on short notice and the specific locations of these materials should be noted in the updated plan.

4.5 BIOLOGICAL IMPACTS

4.5.1 Marine Biology

The following section deals with those impacts resulting from project construction, drilling, and production activities. Oil spill impacts are addressed separately in Section 4.5.2.

4.5.1.1 Intertidal

(1) Sandy Beach/Rocky Intertidal

Drilling muds and cuttings which are disposed of in the vicinity of the platforms are not anticipated to impact either the sandy beach or rocky intertidal communities.

(2) Biofouling Communities

- Construction Phase: Harbor dredging for the pipeline will cause suspension of particulates in the water column as well as possible resuspension of contaminants that have previously settled. Contaminants such as dissolved heavy metals are known to cause reduction in productivity and phytoplankton and increased larval mortalities (Brewer, 1975; U.S. Army Corp of Engineers, 1976). These suspended particulates might have a direct effect on the fouling community, however, it is possible that many organisms currently thriving in the harbor have adapted to high levels of contaminants. The proposed dredging may not have any adverse effects on the adapted fouling communities.

  Indirect effects may occur as a result of increased siltation in the harbor and affect the mechanisms by which more vulnerable filter-feeding forms, pelagic larvae, and juveniles obtain food. Many forms filter particles through mucous membranes and clogging of these membranes, as a result of increased particulates in the water column, could result in mortalities (Nelson-Smith, 1972).

- Drilling and Production Phase. No significant non-spill-related impacts are expected to occur to the biofouling community during these phases.

4.5.1.2 Benthic Communities

(1) Construction

The installation of the submerged pipeline within the breakwater area represents a potential impact on benthic communities.

This process will physically disrupt the existing sediments and benthos. Much of the fauna in the trenching area will be destroyed by habitat disruption or exposure to predators. However, following the pipeline burial, normal re-colonization by planktonic larvae would be anticipated in the disturbed area (Simpson, 1977).

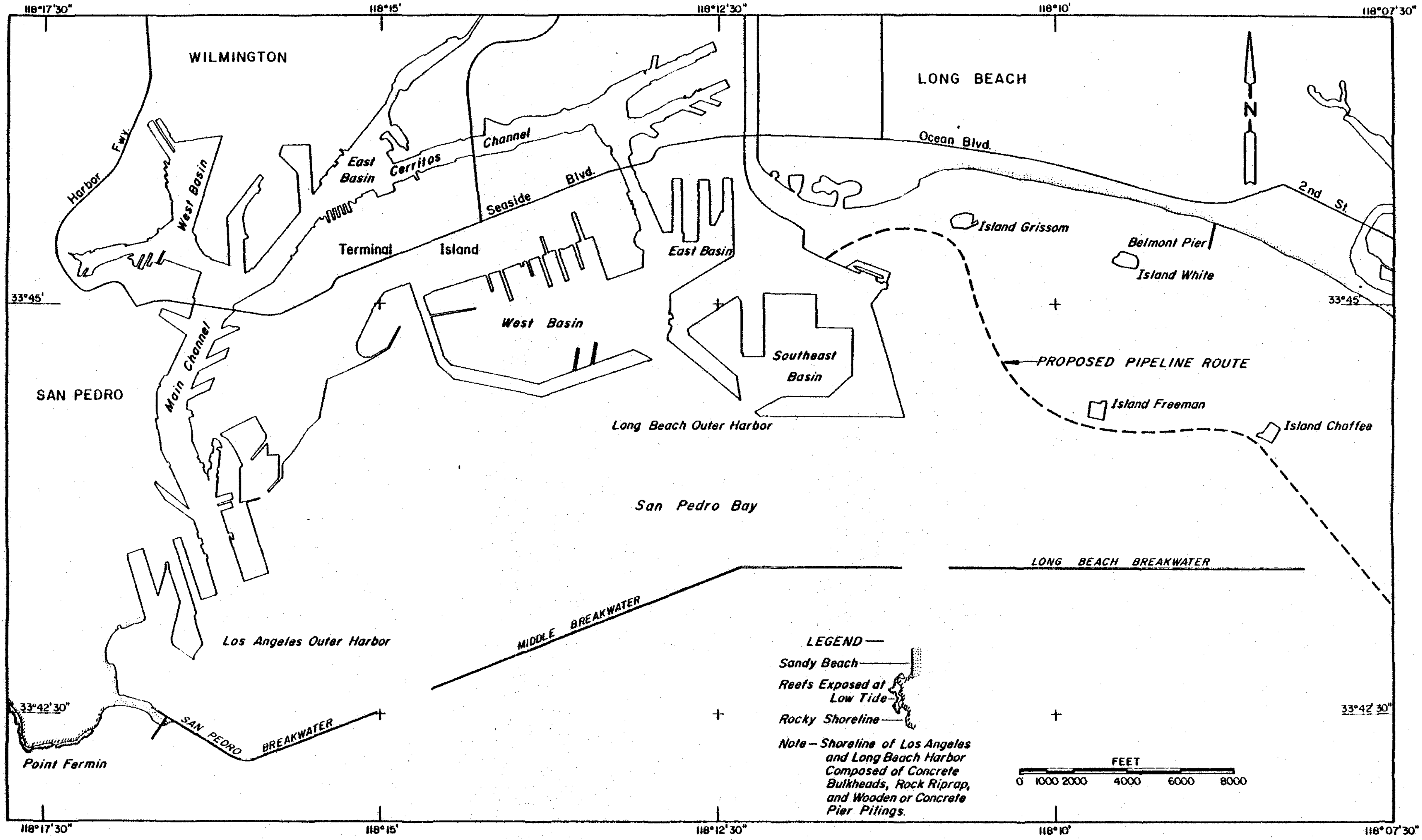
Other effects associated with pipeline excavation include resuspension of previously buried sediments. The turbidity resulting from this sediment may produce adverse effects on neighboring filter-feeding mulluscan and crustacean benthos by clogging their filter-feeding apparatus or blocking respiratory surfaces. In addition, toxic materials such as heavy metals and persistent pesticides may be resuspended to enter into the normal food chain. These substances in turn may be biologically magnified up the food chain reaching dangerous levels in top-level consumers (*e.g.*, fish, and ultimately humans).

(2) Drilling

The benthic community is expected to be impacted from the disturbance and settlement of sediments as a function of drilling operations.

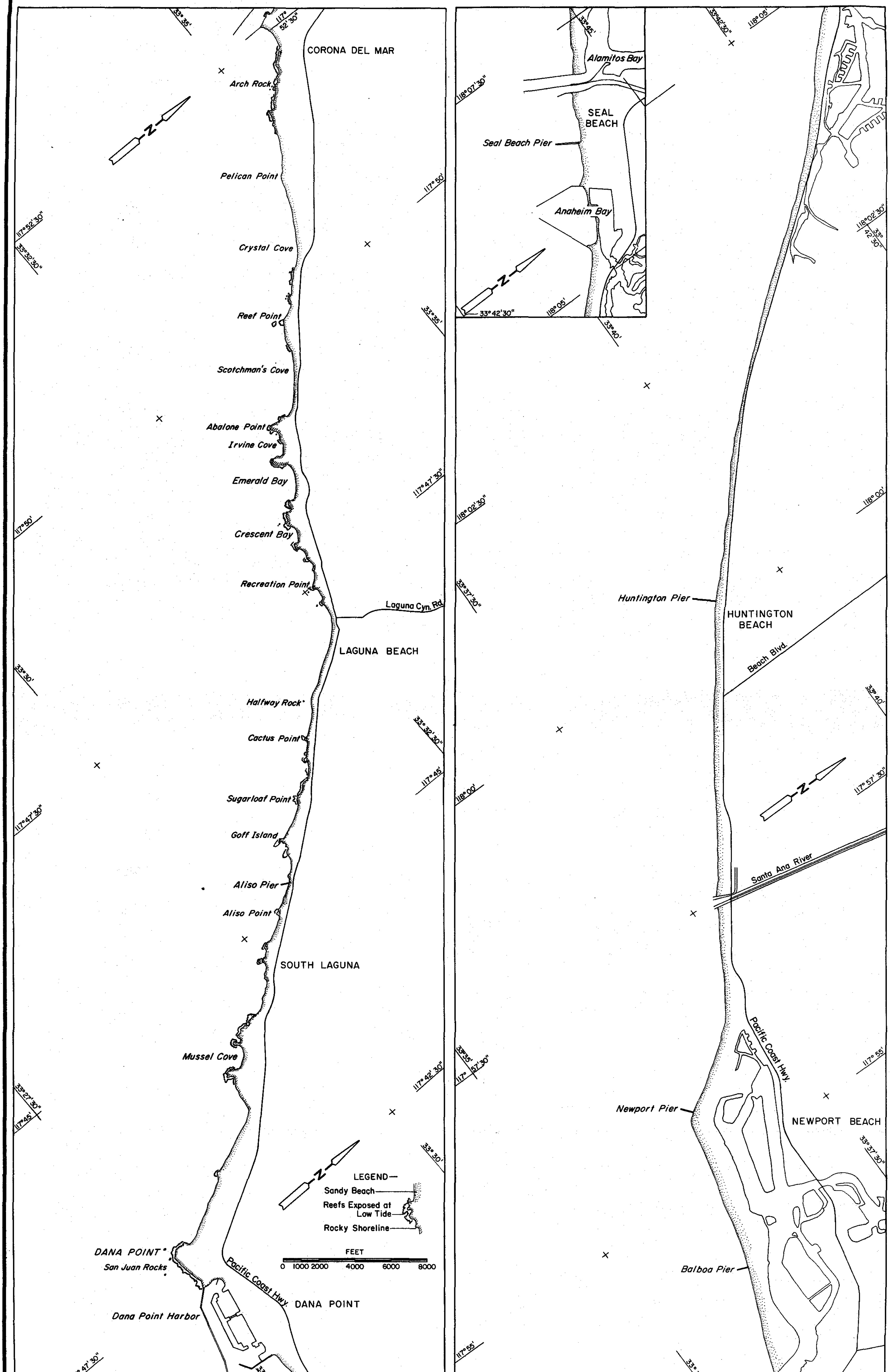
Sediment effects are limited to physical impacts since Shell proposes to dump only "clean" cuttings and drilling muds into surrounding waters. A total of 80 wells are projected for Platform Ellen and up to 60 wells for Eureka. Since a typical 9,000-ft (2745 m) well may generate 540 tons (490 mt) of cuttings, over 76,000 tons (68,932 mt) of cuttings must be disposed. This amount of material will cover and bury a substantial area of the benthic environment surrounding the platforms. A diver survey during a drilling operation in offshore Louisiana revealed that drill cuttings covered a 100-ft (30.5 m) diameter circle in the vicinity of the drilling rig (BLM, 1975). This account reports deposits of up to 4-ft (1.2 m) thick were occupied by benthic organisms normally found in the vicinity. It was assumed that these animals either migrated up through the sediment, or to the area from neighboring areas, or colonized the new substrate. Although this study reported living organisms, no assessment of mortalities was attempted, and, therefore, it cannot be assumed that there was no impact on the local biotic communities.

Drilling will produce localized turbidity and a rain of sediment in the vicinity of the platforms. Both epifaunal and infaunal communities will be impacted to a degree including the more common species of polychaetes, *Prionospio pinnata*, *Pholoe glabra*, and *Pectinaria californiensis*, the mollusks *Axinopsida serricata* and *Nemocardium centifilosum*, the crustaceans *Ampelisca brevisimulata* and *Heterophoxus oculatus*, and the echinoderm, *Amphiodia urtica*. No information is currently available which describes the fauna in the immediate area surrounding the platform sites, precluding assessment of specific impacts. Ray (1978) suggests that in most Outer Continental Shelf areas, mud plumes will have reached



Intertidal Habitats, San Pedro Bay

4.5-1 Figure



Intertidal Habitats, Dana Point – Alamitos Bay

Figure 4.5-2

background levels of suspended solids and heavy metals prior to reaching the bottom. This slow accumulation of sediments may allow the benthos to adapt to the changes. Some organisms could migrate through successive layers of sediments, and move over the surface without being buried. However, a significant data base on the settling rate has not been completely established to preclude more rapid sedimentation which may smother and bury the benthos resulting in high mortalities. In addition, drill cuttings will be of a different consistency, size range, and chemical composition than surface sediments. Deposition of this material will change the nature of the bottom sediments. Organisms which currently occupy the sediments may not be pre-adapted to this changing sediment regime and so may show local replacement by a radically different community assemblage.

Drilling muds may also contribute to the alteration of currently existing benthic communities. Drilling muds contain large quantities of barium, which may alter the chemical nature of benthic sediments. However, Jones (1974) suggests that benthic communities are not harmed by elevated barium levels in the sediments. The drilling muds can thus be considered a sediment source similar to the cuttings discussed above and contributing to the identical impacts of burying a physical habitat, altering the benthic environment.

The normal functioning and interactions of local benthic communities will be upset by the deposition of sediments from drilling and the disturbance of sediments by pipeline construction. Benthic mortalities and alteration of existing communities can be minimized or eliminated by disposal of contaminated cuttings and drilling muds at shoreside landfills. Pipeline construction impacts in the breakwater appear to be very localized and not permanent. The benthos in the vicinity of the pipeline should recover to normal pre-construction levels within a year or less, depending on the settlement periods for various larval forms.

4.5.1.3 Plankton

(1) Construction

Mobilization and staging efforts prior to the beginning of construction should be no different than normal harbor activities, and should not have significant effects on harbor plankton populations (Long Beach Harbor Consultants, 1976). During construction of the platform facilities, localized dumping from support vessels (bilge, toilet, etc.) is regulated by EPA, and should have no significant effects. Rainwater and cleaning washoff not collected in drains and sumps may contain oxidants and residues of coatings, lubricants, and cleaners. This runoff will be rapidly diluted, and the effects negligible and highly localized, primarily at the surface and downcurrent.

Outside Long Beach Harbor the pipeline will not be buried. Any effects on the water column will be highly localized and short-term, mostly due to minor turbidity during placement. The main effects of the pipelines will appear in the harbor itself. Dredging required for pipeline burial will cause high turbidity in the water column, and possible release of toxic heavy-metal pollutants now buried in sediments. Heavy turbidity will reduce the primary production of phytoplankton in the area by impeding solar radiation, and may kill zooplankton and larval forms by fouling gill passages and sensory receptors. Bacteria and detritus contaminated by toxic heavy metals may be ingested by phytoplankton and passed into the food chain through zooplankton and vertebrate larvae (Beers *et al.*, 1977; Reeve *et al.*, 1977; Thomas *et al.*, 1977). Losses of benthic larvae could result in poor recruitment in the area of the pipeline due to dieoff or avoidance of the affected area for a short term.

(2) Drilling

Some limited runoff of fuel oils, lubricants, and chemicals can be expected during this phase. Impacts will be localized near the surface until diluted. However, concentrations of napthalene as low as 3 ppm have caused reductions in bicarbonate uptake by phytoplankton (Kauss *et al.*, 1973).

An increase in the nutrient levels around the platform can be expected to result from excretion by increased numbers of birds and fish commonly associated with drilling platforms. This should cause a slight increase in primary production in the platform vicinity. Platform sites are commonly abundant in marine life, with each component (plankton, attached macrobenthos, fishes, zooplankton) contributing to the food web around the platform.

4.5.1.4 Fishes

With few exceptions, fishes are highly mobile organisms that are capable of moving rapidly and freely over considerable distances. All are extremely sensitive to even slight physical and chemical changes in their environment. In many, olfactory sensitivity, for example, is of such refined acuity that it approaches or exceeds the limits of detection by modern chemical analysis (Hasler, 1957). The combination of physical mobility and physiological sensitivity enables fishes to detect, respond to, and avoid localized areas of adverse environmental conditions to a far greater extent than many other organisms. Therefore, the severity of most of the impacts associated with construction and placement of platforms and attendant pipeline installation, is predicted to be low. A detailed discussion follows and a summary of impacts is provided in Table 4.5-1. It should be noted that Table 4.5-1 has been derived from the OCS Lease Sale No. 35 EIS and therefore covers an area much larger than that of the proposed project.

TABLE 4.5-1

A SUMMARY OF POSSIBLE IMPACTS ON THE NEKTON FOR A RANGE OF ACTIVITY IN THE SOUTHERN CALIFORNIA BORDERLAND (FROM BUREAU OF LAND MANAGEMENT, 1975)

Activity	Maximum Amounts	Open Ocean Area Impacted	Duration	Frequency of Occurrence	Impact	Nekton Impacted	Relative Severity
1. Oil Spills							
Major spill	30,000-100,000 bbl	200-500 square miles	60 days	1/7-10 yrs[9]	Direct kill	Epipelagic fish[1], fish larvae, nektonic invertebrates[2]	Low-moderate
					Decrease in year class strength due to non-availability of plankton food	Epipelagic fish, fish larvae, nektonic invertebrates	Low
					Uptake of PHCs[3] into food chain	Epipelagic fish, fish larvae, nektonic invertebrates	Unknown
					Other sublethal[4] effects	All nekton[5]	Potentially high
Small spill	500 bbl	2-15 square miles	1-10 days	Unknown	Direct kill	Epipelagic fish fish larvae, nektonic invertebrates	Low
					Sublethal effects	All nekton	Potentially high
Chronic low-level discharge and minor spills (<50 bbl)[6]	4,758-41,010 bbl	Southern California Borderland	Production Life: 20-60 yrs	Throughout production phase	Uptake of PHCs into food chain	All nekton	Potentially high
					Other sublethal effects	All nekton	Potentially high
2. Discharge of formation waters	1.5-140.0 billion bbl[7]	Local - around platforms	Third year-life (20-60 yrs)	Throughout production phase	Uptake of water soluble aromatics	Epipelagic fish, nearshore fish	Unknown

TABLE 4.5-1 (CONT)
A SUMMARY OF POSSIBLE IMPACTS ON THE NEKTON FOR A RANGE OF ACTIVITY IN THE SOUTHERN CALIFORNIA BORDERLAND
(FROM BUREAU OF LAND MANAGEMENT, 1975)

Activity	Maximum Amounts	Open Ocean Area Impacted	Duration	Frequency of Occurrence	Impact	Nekton Impacted	Relative Severity
3. Drilling muds and cutting discharge	Mud chemicals discharge 14.0-84.0 thousand tons	Local - around platforms	Drilling phase - 3-7 yrs	Continuous during drilling	Clogging of filter-feeding mechanisms	Northern anchovy, nektonic invertebrates	Low
					Toxicity of chromium	All nekton	Unknown
4. Pipeline burial and platform construction	4,000-8,000 cubic yards of sediment disturbed per mile	Local - around platforms	3-5 yrs	During pipeline burial (<250 ft)	Disturbing habitat and food source	Demersal fish[8]	Low
					Resuspension of harmful pollutants	Demersal fish	Potentially high

[1] Epipelagic fish - fish living between depths of surface and 125 m. Examples: northern anchovy, jackmackerel, Pacific mackerel, Pacific bonito, yellowtail.

[2] Nektonic invertebrates - pelagic red crab, ocean shrimp, bay shrimp, spot prawn, market squid.

[3] PHCs - petroleum hydrocarbons.

[4] Sublethal effects - adverse effects on physiology of growth and reproduction and on instinctive and voluntary behavior. Examples: masking or interfering with prey detection, reproductive behavior, social behavior, migration and homing behavior, carcinogenic effects.

[5] All nekton - epipelagic, deep-sea, nearshore, and bottom dwelling fish and nektonic invertebrates.

[6] Chronic low-level discharge and minor spills - includes pipeline leaks, equipment failure and human error, weather damage, platform fires and explosions, minor spills, ship-platform collisions.

[7] Amount calculated using estimate of 50% water cut of oil and water produced and a range of 1.6-14.0 billion bbl of oil over the life of the proposed area. This range could vary from a 20-30% cut of oil produced during the last half of a well's life.

[8] Demersal fish - bottom dwelling fish. Examples: Dover sole, English sole, lingcod, Pacific sanddab.

[9] Recurrence interval estimated for large spills greater than 90,000 bbl for a range of anticipated production of 1.6 to 14.0 billion bbl of oil for the proposed lease sale.

Production	Spills	Recurrence Interval
Low	1.6	37.5 years
Mean	7.6	7.9 years
High	13.7	4.4 years

(1) Construction

Adverse impacts of construction of platform facilities and pipeline placement and burial would be highly localized and have little direct effect on fishes. Limited disturbance of the habitat and food source of some demersal fishes is expected to occur in the immediate area of construction activities. Other than possible occlusion of the filter-feeding mechanisms of species such as the northern anchovy and pelagic red crab caused by temporary increases in turbidity, the greatest potential adverse impact is a resuspension of polluted sediments that will occur during burial of the pipeline within Long Beach Harbor. Heavy metals, pesticides, and other harmful substances could become incorporated into elements of the benthic community, and thus be passed on through the food chain to bottom-feeding fishes.

Once completed, the submerged surfaces of the platforms and exposed portions of the pipeline will serve as hard substrates for the attachment of encrusting organisms, and will thereby constitute artificial reefs. The appearance of these structures in what was otherwise very uniform open water and benthic environments will permit rapid colonization by a few plants and a wide variety of animals, including reef-oriented fishes. Duffy (1974) briefly summarized earlier studies by Carlisle *et al.* (1964) and Turner *et al.* (1969) on man-made reefs in southern California which revealed that several community development phases could be defined during the first few years of a new reef's existence. An initial barnacle-hydroid phase was followed by mollusk-polychaete, ascidian-sponge, and encrusting-entoproct stages during the first year. In subsequent years, aggregate anemones, gorgonian corals, and stony corals developed in order of a natural animal succession. Studies on fish populations on replicate reefs showed that some adult fishes such as embiotocid surfperches and serranid basses appeared within hours of reef construction, and remained dominant during the first two years. As the reefs matured, other families including gobies, cottids, and rockfishes increased in importance until a natural equilibrium was attained.

Shinn (1974) summarized some of the advantages of offshore oil platforms as artificial fishing reefs. Among these were ease of location by fishermen, high profile and physical continuity throughout the water column from surface to bottom, little resistence to water flow, and a large surface for colonization by encrusting organisms. Ogren (1974) briefly reported on the attractiveness of midwater structures to a number of sportfishes in the Gulf of Mexico. In a subsequent paper, Hastings, Ogren, and Maybry (1976) pointed out that offshore drilling platforms are known to attract various species of fishes as demonstrated earlier by Carlisle *et al.* (1964) in southern California waters. Hastings *et al.* (1976) also mentioned that anglers recognize these platforms as desirable fishing sites. On the basis of their observations of the fish fauna attracted to two U.S. Navy platforms in the Gulf of Mexico, Hastings *et al.* (1976) noted that the major species ultimately occupying platform habitats included fishes characteristic of pelagic, inshore (in the sense of coastal or estuarine), and rocky reef environments. They found that at the platforms the pelagic species and most of the larger predators occupied various levels in the water column, either directly below or surrounding the structure, while most of the other species were associated either with the pilings and crossmembers of the platform or with the bottom. They also noted that for some species, the platform provided food and shelter, while for others it offered only shelter, and it appeared that some species were present only to feed on the numerous fishes and other organisms concentrated on and about the platform.

The Shell Beta platforms may be expected to attract reef fishes such as surfperches (Embiotocidae), rockfishes (Scorpaenidae), sea basses (Serranidae), and sculpins (Cottidae), in addition to oceanic fishes including Pacific sardine *(Sardinops sagax caeruleus)*, jack mackerel *(Trachurus symmetricus)*, Pacific mackerel *(Scomber japonicus)*, yellowtail *(Seriola dorsalis)*, and bonito.

Sport fishing potential will be enhanced by the presence of the offshore platforms and exposed pipeline as they will tend to concentrate fish populations. The distance of the platforms from boat harbors and launching sites should not decrease the sport fishing potential because of predictably generally mild sea conditions in this area of the Southern California Bight.

The impact of the offshore platforms and the pipeline on commercial fishing operations should be minimal. Although some pelagic area and an estimated two to five acres (0.8 to 2 ha) of sea floor per platform would be rendered inaccessible to a bottom trawl fishery, any adverse impact is only a potential one since bottom trawl fishing below Point Mugu is restricted by permit conditions from the California Department of Fish and Game. It is possible that unburied sections of the pipeline and loss overboard of large materials, debris, or tools could constitute an adverse impact on the purse seine fishery through the possiblity of snagging and damaging the nets. Gill net fishing, on the other hand, should be enhanced by the unburied portions of the pipeline.

(2) Drilling and Production

Outer Continental Shelf Order No. 7 forbids ocean dumping of drilling muds containing oil or treated with chemicals of a type or quantity that would result in their becoming toxic and hence detrimental to the marine environment.

Normally, drilling muds are retained and used to drill additional wells or are resold through companies that have the opportunity and available vessels to retrieve them. In any event, the expense of heavy, highly treated muds generally precludes their intentional disposal at sea.

Occasional discharge and normal operational loss of muds (estimated at approximately 200 bbl (32 m^3) per well) will have two effects. The first is a temporary and local increase in turbidity which could occlude the food gathering mechanisms of filter-feeding organisms. This direct impact, however, should be of minor significance since the affected area, in addition to being small, would probably be avoided by fishes. The second impact lies in the release of chromium, a component of ferrochrome lignosulfonate used as a thinner and fluid loss reducer. Some aspects of the physico-chemical behavior of ferrochrome lignosulfonate in sea water are discussed in U.S. Geodetic Survey (1976) and BLM (1975), but no conclusions as to the role and fate of drilling-mud chromium additives, or their effects on marine biota, is presented. The impacts are, therefore, inconclusive.

Recently, Chow *et al.* (1978) and Elomar (1978) reported that the distribution of barium in marine sediments near drilling sites may provide an indicator of anthropogenic chemical contamination originating from drilling operations. The source of the barium is barite (barium sulfate), which is commonly used as a weighting agent in drilling mixtures. In a monitoring survey of the Southern California Bight, they found higher concentrations of barium in mainland intertidal sediments than in those from the Channel Islands. These higher concentrations may be associated with drilling operations. However, they it appeared to not exert toxic effects on marine species.

The effects of drill cuttings disposal is limited to: 1) localized smothering of less mobile elements of the benthic, epifauna, and infauna at the base of the drilling platforms and on the lower portions of the structures, and attendant reduction of available food to animals at higher trophic levels; 2) a temporary increase in water turbidity and consequent reduction of light for plant photosynthesis; and 3) possible interference of recolonization in the cutting mound if textural differences exist between the deposit and adjacent natural sediments. In general, the impact of ocean disposal of drill cuttings is of no significance to the fish fauna.

4.5.1.5 Marine Mammals

(1) Construction

Pipeline trenching operations will resuspend bottom sediments, causing an increase in water column turbidity. Turbid waters will make prey capture more difficult for mammals which do not echo-locate. The resuspension in the harbor of such contaminants as heavy metals will increase chances of their re-entering food chains. Predator species, such as many marine mammals, concentrate these toxic substances in their tissues.

Pipeline and platform construction vessels will provide temporary obstacles to migratory marine mammals (e.g. California grey whale), although healthy marine mammals should readily avoid such vessels.

Cetaceans utilize a sophisticated sound transmitting and receiving system which might be affected by the sounds of the platform and pipeline construction. The construction sounds themselves may serve as an attractant or a repellent to marine mammals in the vicinity of the construction sites.

(2) <u>Drilling/Production</u>

The dumping of drill cuttings into the ocean at the platform would cause significant local turbidity and consequently make prey capture by some non-echo-locating marine mammals more difficult. Subsurface sound may cause behavioral changes in local marine mammals. Enhancement of local fouling and nektonic species in the platform vicinity will attract some marine mammals to the platforms. The California grey whale migrating pathway takes it close to the platforms; however, the platforms should not constitute a hazard to the marine mammals which possess sophisticated echo-locating systems. On balance no significant adverse effects are predicted.

4.5.1.6 Birds

(1) <u>Construction</u>

Platform and pipeline construction vessels will offer temporary resting and roosting sites for marine birds during the construction phase. Food scraps, if dumped overboard, will attract such opportunistic feeders as gulls and terns. Resuspension of bottom sediments, as a result of pipeline burying, will cause turbid conditions in the water column. Turbid waters make food capture more difficult for such diving and plunging species as loons, cormorants, grebes, and pelicans. Since harbor sediments have high concentrations of such contaminants as heavy metals, their resuspension will enhance their chances of entering local food chains. These contaminants are especially damaging to predators at the top of food chains.

Pipeline trenching operations will cause the exposure and consequent death of bottom-dwelling organisms. Some of these organisms will be suspended in the water column or float to the surface, providing a temporary increase in food resources for local birds.

(2) <u>Drilling/Production</u>

When drill cuttings are dumped into the ocean, the turbid waters which result will prevent capture of some prey species by birds. Furthermore, these cuttings may contain substances toxic or harmful to certain prey species on which birds rely for food. The overall impact of this on marine birds is expected to be insignificant.

The platform superstructure will provide resting and roosting sites for pelagic birds. An expected increase in the number of fishes in the vicinity of the platforms will provide a greater food supply for pelagic birds.

4.5.1.7 Kelp Communities

Only oil spill-related impacts (4.5.2) are predicted for the Shell Beta project. Benthic disturbance from pipeline trenching and disposal of drill cuttings and muds are not expected to affect any kelp communities, since they are distant from the project.

4.5.1.8 Marine Reserves

Marine life refuges, ecological reserves, and Areas of Special Biological Significance would not be affected by any known non-spill-related impacts during construction, drilling, or production phases.

4.5.2 Oil Spill Impacts

A discussion of biological impacts related to oil spills in the marine environment must identify the variables contributing to the effects. In addition to environmental and biological variables, potential sources of water pollution vary with the particular stage of development, i.e. construction, drilling, and production.

Straughan (1972) lists nine factors which may alter the effects of spilled oil. These include: 1) the type of oil; 2) the dose or concentration reaching the biota; 3) the physiography of the area of the spill; 4) weather conditions at the time of the spill; 5) the biota living in the impacted area; 6) the season of the year when the spill occurred; 7) previous exposure of the biota to oil or other pollutants; 8) co-contamination of the impacted biota by other pollutants; and 9) the use of treatment agents to clean up the spilled oil. These variables are potentially operative during any stage of oil development.

The type of oil and its concentration are the most important factors in determining biologic impact. The chemical composition determines its appearance and its toxicity. In crude oil, the toxic lighter fractions are mixed with the inertia residues, and more damage may be done by these refined fractions alone (Crapp, 1971). However, the darker, heavier crude oils can be toxic, depending on their composition.

The magnitude of potential spills can vary tremendously. The impacts discussed in the following sections concentrate on scenarios from: 1) a small-scale spill of 50 barrels (8 m^3); 2) a major spill of greater than 5,000 barrels (795 m^3); and 3) a catastrophic spill of 80,000 barrels (12,720 m^3). Spill situations are discussed in Section 4.4.3. Small-scale spills of diesel fuel, lubricating oils, and crude oil are most likely during the construction and drilling phases. During drilling and production phases, the potential exists for small, medium, and major crude oil spills from both offshore platforms and the submerged pipeline. However, in discussing marine biology impacts it was assumed that whether 50 barrels (8 m^3) or 5,000 barrels (795 m^3) reached the shore, the impacts would be the same, only the magnitude would vary.

Physical and chemical properties of the crude oil from the Shell Beta wells are presented in Table 4.5-1. Ottway (1971) chemically assessed a variety of crudes and formulated a toxicity heirarchy. The Shell Beta crude resembles the CT_{10} crude of Ottway's (1971) and is predicted to exhibit similar effects. Ottway (1971) found the CT_{10} crude to be very thick and black with less toxic effects than some of the lighter, thinner crude oils tested. In addition to potential crude oil spills, the analysis has taken into account impacts from diesel fuel spills. Diesel fuel will be stored and loaded within the harbor area and offloaded, stored, and used at the platform for power generation.

Effects of oil spills are not limited to mortalities of organisms. Impacts may be sublethal, that is, they may alter normal physiological functioning of the organism or inhibit reproduction capabilities. These effects are discussed where information exists.

4.5.2.1 Intertidal

The southern California coastline includes both rocky and sandy beach intertidal habitats, both of which can support extremely rich and diverse communities. These habitats are often intermingled, occupying alternate stretches of the shoreline. Figures 4.5-1 and 4.5-2 depict sections of coastline between Point Fermin and Dana Point which could be impacted by an oil spill from the Beta project. This section of coastline contains large stretches of continuous sandy beaches (at Huntington Beach, Newport Beach, Seal Beach) and rocky shores (Corona Del Mar, Laguna Beach, Dana Point, and Point Fermin). However, because data are not available which provide specific probabilities for impacts on selected beaches, the biological impacts for intertidal habitats are discussed in general terms, concentrating on the more common inhabitants, but not on selected localities.

Intertidal habitats also occur within harbors and bays. Much of the biota in these areas reside on man-made structures including pilings and breakwalls. These communities are also addressed.

(1) Sandy Beach Habitat

Sandy beaches dominate the southern California shoreline (Figure 4.5-2). Impacts on the fauna of this environment will result primarily from oil reaching the shoreline. Small (less than 50 bbl -8 m^3) spills of diesel fuel, occuring during any phase of the Beta platform development are expected to cause mortalities if washed ashore in sufficient concentrations. The spill of No. 2 fuel oil in West Falmouth, Massachusetts from the tanker *Florida* resulted in high mortalities among sandy-beach inhabitants (Blumer *et al.*, 1970). Sanders (1973) in a post-spill survey reported long-lasting effects resulting from the gradual release of toxic pollutants which were retained in the sediment. The southern California beach faunas are expected to react in a similar fashion upon initial exposure to a diesel spill. Common sandy-beach species, such as those reported by Straughan and Patterson (1975) are expected to display drastic population density decreases. These decreases will include mortalities of the common sand crab *(Emerita analoga)*, the spiny sand crab *(Blepharipoda occidentalis)*, the polychaetes, *Nephtys ferruginea* and *Nerinides acuta*, and the mollusk *Olivella biplicata*. A total of 22 susceptible species have been recorded from Outer Cabrillo Beach and 19 from Inner Cabrillo Beach (Straughan, 1975). These beaches represent two energy regimes (medium and low wave energy) found along the southern California coast. In the absence of site-specific information related to target beaches, these two examples are considered typical. The long-term (greater than 1 yr) persistence of petro-chemicals in intertidal sands similar to that in West Falmouth is doubtful. Tremendous volumes of sand are removed and deposited through the seasons. The turnover time for this sand is usually a year or less, depending on the severity of storm-caused waves (Kolpack, 1971; Straughan and Patterson, 1975).

A major spill or concentrated small spill of Shell Beta crude may impact the sandy beach in a similar manner. Ottway's (1971) CT_{10} crude (which is similar to Shell Beta crude) is noted for its thick, black physical properties. This suggests that physical effects of this crude are probably more harmful than acute chemical toxicity. The composition of Beta crude is expected to change slightly after the loss of toxic volatile components through weathering and dissolution prior to possible deposition on the shoreline. Once ashore, the crude oil can mix with the sand, forming an "asphalt-like" substance. This layer of oil is also expected to permeate lower layers of sediment, resulting in contamination of the top several inches similar to that observed by Kolpack (1971). The organisms which normally inhabit this area are likely to encounter the oil directly, with several possible responses.

Most of the sandy beach organisms live directly in the sand, utilizing it for both a home and often a food source. Burrowing forms such as the polychaetes *Euzonus* sp. and *Nepthys* sp. are expected to find burrowing through and dwelling in oil-impregnated sands difficult if not impossible. Sand crabs *(Emerita analoga* and *Blepharipoda occidentalis)* often feed and migrate within the swash zone. These organisms are predicted to experience severe mortality resulting from the physical contact with oil washed ashore. This oil contamination will also impede feeding by fouling of accessory appendages. The beach hopper amphipods *(Orchestoidea* sp.) are expected to be fouled by sticky stranded oil, thus inhibiting mobility and feeding, ultimately resulting in death. Although chemical toxic effects are possible, deaths through physical effects seem to be more immediate and likely.

Many sandy beach species display periods of peak settlement, *e.g.*, large numbers of juvenile sand crabs appear on sandy beaches during the spring (Straughan, personal communication). This same pattern of peak settlement periods has been noted for many intertidal species (Cimberg, 1975). A spill occurring during these periods is predicted to have far-reaching effects on future generations by reducing potential breeding stock. In addition, an impact may be expected in the populations of predators, e.g. shore birds which depend on sandy beach fauna for food. Gray (1971) presents evidence for impacts on micro-and meiofauna sandy beach inhabitants. He suggests that various pollution sources, including phenols, heavy metals, and sulfuric acid may drastically reduce those sandy beach constituents which serve as a food source for many organisms in higher trophic levels.

Containment and recovery of spilled oil is not always achieved following a mishap. Physical and chemical removal techniques have been used and abused in the past, *e.g.*, following the Torrey Canyon spill (Smith, 1968). Several laboratory studies suggest that use of chemical dispersants and surfactants adversely affects larval forms. Hidu (1965) found that surfactants inhibited growth and development of larval clams and oysters, *Mercenaria mercenaria* and *Crassostrea virginica*. Wilson (1968 reported similar results when he exposed polychaete larval forms to detergent oil remover BP 1002. Severe adverse effects on fertilization and development of several species of sea urchins and marine fishes were reported by Lönning and Hagström (1976) for the recently developed COREXIT 9527. Although these experimental results were criticized by Canevari and Lindblom (1976), the toxicity of COREXIT 9527, particularly in combination with oil, has been reported in other research (Hagström and Lönning, 1977; Sekerah and Foy, 1978; Hsiao, Kittle, and Foy, 1978). Although tested dispersants have been shown to have some toxic effect, Environment Canada (1976) has accepted the dispersants BP 1100X, COREXIT 8666, Oilsperse 43, and Sugee #2 for application under certain conditions outlined in "Guidelines on the Use and Acceptability of Oil Spill Dispersants," (1973). The Environmental Protection Agency has also developed an accepted list of dispersants (1978). These agents are Seamaster MS-555, Goldcrew, Atlantic-Pacific Oil Dispersant, Cold Clean, BP-1100X, BP-1100WD, COREXIT 9527, and Conoco Dispersant K. On the state level, the State Water Resources Control Board (1978) has promulgated a licensed list which includes the following dispersants: Nokomis 3(f-4), COREXIT 9527, COREXIT 7664, ECO=+, and Atlantic-Pacific Oil Dispersant.

Even physical cleanup of oil washed ashore is also not without its impact on sandy beach fauna. Straughan (1975) reported that the bulk of sandy beach organisms live in the top few inches of sand. Thus, scraping up oil and sand from the surface layers is likely to cause population impacts by its removal. Chan

(1974) noted this effect after cleanup operations removed sand from Stinson Beach following the San Francisco oil spill. However, difficulty exists in separating the effects of physical removal, from the effects of oil spill and natural depressions of the patchily distributed sandy beach fauna.

Given enough time for complete oil removal and/or decomposition, beach faunas are likely to re-establish themselves. Recruitment of larval forms occurs primarily from the plankton of impinging waters. Thus, through a year's time, or at least through one breeding season, most species will reappear.

(2) Rocky Intertidal Habitat

Although sandy beach shorelines (Figures 4.5-1 and 4.5-2) may quantitatively outnumber rocky areas, the number of microhabitats and the biotic richness are rarely comparable. The rocky intertidal area is ecologically important because it supports a tremendous number of both animal and plant communities. In addition, since rocky intertidal areas are the prominent seaward extension of land formations, they frequently receive spill oil first and in higher concentrations than neighboring sandy beaches.

As described previously, a small-scale spill (less than 50 bbl -8 m^3) of diesel fuel during construction, drilling, or production may reach the shoreline. Chia (1971) presented a preliminary assessment of high mortalities in the Puget Sound intertidal after a spill of No. 2 diesel fuel. North *et al.* (1964) report large-scale deaths of intertidal biota following the release of diesel fuel by the tanker *Tampico Maru* in a cove with limited circulation in Baja California.

Many species inhabiting distant Pacific Coast intertidal areas live along local rocky shores potentially impacted by a Shell Beta spill. These include the common marine mussel *(Mytilus californianus)*, the black abalone *(Haliotis cracherodii)*, the barnacles *(Balanus glandula* and *Chthamalus* sp.), the marine plants including surf grass (*Phyllospadix* sp.), sea lettuce (*Ulva* sp.), and the feather boa (*Egregia* sp.). These and many other species (Table 4.5-2) are likely to succumb to the toxic effects of spilled diesel. In addition to the macroscopically dominant species, many small forms occupy interstitial microhabitats within the intertidal, such as the assemblage of species which dwell among dense clumps and beds of the mussel *(Mytilus californianus)*. Kanter (1977, 1978) described this extremely diverse community in detail with some mussel beds supporting in excess of 120 invertebrate species in less than a square-meter grid. These species too are vulnerable to the toxic effects of spilled diesel because of the confined and specialized nature of their microhabitat.

Physical effects of spilled crude oil appear to be the primary threat of this pollution as opposed to acute toxicity.

TABLE 4.5-2

PHYSICAL AND CHEMICAL PROPERTIES OF CRUDE OIL FROM SHELL BETA WELLS AND CRUDE WHICH CLOSELY RESEMBLES IT

	Shell Beta Crude	Ottway (1971) CT_{10}
Specific gravity at 16/16°C	-	0.971
Specific gravity at 12/20°C	0.93-0.98	-
Sulfur content, % weight	2.8	2.59
Pour point	-26°	15°
Viscosity at 38°C, cSt	480	739
Asphaltenes content, % weight	3.40% @ 1000°F	5.8
Wax content, % weight	0.0	3.0

Crude oil floating ashore following the Santa Barbara oil spill primarily caused mortalities of intertidal invertebrate species by smothering (Nicholson and Cimberg, 1971). Depressed standing crops of algae were noted, but with accurate prespill data lacking, no definitive statement could be made concerning a cause and effect relationship. A spill of Bunker C oil which occurred in the San Francisco Bay produced similar results (Chan, 1974). Table 4.5-3 lists species which suffered mortalities from the Santa Barbara and San Francisco spills. Note that these species lists are similar. Many of the same genera and species are represented on local shorelines potentially threatened by a Shell Beta crude oil spill. A spill of Beta crude would be expected to cause mortalities of rocky intertidal species similar to those reported above. Again, the physical smothering by oil deposits is expected to cause the greatest impact. Isolated tidal pools where oil may sit for periods of time under higher temperatures may increase the probability of toxic components entering the solution and causing acute toxic effects. Mortalities of tide pool inhabitants were noted by Cimberg and Kanter during surveys following the Santa Barbara spill and included the purple sea urchin (*Strongylocentrotus purpuratus*), bay mussel (*Mytilus edulis*), and the turban snail (*Tegula funebralis*). Crude oil spill impacts following events such as the San Francisco and Santa Barbara spills were more pronounced (but not limited to) upper intertidal areas where oil was stranded in greater quantities. We would expect similar results with a spill of Beta crude. Upper intertidal inhabitants such as the barnacles *Balanus glandula, Chthamalus fissus, C. dalli,* some of the limpets *Collisella scabra, C. pelta,* and *C. digitalis* are particularly vulnerable to the smothering effects of crude oil coatings. Chan (1974) reported a two percent dieoff of mussels (*Mytilus californianus*); however, the lack of natural-mortality baseline information makes this figure suspect. None of the major oil spill surveys of the past have examined the rich community associated with mussel beds (*Mytilus californianus*). A coating of oil which flows over the mussels and runs into the inter-mussel spaces is predicted to severely impact this community. The oil coating can seal these organisms in, preventing food and oxygen-bearing seawater from circulating within the microhabitat.

Algal species inhabiting intertidal areas have been impacted by previous crude oil spills. Red algae (Rhodophyta) suffered the greatest damage during the Torrey Canyon and Tampico Maru spills. Foster (1974), following the Santa Barbara spill, reported damage to such genera as *Enteromorpha, Ulva, Porphyra, Gigartina,* and *Hesperophycus*. The California Department of Fish and Game (1969) reports denudation of entire areas where oil-coated algae blades had broken off. Those genera of algae mentioned above as well as the marine angiosperm *Phyllospadix* sp., commonly occur on our shoreline and may suffer some damage, e.g. loss of blades and reduced biomass. However, both Nelson-Smith (1973) and Smith (1968) suggest that algae survive exposure to oil spills better than many of the animals. Several of the algal forms, particularly the Phaeophytes (brown algae) produce a mucilaginous film, which not only affords protection against absorption, but also absorption of

TABLE 4.5-3
INTERTIDAL SPECIES IMPACTED BY VARIOUS OIL SPILLS

Species Killed or Damaged From the Santa Barbara Oil Blowout (From Foster, 1974)

Rocky Intertidal Zone
- Barnacles (*Chthamalus* sp. and *Pollicipes* sp.)
- Kelp crabs (*Pugettia producta*)
- Hermit crabs (*Pagurus* sp.)
- Isopods (*Idotea* sp.)
- Snails (*Lacuna* and *Acteon* (?))
- Algae (*Enteromorpha*, *Ulva*, *Porphyra*, *Gigartina*, *Hesperophycus*)
- Surf grass (*Phyllospadix* spp.)
- Polychaete worms
- Limpets (*Acmaea paleacea*)
- High intertidal crevice fauna (mostly arthropods)
- Mussels (*Mytilus* spp.)

All rocky intertidal organisms (including Santa Barbara Harbor) affected by cleanup activities.

Sandy Beaches
- Sandy beach macrofauna (*Euzonus* sp, *Emerita* sp, *Orchestoidea*)

Intertidal Species Killed as a Result of the San Francisco Bay Oil Spill (From Chan, 1974).

- Acorn barnacles (*Chthamalus dalli* and *Balanus glandula*)
- Limpets (*Acmaea* sp.)
- Striped shore crab (*Pachygrapsus crassipes*)
- Periwinkle (*Littorina planaxis* and *L. scutulata*)
- Stalked barnacles (*Pollicipes polymerus*)
- Oil may have contributed to a population decrease of *Tegula funebralis*
- Only slight die off of *Phyllospadix scouleri*

oil in the plants. Oil contamination of the algae by Beta crude is predicted to have minimal impact and rather rapid recovery is expected.

Sublethal effects have been noted for various forms of oil pollution. Shiels *et al.* (1973), North *et al.* (1964) and Clendenning and North (1960) reported depressed photosynthetic abilities in algae exposed to various fuel oils. Enhanced growth of blue-green algae has been noted by several authors (Spooner, 1970; Baker, 1971; Cabioch, 1971). Sublethal effects on animals have also been reported and may occur during a spill of Beta crude. Impacts on larval settlement and recruitment can also arise when oiled surfaces physically and chemically repel potential inhabitants.

Cleanup operations following the *Torrey Canyon* and Santa Barbara oil spills resulted in increased mortalities from both physical and chemical cleansing. Dispersants and surfactants often are more toxic than the spilled oil (Tarzwell, 1972; Hagström and Lönning, 1977; Sekerah and Foy, 1978). Physical cleaning of rocks by steam in Santa Barbara Harbor not only removed oil, but also all animals and plants which survived the spill (Kanter, personal observation). In light of these effects, oil which cannot be contained and recovered should be left alone for natural processes to disperse and break down.

(3) <u>Biofouling Communities</u>

Watson (1971) and Woodin (1973) reported localized damage to marine algae, bivalves, barnacles, and worms from small amounts of diesel fuel. The damage resulted from ingestion of lethal toxins and suffocation. Colonization of denuded areas is expected and no long-term effects are predicted. The effects of a crude spill on the littoral biofouling community could be fatal to all or part of this community depending on the dose and time of exposure. Nicholson and Cimberg (1971) reported extensive mortalities to the barnacles *Chthamalus* and *Balanus*, the limpet genus *Collisellia*, and the mussel *Mytilus*, as a result of the 1969 Santa Barbara oil spill. Mortality was due to suffocation and not to ingestion of toxins; recolonization was slow compared to control sites. It is expected that recuperation of the littoral biofouling community following a small spill would be accelerated by weathering and dispersal of the crude oil by wave action at the platform site. The subtidal biofouling community is not expected to experience any adverse effects from a small spill of crude oil. This is predicated because any oil reaching this community will have gone through extensive weathering, dispersal, chemical, and microbial degradation prior to contact with the subtidal community. Nicholson and Cimberg (1971) report mortalities in intertidal species which are also common to fouling communities, when those species were exposed to heavy crude oil from the Santa Barbara spill. The biofouling community associated with the offshore platform would be impacted similarly by a spill; however, recruitment would begin as soon as water quality and substrate became suitable. Harbor and offshore biofouling communities are exposed to alternating periods of immersion and exposure, sudden infusions of freshwater, deviations in salinity, changes in temperature, and contaminants, including oil. Organisms accustomed to this type of habitat tend to be hardier and more resistant to sudden changes to their environment. After the *Torrey Canyon* disaster, Crapp (1971) demonstrated that several species of *Chthamalus* and *Balanus* were unaffected after being subjected to long-term coating by weathered Kuwait crude. However, in a worst-case situation, where fracture of the pipeline occurred inside the harbor and weathering of the oil would not be possible, extensive mortalities would be expected with possible long-term inhibition of settlement.

Coating of a substrate (such as the surface of a newly constructed offshore structure) with crude oil will affect settling and recruitment by fouling organisms. Other possible effects include mortalities of less-tolerant juvenile forms of these organisms, thus inhibiting recruitment. Depletion of food supply, especially marine algae, could affect distribution of limpets and other grazing populations associated with biofouling communities. Oil at sublethal concentrations may have adverse effects due to organisms having different tolerance levels with respect to recruitment. Hence, alteration in the relative species abundances in the population can occur. In addition, resistant species may flourish when populations of less-tolerant species decline and make available previously limited resources, *e.g.*, primary substrate. Stainken (1975) and Neff (1975) demonstrated that several species of bivalves can magnify the concentration of petroleum hydrocarbons up to five times that of ambient concentrations, yet there seems to be no direct effect to the organisms. Latent effects nonetheless may occur and include mortalities and reduction of reproductive potentials of fish and other populations dependent upon the biofouling community as a food source.

4.5.2.2 Benthic Communities

Spilled oil reaches the benthic environment principally by two modes: 1) soluble components diffuse in solution and spread throughout the water column, eventually contacting the organisms; and 2) higher molecular weight fractions flocculate with detritus and sediments and eventually settle along with "clean" sediments onto the benthos.

Past diesel fuel spills, *e.g.*, that in West Falmouth, Massachusetts *(Florida)* and in Mexico *(Tampico Maru)* have resulted in severe impacts on the shallow subtidal benthic communities of these areas. In the project area immediate deaths would be expected in many groups of benthic invertebrates. Sanders, Grassle, and Hampson (1972) reported nearly complete mortality of several benthic forms following the *Florida* incident. North *et al.* (1964) and North (1967) reported similar impacts on the shallow subtidal communities in Baja California following the *Tampico* spill. In general, extremely high mortalities would be expected in the harbor benthic communities, including *Nothria-Tellina* association described by

Jones (1969) and the assemblages of organisms reported by Long Beach Harbor Consultants (1976), e.g. the polychaetes *Tharyx* sp., *Cossura candida, Armandia bioculata,* and the clam, *Macoma* sp. A small-scale spill of diesel that is not confined and is outside of the harbor is expected to have negligible impact on the benthos because of dilution and dispersion of the petroleum residues.

Crude oil spills will primarily reach the benthos through sinking in flocculent masses with sediment and detritus. Studies of open sea crude oil spills such as the one at Santa Barbara have provided little definitive information on the response of benthos, the primary reasons being lack of recent baseline data for before-and-after comparisons and inadequate sampling.

It is concluded that little is known about the impact of crude oil on the benthos. A certain degree of smothering is expected as the suspended material reaches the bottom. However, mobile organisms are expected to be able to move through this material. In addition, the physical "stickiness" and toxicity of the crude oil that settles in sediments is questionable, and, therefore, may have little impact.

Crude oil spilled from the Beta pipeline within the harbor presents a greater potential hazard to the benthos than crude oil spilled in the open ocean, due to the lack of dilution and dispersion of oil. As a result, soluble toxic fractions of the crude oil may reach the benthos in concentrations high enough to impact the fauna. In addition, crude oil may reach the bottom sooner and with less decomposition and may physically smother the benthos. The results of these impacts may resemble those of the *West Falmouth* and *Tampico* spills. Large-scale mortality may result from chemical or physical effects. The harbor communities expected to suffer from these impacts include the *Nothria-Tellina* association described by Jones (1969) and the organisms reported by Long Beach Harbor Consultants (1976) including several species of polychaetes, mollusks, and echinoderms.

While the use of dispersants does reduce the potential that oil will reach the shoreline, post-spill cleanup operations of the past have often created more problems than they have solved. Dispersants and surfactant substances are often more toxic than the oil they are treating, or have altered the oil being treated, rendering it more toxic than its original state (Tarzwell, 1972; Hagström and Lönning, 1977). Sinking agents used following the *Torrey Canyon* spill may have removed the visible signs of oil presence, but its impact on the benthos was potentially very harmful (Smith, 1968). Crude oil which sinks rapidly has very little time to lose the more toxic, volatile, and soluble fractions, the result being that these toxic materials are carried with the unaltered crude oil directly into the benthic environment. Although no information is available from specific studies of this phenomenon, it is highly probable that this practice will greatly increase benthic mortalities. Physical containment and recovery of spilled oil remain the best cleanup measures, since they have the least harmful effect on marine organisms.

4.5.2.3 Plankton

During a spill, some of the released oil will volatilize and be carried away in the atmosphere. Water soluble fractions of the crude oil are lost to solution. The remainder of the oil will be dispersed as minute droplets. Both floating and soluble forms of the oil have the potential to enter the marine food web and damage marine organisms (BLM, 1975). Those plants and animals found nearest the surface will be most affected, including larval fishes and invertebrates, zooplankton, and phytoplankton.

Sublethal effects of spilled oil on plankton have been reported by several researchers. Shiels *et al.* (1973) reported that inhibition of phytoplankton photosynthesis by spilled oil varied seasonally depending on physical and chemical factors and species composition and abundance. Mironov (1971) exposed 11 phytoplankton species to concentrations of crude oil, and found that concentrations of oil from 0.01 to 1,000 ppm delayed or inhibited cell division. Gordon and Prouse (1972) reported that concentrations of 50-100 ppm of crude oil and No. 2 and No. 6 fuel oil significantly reduced uptake of labeled bicarbonate.

Prouse, Gordon, and Keizer (1976) reported that oil concentrations as low as 50 *g/l (50 ppb) could reduce photosynthetic potential. Upon longer exposure, when subjected to diminishing concentrations of oil (as would be expected with dispersion), some species showed signs of growth stimulation after 11 days.

Many investigators have demonstrated no harm, but rather enhancement of phytoplankton growth when exposed to crude oils. Smith (1968) reported that while oil from the wreck of the *Torrey Canyon* apparently did great harm to populations of flagellates in the vicinity, diatoms and dinoflagellates were not greatly harmed, and apparently neither were the zooplankton. Prouse *et al.* (1976) reported that at crude oil concentrations of less than 1 ppm, oceanic phytoplankton did not display growth characteristics significantly different from controls. Prouse *et al.* (1976) found the growth of some phytoplankton was stimulated by small concentrations of crude oil. Phytoplankton exposed to 0.003 ppm crude oil by Shiels *et al.* (1973) had photosynthetic rates that were more than double the rates of phytoplankton in seawater containing no oil. Gordon and Prouse (1972) indicated that levels of oil of less than 45 *g/l (45 ppb) stimulated uptake of bicarbonate by as much as 20 percent.

Larger zooplankton, *e.g.*, *Calanus finmarchicus*, have been observed to ingest small oil particles, passing them through their gut unchanged (Freegarde *et al.*, 1970). Lee (1975) reported that only zooplankton crustaceans took up suspended hydrocarbons. When placed in clean seawater for several days, high tissue hydrocarbon levels became significantly reduced. Stockner and Antia (1976) urged that oil exposure experiments be of sufficient length to allow adaption to stress. In their experiments, phytoplankton exposed to moderate oil levels regained photosynthetic capabilities. Continued exposure to the same pollution levels had little or no effect.

Larval fishes may not be as tolerant as phytoplankton. Mironov (1971) found that flounder larva exposed to crude oil concentrations of 1-100 ppm had a mortality rate of 100 percent, and those exposed to concentrations down to 0.01 ppm developed abnormally.

The impacts depicted above are usually more severe when the spills occur within bays or coves because these protected areas tend to serve as nursery grounds.

4.5.2.4 Fishes

Fishes are susceptible to the effects of spilled oil at all stages of their life histories. As adults, they may be directly affected through physical contact with oil or its derivatives, or indirectly through the food chain by ingestion of contaminated food items.

Whereas it is reasonable to assume that juvenile and adult fishes will be able to physically avoid areas contaminated by oil spillages, the eggs and larvae of those species whose development includes some period of time in the surface-dwelling plankton community will not be able to do so. The total lack of mobility of eggs and the limited extent to which larvae could avoid spill areas renders these life stages the most susceptible to adverse impacts (Rice, 1977). Furthermore, these early development stages are the most sensitive of all in the life cycle of any species. Species that spend some part of their embryonic development in surface water include most of those which are valued either commercially or as a sport fishing resource.

Studies on the effects of oil on fish eggs are varied, come from a number of different geographical locations, and do not provide many data on species that inhabit the Southern California Bight. However, the results may be assumed to be generally applicable to the local ichthyofauna. Mironov (1968, 1969, 1972) showed that concentrations of oil in water of 1.0 ppm or lower had adverse effects on eggs of the turbot (*Rhombus maeoticus*), plaice (*Pleuronectes platessa*), anchovy, scorpion fish, and sea parrots of the Black Sea. Hufford (1971) cited several early studies which showed that crude and bunker oils harmed or killed fish eggs in laboratory experiments. Kuhnhold (1974), also experimenting with laboratory culture systems, found that cod eggs were most sensitive to extracts of Venezuelan, Iranian, and Lybian crude oils during the first few hours after fertilization, and that mortalities were significant after 10 hrs of exposure. Furthermore, development was retarded, hatching was delayed, or did not occur in some cases, and the larvae which were produced were abnormally developed, or swam abnormally, and died after a few days. These findings are supported by additional studies by Struhsaker (1977), Longwell (1977) and Morrow (1974).

As pointed out by BLM (1975), the effects of a spill greater than 5,000 barrels (795 m^3) would be largely restricted to direct kill and gill damage to epipelagic and neritic adult fishes and nektonic invertebrates inhabiting the upper layers of the ocean. This is based on the assumption that the areal extent of the spill is too large to permit effective avoidance. In all cases of a major spill, fish eggs, larvae, and fry would be most severely affected since they are concentrated in the upper mixed layer of oceanic waters and the upper part of the thermocline. Particularly vulnerable are northern anchovy, which are of primary concern since the species constitutes the largest and most important element at lower trophic levels in the food web of the Southern California Bight. Juvenile anchovies have appeared in the Long Beach Harbor population throughout the year with greatest numbers occurring in March and May (Environmental Quality Analysts, Inc., and Marine Biological Consultants, Inc., 1977). This is consistent with a report on the biology of northern anchovy in San Pedro Bay by Brewer (1975) which states that although anchovy spawning has been noted in every month of the year, it is most intense off southern California between February and May. Most spawning occurs outside of the Los Angeles-Long Beach breakwaters in deeper and cooler offshore waters. Thus the timing of an oil spill would greatly affect the severity of its impact on the local anchovy population.

In spite of potential adverse impact on the nekton of the nature described in the sections above, studies conducted after the Santa Barbara oil spill in 1969 by the California Department of Fish and Game (1969) revealed no contamination resulting from oil spillage. No adverse effects were detected at the Santa Barbara Undersea Gardens Aquarium, and divers reported fishes responding to surface oil as if it were a kelp canopy. Furthermore, Ebeling *et al.* (1971) noted no effects on the nekton except for temporary disappearance of mysid shrimps from kelp canopies.

In summary, a substantial oil spill would result in some direct kill of fishes and nektonic invertebrates in the upper layers of the water column. Death of planktonic organisms could remove important food sources resulting in decreases in the year strength of the year class of affected species. However, the nekton should be able to recover fairly rapidly because of generally widespread geographical distribution and large reproductive potentials. Sublethal effects may be anticipated; however, their nature and severity are unknown.

4.5.2.5 Marine Mammals

Available information suggests that marine mammals often avoid areas covered by oil spills, and that the effects of oil vary with each species. Impacts also depend upon the oil type, the extent of coverage, season and weather conditions, and an animal's age and health. Sea otters are especially vulnerable to oil spills since they maintain an insulating layer of air between their skin surface and the water. Oiling disrupts the integrity of this fur layer and reduces or eliminates the air layer insulation. Heat loss can be quickly fatal when air and water temperatures are low.

The Santa Barbara spill in 1969 caused oil to wash ashore at San Nicolas and San Miguel Islands, the sites of important pinniped rookeries. Several studies (Brownell and LeBoeuf, 1971; Brownell, 1971; LeBoeuf, 1971; Simpson and Gilmartin, 1970) were conducted to determine the effect of the spill on marine mammals. Simpson and Gilmartin (1970) took tissue samples from the kidney, liver, and spleen of dead California sea lion pups and northern elephant seals on San Miguel Island. Tests for hydrocarbons, DDT, and DDE proved negative. They concluded that the deaths were from unknown causes.

Brownell and LeBoeuf (1971) attempted to assess the effect of oil on sea lion pup mortality by censusing the total population of living and dead pups within Northwest Cove on San Miguel Island in June 1969. Since the overall pup mortality was 12.7 percent, which was within the expected range for uncontaminated rookeries, Brownell and LeBoeuf (1971) concluded that the effect of oil on pup mortality was negligible. Connell (1973) disputed Brownell and LeBoeuf's findings by analyzing their data on sea lion pup mortality. Connell found that dead pups had more oil on their bodies than could be expected by chance.

LeBoeuf (1971) reported on an oil contamination study of northern elephant seals (*Mirounga augustirostris*) at San Miguel Island in March 1969. Fifty-eight oil-covered pups and control pups were tagged. Subsequent observations over the next 15 months revealed that 40 percent of the oiled and 25 percent of the unoiled pups were sighted in apparent good health. LeBoeuf concluded that the oil had "no significant immediate or long-term deleterious effect on their health."

Cetaceans (whales, dolphins, porpoises) are endangered by drawing oil into their respiratory system through their dorsal blowhole. Once a thin film of oil coats the alveolar surface and the respiratory passages, gas exchange stops and the animal dies. The effect is similar to that of the reduced respiratory function typical in pneumonia. A mass of crude oil might also plug the blowhole and quickly asphyxiate the animal. This hazard might be greatest in smaller dolphins and porpoises where the blowhole is small and respiratory air volume smallest.

Orr (1969) reported that no increase in the incidence of marine mammal death subsequent to the Santa Barbara spill could be documented. He reviewed records of dead California grey whales during a ten-year period and found that there was no significant increase in early 1969, at the time of the spill.

In summary, an oil spill which is not dispersed could potentially cause these effects to marine mammals: 1) death by exposure due to destruction of their insulating air layer; 2) death by ingestion of oil, *i.e.*, nursing pups taking oil off the teats of their mothers; 3) death by coating respiratory surface (cetaceans primarily); 4) death by asphyxiation when the blowhole becomes blocked (cetaceans primarily); 5) death of young on rookery breeding beaches (Santa Catalina Island); and 6) changes in normal migration routes (*i.e.*, California grey whale) to avoid oil slicks. The significance of the impact will be highly dependent on the magnitude and location of the spill.

4.5.2.6 Birds

Although the precise biological impact of a given oil spill is impossible to predict, birds are usually adversely affected. Deaths in birds result from the effects of 1) oil coating their plumage, and 2) the toxic effects of ingesting oil. Birds may also suffer from sublethal effects of oil consumption which can modify normal egg laying, food gathering, and migration patterns.

Certain birds are more likely to be harmfully affected by oil spills. Loons, grebes, cormorants, and alcids are particularly susceptible, since they float low in the water and dive for food. Repeated dives for food may cause the birds to become so coated with oil that they can no longer fly. Gulls, and those birds which only dive for food that they can see, are less susceptible to the effects of an oil spill.

Seabirds are the most susceptible group of marine organisms to the effects of oil spills because of several factors: 1) the insulating properties of their plumage is destroyed by a coating of crude oil or refined petroleum products; 2) local populations are often small, which increases the risk of extinction; 3) typically mated pairs produce two to three young per nesting season, which severely limits their ability to recoup losses; 4) reproductive maturation of young often takes three to four years, further delaying population recovery; 5) many bird species tend to aggregate seasonally, thus exposing entire populations to the effects of an oil spill.

Straughan (1971) reported on bird losses associated with the Santa Barbara oil spill at Platform Holly in the winter of 1969. Aerial surveys were conducted by the California Department of Fish and Game over a 1,075 square mile area during winter and spring. The winter survey estimated a population of 12,000 birds which rose to 85,000 birds in spring. Significant influxes of pelagic species caused the seasonal increase.

Bird losses from Point Conception to the Ventura River were estimated to be 3,686. This total was based on beach counts and birds collected for rehabilitation which later died. The total did not include the many thousands of birds that died at sea, but failed to drift ashore.

Two tankers collided in San Francisco Bay in January 1971, releasing 840,000 gallons of bunker oil, which caused the death of thousands of birds (Lassen, 1971). At receiving stations, 4,557 birds were identified. Western grebes represented the largest mortality, representing 55.7 percent of the known kill. Other oil mortalities included scoters (22.5 percent), common murres (9.8 percent), loons 4.1 percent), other ducks (2.8 percent), other grebes (2.5 percent), and less than one percent each for American coots, cormorants, and gulls (Wallace, 1971).

Common murres accounted for an estimated 60 percent of the bird kill after a 1938 San Francisco Bay oil spill. Many western grebes and white-winged scoters also perished (Aldrich, 1938).

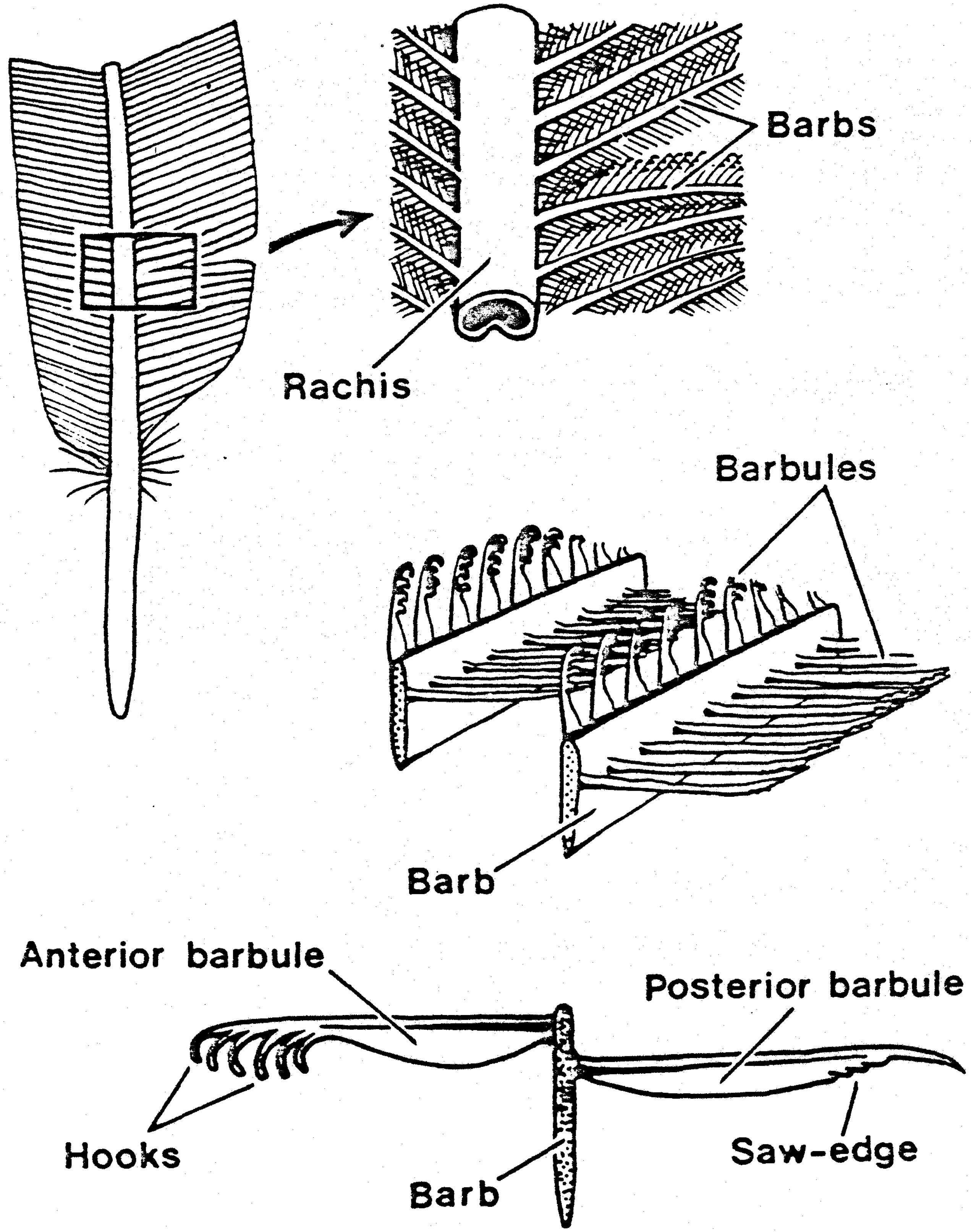
The fate of oiled birds is largely determined by the extent of oiling, the oil type, and prevailing weather conditions. Bird feathers rely upon a system of interlocking barbules which connect adjacent barbs to one another (Figure 4.5-3). The barbs in turn are attached to a central semi-rigid spine called a rachis. Barbule interconnections and overlapping adjacent feathers produce a water-resistant hydrophobic surface. Beneath the feathers, a layer of air becomes trapped, aiding heat conservation. Small quantities of oil are naturally produced by birds in a gland at the base of the tail to aid in grooming. While small amounts of oil actually assist in waterproofing a bird's plumage, large amounts destroy a feather's insulating and waterproofing characteristics. If the oil is particularly viscous (i.e. crude oil), the feather becomes essentially useless, and a bird's survival depends upon the growth of replacement plumage.

Oiled ducks greatly increase their metabolic rates to compensate for heat loss (Hartung, 1967). As a result, accelerated starvation often results, particularly during winter. A one-inch patch of oil on the belly of a murre was enough to cause its death from the chilling effects of seawater by destroying its insulating air pocket (Tuck, 1969).

Contamination with sublethal doses of oil during breeding season can cause a disruption in normal reproductive behavior. Ducks fed with small doses of lubricant oil stopped laying eggs for about two weeks (Hartung, 1965). This cessation could cause complete nesting failure at high latitudes where the nesting season is brief.

Embryo viability has been shown to be greatly reduced when an eggshell becomes covered with oil from the plumage of a female (Hartung, 1965). Hartung reported only 20-percent hatching success in mallard eggs after they had been smeared with a thin layer of medicinal mineral oil. Eighty percent of unoiled control eggs hatched successfully.

• Rehabilitation of Oiled Birds. Attempts to rehabilitate oiled birds and return them to the wild have largely been a failure. Clark and Kennedy (1968) reported that of 7,848 oiled birds recovered after the *Torrey Canyon* spill, only 5.7 percent of the birds survived for one month beyond their recovery date. Bourne (1970) calculated that only 0.25 percent of the recovered *Torrey Canyon* birds survived in the wild.



The structure of a contour or flight-feather, showing the way in which the barbules are hooked together to seal the space between each barb. From Ede (1964).

Structure of Flight Feathers

4.5-3
Figure

Rehabilitation efforts were not much more successful following the collision of the oilers *Arizona Standard* and *Oregon Standard* within San Francisco Bay in 1971. Of the approximately 7,000 dead and dying birds brought to cleaning stations after the spill, only 200 birds were still alive four months later (Wallace, 1971).

A review of the problem of oiled birds by Aldrich (1970) concluded: 1) oiled feathers cannot be restored to their natural water repellent qualities by application of any known solvents. Only those birds held in captivity through their annual molt, so that their entire plumage is replaced, can be successfully returned to the wild; 2) treatment of the toxic effects from ingested oils must be part of any rehabilitation program; 3) successful treatment is species specific; and 4) avicultural solutions must be found for all species brought to a rehabilitation center.

4.5.2.7 Kelp Communities

Effects of the Shell Beta project on kelp communities would be limited, as these communities are several miles from the project site. Contamination from a spill would be similar to that experienced during the Santa Barbara spill where the oil traveled several miles, allowing it to spread out in a film and release its more toxic volatile components (Foster *et al.*, 1971). Observations of the effect of the Santa Barbara spill on *Macrocystis* plants indicated little or no damage. The mucus coating of *Macrocystis* spp. protected the plant from direct contact and damage (Anderson *et al.*, 1969).

Effects on associated kelp bed organisms were unclear. The most susceptible would be the fauna inhabiting the canopy region of the kelp bed. The only observed damage from the Santa Barbara spill was a reduction of mysids (Ebbeling *et al.*, 1971). Mysids are one of the abundant associates of the kelp canopy and an important food source of the canopy fishes (North, 1971).

Damage to encrusting animal forms living on the canopy kelp blades was not studied during the Santa Barbara spill; however, effects similar to those observed for encrusting intertidal fauna could be expected in the kelp bed (Table 4.5-4).

4.5.2.8 Marine Reserves

Large oil spills greater than 5,000 barrels (795 m^3) could seriously impact all marine reserves, marine life refuges, and Areas of Special Biological Significance in the area. These areas were identified in Section 3.5.1.8, and are shown in Figure 4.5-2. Precise impacts would depend upon the amount and type of oil, the speed and type of cleanup operations, and the character of the affected reserve. Designation as a protected reserve implies that the area possesses critical or unique habitat(s). Therefore, every possible effort should be made to prevent the spill from reaching the reserve.

The enclosed nature of estuarine areas such as Anaheim Bay, Alamitos Bay, and Upper Newport Bay make them particularly vulnerable to oil impacts. Whatever toxic ingredients the oil possesses will be concentrated within a relatively small body of water, potentially causing greater mortalities.

Although local estuaries are potentially vulnerable, they are also the easiest to protect. All are located within man-modified harbors where booms and other protective devices could be used to stop the advance of oil at jetty entrances before entering a harbor.

Open coastal reserves cannot be so easily protected. However, they usually have the advantage of wave-generated and tidal flushing, so that toxic substances are not likely to become concentrated except in some tidepools. The most serious potential impacts occur when oil enters a semi-enclosed bay where flushing through tidal exchange is restricted.

4.5.2.9 Mitigation

Mitigation for oil spill impacts is discussed in Sections 4.4.3.6 and 4.4.4.

4.6 SOCIOECONOMICS

4.6.1 History/Archaeology

4.6.1.1 Archaeological Impacts

Magnetometry has proven value (Clausen, Arnold, Frey, *et al.*) in locating underwater archaeological sites where ferrous metal exists intact such as historical maritime artifacts, or where magnetic "signatures" of geological origin can indicate prehistoric human occupation (*i.e.*, confluence of streams, protected bays, estuaries). The analysis of magnetometry data for submerged sites of human habitation is a present focus of archaeological research, with investigators working actively on all North American coastlines to perfect the methodology. A magnetometry anomaly indicative of an archaeological resource is still largely a matter of interpretation by the survey data researcher. The excursion of gradient distortion (anomaly) evident upon the magnetic record is a function of mass versus distance from the sensor.

As noted in Table 3.6-2, there are seven anomalies in the pipeline route survey which cannot be traced to known features such as abandoned wells, oil islands, or distinctive geologic features. Whereas the project area has seen over 400 years of historical maritime activity and an indefinite amount of aboriginal watercraft prior to historic times, there is a potential that at least six of these anomalies represent historical resources. The anomaly shown as a linear alignment in Figure 3.6-1 (Station 7) is not felt to be of cultural value because of the linearity of the data.

The degree of impact is difficult to assess because of the limits of electronic surveying. The proximity of the majority of the anomalies to a modern harbor presents a high potential that many of these anomalies are, in fact, modern debris, and therefore would not be adversely impacted. However, because of the general historical sensitivity of the area (BLM, 1978), the potential for resource impact cannot be completely ruled out. Therefore, procedures have been proposed to field-verify the anomalies and mitigate the potential for impact.

The subbottom profiling systems data (pinger, boomer, and sparker) were essentially negative with respect to discerning cultural resources. The side scan sonar returns for the survey route show a tremendous amount of debris of probably modern origin scattered along the survey route. This situation had the effect of eliminating the normal potential for associating magnetometer anomalies with side scan sonar returns. No sonar returns were seen of themselves to indicate archaeological resources. It is possible, however, that some amount of debris appearing on sonar records could be of a historical nature due to the maritime history of the region.

4.6.1.2 Mitigation Measures

It is recommended that, prior to laying of the offshore pipeline, six magnetic anomalies (Table 3.6-2) be investigated, by using a mobile video system (where visibility permits) with permanent record capability, for analysis by a marine archaeologist. If historical resources are positively identified, then appropriate salvage should be performed by certified archaeologists, or the pipeline route could be altered to avoid the resource. The seventh linear anomaly should be investigated to ensure that no impact to the pipeline will be sustained. However, this recommendation is not based on potential cultural resource value, but rather on the fact that it is a large, unknown anomaly.

4.6.2 Recreation/Coastal Land Use

4.6.2.1 Recreational Impacts

No recreational facilities have been proposed in the project. Due to negligible employment-generated population growth (see Section 4.6.4), project implementation would not contribute significantly to the use of coastal recreational or commercial recreational facilities. Ocean-floor placement of the pipeline precludes its interference with public enjoyment of the beach and water areas. Beach visitors, including swimmers and surfers, would not be restricted in their activity because of the distance of the platforms from the shorelines (12 miles (19.2 km) from Long Beach, nine miles (144 km) from Huntington Beach). Development and operation of the Shell facilities would not significantly affect circulation patterns in the harbor and adjacent waters, and thus would not hinder marina and beach area boat activity. Small craft and support boat traffic will be increased through shuttling men and equipment between shore and platform sites. The impact would be visual and not particularly detrimental as ships and boats are generally accepted to be part of the ocean scene.

The project could adversely impact recreational and commercial recreational activity in the event of an oil spill. The volume and extent of the spill would be influenced by factors such as the effectiveness of containment (Section 4.4.4) and wave and weather action transporting the oil inland and southward (Section 4.4.3). However, small spills would tend to be primarily a source of annoyance by creating tar balls which are found buried or on the surface of the sand in the surf zone or tossed above the wave-wash zone on the beach where they can soil feet or clothing.

Large oil spills could cause losses which could have major, though not permanent, recreational impacts. If a spill or chronic contamination caused the demise of any biological species either totally or throughout a significant portion of its range, and if the species was important recreationally, then its loss would be a loss to the recreation resource base. However, experience with the Santa Barbara oil spill indicates this situation is highly unlikely. In a worst-case situation, the impacts of a spill would be especially significant if the spill occurred during the summer months (height of the tourist season), and reached mainland beaches which were intensively used or have unique recreational values. Recreational use of an area would be impeded for the time that oil covered the beaches and until cleanup or replacement of the contaminated sand was completed. Interference with public enjoyment of the coastal beaches and water might range from a temporary halt or restriction of boating activities and water sports for reasons of public safety and health.

If an oil spill were to occur during the tourist season, the business community dependent upon expenditures related to use of recreational resources would also be adversely affected. The loss in tourist attraction to the area would bring about some economic loss to the local area. As 14 percent of southern California's 8.5 million out-of-state visitors plan beach or coastal visits in their itinerary, some portion of those people would be deterred by an oil spill (BLM, 1978). While some would seek alternative recreation trips to unaffected beaches, trip cancellations would also transpire. An additional repercussion might include crowding at the alternative facilities selected.

Recreational fishing could also be interrupted by a significant oil spill which persists for an extended period. The fisheries located in the harbor area might be temporarily destroyed or dislocated, thereby adversely impacting commercial, as well as recreational, fishing activity and related expenditures. However, there are also beneficial impacts on recreational fishing. As discussed in Section 4.5, the platforms act as an artificial reef, resulting in significant long-term enhancement of marine resources in the vicinity. Experience at other platforms indicates that they will be popular locations for recreational fishing and hence in this respect will enhance recreational opportunities.

No specific mitigation measures outside of that proposed for oil spill planning and handling discussed in Sections 4.4.3 and 4.4.4 are proposed for recreational resources.

4.6.2.2 Coastal Land Use Impacts

The California Coastal Act has established a series of policies which guide development of energy facilities in the Coastal Zone. Two policies in particular are pertinent to this development as found in Sections 30262 and 30263. Additional policies which may influence this project are shown in Sections 30260 and 30261. However, only the key policies are discussed below.

> *30262. Oil and gas development will be permitted in accordance with Section 30260, if the following conditions are met:*
>
> *(a) The development is performed safely and consistent with the geologic conditions of the well sites.*

Based on data supplied by the applicant, its consultants, or other information collected as part of this analysis, it appears that the project has been designed using state-of-the-art methodology. If the project is constructed as designed, it will be compatible with the geologic conditions of the well site (see Section 4.1).

> *(b) New or expanded facilities related to such development are consolidated, to the maximum extent feasible and legally permissible, unless consolidation will have adverse environmental consequences and will not significantly reduce the number of producing wells, support facilities, or sites required to produce the reservoir economically and with minimal environmental impacts.*

The Beta field is to be unitized to comply with this policy. Both drilling and production platforms can provide additional capacity beyond that required by the operator. Shell proposes to use only 60 of the 80 possible well slots on Platform Ellen, and Platform Elly has room for an additional production train to handle possible future production from nearby leases.

(c) Platforms or islands will not be sited where a substantial hazard to vessel traffic might result from the facility or related operations, determined in consultation with the United States Coast Guard and the Army Corps of Engineers.

All structures will be located within the separation zone outside of traffic lanes and proposed buffer zones (see Section 4.6.3).

(e) Such development will not cause or contribute to subsidence hazards unless it is determined that adequate measures will be undertaken to prevent damage from such subsidence.

(f) With respect to new facilities, all oil-field brines are reinjected into oil-producing zones unless the Division of Oil and Gas of the Department of Conservation determines to do so would adversely affect production of the reservoirs and unless injection into other subsurface zones will reduce environmental risks. Exceptions to reinjections will be granted consistent with the Ocean Waters Discharge Plan of the State Water Resources Board.

Produced water and source water will be injected into the reservoir to prevent subsidence (Section 4.1 and Section 4.4).

30263. (a) New or expanded refineries or petrochemical facilities not otherwise consistent with the provisions of this division shall be permitted if (1) alternative locations are not feasible or are more environmentally damaging; (2) adverse environmental effects are mitigated to the maximum extent feasible; (3) it is found that not permitting such development would adversely affect the public welfare; (4) the facility is not located in a highly scenic or seismically hazardous area, on any of the Channel Islands, or within or contiguous to environmentally sensitive areas; and (5) the facility is sited so as to provide a sufficient buffer area to minimize adverse impacts on surrounding property.

Adverse impacts from project implementation have been identified along with appropriate mitigation within the body of this report.

(b) In addition to meeting all applicable air quality standards, new or expanded refineries or petrochemical facilities shall be permitted in areas designated as air quality maintenance areas by the State Air Resources Board and in areas where coastal resources would be adversely affected only if the negative impacts of the project upon air quality are

offset by reductions in gaseous emissions in the area by the users of the fuels, or, in the case of an expansion of an existing site, total site emission levels, and site levels for each emission type for which national or state ambient air quality standards have been established do not increase.

See Section 4.3 for the air quality analysis. The applicant has proposed emissions tradeoffs as defined in Section 2.5.

(c) New or expanded refineries or petrochemical facilities shall minimize the need for once-through cooling by using air cooling to the maximum extent feasible and by using treated wastewaters from inplant processes where feasible.

The offshore facility will use all produced waters for injection. In addition, by locating the production facility offshore, the limited natural gas within the reservoir can be utilized for short-term energy for the turbine generators. Waste heat from the turbines and the process steam is to be used for oil dehydration.

4.6.2.3 Port of Long Beach Land Use

The proposed pipeline right-of-way crosses through an area slated by the Port of Long Beach for the possible future development of a 571-slip marina located in Queensway Bay just southeast of the Queensway Hilton Hotel. However, the Port of Long Beach's final master plan mentions both the Queensway Bay Marina and the proposed pipeline corridor as possible uses in this area. The master plan separates the two potentially conflicting uses by forbidding construction of permanent moorings over the THUMS and future pipeline corridor. The proposed pipeline would parallel the THUMS corridor.

There is a possible conflict of use that could exist as a function of the timing of construction of the pipeline and the marina. At this time, it appears that the proposed pipeline will be constructed before the proposed marina (McDaniel, 1978). If this is the case, there should be no adverse impact as long as the pipeline is located outside any areas in which dredging may occur to construct the marina. When completed, the pipeline will show no surface expression until it reaches the distribution manifold near Pier I, and should, therefore, not detract from the use of the marina as a buffer or recreational land use.

However, if the proposed project was delayed to the extent that the Queensway Bay Marina was developed prior to the pipeline, short-term impacts could occur. These would include disruption of marina activities and onshore ancillary activities from construction activities associated with the burial of the pipeline. These impacts would be short-term in nature and, once the pipeline was in place, the uses are felt to be compatible.

In addition to the pipeline, the onshore distribution facility in the Port of Long Beach is also consistent with the Port's master plan. While the master plan does not specifically mention this project, the proposed uses are generally permitted under the Petroleum Import/Export and Primary Port Land Use categories. Specifically, distribution facilities are permitted uses under the Petroleum Import/Export category, and are permitted within the Port's Northeast and Middle Harbor Districts. The proposed distribution facility is in the Northeast District, and therefore will be consistent with the master plan.

Materials storage and transport facilities are permitted use under the Primary Port Land Use designation within the Northeast and Middle Harbor Districts. Thus, the storage yard will be consistent with the master plan.

In terms of long-range planning in the Port, the project should not conflict with any of the anticipated port projects, as detailed in the Port's master plan (McDaniel, 1978). In fact, because of the temporary nature of the proposed storage terminal, its potential for conflict with any future port activity is remote. The other onshore facilities, while more permanent in nature, will have no land use conflict potential by virtue of their locations and small size. However, as noted in the circulation analysis, there is a need to carefully coordinate the installation of the main pipelines proposed for this project, SOHIO, and the MacMillan Ring Free Oil Company. This will prevent long-term disruption within the pipeline right-of-way and will avoid crossing of lines within areas of high water tables, which could limit burial depths.

In summary, all portions of the proposed project within the Port of Long Beach are consistent with the goals and objectives of the Port master plan.

4.6.2.4 Mitigation

An oil spill or leakage along the pipeline route could temporarily interfere with or restrict recreational use of coastal waters and beaches. Mitigation of those impacts are discussed under the oil contingency plan sections of this report (Sections 4.4.3 and 4.4.4).

As the project is now proposed, with both on and off-shore facilities, it does not appear that adverse impacts will be sustained on the Coastal Zone. Through the process of unitization, the applicant has mitigated those impacts that would occur if a processing facility were to be located onshore. The project appears to be consistent with the goals and policies of the Port master plan therefore, alternative sites or pipeline right-of-way within the Port are not felt to be warranted. However, alternatives outside the Port are discussed in Section 5.1.

4.6.3 Marine Traffic and Navigation

4.6.3.1 Marine Traffic Impacts

4.6.3.1.1 Background

Construction and placement of offshore oil platforms in an area of marine traffic in the Gulf of Catalina imposes certain risks on parties (both those associated with the project and marine interests) due to the finite probability of a ship-to-structure collision (ramming). This section assesses the level of such risks. Consistent with the nature of risk, this section consists of two parts. The first part identifies the potential consequences of a ramming, the parties subject to such risk, and a classification of these parties according to the type of risk to which they are subject and the benefits they might potentially receive from the project. The second part estimates the probability of occurrence of an event leading to the consequences identified in the first part.

Two major categories of marine vessels are considered, those classes above 500 gross tons and those classes below 500 gross tons. This categorization is made in order to handle differences in the estimates of probability of collision and differences in the potential consequences of a collision. This division fairly well separates commercial shipping from fishing boats, barges, and pleasure craft, and the U.S. Coast Guard has data segregated in this manner. Further, the larger ships can be expected to normally operate in the Gulf of Catalina Traffic Separation Scheme (TSS) as described in Section 3.6.3, while smaller ships cannot be assumed to utilize the TSS. Similarly, the collision of a ship larger than 500 tons with a platform could cause substantial damage to the platform and release significant quantities of pollutants from the platform and the ship, whereas the collision of smaller craft is expected to cause only minimum platform structural damage and should not result in the release of significant quantities of pollutants.

4.6.3.1.2 Collision Consequences and Parties Affected

The consequences of a collision of a ship with a fixed drilling or production platform can range from minor damage to a total loss of both the ship and the platform. These consequences impose a potential loss to various parties who are either voluntarily or involuntarily exposed to such risks, as follows:

Potential Nature of Loss	Affected Party	Nature of Risk
Personal injury	- Ship operators - Platform operators	- Involuntary - Voluntary

Potential Nature of Loss	Affected Party	Nature of Risk
Equipment damage	- Ship owner - Platform owner	- Involuntary - Voluntary
Environmental damage	- Public	- Involuntary

Each of the parties affected, however, gain some potential benefit (either direct or indirect) from the project which should be considered in evaluating the acceptability of the imposed risk:

Potential Benefit	Affected Party	Nature of Benefit
Wages	- Platform operators/ support personnel	- Direct
Return on investment	- Platform owner	- Direct
Navigational aid	- Ship owner/operator	- Direct
Secondary economic effects	- Public	- Indirect - Direct
National security considerations/balance of payments	- Public	- Indirect

Based on the foregoing, it was determined that the Shell Beta marine traffic risk assessment should consider risks in three different categories:

- Environmental damage - involuntary risk imposed on a party indirectly benefited.
- Ship damage[2] - involuntary risk imposed on party directly[1] and indirectly benefited.
- Platform damage[2] - voluntary risk taken by party receiving direct benefit.

1. If ship is engaged in operations supplying or supporting the platform operations, it receives direct benefits.
2. Including personal injury

Each of these risks is described in the following paragraphs.

(1) Environmental Damage

The principal adverse environmental consequence of a a ship collision (ramming) with one of the proposed platforms is the release of oil (refined or crude) to the environment, either from the platform or the ship involved.

The analysis of collision consequences in the following paragraphs establishes a likely, but somewhat conservative, spill volume based on statistical data. It does not assume a catastrophic collision of the type used in Section 4.4.3 to establish a worst-case scenario.

Oil releases from the production platform (Elly) can be expected to be limited in amount and represent a worst case in terms of platform discharges as a result of a major collision. Potential sources of oil from Elly include the well supply lines, oil being processed or stored on Elly, and oil in transport to shore via the pipeline. Oil loss from wells is expected to be minor, regardless of the nature of an incident, since the oil to be produced from this project is very viscous, has limited natural gas or water energy to sustain the flow, and, consequently, must be artificially lifted (Shell, 1978). Further, all wells are to be equipped initially with surface-controlled sub-surface safety devices installed below the mudline and held open by hydraulic and pneumatic pressure from the platform (Shell, 1977). Any platform accidents which could be presumed to cause a well rupture could be reasonably assumed to result in an automatic shutting of these subsurface safety devices. The maximum quantity of oil in process or storage systems on Platform Elly is expected to be no more than 10,000 barrels (1,590 m^3). Rupture of the platform-to-shore pipeline can be expected to contribute to a potential spill through a depressurization (expansion) volume, and direct leakage from the ruptured piping. Leakage of oil contained in the affected piping connected to the shore installation is expected to be minimal due to the slope of the shelf and the oil specific gravity. The additional oil from this pipeline is estimated to be about 150 barrels (24 m^3) for Ellen and Elly and 250 barrels (40 m^3) for Eureka. The probability that all oil available to spill will be spilled depends on the extent of damage received by the platform structure from the collision. Data collected and reported by the U.S. Coast Guard and summarized in the Technical Appendix indicates that about 50 percent (6 of 13) of reported incidents involving ships in excess of 500 gross tons resulted in severe damage (*e.g.*, total loss of structure or economic losses in excess of $500,000) to the platform structure, although only two such incidents caused a total loss of the structure or detectable oil pollution. On the basis of the foregoing data (6 of 13 incidents), the probability of a collision resulting in a release of the maximum quantity of oil in storage or process systems on a platform can be conservatively estimated as 0.5.

A second potential source of oil pollution is that of a release from the ship itself if it is carrying oil. Analysis of tanker damage data indicates that spills from tankers involved in rammings or collisions are generally small and much less than the contents of a single cargo tank (FPC, 1976). Since a tanker collision with a platform can reasonably be assumed to result in the largest oil release from a ship, a tanker collision is used to conservatively estimate the worst-case oil release. Oil releases from non-tankers (i.e., bunker fuel) following a ramming are expected to be rare and, when occurring, of a magnitude on the order of a small percentage of that expected to be released from structures. Thus, this potential source is not specifically accounted for in the following estimate. The U.S. Coast Guard records for incidents involving structures in the Gulf of Mexico indicate no oil pollution as a consequence of rammings involving non-tankers during the years 1963-77. An estimate of the expected quantity of oil spilled from a tanker ramming the platform can be provided by considering the weighted average size of a tanker using the traffic lanes near the platforms, and the likely spill size if such a collision occurred. McMullen (1977), in connection with the Point Conception traffic studies, conservatively estimated a weighted average tanker size (by number of trips) for this area of 100,000 DWT. The size of a spill from such a ship can be estimated from a Federal Power Commission (FPC, 1976) study of marine transportation hazards. They estimated that the maximum observed fraction of the tanker's load spilled in a collision was seven percent; that the probability of a spill of this size in a collision was only 10 percent; and that only a fraction of rammings (about 10 percent) resulted in oil spills. This approach (700,000 bbls X 0.07 X 0.1 X 0.1) leads to an estimated spill volume from a tanker of about 500 barrels (80 m^3). An estimation based on the largest crude carrier dockable in the Los Angeles/Long Beach Harbor area (165,000 DWT) results in an expected spill volume of on the order of 825 barrels (McMullen, 1977). As a result of the foregoing, the following expected values of oil spilled per collision accident will be used to estimate the environmental consequences of a ramming:

	Estimated Total Oil Release (Barrels per Collision)		
Vessel size	Elly	Ellen	Eureka
Vessel less than 500 gross tons	0	0	0
Vessel greater than 500 gross tons (non-tanker)	5150 (1)	150	250
Tanker (500 bbls released from ship)	5650	650	750

It should be noted that the oil spill scenarios developed in Section 4.4.3 considered a collision related spill of about 5,000 barrels (795 m^3).

(1) 10,000-barrel maximum storage x (0.5) = 5,000 bbl loss through connecting pipelines.

(2) Ship Damage

An estimate of potential ship damage can be made using data collected for previous incidents of a similar nature. Data collected by the U.S. Coast Guard over the 15 years ending June 30, 1977 provides a record of a total of 67 incidents involving ship collisions with stationary structures in circumstances similar to those being calculated. Collisions with piers, etc. were eliminated as were collisions where tugs were moving oil rigs or self-propelled oil rigs were involved in collisions. Also, any river incidents were eliminated. The information provided by these records is summarized in Table 4.6-1. Detailed descriptions of major incidents involving large ships are provided in the Technical Appendix.

(a) Ships Greater Than 500 Gross Tons

Information collected by the Coast Guard, provided in the Technical Appendix, and summarized in Table 4.6-1 indicates that damage to large ships involved in a ramming incident generally falls into one of three categories:

- Total loss of vessel, including the potential for one or more crew members' death;
- Significant accidents, possible crew member injury, and vessel damages on the order of or exceeding $100,000;
- Minor incidents resulting in little or no economic loss.

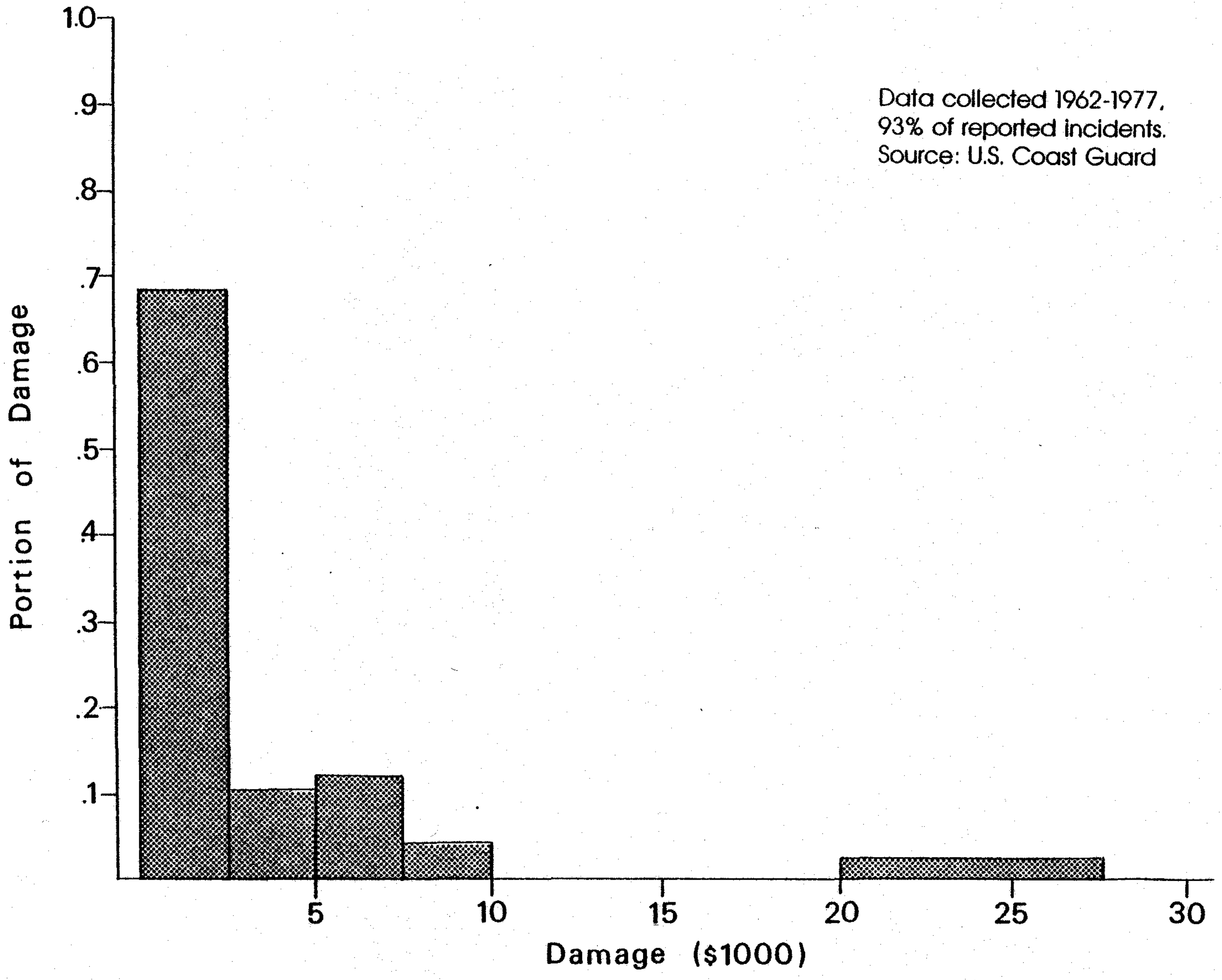
The conditional probability of occurrence of each of these damage categories resulting from a ship/structure collision is estimated at 0.08, 0.23, and 0.69, respectively, based on the number of incidents in each category of the Coast Guard data.

(b) Ships Less Than 500 Gross Tons

In the case of smaller ships, damage reports indicate that the consequences generally fall into one of two categories. A small number of incidents (about 6 percent) result in a significant damage to the craft, including total loss of the craft and crew member injury. The balance (94 percent) of reported incidents resulted in only minor (less than about $30,000) economic loss. The distribution of these damages is shown in Figure 4.6-1. The calculated mean damage for events in this category is about $4,000. The standard deviation for the distribution used is about $5,500.

(3) Structure Damage

An approach similar to that for ship damage, considering only structures physically similar to the platforms



Loss to Structures as a Result of Ship Rammings

4.6-1
Figure

TABLE 4.6-1

SUMMARY OF RAMMING INCIDENTS IN THE GULF OF MEXICO INVOLVING FIXED OFFSHORE STRUCTURES[1] (1963-1977)

	Vessel Size (gross tons)	
	Less than 500	Greater than 500
Total incidents	54	13
Incidents in Gulf of Mexico outside Zone 1 (Shallow Water)	36	10
Estimated range of damage to vessel ($1000)	<1 - 130	<1 - 10,000
Estimated range of damage to structure[2] ($1000)	<1 - 1000	5 - 10,000
Incidents resulting in death/serious injury[3]	1	1
Incidents resulting in total loss of vessel	2	1
Incidents resulting in total loss of structure	0	2
Incidents resulting in substantial damage to vessel ($100,000+)	3	3
Incidents resulting in substantial damage to structure ($100,000+)	4	8
Incidents involving vessels supplying or supporting the structure	23	0

(1) Unless otherwise noted, 'fixed structure' includes artificial islands, mobile drilling rigs, and work over rigs.
(2) Artificial islands only.
(3) Same incidents as those resulting in vessel loss.

SOURCE: U.S. Coast Guard

involved in the Shell Beta project, also provides an estimate of potential losses per ramming incident.

(a) Ships Greater Than 500 Gross Tons

As in the case of ship damages, information available suggests that the consequences to an offshore structure involved in a ramming incident with a major ship will fall into one of three categories:

- Total loss of structure, including, possibly, crew member death;
- Significant incidents resulting in damages of $100,000 or greater;
- Minor events resulting in limited economic loss.

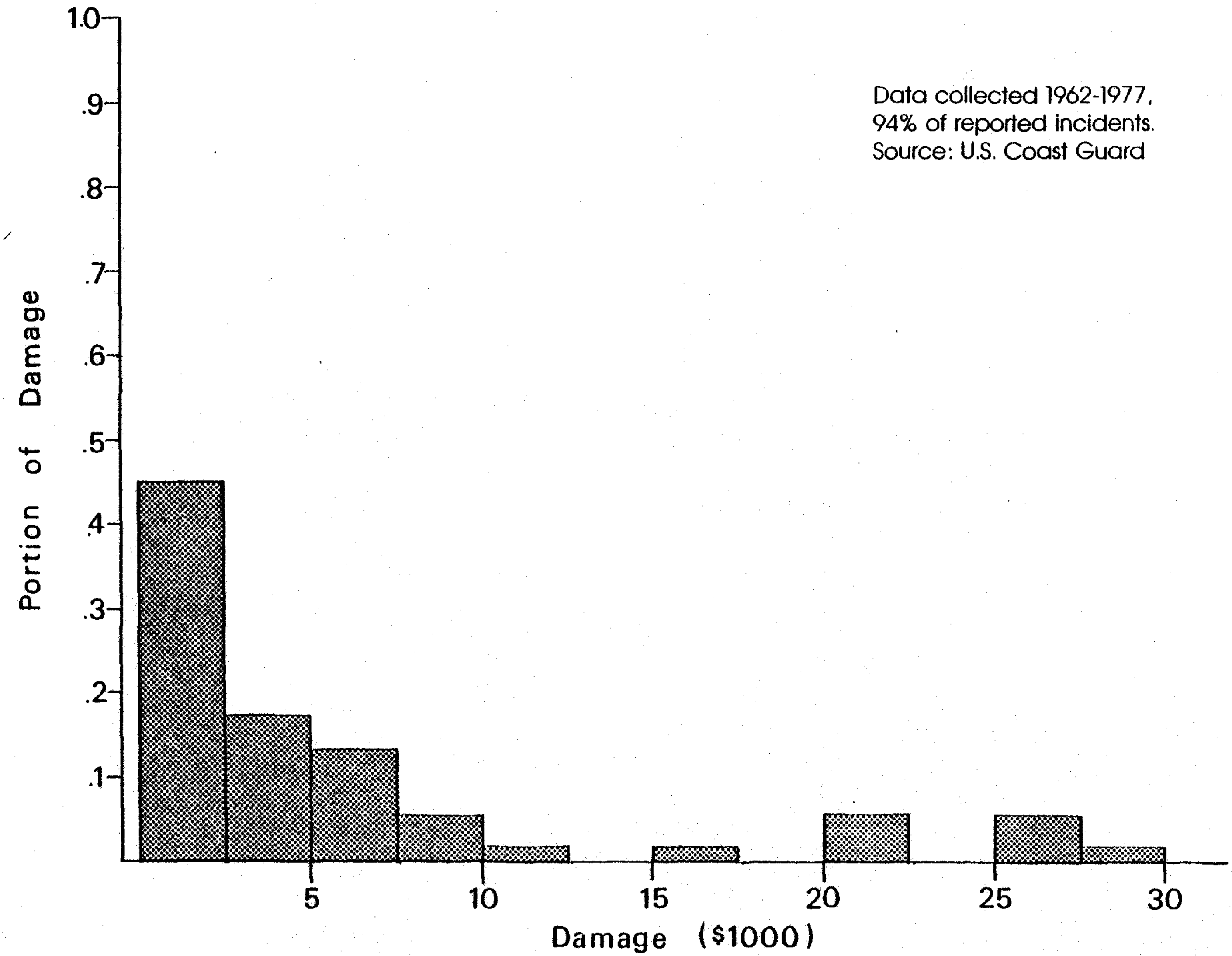
The conditional probability of the occurrence of each of these damage categories resulting from a ship/structure collision is estimated at 0.15, 0.62, and 0.23, respectively, based on the number of incidents in each category of the Coast Guard data.

(b) Ships Less Than 500 Gross Tons

In the case of smaller ships, structural damage appears to result in one of two categories. In a very small number of cases (about 7 percent), substantial damage (in excess of about $100,000) has been reported. The remaining events (93 percent) have resulted in only minor (less than about $30,000) damages. Distribution of these reported damages is shown in Figure 4.6-2. The calculated mean damage for events in this latter category is about $6,200, and the standard deviation for the distribution used was about $7,800.

4.6.3.1.3 Accident Probability Estimates

Although insufficient oil platform structure history in the southern California Bight precludes direct estimation of the incremental probability associated with new platform structures in this area, an estimate of the probability of damaging events associated with these structures can be made on the basis of statistical information obtained from the Gulf of Mexico. Drilling operations in the Gulf of Mexico have taken place over a number of years, and a substantial body of data is available concerning structures, locations, and accident consequences. The ability to use data observed in the Gulf of Mexico confidently in order to derive an estimate for the potential hazard in the project area requires that the hazard environment in these locations be substantially equal. Consideration of two environmental factors, meteorological and physical, indicate that the hazard environment for the two locations are substantially the same and, thus, that no detailed quantitative comparison of such factors is necessary.



Loss to Ships as a Result of Structure Rammings

4.6-2
Figure

In the case of meteorological factors, data compiled by the National Weather Service, and displayed in Table 4.6-2, suggest no substantial difference in inclement weather conditions which might affect the probability of marine accidents in the two locations. Heavy fog seems slightly more frequent in the California coastal area than the Gulf Coast. This difference, however, appears to be compensated for by the more frequent occurrence of other visibility reducing phenomena, thunderstorms and rain, in the Gulf Coast area. Wind conditions are comparable. As an additional consideration with respect to weather comparisons it should be noted (Technical Appendix) that extreme weather (high winds and sea states) does not appear to be the major cause of reported incidents. Visibility was generally good in all but two cases and winds above 20 knots (36 km/hr) were reported for only four of the cases, a frequency equal to that reported for winds less than 10 knots (18 km/hr). The common factors in the majority of the cases appear to be that the accident occurred after dark (8 of 10 cases) or involved operator inattention or error (6 of 8 cases for which cause was reported). Neither of these two factors can be expected to cause a substantial risk differential between the two locations.

Physical considerations also tend to indicate that no substantial difference in hazard need be accounted for when deriving accident frequencies in the Los Angeles/Long Beach area on the basis of data from the Gulf of Mexico. Offshore structures in the Gulf are fitted with aids to navigation - lights and fog horns specified by the U.S. Coast Guard - as are the proposed Shell Beta platforms. Further, both areas are provided with charted traffic lanes: safety fairways in the Gulf of Mexico and a traffic separation scheme in San Pedro Bay, which allow the mariner to navigate in zones designated free of interference from fixed structures or meeting traffic.

A second physical condition, marine traffic density can also be considered as a potential contributor to increased hazard. Higher traffic density may increase the probability of a ramming due to increased frequency of ship maneuvers for collision avoidance and allow an increased opportunity for misinterpretation of radar information. This consideration indicates that operations in the Gulf area are probably more hazardous, since the traffic generated by New Orleans and Galveston, at either end of the Gulf offshore area, is substantially greater than that in the approaches to Los Angeles/Long Beach. The average annual transits reported for 1968-70 were about 12,000 and 14,000 per year for New Orleans and Galveston, respectively (Walker *et al.*, 1975). Each is a factor of at least three greater than that expected for traffic entering and leaving the Los Angeles/Long Beach area via the Gulf of Santa Catalina TSS. This factor, considered in isolation, tends to make the results of this analysis conservative.

(1) Ships Transiting Traffic Lanes (TSS) (vessels greater than 500 gross tons)

Probability estimates of collision for ships transiting the Gulf of Santa Catalina TSS can be made on the basis of observed incidences in the Gulf of Mexico involving vessels greater than 500 gross tons also in transit in areas provided with safety fairways.

(a) Methodology

For the case where ships are to be navigated through a field of fixed obstacles, the maximum probability of a collision during a given transit can be estimated on the basis of geometry. Specifically, the probability of collision (P) of a ship on a random selected course proceeding through a field of width (W) can be stated:

$$P = N\,(S + V)/W$$

where N = number of structures
S = width of structure (average)
V = width of vessel (average)

and the number of rammings generated (Rg) by M passages per year can be stated as follows:

$$Rg = M \times P \text{ rammings/year}$$

If an observed collision (ramming) rate (Ro) differs from that calculated on the basis of geometry, this deviation can be incorporated in a formulation as follows (MacDuff, 1974):

$$Ro = Pc \times Rg$$

where Pc is a "causation" probability which can be understood as the probability that one or more of many factors (example: carelessness, fog, high wind, steering failure, navigational failure) will result in the failure of the vessel master to prevent a collision.

(b) Probability Estimate

Offshore structures located in the Gulf of Mexico are generally located in the region between New Orleans and Galveston. Previous evaluations for the years 1968-1970 revealed an average distance traveled in this structure area of approximately four million miles per year for vessels greater than 500 tons with an average number of structures in the area of approximately 1728 (Walker, *et al.*, 1975). Use of this information and a disaggregation of ship transits by number and course length in the structure area suggests a causation probability (Pc) of about 8×10^{-5}. The product of this probability and the following factors: (1) a conservative estimate of the projected average annual ship traffic transiting north or south between Santa Catalina Island and the Mainland (110% of 1977 traffic)(McMullen, 1977); and (2) the ratio of ship plus structure dimension to the width of the approach in the vicinity of the structures (both measured normal to the path of ship movements), can be used to derive the following estimates of the annual probability of a ramming incident involving each of the three structures:

Ellen: 1.45×10^{-3} yr^{-1} (one incident every 690 years)

Elly: 1.62×10^{-3} yr^{-1} (one incident every 617 years)

Eureka: 1.53×10^{-3} yr^{-1} (one incident every 654 years)

and a cumulative probability of a ramming incident involving any of the structures and a single vessel in excess of 500 tons is approximately 4.6×10^{-3} yr^{-1} (one incident every 217 years). The difference in risk estimate between platforms is a function of its cross section normal to TSS traffic flow.

(2) Craft Operating in General Vicinity of Structures (vessels less than 500 tons)

When considering smaller ships, a risk estimate can be based on an estimate of the probability that any one offshore structure will be struck by a vessel.

(a) Methodology

Since vessels in this class, consisting principally of fishing vessels, pleasure craft, platform support work, and cargo boats, cannot be presumed to be taking courses generally conforming to that of the traffic lanes, an estimate is made of the probability that any one offshore structure will be struck by a vessel of 500 gross tons or less. This estimate can be derived from the ratio of the number of observed collisions to number of structures in the area of interest over the time investigated (Walker, *et al.*, 1975).

(b) Probability Estimate

Data collected by the U.S. Coast Guard indicates that during the 15 year period from 1 July 1962 to 30 June 1977 a total of 36 fixed structures in the Gulf of Mexico outside Zone 1 (shallow waters) were involved in rammings with small ships of various types. Data concerning the number of oil platforms in the Gulf in this area are either available or can be derived to provide a history of offshore structures within these waters over the same period of time (Walker, *et al.*, 1975; Long, 1978). A point estimate of the annual probability that a specific structure (in the area for which the data are collected) will be struck by such a ship is provided by the ratio of the structures hit to the summation, over the years investigated, of the annual number of structures available. Available data indicate that such an annual probability is about 1.4×10^{-3} per structure, or about 4.2×10^{-3} for a collision with any of the three structures proposed by this project. Indicated another way, one small ship collision every 238 years is indicated by historical data.

4.6.3.1.4 Risk Estimates

The estimated annual and project lifetime risks associated with the proposed Shell Beta offshore platform hazard to marine navigation are provided in Table 4.6-3. They are based on the methodology described in 4.6.3.1.3 and the Coast Guard collision data shown in the Technical Appendix.

4.6.3.2 Pipeline Impacts

The crude oil pipeline extending from Platform Elly to shore traverses an area of heavy marine traffic. Originally Shell planned to route the pipeline directly north into the breakwater and thence to the Port of Long Beach. However, consultations with the U.S. Coast Guard revealed their plans for a proposed anchorage area outside of the breakwater in the precautionary area. Shell rerouted the proposed pipeline to remain outside this area. As a result, the pipeline has a dog-leg configuration extending from Platform Elly to the breakwater entrance. The pipeline will be on the ocean bottom in this portion of its run. Because it is vulnerable to damage from anchoring, particularly by large ships, it is important that the anchorage area be separated from the pipeline.

Even if separation is achieved, there remains the possibility that the pipeline could be ruptured or pierced by an accident, such as an emergency or accidental anchoring, collision, dredging error, etc. The impacts of an oil spill resulting from such an accident were analyzed in Section 4.4.3. As noted previously in this section, the amount of oil spilled from the pipeline in the event of such an accident, because of the nature of the oil and the pipeline configuration, would probably be small.

Once inside the breakwater the pipeline will be buried to a depth of at least four feet (1.2 m). This is to avoid the more concentrated marine activities in the harbor area including small craft and military vessel anchoring. While the depth of trenching and burial has not been specified, it may be that a depth greater than four feet (1.2 m) will be required by the Corps of Engineers to avoid harbor use conflicts and to preclude damage from such activities. The impacts of an oil spill in the harbor area resulting from a pipeline accident or leak in this area were also assessed in Section 4.4.3.

4.6.3.3 Marine Traffic Mitigation

Several measures to mitigate collision risks or pipeline accidents associated with the Shell Beta project are available:

(1) Navigation Aids. The U.S. Coast Guard has approved Shell Oil Company's application for lighting and other navigation aids on Platforms Ellen and Elly. These aids were discussed in the Project Description, Section 2.4, and a copy of Shell's approved application is provided in the Technical Appendix.

If additional offshore platforms are constructed in the Beta Field (such as Chevron) or in other nearby lease areas, further measures to identify and discriminate between offshore platforms in San Pedro Bay may be required. One such device which is available is called (RACON). RACON (Radar Responder Beacon) is a radio navigation system transmitting a response to a predetermined received radar signal. This response is a pulsed radar return signal with specific characteristics which provide bearing and distance data. The Coast Guard is considering testing a RACON unit in a Santa Barbara area offshore platform sometime in the near future. As a result of this evaluation, RACON units may be determined effective in offshore oil platform identification and collision avoidance. In this case their use could be extended to San Pedro Bay platforms.

(2) Visual Identification Measures. A conflict in objectives exists in terms of the color scheme and visual characteristics of the platforms. From the standpoint of onshore aesthetics, the platforms should be as unobtrusive as possible, blending with the marine environment. From the standpoint of marine traffic conflicts and collision avoidance, they should be highly visible and identifiable. Because of the platform locations in the separation area of the TSS, and because they are sufficiently offshore to preclude major onshore aesthetic impact (Section 4.6.9), identification for collision avoidance purposes is considered paramount. It is recommended that platforms be clearly identified and visible to marine traffic utilizing the TSS.

(3) Notification to Marine Interests. If the project is approved and prior to the commencement of platform and pipeline installation, appropriate notification must be given to marine interests. Early notification of impending installation activities such as jacket installation and pipeline laying will be via Notices to Mariners by the Eleventh Coast Guard District and the Defense Mapping Agency Hydrographic Center. These notices will then be incorporated in the Pacific Coast edition of the U.S. Coast Pilot 7, published by the National Oceanic and Atmospheric Administration (NOAA). All permanent facilities will be identified in this publication, along with necessary safety precautions to avoid traffic conflicts. Mariners will make immediate chart corrections as a result of these notices and publications. Eventually, updated marine charts (such as San Diego to Santa Rosa - NOAA) will be published which show the specific locations of the project platforms. These measures should ensure adequate notification to marine interests. Notices regarding anchoring restrictions will be particularly important to preclude pipeline damage.

(4) Safety Zones. In accordance with Inter-Governmental Maritime Consultative Organization (IMCO) Resolution A.379(X), the establishment of a 500-meter safety zone around each platform should be considered. This should provide reasonable separation between shipping activities and the platforms. As presently situated and planned for installation, all three Shell Beta platforms are further than 500 meters from the Gulf of Santa Catalina traffic lanes. Hence, no adjustment in either the traffic lanes or the platform locations is required to preserve 500 meter separations for this project.

This recommendation does not attempt to prejudge the efforts of other oil and gas development activities in San Pedro Bay, since their impact is unknown at this juncture. The Corps of Engineers is preparing guidelines for the placement of fixed structures in the Gulf of Santa Catalina TSS. Any additional measures, such as Safety Fairways or traffic lane relocations, will depend on agency responses to future oil and gas development plans. Again, these measures are not appropriate for the specific project.

4.6.4 Demography

Population increases will result from the creation of new job opportunities primarily in the Los Angeles and Orange County areas. Using the direct and secondary employment figures outlined in the next section, and a family size factor of 2.4 persons (BLM, 1975), it is estimated that, at a maximum, the project will affect population as follows (NOTE: table assumes full in-migration of workers and families to represent worst case level):

Phase	Activity	Estimated Population Increase	Time Period (Months)
1	Fabrication	Note 1	18
2	Site Preparation and Installation	1,900	9
3	Drilling and Production	790	36
4	Production	240	30 years

NOTE 1: Inasmuch as current plans call for the fabrication of the jackets, decks, and pilings in the Far East, little or no localized impact is expected to occur as a result of this phase.

These estimates take into account both direct employment and secondary job opportunities: they also apply the same factors regarding the relationship of employment, family size, and population as were developed in the earlier environmental documents (BLM, 1975; BLM, 1978).

The environmental analyses covering OCS Sales No. 35 (of which Shell Beta is a part) and No. 48 concluded that the population changes engendered by these much larger undertakings would be "minor" for Los Angeles County and "insignificant" for Orange County over the life of the projects. Carrying these analyses one step further, the sum total of long-term population increases related to the Shell Beta project would constitute just 0.03 percent of the current population of the Los Angeles/Orange County region and would represent only 0.1 percent of the net increase in population expected throughout this region over the next 25 years. Thus, the impacts related to population and demography are seen as being negligible.

4.6.5 Economics

4.6.5.1 Employment/Income Disposal

(1) Project Construction. Table 4.6.5-1 provides an estimate of the total direct employment opportunities that would be created over the life of the Shell Beta project. For purposes of this analysis, "Project Construction" is defined as encompassing Phase 1 (Fabrication) and Phase 2 (Site Preparation and Installation). Contracts for fabrication of the Ellen and Elly jackets have been awarded to an East Malaysia firm. The platform decks and pilings are being fabricated in Japan. This comprises the bulk of the construction work. For this reason, impacts related to employment or personal income on a local level from Phase 1 were seen as being negligible, and treated accordingly in this analysis.

As shown in Table 4.6.5-1, Phase 2 direct employment will total a maximum of 360 persons (not more than 220 at any one time); the figure 220 also represents the apparent peak in the number of persons that will be employed at any one time throughout the life of the project. These employees will participate in the nine-month site preparation and installation phase. Using the ratio of 1:1.2 (or a gross multiplier of 2.2) developed in the OCS Sale No. 35 EIR to determine the secondary employment that will be generated by the project, a total of 790 (360 + 430) employment opportunities would be created during Phase 2. Although it is recognized that some of these jobs will be filled through in-migration, while others will represent opportunities for workers already living in the area, a worst-case methodology has been applied which assumes that all new jobs will be filled through in-migration. This general methodology has also been applied to subsequent discussions regarding employment and to prior analyses concerning population. Application of the estimates calculated above to the baseline employment figures outlined in Section 3.6.5.1 indicates that the construction phase of the Shell Beta project will represent 0.02 percent of the estimated July 1978 employment figure of 3.9 million persons throughout the Los Angeles/Orange County areas. This impact is considered insignificant.

Using a direct project salary income estimate of $18,000 per year and a secondary employment income of $10,750 annually (BLM, 1975), the total income expected to be generated through employment opportunities during the construction phase would be:

	Annual Salary	Estimated Employees	Annual Income
Direct Employment	$18,000	360	$ 6,480,000
Secondary Employment	$10,750	430	$ 4,622,500
		790	$11,102,500

Taken as a percentage of the total personal income forecast for Los Angeles and Orange Counties during 1977, the above annual income figures would represent 0.02 percent. Again, this is considered to be a negligible impact on the regional economy.

(2) Drilling and Production Operations. As shown in Table 4.6.5-1, Phase 3 will consist of both drilling and production activities and will employ approximately 150 persons for a 36-month period. Secondary employment would approximate an additional 180 persons, for a total of 330 jobs for this phase. This figure is considered to be negligible when considered in light of the large baseline employment figures for the two-county region.

Personal income for this phase of the work would amount to $4,635,000 annually, or $13,905,000 over the three-year period. This sum is felt to be insignificant.

(3) Production. Following completion of the initial phases of the project, a long-term production phase will begin, scheduled to extend for the life of the project which is estimated to be at least 30 years. During this period, approximately 45 persons will be employed. Secondarily-induced employment will add another 55 jobs.

Using the salary estimates discussed earlier, annual employment income during the production stage will equate to about $1.4 million in constant dollars, or a total of $42 million during the 30-year production life (probable inflation factors not applied).

(4) Summary - Employment/Income Disposal. The following provides a summary of the foregoing information:

EMPLOYMENT AND INCOME DISPOSAL SUMMARY

	Phase 1	Phase 2	Phase 3	Phase 4
Direct Employment	N/A	360	150	45
Secondary Employment	---	430	180	55
Total Employment		790	330	100
Annual Personal Income ($ million)		$11.1	$4.6	$1.4

Based on the foregoing, the impact of neither the additional employment opportunities nor the increased personal income that will be generated through direct and secondary employment is seen as being significant.

4.6.5.2 Government Services

(1) Project Construction. No significant adverse impacts on municipal service costs are expected to occur as a direct result of project construction. It is felt that all demands on municipal services can be met with existing resources. Specific demands on municipal services could be in the area of police services for traffic control during the construction period. There will be no significant impact on fire inspection and prevention services over that required today. Solid waste management will be handled by the applicant through contractual agreements with private firms. Increased demands on local sanitary sewer systems and storm drain systems will be negligible. All public utilities provided will be paid for by project contractors, thus imposing no additional burden on municipal service costs.

(2) Drilling and Production Operations. A recent environmental analysis (BLM, 1978) projected increased state and local government expenditures throughout Orange and Los Angeles Counties for hospitals, increased school enrollments, police, and other services related directly to OCS Sale No. 48, and, secondarily, to population increases induced by the sale. It could be postulated that the Shell-Beta project would increase expenditures related to such services on a basis proportional to the relative scope of the two undertakings, i.e. Shell-Beta versus OCS Sale No. 48. Inasmuch as the services involved tend to be related more directly to population than to other factors (capital outlay, production, etc.), increased population (through direct employment plus secondary effects) was used as the basis for making such a comparison. Application of this approach indicates that Shell Beta might be expected to increase local government expenditures in Los Angeles and Orange County by a maximum annual figure of roughly $400,000.

4.6.5.3 Tax Benefit

(1) Project Construction. Funds related to the Shell Beta project will accrue to the federal government through the sale of the leases themselves prior to the construction phase of the project, and later, through imposition of the royalty burden on annual production. Estimated capital costs associated with various aspects of the construction phase are outlined below:

BETA PROJECT CAPITAL INVESTMENT[3]

		Total ($million)
Platforms	2 @ $17,000,000	$34.0
Rigs	2 @ $ 9,000,000	18.0
Platform Outfitting	@ $40,000,000	40.0
Pipelines:		
Off-shore	17 miles @ $800,000/mile[1]	13.6
On-shore	2 miles @ $480,000/mile[1]	1.0
On shore construction[2]		3.4
Total estimated project cost[4]		$110.0

[1]16-inch diameter pipe.

[2]Includes Long Beach and Huntington Harbour facilities.

[3]WESTEC Services estimates.

[4]If Platform Eureka is constructed, the total cost will increase by $20-30 million.

Inasmuch as the platforms, rigs, and majority of the pipeline will be constructed on federal and state lands not subject to local property tax assessment, the only tax revenues that will accrue to local governments (other than sales taxes, as discussed later) will involve the facilities constructed on-shore. Assuming a combined market value of $5 million for the on-shore portion of the pipeline and other on-shore facilities, property tax revenues would approximate $50,000 annually, compared with a total of over $3.4 billion in property tax revenues generated within Los Angeles and Orange Counties during 1975-76.

(2) Drilling and Production Operations. The project will not directly generate sales tax revenues. Sales tax would only be levered against the refined products at the consumer level. Assessment of the impacts has been limited to the delivery of the crude to the refinery, and not its processing or distribution. The tax revenues associated with Shell's onshore lease properties are inconsequential compared to the tax base of the affected local governments.

4.6.5.4 Oil Production Impacts

(1) Refining Capacity in California and Petroleum Administration for Defense District No. V (PADD V)

An A.D. Little study for the SOHIO project estimated levels of future refining capacity for PADD V and California for each of the petroleum product demand cases referred to in Section

3.6.5.4 (see Table 4.6.5-2). The analysis was based on operable refinery capacity as of January 1, 1976, plus planned expansions.[1]

Comparing required refinery capacity (based on a 90% utilization factor[2]) to meet product demand with projected refinery capacity (Table 4.6.5-3), it can be seen that for the Low Demand Cases less than 80 percent of refinery capacity in California would be utilized. For the Best Estimate Case, sufficient capacity would exist for 1980. In all other cases, however, additional capacity would be required. Referring to the Best Estimate Case for 1985 (the year in which Beta production would be near its peak), it was concluded that an additional 190,000 barrels of capacity per day would be needed in order to effectively handle the crude oil processing requirements for that year.

The addition of 24,000 barrels per day which would be generated by the Shell Beta project during its peak year(s) could contribute to an overload condition which would exist in California's refineries at that time, if additional capacity were not provided in the interim. The specific contribution of the Shell Beta output to this condition would be as follows[3]:

- 1.1 percent of the State's "minimum 1980 refinery capacity" of 2,265,000 b/d.
- 1.0 percent of the 1985 refinery capacity required within the State (2,455,000 b/d).
- 12.6 percent of the additional capacity required (190,000 b/d) in 1985.

There are 18 refineries in the Los Angeles Basin, with a total operating capacity of over 1,246,870 barrels per calendar day (b/cd) in 1977. This equates to approximately 53 percent of California's total operating capacity. A further breakdown by refineries is listed in Table 4.6.5-4. As is apparent from this table, several of these refineries are quite small (*e.g.*, Lunday-Thagard Oil Company with a crude capacity of only 9,500 b/cd), while Chevron's El Segundo refinery with 405,000 b/cd and Shell's Wilmington refinery at a design capacity of 108,000 b/cd are two of the larger installations in the area.

It was noted above that under the Best Estimate Case of crude oil supply and demand in California, refinery capacity may

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[1] The most recent information published in the "Annual Refinery Survey" by the <u>Oil and Gas Journal</u> indicates operable capacity for 1977 of 2,374 thousand barrels per calendar day, thus surpassing projections of 2,265 thousand barrels per day for California for 1978-1979. However, much of this disparity can be accounted for by the study's inclusion of only major refineries in California.

[2] The latest survey by the National Petroleum Refinery Association (March 15, 1978) indicating an 88.1 percent PADD V utilization factor supports this assumption.

[3] Assumes 1985 Best Estimate from Table 4.5.6-3.

be inadequate to satisfy 1985 product demands. Even assuming that the necessary steps will be taken to insure that adequate capacity will exist, however, there remains the problem of the ability of California refineries to process both Alaskan North Slope oil and indigenous sour[1] California crude, which would include the sour crude output of the proposed Shell Beta unit.

California refineries process a mixture of domestic crude and imported crude oils. Imports are needed to provide sweet and light crudes with which refiners balance feedstocks. In addition, there is less incentive for refineries to process heavy crudes exclusively or predominantly unless they are priced sufficiently lower than foreign alternatives, in which case the costs of refinery conversion can ultimately be passed on to consumers in the form of product prices. Differing forecasts which predict a continuing surplus of crude oil on the West Coast are thus influenced not only by the availability of domestic versus imported oil, but also by the relative quality of the oil available in domestic and foreign markets. For this reason, it is probable that a large volume of foreign oils (due to their sweetness) will continue to be imported and processed in the forseeable future.

To illustrate, crude oil imports to the Los Angeles Basin for 1975 are shown in Table 4.6.5-5, by country of origin, sulfur content and API° gravity. Of total imports, roughly 60 percent were low sulfur crude. Imports from Indonesia comprised the bulk of imports to the Los Angeles Basin, with lesser, but sizeable, volumes of sour crude being imported from Saudi Arabia, the United Arab Emirates, Iran, and Ecuador.

It has been noted in a prior analysis regarding the availability of sweet versus sour crude on a global scale that sour crude reserves were 5.5 times greater than sweet crude reserves in 1975 (BLM, 1978). The reserves-to-production ratio of sour crudes in that same year was 49 to 1, versus 33 to 1 for sweet crudes, suggesting that the recent tendency has been to draw down sweet crude reserves relatively more rapidly than sour crude reserves. This trend accelerated in 1976 and into early 1977. Actual sweet crude imports into the U.S. from 1969 to the present have ranged from a high of 66.9 percent in 1972 to a low of 54.7 percent in 1977.

In 1969, a study of the sulfur content of this nation's crude oil reserves and production revealed that 64 percent of all U.S. crude oil reserves were in the sweet crude category (0.5 percent sulfur or less). The same survey indicated that 66 percent of that year's production was sweet crude. Six years later, in 1975, 68 percent of the crude oil production in the U.S. was sweet. However, sweet crude reserves have diminished in terms of percentage with the discovery of the Prudhoe Bay field, aided by enhanced recovery projects in California, in which the production of heavy,

[1]Refers to high sulfur content (>1 percent) heavy crude oil, as defined more precisely at a later point. Sweet crude has a lower sulfur content (<0.5 percent).

high-sulfur crude is inevitable. The result is that in 1978, the sweet/sour split in U.S. production will change significantly toward an increased percentage of sour crude, thus forcing refiners to rely increasingly on sour crude supplies. As mentioned previously, recent experience in reserves analysis and actual production history indicates that this trend will continue.

This country's increasing reliance on imports of sweet crude to balance domestic production of sour crude is a problem from both a regional as well as a national perspective. It is documented in the most recent report of the National Petroleum Refiners Association (NPRA), entitled "Capability of U.S. Refineries to Process Sweet/Sour Crude Oil" (March 15, 1978). The NPRA broke down the composition of crude runs for domestic and foreign crudes, and for sweet, medium sour, high sulfur light, and high sulfur heavy crudes. The definitions of these crudes accompany the following table (Table 4.6.5-6) which presents a comparison of PADD V's recent 1978 survey figures with those published in the NPRA's earlier (1973) survey. On the domestic side, refining of sweet crude oils has declined from 266-thousand barrels per calendar day (mb/cd) to 164 mb/cd in 1978, while that of high sulfur light crudes has made a remarkable jump from 140 mb/cd to 629 mb/cd. Processing of foreign sweet crude rose from 403 mb/cd to 550 mb/cd. Only 10 mb/cd of high sulfur heavy crude was imported for refinery processing, down from 64 mb/cd in 1973.

In its Plan of Development, Shell has proposed that the Beta Unit production be transported to a site in the Port of Long Beach, from which the oil could be routed to various refineries within the Los Angeles Basin. Onshore facilities near the THUMS seven company distribution manifold are proposed so that once onshore, the oil could be routed to various refineries in the area. Initial production from Platform Ellen is scheduled for 1981 and is expected to peak at a rate of about 16,000 b/d in 1982, assuming that the development program for this platform is not delayed. Plans for the completion of Platform Eureka have been delayed to the extent that the estimated combined peak rate from both platforms of 24,000 b/d of 14°-16° API oil will not occur until about 1986. At present, it is unknown which refineries will actually process the oil, although there is a greater likelihood that Shell's Wilmington refinery may ultimately process the bulk of production from the Beta Unit. It is also unknown whether the U.S. Government will take their royalty share in kind or sell the crude oil to a refinery for processing. In addition, should the alternative landfalls at Huntington Beach or Seal Beach be ultimately selected, the oil would likely be refined at Chevron's El Segundo refinery or Shell's Wilmington refinery, respectively. In any event, it is expected that the entire production of the Shell Beta Unit would be refined within the Los Angeles Basin.

If it could be assumed that all of the 1978 volumes of heavy crude shown in Table 4.6.5-6 are currently being refined in the Los Angeles Basin, Shell's production of 24 mb/cd of high sulfur heavy crude oil from the Beta Unit would completely displace the importations of similar volumes, thereby reducing the need for further imports. As noted earlier, however, it would also add to the need for additional West Coast refinery capacity capable of processing this typically high sulfur heavy crude oil (3-4 percent sulfur at about 16° API) by an additional 14,000 barrels per day (assuming that the 10,000 barrels of imported sour shown in Table 4.6.5-6 were reduced to zero). Nevertheless, it does indicate that the relatively small production volumes considered herein can contribute, albeit to a limited degree, to the national goal of energy self-sufficiency.

(2) California Crude Oil Quality Forecast

In the Energy Supply/Demand analysis prepared by A.D. Little Associates (1976) for the proposed SOHIO project, California crude oil quality was forecasted through 1985. This time frame is appropriate for the present analysis, in that production from the Beta Unit is expected to commence in 1981, with peak production occurring by 1986. The height of the production from both proposed platforms, therefore, corresponds closely to the time frame selected for the SOHIO study. The A.D. Little analysis concluded that: (1) California-produced crude oils will become gradually lighter in the future, ranging from 22°API to 24°API; (2) the sulfur content will remain almost stable at just under 1.0 wt. % sulfur; and (3) a large proportion of California production will be heavy oil from enhanced recovery programs on the state's remaining reserves while exploration of deeper producing horizons and new offshore areas will add large volumes of lighter gravity crudes. (Production from the Beta Unit will obviously qualify as an exception to this trend.)

(3) Gravity Distribution of California Crude Oil

Table 4.6.5-6 presents projections of California crude oil production based on a number of items, including: 1) 1975 gravity data; 2) estimates of production declines of existing reserves; 3) production from Elk Hills; and 4) new onshore and offshore discoveries. The projected trend is for the proportion of total state production of crude <20°API to decline fairly rapidly because of the reasons mentioned earlier.

(4) Distribution of California Crude Oil Production By Sulfur Levels and Producing Regions

To arrive at a projection of California crude production by sulfur content, (Table 4.6.5-8), A.D. Little first analyzed the breakdown of California crude by sulfur levels (Table 4.6.5-9). The historic percent of state production by sulfur level was then applied to crude oil volumes projected for production under the Best Estimate Case, which are shown in Table 4.6.5-10.

The projections of crude production by sulfur content outlined in Table 4.6.5-8 included reserves to be produced in the offshore area (included in Coastal and Los Angeles Basin figures).

If accurate, one can assume that in 1980, approximately 181.1 mb/d of 2%+ sulfur crude oil will be produced (and, by inference, refined) in California; in 1985, slightly higher volumes (188.7 mb/d) will be available to refineries. If, in fact, peak production from the Beta Unit occurs in this latter time frame (1986), it is questionable whether there will be available refinery capacity in the Los Angeles area to handle all projected volumes, including Shell's peak year estimate of 24,00 barrels.

The question of the impact, if any, of Shell's Beta Unit production on L.A. Basin refineries may be best answered by referring to NPRA's most recent survey. In response to refinery capability to handle sour crude under present government restrictions of sulfur content for product and plant emissions from two periods -January 1, 1978 - January 1, 1979 and January 1, 1979 - January 1, 1980, refiners in PADD V stated they could run 3.017 and 3.127 million b/cd of sour crude, respectively, while operating at rated capacity during 1978.[1] Their crude slate for each case is indicated in Table 4.6.5-11.

With specific reference to volumes of high sulfur heavy crude, refiners reported a 70 percent increase in capability to process this category of crude for the <u>entire</u> 1978 period over capability reported as of January 1, 1978. This capability would increase proportionately for the succeeding 1979-1980 period, one year before projected Beta Unit production is to come on-stream. More importantly, a comparison of these refinery sour crude capability figures with projections of California crude production in 1980 and 1985 (Table 4.6.5-8) reveals an interesting point. Acknowledging the fact that California refineries contribute about 50 percent of PADD V refinery capacity and that L.A. operating refinery capacity accounts for approximately 50 percent of California capacity, one-fourth or about 237,000 b/cd of the 1978 high sulfur heavy crude capability can roughly be attributed to Los Angeles Basin refineries. Since refiners were not listed by name in the NPRA report, this increased capability is only an estimate. However, if valid, this 237,000 b/cd capability of the Los Angeles Basin refineries to process high sulfur heavy crude oil would be more than adequate to handle the 181,100 b/cd of projected (1980) and 188,700 b/cd of projected (1985) high sulfur crude production from both the Coastal and Los Angeles Basin areas (which include offshore reserves) (see Table 4.6.5-8).

(5) <u>Use of Alaskan North Slope Oil in California Refineries and Surplus Crude Projected for PADD V</u>

The impact of potential production from the federally

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[1] Federal, state, and local sulfur emissions regulations require that almost all fuel burned in California contain 0.5% sulfur or less. The sulfur content may be slightly higher in the San Francisco Bay area and substantially higher in the San Joaquin Valley. Oregon and Washington regulations are much less restrictive.

leased Beta Unit cannot be viewed in isolation from ongoing production in other parts of PADD V. For this reason, this study has utilized extensively the California energy supply/demand analysis prepared by A.D. Little in conjunction with SOHIO's proposal to transport surplus Alaskan crude to Midwest refineries. A major thrust of that analysis was to determine the capability of PADD V and California refineries to absorb North Slope crude based on calculations related to the 1975 imported crudes. No assumptions were made about the capability to absorb North Slope crude in conjunction with any changes in locally available crude, but were simply calculations based on the ability to substitute North Slope crude for 1975 imports. All indigenous California production, including federal offshore reserves such as the Beta Unit, were assumed to have first priority use of local refineries. Inasmuch as nothing significant has happened since the publication of the A.D. Little study to disrupt the ranges of supply and demand figures generated therein, several general conclusions with respect to this study can be made.[1]

In contrast to Alaskan North Slope oil which has an average sulfur content of 0.97 percent, crude oil from the Beta Unit will average 3-4% sulfur and 14-16° API. Obviously, if the Beta Unit is not developed, regardless of the landfall site in the Los Angeles Basin, excess supplies of Alaskan North Slope oil could immediately be substituted under existing refinery conditions for the high sulfur, heavy crude projected for Beta crude oil. A comparison of studies projecting surpluses of North Slope oil between 1980 and 1985 is shown in Table 4.6.5-12. At peak production of 24,000 b/d in 1986, Beta Unit production, as part of the California supply which was taken into account by the A.D. Little study, will contribute to the overall impact of a burgeoning surplus on the West Coast if the SOHIO project is not implemented.

(6) Impact of Beta Unit Development on Onshore Production

The impact of the potential surplus of crude oil on the West Coast in 1985 has been more than adequately addressed by the previously mentioned studies. Of perhaps more immediate local concern is the impact that Beta Unit production will have on the marketability of onshore production of the Wilmington oil fields, of which the Beta tracts are the eastern extension. The sulfur content and API gravity of both oils are similar, *i.e.*, heavy and high in sulfur.

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[1]As noted in the ADL study, there was and still is uncertainty as to the disposition of Elk Hills crude production (projected at 200-350 mb/cd, but currently projected to procude closer to 300 mb/cd by 1980. For the ADL study, Elk Hills crude was assumed to be indigenous California production, with shallow-zone production assumed to go to the Los Angeles Basin or San Joaquin Valley refineries. In part because of the alleged unavailability of adequate California refinery capacity, there is now a proposal to tie in Elk Hills production to the proposed SOHIO crude oil line to the east.

These characteristics make both less desirable than imported or Alaskan oil to refiners whose facilities are further limited to some extent in their capability to process this type crude. Questions have been raised regarding the difficulties producers of onshore crude have had in selling this crude. It was feared that Beta Unit production might only contribute to what was seen as a surplus of high sulfur heavy crude in the region. It was suggested that the source of this problem (inability to sell cheaper domestic crude in competition with more costly foreign oils) was the Department of Energy Entitlement regulations. It has been concluded that recent (June 1978) amendments to the Mandatory Petroleum Allocation Regulations ("Entitlements") (10 CFR Part 211) and to the Mandatory Petroleum Price Regulations ("Crude Oil Pricing") (10 CFR Part 212) are expected to alleviate this concern and may mitigate any negative impacts resulting from potential offshore Beta Unit production. This section will discuss briefly the previous regulations and the recent amendments thereto.

Regulation of domestic crude oil prices (and the companion entitlements program) is scheduled to expire in mid-1979, well before production from the Beta Unit is scheduled to commence. If decontrol occurs, it is projected that California crude would sell for an estimated $10-$12 per barrel, well below the price of foreign crude but above today's average for most California crudes. At this price, it has been suggested that refiners would have more incentive to switch from foreign to California crude and to invest in new facilities to handle California crude.

The competition now facing California producers of heavy crude is, in part, the result of these pricing and entitlement regulations. Therefore, it will be assumed for the purposes of assessing the impact of Beta production on Los Angeles Basin producers that the regulations in effect today will exist in 1981 when production is scheduled to begin.

(7) Background of Entitlements Program

In developing the entitlements program, the Federal Energy Administration (FEA) (now the Department of Energy - DOE) sought to allocate the benefits of low priced "old" oil and the rising costs of "new" oil throughout the entire industry so that no refiner would be forced from the competitive market. As a result, since November 1974, refiners have been required to have an "entitlement" to refine a barrel of "old" crude oil, with those refiners having a supply of more than the national average of "old" crude generally required to purchase entitlements from refiners having less than the national average of old crude.

To determine the number of entitlements a refinery is issued each month, the FEA first computes the national "old" oil supply ratio - that number of barrels of "old" oil each refiner would have if all "old" oil were equitably allocated among all domestic refiners. This ratio is adjusted to provide for a "small refiner" bias. The adjusted ratio is then applied to each refiner's volume of crude oil runs. A sufficient number of "entitlements" are issued to cover that percentage of its crude runs.

(8) Crude Oil Pricing and Entitlements Program Specific to California Crude Oil

Controls on domestic "old" (i.e. lower tier) oil were imposed in 1974. With controls, the price at which a barrel of "old" or lower tier oil could be sold could not exceed the May 15, 1973 sales price of a similar barrel of oil in the same or nearest field. In California, lower-tier heavy crude has historically been priced below the national average due to the larger than average gravity price differentials which existed on May 15, 1973. Subsequently, the FEA sought to rectify this problem by permitting ceiling prices to increase for California lower tier heavy crude. Nevertheless, actual (not ceiling) prices were unaffected. As further encouragement, the entitlement obligations of refiners purchasing low-gravity lower tier California crude were reduced (effective December 1977) to remove the disincentive that the entitlements program was creating for refiners to purchase such crude. Specifically, refiners' entitlement obligations for low gravity (defined as 25.9°API or below) lower tier California crude oil were reduced by $1.75 per barrel. This amount was considered the effective entitlement "penalty," i.e. the amount by which the effective <u>after</u>-entitlement acquisition cost to refiners of such crude exceeded the after-entitlement acquisition cost in the same region of <u>uncontrolled</u> domestic crude in the same gravity category. By lowering the after-entitlements acquisition costs of this crude, the FEA hoped that the pre-entitlements crude purchase price would rise, thereby encouraging California production otherwise threatened to be shut in. This December 1977 FEA adjustment had several effects. One effect was to further decrease the value of upper tier crude relative to lower tier crude of the same gravity category. The single adjustment for crudes below 26° also served to depress the value of crudes just above the threshold.

Therefore, recent amendments now provide, in part, that (1) upper tier California crude, as well as lower tier crude, receive additional entitlement benefits; (2) such benefits are graduated, the adjustment being less for higher gravity crudes and more for lower gravity crudes; and (3) production from federal offshore leases are eligible for these adjustments. (A proposed separate sulfur content adjustment was rejected because sulfur content was found not to be a significant independent factor in the pricing of California crude oils.)

Amendments specifically provide that the entitlements obligations of refiners taking lower tier California crude will be reduced by an amount equal to $2.38 per barrel plus (or minus) 0.09¢ per barrel for each degree that the weighted average gravity of such crude rises (or falls) below 18°. In addition, refiners of upper tier California crude shall have entitlement obligations reduced by an amount equal to $1.45 per barrel plus (or minus 0.09¢ per barrel that the weighted average gravity of such crude rises (or falls) below 18°.[1] These amendments replace those implemented in December 1977.

The effect of purchasing upper tier California crude including offshore federal oil would obviously be slightly less as the entitlement obligation is reduced by a smaller amount. Nevertheless, the FEA expectation is that the production and sale of relatively low gravity crude oil such as projected for Beta and as produced onshore in the Los Angeles Basin will be fostered by these amendments. Assuming these regulations will remain in force at the commencement of Beta production, impacts caused by this production on the present onshore production should be negligible.

4.6.5.5 Crude Oil Pricing Impacts

(1) Projected Price of Crude Oil (Lower 48 States) Under Controls

As previously noted, the Energy Policy and Conservation Act (EPCA) mandated domestic crude oil price controls, but would permit price controls to expire in 40 months (mid-1979), before initial production from the Beta Unit. The Act also fixes the average price of domestic crude at $7.66 per barrel for 1976, but allows this price to increase 3 percent per year in real terms, assuming it can be shown that such an increase is needed to provide incentives for domestic exploration. Assuming controls were to

[1]For a simple example, assume the entitlements price for a particular month is $8 per barrel. Further assume a refiner has supplies of lower tier California crude in the following volumes and gravities:

100,000 bbl of 21° API crude
100,000 bbl of 24° API crude
50,000 bbl of 17.6° API crude
250,000

The weighted average gravity of these volumes is approximately 21.5° API. For each full degree above 18°, the refiner would subtract 0.09¢ from $2.38

or $2.38
- .27 (3 x 0.09¢
$2.11

This adjustment would be multiplied by the number of barrels of old oil the refiner had received, here 250,000 barrels divided by the monthly entitlement price ($8).

$$\$2.11 \times 250{,}000 \text{ bbl} = \frac{\$527{,}000}{\$8} = 65{,}938 \text{ entitlements}$$

The entitlements' benefits of this refiner would thus be 65,938 additional bbl, worth approximately $527,000.

continue beyond 1979, Table 4.6.5-13 projects the price of a barrel of domestic crude oil (average of lower tier and upper tier oil) to the year 2000.

Since the production of Beta crude is offshore production from new reserves, however, it would qualify for the much higher upper tier crude price, which, for example, had a ceiling of over $12 for the months of June-August 1978.

A pricing forecast made for new oil (still assuming no decontrol) projected that costs as calculated ran $1-$2 per barrel over the average controlled price, which is consistent with the present relationship of the allowed price of new oil compared to the average (of new and old oil).

To determine the projected costs of regulated new oil, Foster Associates, Inc. utilized a discounted cash flow (DCF) approach (presently used by the FERC in pricing the cost of "new" natural gas). This methodology separately forecasts the different cost components such as drilling costs, lease acquisition costs, operating costs, and carrying charges and based on a DCF calculation determines the required price at an internal 15% rate of return. Each cost component included is projected in total dollars and then divided by an estimated productivity factor[1] to arrive at a dollar per barrel figure.

(2) Projected Price of U.S. Crude Oil (Lower 48 States) Under Free Market Conditions

Foster Associates performed a separate analysis to project the price of a barrel of crude under free market conditions (Table 4.6.5-14). These projections are attended by uncertainty due to the dependency of domestic crude oil prices on the projected foreign crude price. The domestic price is assumed to equate to the projected crude oil price delivered to the U.S. refineries after adjustment for quality differences. The analysis projected the landed price of foreign crude oil (Saudi Arabian light utilized) then added a 30¢ per barrel differential to this price (an approximation of the difference between the 1975 average price of all delivered foreign crude and the price of the marker crude (i.e. Saudi Arabian). To the landed price of a barrel of foreign crude was added a per-barrel "quality premium" figure to reflect the lower sulfur content of U.S. crude versus most world oils (the Saudi Arabian light contains 1.8-2.4% sulfur).

It must be emphasized that the above price forecasts are only that - rough estimates of the <u>national</u> price of crude well into the future. Major uncertainties associated with predicting world oil prices, and with assumptions regarding quality premiums, the average quality of foreign crude delivered, and transportation differentials could substantially affect future prices. The "penalty"

[1]Defined as reserves added per foot of successful oil wells drilled.

normally assumed by high sulfur heavy crude, such as that expected from the Beta offshore tracts, may no longer be relevant, as a larger percent of refineries have the ability to run sour crude as a result of refinery modifications and of new refinery construction.

4.6.5.6 Mitigation - Economics

(1) The only effective measures that would mitigate the impact of adding Beta's 24,000 b/d of heavy, high sulfur crude to what may become overloaded refinery conditions in California would be to modify and expand the existing refinery capacity prior to the anticipated overloads (1985), or to divert the crude to other locales for processing. However, if the rationale offered in Section 4.6.5.4(5) stating that, based on other sources, more than enough refinery capacity for this grade of crude will exist (237,000 b/cd versus a demand of 181,100 b/d), no mitigation measures would be required.

(2) The June 1978 amendments to the Mandatory Petroleum Allocation Regulations ("Entitlements") (10 CFR Part 211), and to the Mandatory Petroleum Price Regulations ("Crude Oil Pricing") (10 CFR Part 212) are expected to mitigate any negative impacts that production from the Beta Unit may have on the surplus of high sulfur heavy crude within southern California, assuming that such amendments are still in force at the time the Beta Unit begins production.

(3) If regulations have been removed, thus creating a free market condition, there should be no difficulty in selling southern California crude. Without controls, all oil could be sold at a price below that of world levels. Lower prices, without the system of entitlement "credits" and "penalties," would presumably provide refiners the financial incentive to process high sulfur heavy California crude oil.

4.6.6 Services/Utilities

4.6.6.1 Energy (Electricity and Natural Gas)

Onshore demand will be limited to outdoor lighting of storage yards, indoor lighting of crew terminal supply building, and operation of an unmanned control center and pump and manifold system. The pumps represent the largest consumer of energy at an estimated average of 400 kilowatts (kw) per hour or 3,504,000 KWH annually. Existing systems have ample capacity to meet projected demands (Harris, 1978). Offshore facilities will be self-sufficient, with turbines running on the limited quantities of natural gas from the field. Eventually, diesel fuel transported from shore will replace the diminished supply of natural gas for purposes of platform power generation.

4.6.6.2 Impact

The solid and liquid waste (i.e. oily drilling muds and debris) generated at the platforms will be transported to shore for proper disposal at the BKK Landfill. In a typical month, this facility receives approximately 72,000 tons of solid waste and 43,000 tons of liquid wastes (MacIntosh, 1978).

It is expected that the Shell Beta project will generate about 57 tons of solid waste in a given month during the construction period, reduced to 10 tons during long-term drilling and production. (These figures are based upon an average generation of 15 pounds of solid waste per employee per day.)

Based upon experience gained during the exploratory effort, it is estimated that the two drilling rigs produce a daily average of 7-8 tons of oily waste (most of which would be oily rotary mud) requiring transport to shore and disposal at the Class 1 landfill. This would equal about 210-252 tons per month during the drilling phase. The amount will be reduced by approximately 75 percent during production phases. The amount of liquid waste generated during drilling operations represents approximately 5 percent of the total monthly volume at the landfill. Whereas the landfill has a long lifespan, and this amount is a very small part of the total daily volume, no adverse impact is anticipated.

Sewage will be treated on the platform through an "extended aeration system," then deposited in the ocean. The water quality impacts from this action are discussed in Section 4.4.

4.6.6.3 Fire

The level of service currently supplied by the City of Long Beach would not be adversely impacted by the Shell Beta Unit development. However, a cumulative impact could be expected in conjunction with other projects involving the Harbor District (Souders, 1978). Special services stemming from the project will consist of routine inspections of onshore facilities by the Fire Prevention Bureau. No adverse impacts are associated with the crew terminal. Removal of the present gas station and pumps (in order to provide parking for the production crew) will reduce fire hazards (Adams, 1978). In the event of an oil spill, fireboats would be deployed to the area in question. Onshore support would be determined by the nature of the emergency (Souders, 1978).

4.6.6.4 Police

No increases in security personnel, patrol, or other special services are anticipated as a result of onshore project facilities (Harnagle, 1978; Stearns, 1978; Graham, 1978). Although the crew and supply terminals will receive normal patrol service, prevention against vandalism and theft of automobiles and supplies cannot be assured unless those areas are properly secured.

Special services, including supplementary police officers, would be called for in the event of oil spills, vessel collisions, or accidents. The availability of emergency response plans and reserve officers in local communities should preclude impacts on levels of police staffing.

4.6.6.5 Emergency Services

Paramedic units do not foresee any difficulty in meeting calls for emergency medical services should they be required at the proposed platforms or onshore facilities. Depending upon the nature of the emergency at offshore facilities, medical personnel would be flown to the platforms and/or the injured party or parties transported via helicopter to one of several hospitals in the area (Long Beach maintains one of the largest number of hospital beds per capita in the Southland). The impact upon the Long Beach Paramedics is not considered adverse due to the project size and temporary nature of construction activities (Gupton, 1978). Impacts from the production phase are not considered significant.

4.6.6.6 Mitigation

(1) Police. Fencing and secured gates enclosing the crew and supply terminals will substantially reduce risk. Local police contacts should be identified in the Spill Contingency Plan to ensure an early alert for marshalling of emergency forces.

(2) Fire. While continued development in the Harbor District will cumulatively impact service levels, compliance with fire and safety codes will minimize the fire risk. An up-to-date list of appropriate representatives of fire service organizations to ensure marshalling of emergency forces should be maintained in the Spill Contingency Plan.

(3) Emergency Services. The platform will be equipped with a standard first aid treatment center for minor injuries in compliance with OSHA standards. Helicopter landing facilities are available for Platforms Ellen and Eureka. Also, the crew boat is available for transit of injured workers.

4.6.7 Onshore Circulation

4.6.7.1 Impacts

(1) Port of Long Beach

The construction and operational phases of the project will place different demands on the circulation system of the Port.

During construction, there will be a short-term increase in traffic volumes from construction workers (400 average daily trips) and from delivery of construction materials (maximum of 100 average daily trips). As noted in Section 3.6.4, the primary access to the distribution facility and the storage yard would be from the major freeways serving the area, Ocean Boulevard/Seaside Avenue, and Anaheim Street. With the exception of Anaheim Street, all of these arterials have adequate capacity to absorb the additional traffic without creating an adverse impact. Anaheim Street is operating over capacity in both the AM and PM peak hours. However, access to this project can be obtained without entering Anaheim Street. It is anticipated that only 15-20 vehicles would be added to Anaheim Street during peak hours, representing approximately one percent of the present volume. This would be an adverse impact because the street is presently at capacity. In addition to the construction vehicles, there will be an impact on the street system of the Port from the installation of the pipeline. The resultant congestion will be short-term in nature and is not considered to be significant if properly coordinated with the Port's operations staff.

In summary, there will be minimal short-term impact from construction activities on the Port's circulation system. However, while this project in itself is not significant, there are several other projects within the Port in various stages of approval which could potentially be under construction at the same time as the Shell Beta project. The cumulative effects of such a situation could be significant and adverse. Mitigation measures are discussed in Section 4.6.7.2.

Following construction and throughout the 30-year lifespan of the Beta project, traffic impacts in the Port of Long Beach will be negligible, if at all noticeable. The only traffic the proposed project will add will be a small number of workers travelling in and out of the marshalling yard plus one maintenance person at the tank and manifold distribution facility.

(2) Ship and Rail

The proposed project will not increase ship traffic inside or outside of the Port of Long Beach. It is possible that some of the materials and supplies used in the construction of the proposed project could be transported to the Port of Long Beach by rail. However, the amount of added rail traffic to the Port would be less than one percent of current volumes, which is considered insignificant.

(3) Huntington Harbour Crew Boat Launch

Traffic impacts of the proposed project's Huntington Harbour Crew Boat Launch Facility will be negligible. During the peak portion of the construction and production phases of the proposed project, approximately 100 people (including Shell employees and contract labor) will be shuttled out to the drilling and production platforms via a crew boat. This activitiy will occur for a period of approximately nine months, after which only 60 persons will be shuttled to the platforms, with progressively fewer as the proposed project enters production.

Thus, at the height of construction, the Huntington Harbour facility will create an average daily trip figure of 220, bringing the total traffic figure on Pacific Coast Highway to 26,200 vehicle trips per day. This is an increase of 0.8 percent, and is well within the capacity of the immediate section of Pacific Coast Highway near the site. However, existing traffic volumes north and south of the proposed crew boat launch along Pacific Coast Highway are above capacity, and each would be impacted by traffic generated by this facility. The facility will operate on off-peak hour shifts, however, and therefore the peak hour impacts on Pacific Cost Highway would be minimal. In addition to the congestion problems, the section of Pacific Coast Highway near the proposed launch facility has a high accident rate as a function of traffic volumes, the number of turning movements, and poor sight/distance relationships. However, it is estimated that there will be a 60 percent reduction of vehicular activity on the site as a result of removal of the commercial gas stations.

Parking impacts at the proposed launch facility are potentially adverse. The project description calls for 30 to 40 parking spaces to be constructed onsite for the launch area. This will be inadequate during the installation and construction phases of the proposed project. In an absolute worst-case situation, where each worker drove a car, there would be a need for an additional 60 to 70 spaces for a period of nine months, after which the additional spaces needed will be lowered to 20 to 30 spaces for three years following. Room for these extra spaces is currently not available, and parking in the vicinity is at a premium. This situation will become particularly critical on weekends when recreational beach users will compete with workers for street parking.

Boat traffic added by the proposed project will have a negligible effect upon waterborne traffic in the Huntington Harbour area. In the worst case, there would be less than ten round trips per day resulting from the crew boats. This would present an extremely minor impact upon present traffic volumes. Boat traffic volumes in Sunset, Anaheim Bay, and under the Pacific Coast Highway Bridge will all remain well below saturation levels despite the additional trips.

4.6.7.2 Mitigation Measures

4.6.7.2.1 Huntington Harbour Crew Launch

The following measures are proposed to mitigate the negative traffic impacts that would result from the Huntington Harbour crew boat launch: 1) the fencing and installation of a control gate on the parking lot to prevent unauthorized parking; and 2) encouragement of car pooling to reduce traffic and parking impacts. Officials of the police department of the City of Seal Beach have recommended that access to the parking lot be restricted to right turn inbound and right turn outbound only. In theory, this would eliminate left turns associated with the facility, thereby reducing the accident hazard. However, if workers are forced out of the direction they wish to travel, they will make U-turns further down Pacific Coast Highway which may increase the accident potential. Application to the State has been made for a traffic signal for this area, although no action has been taken on the request. Even with the institution of these measures, parking impacts resulting from this project are likely to remain adverse during peak construction and production of the project. To fully mitigate parking impacts, the amount of overflow cars (those cars unable to park in the designated lot) would have to park remote from the launch area and the workers would have to be shuttled in and out by bus. An additional option would be to limit the number of workers going out of the launch facility, sending the balance out of the supply facility proposed within the Port of Long Beach. Another option would be to select a new launch site in a more industrialized area, such as the Port of Long Beach or Los Angeles.

4.6.7.2.2 Port of Long Beach

Construction traffic, in particular truck deliveries, should be restricted away from Anaheim Street. Also, scheduling of construction work hours should be phased so as to ward normal AM and PM peak hour traffic. Since permanent traffic impacts within the Port will be negligible, no mitigation is needed. If in the event that other pipelines originating from the Pier J Basin were to be constructed at the same time as that of the proposed project, coordination of construction activities between the parties involved could reduce construction impacts. This is especially true if the proposed project's onshore section of the pipeline was constructed concurrently with the pipelines for the Macmillan Ring Free Oil Company or the SOHIO Terminal. These two pipelines will follow much the same route, and would provide less disruption, if they were laid at the same time.

4.6.8 Noise

4.6.8.1 Impacts

Locally, high and intermittent noise occurrences may be expected from use of equipment during the construction phase of the onshore facilities in both the Port of Long Beach and Huntington Harbour areas. Typical noise levels produced by earthmoving, materials handling, and stationary and impact type equipment used during construction range between 85 and 90 dB(A)[1] at 50 feet.

[1] A-weighted sound levels expressed as decibels. The A scale approximates the frequency response of the human ear.

Where there is extensive use of jackhammers and rock drills, peak noise levels may range as high as 95 to 100 dB(A) at 50 feet. Impacts from construction are considered to be minimal due to the short-term nature of the construction and the fact that work would take place during normal working hours.

The generation of traffic in the Port of Long Beach and Huntington Harbour areas while offshore facilities are undergoing construction will, at their peak, reach approximately 400 ADT and 220 ADT, respectively. Short-term onshore noise levels will not be noticeably amplified by traffic sources due to the existing high background noise.

Following the completion of construction activities and commencement of drilling and production, project-related traffic at the Port will be reduced to less than five trips per day. Long-term noise onshore will stem from operation of stationary equipment at the product distribution site. Noise levels of about 70 dB(A) will emanate from pumps at a distance of 50 feet. The combination of traffic noise (especially high volume truck traffic) from the surrounding freeway loop and the absence of areas of conflicting use (i.e. residential, park, etc.) precludes an adverse impact.

Long-term impacts from activity at the crew terminal in Huntington Harbour will create only negligible noise impacts. As that facility will primarily function to transport employees via crew boat to the platforms, noise impacts will be associated with traffic. Permanent employee generated traffic (representing approximately 0.1 percent of existing traffic) will incur an insignificant increase in noise levels of less than one decibel. When Platform Eureka is constructed and put into operation, the production crew will increase by approximately 25 percent. Assuming parking provisions at the same crew terminal, traffic generated noise levels would still remain negligible.

4.6.9 Aesthetics

4.6.9.1 Onshore Facilities Impacts

(1) Port of Long Beach

The addition of the two facilities associated with the proposed project to the Port of Long Beach will not significantly alter the aesthetic nature of the specific sites or the overall aesthetic nature of the Port area. The product distribution site will fill an area that is mostly open space at this time, however, the area is largely hidden from view and is not of particular aesthetic value in its present state. This type of facility will be compatible with other developments in the area and should not significantly impact the well pump existing at the site. The 10,000 bbl (1590 m^3) tank will impair the view across the freeway towards Long Beach from the traffic loop. This impairment is not considered significant as the view is not of particular value and goes generally unnoticed by drivers negotiating the tight curve. The distribution facility will be visible from tall, downtown buildings in the City of Long Beach. However, the tank proposed for this facility is quite small when compared to other features of the Port. Notably, it would be overshadowed by: the Koppel Grain Terminal; the Proctor and Gamble facilities; the proposed Kerr-McGee bulkloader, and numerous container cranes which dominate the Port skyline. Because of these surrounding facilities, the distribution facility will have limited visual impact, since it will blend with other facilities in the Port.

The construction and the operation of the staging yard at either the prime or alternate site will not have a significant effect upon aesthetics. Regardless of the site chosen, the use will be temporary, and the functions of the facility are low-profile and will not alter views to, from, or across the facility. In fact, selection of the preferred site on the Seventh Street Penisula would have a positive impact by changing the haphazard, blighted appearance it now has to one of an organized, functional facility.

(2) Huntington Harbour Crew Launch

The alteration of the Huntington Harbour site will not have any significant aesthetic impact. While Pacific Coast Highway has been proposed as a scenic corridor, no design standards are available against which the crew launch can be assessed. If design standards are established prior to permitting of the project, project fencing may have to be assessed in terms of those standards.

4.6.9.2 Offshore Facilities

The placement of two and ultimately three platforms in the waters off Huntington Beach will create an impact upon the viewshed and the aesthetics of this offshore area. Figure 2.4-3 shows that the heights of the structures above mean high water (MHHW) varies. Platforms Ellen and Eureka will extend approximately 241 feet (73.5 m) above MHHW due to the drilling rig structures. Platform Elly, on the other hand, will have visible equipment and structure only 81 feet (24 m) above MHHW. As noted in Section 3.6.9, good offshore visibility conditions of greater than 10 miles (16 km) occurs up to 53 percent of the time. Because of the distance to the platforms offshore and the curvature of the earth, not all of the structures would be visible. Curvature reductions based on sea level calculations from Huntington Beach and Long Beach are as follows:

SEA LEVEL SITE	PLATFORM DISTANCE	CURVATURE LOSS	HEIGHT VISIBLE ABOVE MHHW	
			Ellen/Eureka	Elly
Huntington Beach	9 miles (14.4 km)	19 ft. (5.8 m)	222 ft. (67.7 m)	62 ft. (18.9 m)
Long Beach	15 miles (24 km)	44 ft. (13.4 m)	197 ft. (60 m)	37 ft. (11.2 m)

Due to the distance from shore, and the curvature reduction of the visible structure, the platforms will occupy only a small portion of the viewshed. Assuming a 180° horizontal view plane from Huntington Beach, the structure would occupy only 0.28 degrees or 0.15 percent of the viewshed. Vertically, using a 90 degree plane, the platforms would occupy 0.29 degrees or 0.32 percent of the viewshed. However, aesthetic values are difficult to quantify, and to some individuals even this minor intrusion in the existing viewshed may be felt to be adverse. Figure 4.6.3 provides a photograph of the relationship of the proposed platforms to Huntington Beach on a day with visibility greater than 10 miles (16 km). Existing Platform Emmy, approximately one mile (1.6 km) offshore, is on the right. The picture was taken when Shell Oil was conducting exploratory drilling operations at the Shell Beta platform sites. The height of the drilling rigs and their distance from shore (left center in photo, shown by arrow) is comparable to the location and size of Platforms Elly and Eureka.

4.6.9.3 Mitigation Measures

(1) Onshore Facilities

(a) Port of Long Beach

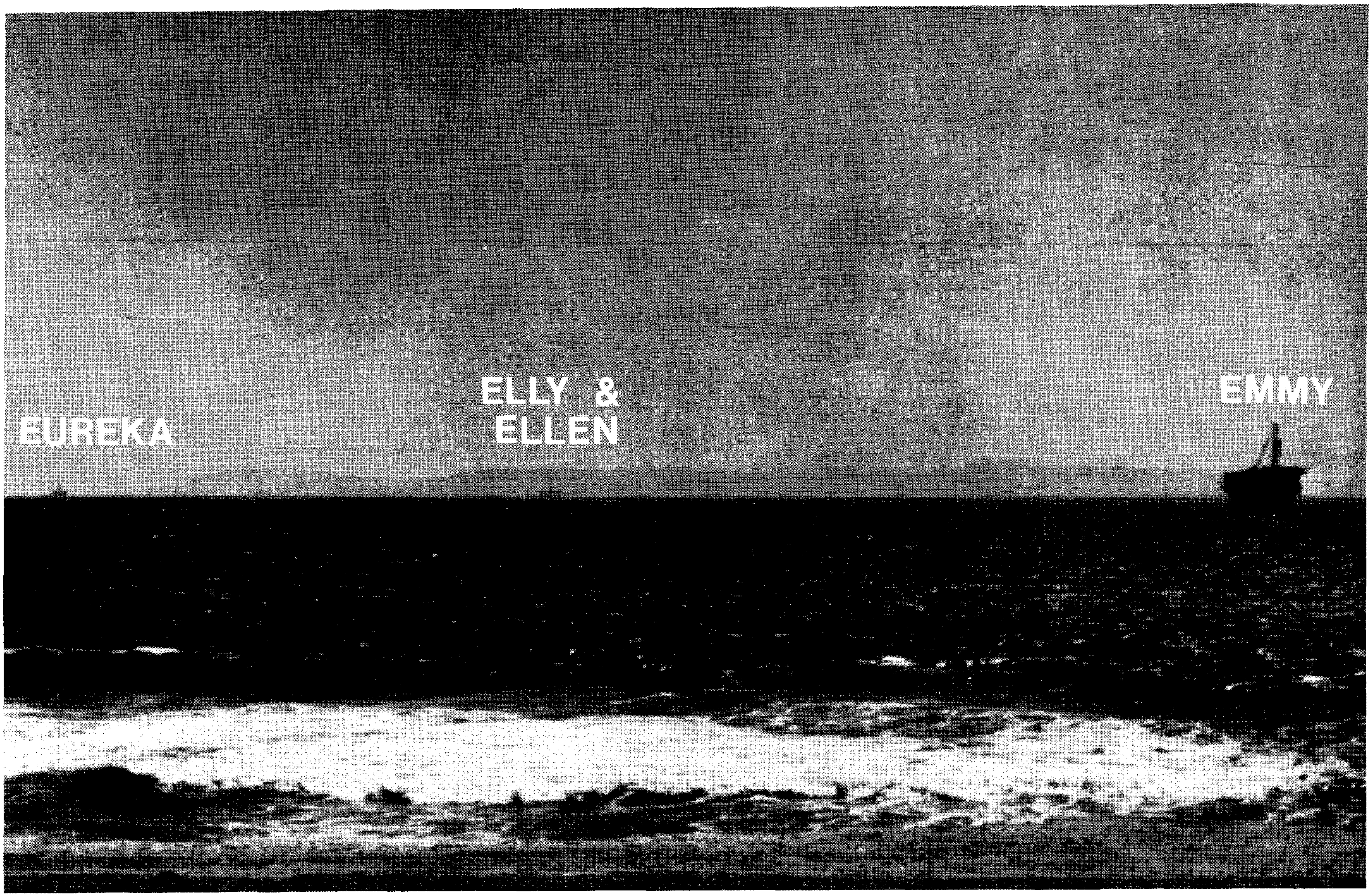
No mitigation measures will be required for aesthetic impacts for the sites associated with the project within the Port of Long Beach. All building code standards dealing with aesthetic controls (architecture, colors, signs, etc.) imposed by the Port of Long Beach will insure the protection of aesthetic resources.

(b) Huntington Harbour Crew Launch

No mitigation is needed at the Huntington Harbour crew launch in its proposed format. All design standards in effect for the area imposed by the Cities of Huntington Beach and Seal Beach, and the County of Orange will be followed. In addition, Coastal Act policies dealing with scenic corridor design standards will be considered upon their issuance.

(2) Offshore Facilities

To mitigate aesthetic impacts of the offshore platforms, they may be painted a color(s) to blend with the marine environment. This color choice could be selected by Shell in conjunction with the U.S. Coast Guard. It should be noted that the platforms may be painted a visible color to reduce marine traffic hazards. This need is considered overriding since the platforms are sufficiently offshore to preclude significant onshore aesthetic impacts due to color selection.



Beta Unit Offshore Platform View Shed from Huntington Beach

4.6-3
Figure

SECTION 5.0

ALTERNATIVES

5.1 NO PROJECT

The no-project alternative has already been considered at the Federal level in conjunction with decisions made concerning OCS Lease Sale No. 35 by the Bureau of Land Management (BLM, 1975). In accepting bids from Shell and others for leases in the Beta Unit, this alternative was rejected. Moreover, current Department of Interior policy seems to be that oil and gas leases must be explored and developed within a reasonable time or the lessee faces the possibility of relinquishing the leases to the government. This situation has already occurred in the offshore Santa Barbara area. Consequently the no-project alternative is not seen as a viable alternative insofar as the Federal government is concerned.

State and local authorities having jurisdiction over specific aspects of the project may, however, consider the no-project alternative as viable. In this case, the no-project alternative can be considered as three subalternatives. One of these subalternatives is to deny the project. The second is to allow only partial implementation of the proposed project. The third is to postpone the project until some future date. Each subalternative is discussed below.

5.1.1 Project Denial

If the project is denied, several impacts may result. The oil that the project would produce would not be available for use. The oil would likely be replaced by other oil, possibly from foreign sources. Additional importation of foreign oil would have a negative effect on U.S. balance of payments. Some costs of refinery modifications to process heavy sour crudes could be avoided.

The impacts of a no-project alternative in this case can be assessed by estimating the marine traffic consequences of importing by tanker the crude expected from the Shell Beta project (approximately 1.5×10^8 barrels, or about 12,000 barrels (1920 m^3) per day over the life of the project. A Library of Congress study (1976) on offshore oil operations summarized research concerning oil spills from various sources. The combined through-put spill rate from offshore operations not involving tankers was estimated at 0.0089 percent. For this project, that spill rate would equate to 133 barrels over the life of the project. The same study estimated the throughput spill rate for tankers and barges to be 0.016 percent. If the equivalent Shell Beta output was imported via tanker this would equate to a spill rate of 240 barrels over the life of the project. While it is recognized that the impacts of spills are highly location dependent, it nevertheless gives an indication of overall environmental impact. Statistic's such as these are greatly influenced by significant events such as major blowouts or tanker losses, and therefore may have little bearing to the specifics of this project.

Similarly, an estimate can be made of the expected number of tanker collisions which might be expected to result from the alternative of importing oil. An estimate of the probability of an accident per tanker trip of about 4.4×10^{-3} has been developed by the Oceanographic Institute of Washington (1974). Data collected by Poricelli (1971) and consolidated by the Federal Power Commission (FPC, 1976) to treat collisions, rammings and groundings only, indicate that collisions at piers, harbor entrances, and coastal waters constitute about 38 percent of all tanker casualties. Considering a typical 59,800 DWT tanker as an alternative, approximately 330 trips would be required over the project life to import the crude equivalent of the project. Application of the accident estimates to the number of voyages identified (330) as that displaced by the proposed project, indicate that about 0.55 collisions could be expected in the harbor and coastal region due to tanker traffic should the project not take place and if the crude equivalent to that expected from the Beta field was imported. This number of collisions, when compared with the cumulative value of about 0.2 identified in Table 4.6-3 suggests that the project as proposed is the less risky alternative.

If the oil produced by this project were not made available, or were not made up by imports or other energy sources, then a reduced amount of energy would be available for consumption. On a national basis, a reduced availability of energy tends to drive energy prices up in the short run and has the potential of eventually reducing total energy demand. However, the quantities of oil expected from the Shell Beta Unit would likely have an insignificant effect on the total national energy supply and demand situation when compared with other reserves and total imports. Alternative energy sources were evaluated as part of the OCS Lease Sale No. 35 EIS (BLM,1975).

Denial of the project will result in the loss of potential income to Shell Oil and its co-lessees, the Federal government, the State of California, and Port of Long Beach, other local agencies, and the contractors and personnel who would conduct the drilling, production, construction, and supply operations. The total economic impact of this project at current energy prices is approximately $2 billion.

Other impacts which would be eliminated include:

- Marine Traffic - potential for collision between shipping and Beta platforms.

- Oil Spills - potential oil spill damage to coastal areas (except Port facilities);

- Marine Biology - short term loss of benthic habitat due to platform and pipeline construction;

- Geologic - limited potential for exacerbating local geologic hazards at platform site and along pipeline;

- Cultural - possibility of disrupting marine cultural resources if present;

- Aesthetics - visual impact of platforms from shore and offshore areas;

- Onshore - minor localized impacts on traffic and noise.

In addition to these impacts, beneficial environmental effects of the project would not be realized, including:

- Air Quality - reduction in SCAB emissions as a result of project offsets.

- Marine Biology - long-term marine habitat enhancement in vicinity of platforms;

- Marine Traffic - navigational aid.

5.1.2 Partial Project

This alternative might include construction of only one drilling platform (Ellen) and elimination of the deep-water platform (Eureka). Such a project would result in slightly reduced offshore impacts as discussed above; the most significant of which would be elimination of one potential source of conflict with shipping and reduced possibilities for oil spills. However, this alternative might not permit the recovery of the total reserves because directional wells could not reach the entire Beta field. Partial field exploitation may not provide the necessary income to Shell and its partners to justify implementation of a partial project. Further, as discussed in Section 5.2.2.3, this would be a less efficient use of the reserves. A partial project is, therefore, seen as a non-viable alternative by the applicant. Moreover, it is not seen as being in the best interest of either the responsible agencies or the public, since it represents a limited achievement of objectives in terms of energy development and an inefficient application of development resources.

5.1.3 Delayed Project

The proposed developed program could be postponed to a future date. The impacts of this alternative are essentially the same as those for the proposed project, except that the impacts will occur at a later date. Postponement could also mean an increase in energy imports in the short run, with attendant economic consequences. As previously noted, the total consequences of this project vis-a-vis the nation's total energy requirements are very small. Postponement could eliminate the applicant's ability to implement the project, especially if the Department of Interior terminates the leases due to non-exploitation. From the Federal government standpoint, a significantly delayed project is not a viable alternative.

Possible advantages could result from delay. A better adjustment of crude reserves on the west coast and the formulation of a national energy policy could result in a potentially better plan for development of these resources. Future technological developments in oil and gas production could further reduce the risk of potential adverse impacts. Theoretically, a long postponement could mean that these oil resources would be more valuable as raw materials (such as petrochemicals) than as fuel, resulting in another project to produce the resources, with a different primary use for the produced products. It must be recognized that in this case development costs will also be significantly higher.

5.2 ALTERNATIVE OFFSHORE FACILITIES

The following prime alternatives exist to the offshore facilities portion of the project as proposed by Shell:

(1) Drilling Facilities

Alternatives to the proposed Ellen and Eureka drilling platforms include:

(a) Single drilling platform;
(b) Three or more drilling platforms;
(c) Subsea drilling chambers and individual or clustered multi-well completions;
(d) Floating or semisubmersible drilling vessels;
(e) Alternate platform locations.

(2) Processing Facilities

Alternatives to the proposed Elly production platform include:

(a) Combined drilling and production platform;
(b) Alternate location (shallower water);
(c) Onshore treating.

(3) Crude Transport

(a) Offshore storage and lightering to shore via barge;
(b) Alternate pipeline routes.

Each of these alternatives and the primary environmental impacts are evaluated in this section.

5.2.1 Drilling Facilities

The configuration of the Beta Field, as shown in Figure 2.4-3, is such that a single (larger) drilling platform cannot be utilized to develop the entire reservoir on the Shell *et al.* leases because of the distances involved. This alternative is synonymous with a partial project, as discussed in Section 5.1.2, and has the same environmental consequences.

Alternatively, three or more drilling platforms could be used with a lesser number of slots per platform. The economic consequences of such a scheme would be penalizing to Shell because of the high costs of platforms, and might make the project infeasible. Moreover, there are no environmental benefits from such an approach considering increased hazard to marine traffic and the higher probability of oil spill.

Originally, Shell and the USGS discussed utilizing clustered multi-well subsea completions for the Beta project as a method of reducing hazards to marine traffic in the TSS. Drilling would be via either subsea drilling chambers or floating or semisubmersible drilling vessels. The subsea completion alternative was later abandoned as infeasible because field exploration showed the deposits to be highly viscous oil located in relatively shallow deposits at the top of the Miocene sands. Slant drilling from subsea clustered multi-well locations would be considerably more difficult. Moreover, the economics of field development would not justify a subsea completion method utilizing floating drilling and maintenance vessels (Shell, 1977). The nature of the oil deposit requires continuous artificial lift by submersible pumps in the wells which in turn means frequent well servicing. The primary reason for subsea completion would be to avoid conflict with marine traffic in the TSS since other aspects are more environmentally penalizing, particularly the increased potential for oil spill. Also some aesthetic impacts could be avoided. While such an approach would eliminate the placement of permanent platform facilities in the separation zone, it would not eliminate marine traffic hazards. Continuous well servicing and workover would require rig vessels to be in station 4200 rig days per year. The variable nature of their location would pose distinct marine hazards.

Finally, alternate locations for the platforms could be selected in the field. The locations selected in the separation zone are intended to keep the platforms outside of the traffic lanes and proposed buffer zones. It is not feasible to locate the platforms outside the TSS and still reach the Beta field. Some movement of platform locations in the separation zone is possible; however, no environmental benefits are forecast. In particular, data relating to ship collisions in the Gulf of Mexico with offshore platforms show little relationship to platform location vis-a-vis TSS and shipping corridors. The prime collision cause seems to be darkness and operator inattention or error. Because of the platform location near the entrance to Long Beach/Los Angeles Harbors, operator attention should be higher (due to entering and leaving port) than it might be in an open ocean situation. Therefore, alternative platform locations in the separation zone are viewed as having little overall effect on environmental issues.

5.2.2 Processing Facilities

Alternatives to treating (dehydrating) the crude in the manner Shell has proposed include combining drilling and processing functions on a single platform (i.e., combine Ellen and Elly), treat at a different location, or treat onshore.

5.2.2.1 Drilling/Processing

In the development of the Beta design, Shell evaluated a single larger platform for combined drilling and treatment functions. Safety factors and higher costs caused the rejection of this alternative. Drilling and treatment functions on individual platforms provided an inherently safer operation because of separation of equipment trains and operational activities in Shell's opinion. Moreover, it allowed a single platform to process the field production, including potentially the Chevron leases, if developed. The environmental impacts of a combined platform would be:

(1) Geology - slightly reduced geologic associated risks due to elimination of one structure;

(2) Marine Traffic - slightly reduced risks of collision (reduction is not 50 percent of the two platforms because combined platforms would be larger than present design);

(3) Aesthetics - limited change. Although there would be only one platform, it would be larger and potentially more visible from shore.

(4) Marine Biology - reduced short-term benthic impacts; fewer long-term habitat enhancement impacts.

Inasmuch as the same two-platform operations would be taking place on one platform, the probability of oil spill is considered equivalent and hence not affected by this alternative.

5.2.2.2 Alternate Location

It is possible to locate the production platform in a different location other than adjacent to Ellen. For instance, it could be located in shallower water along the pipeline route. An advantage of this approach might be reduced platform costs since the jacket would be smaller. Shell rejected this alternative, however, because of inefficiencies in energy utilization and for the convenience of operations. If the platforms are substantially separated, some of the natural heat in the crude would be lost in transport from the drilling platform to the processing platform. This would be a function of separation distance; however, it would be more difficult and costly to transmit power back to the drilling platform. Also, larger pipelines would be required to transmit wet crude to the treatment platform and to transmit reinjection water to the reservoir. Finally, the efficiency of crew operations and logistics is enhanced by the connected platform concept.

The changed environmental impacts of a shallow water treatment platform include:

(1) Oil Spills - greater risk of oil reaching shore due to closer proximity to shore, increased marine traffic volumes, and reduced response time if spill occurs. Conversely, the closer proximity improves the response time for shorebased containment teams;

(2) Marine Traffic - higher risks of collision due to three separated platform locations versus two prime locations in current proposal. Specific risks dependant on exact location;

(3) Aesthetics - increased impact due to closer platform proximity to shore;

(4) Energy - increased energy requirement because of heat loss, power transmission factors, and injection water return;

(5) Air Quality - increased impacts due to reduced offshore dispersion opportunity before emissions reach shore.

Specific impacts are a function of location and distance to shore. Potentially, major consequences could result due to the fact that the production platform is the primary source of air emissions.

From an environmental impact standpoint, a shallow-water processing platform has significant penalties and offers no substantial benefits.

5.2.2.3 Onshore Treatment

An alternative to offshore treatment is to transport the wet crude directly to shore via pipeline and process it onshore prior to refinery distribution. Because of the volumes of produced water, a larger pipeline would be required (24 inch, or 0.6 m, versus 16 inch, or 0.4 m) to transmit the product ashore. Also, another pipeline would be required to transmit injection water back to the reservoir from shore, and a separate cable would be needed to take energy to the drilling platform. Facilities would be required ashore for dehydration. The natural heat of the crude would be lost in transport, requiring more energy to dehydrate onshore. The natural gas from the crude will be lost as an energy source because the gas would not be brought ashore, but flared at sea. Hence, from an energy standpoint, this approach is much less efficient. Such an approach, however, would eliminate one offshore platform and would reduce certain environmental impacts and risks, while at the same time worsen others. These include:

(1) Marine Traffic - reduced potential for collision due to eliminating one platform;

(2) Oil Spills - reduced potential for spills due to elimination of production platform;

(3) Aesthetics - reduced impacts due to elimination of one platform;

(4) Energy - increased energy demands. Loss of both crude natural heat and use of produced gas as fuel;

(5) Air Quality - more severe localized impacts due to placement of production facilities onshore. Net basin effect is presumably equal because of potential offset requirements of the SCAQMD. Higher emissions from flaring of all natural gas.

(6) Land Use - additional requirements for industrial land with attendant aesthetic, noise, and traffic impacts. Incompatible with principal of field unitization. Also, production facility might be in conflict with Coastal Zone policies 30262, 30260, and 30263.

Thus, onshore treatment is a possible alternative, although the economics of such an approach are probably penalizing to the applicant.

5.2.3 Crude Transport

Two alternatives can be evaluated in terms of crude transport schemes: transport to shore by lightering to barge or transport to shore by alternate pipeline routes.

5.2.3.1 Barging

An alternative to the pipeline is to barge the crude to shore after treatment on the production platform. This would require offshore loading facilities and significantly greater crude storage facilities on the production platform, probably in the vicinity of at least 175,000 barrels (28,000m^3). In the project planning phase, Shell evaluated a number of systems for this purpose (Shell, 1977). If offshore loading and storage were required, Shell would use a Single Buoy Storage System consisting of a Catenary Anchor Leg Moorning System (CALM) loading buoy combined with a permanently moored 29,000 dwt tanker (with 175,000 bbls capacity). A specially assigned shuttle tanker of 20,000 dwt (120,000 bbls (19,200 m^3)) would be used to transport the crude to the Shell Oil refinery in Martinez, California. While such a system is economically unattractive to Shell, it is a possible alternative.

The primary environmental consequences of such a system would be:

(1) Marine Traffic - greater risks of collision due to creation of lightering operations in TSS;

(2) Oil Spills - greater potential for spills due to increased platform storage facilities and offshore loading operations. These would outweigh any benefit of reducing risk of pipeline failure.

(3) Air Quality - Implementation of this alternative would result in significant air pollution emissions from the tankers. Specifically, large amounts of ozone producing hydrocarbons would be emitted during unloading, ballasting, purging, and venting operations. Combustion emissions of SO_x and NO_x could create adverse impacts under worst-case meteorological conditions. The emissions for selected pollutants from this activity alone would be higher than the combined total of the proposed project. For instance, annual SO_x emissions for the proposed project would be approximately 73 tons. If the crude was lightered, the annual SO_x emissions would be 386 tons. The total emissions from implementation of this alternate are shown in Table 5.2-2. They are based on emission rates shown

in Table 5.2-1. It should be noted that the transit emissions were calculated from the platform to Point Conception only a distance of approximately 140 miles. The California Air Resources Board and the SCAQMD concluded that emissions as far north as Point Conception reach the South Coast Air Basin, whereas emissions north of Point Conception have little or no impact on the basin;

(4) Energy - additional energy demands to transport crude via ship;

(5) Land Use - eliminates impacts of project on state lands and Port of Long Beach, as well as other Los Angeles basin localized impacts;

(6) Geologic - eliminates project element (pipeline) subject to geologic hazards.

Overall, the potential impacts of offshore storage and barging are considered more significant because of oil spill and marine traffic hazards. Air quality impacts could be significantly worse depending on offset criteria application. Onshore distribution facility impacts in Long Beach would be eliminated, but these are not considered of major consequence. Local economic benefits would be somewhat reduced.

5.2.3.2 Alternate Pipeline Routes

The alternate pipeline routes considered for this project were landfalls at Huntington Beach, Huntington Harbour, and Seal Beach. These alternative routes are shown in Figure 3.1-10.

(1) Huntington Beach

The Huntington Beach landfall has the advantage of being the shortest direct route to shore (approximately 7 mi (11.3 km)) and would require the least amount of pipeline dredging. However, it would require the onshore construction of about 38 mi (61.2 km) of 16-in (0.4 m) pipeline to connect into the existing refinery system, because existing pipelines are at capacity. It would also require heating the crude at Huntington Beach and at an intermediate pump station. Additionally it would require crossing both an offshore reef and a beach. The major impact variations would be:

(a) Marine Biology - fewer short-term dredging impacts; potential limited loss of reef habitat;

(b) Oil Spills - greater potential for oil spill damage to Bolsa Chica and other marshland areas;

TABLE 5.2-1

EMISSION FACTORS FOR TANKERS

Activity	HC	SOx	NOx	Part.	CO
			Emission Factor		
Transit					
Combustion Emissions	0.13 $\frac{lb}{bbl}$	13.44 $\frac{lb}{bbl}$ (1)	2.11 $\frac{lb}{bbl}$	0.8 $\frac{lb}{bbl}$	0.025 $\frac{lb}{bbl}$
Purging	0.023 lb/ DWT/hr				
Ballasting	0.067 lb/ DWT/hr				
Venting/ Breathing	0.014 lb/ DWT/hr				
Moored Tanker					
Unloading	0.6 lb/ 10^3 gal				
Tanker Unloading Combustion	0.13 $\frac{lb}{bbl}$	13.44 $\frac{lb}{bbl}$	1.8 $\frac{lb}{bbl}$	0.3 $\frac{lb}{bbl}$	0.4 $\frac{lb}{bbl}$

(1) 2% weight sulfur fuel

Reference: "Supporting Information for the SOHIO Permit Application", February 1977
"Air Quality Analysis of the Southern California Bight in Relation to Potential Impact of Offshore Oil and Gas Development", November 1977

TABLE 5.2-2

NO PIPELINE ALTERNATIVE TRANSPORTATION
EMISSIONS ASSOCIATED WITH THE DELIERY OF BETA CRUDE

Activity	SOx (2)	NOx	Part.	HC	CO
	Emission (lb/Trip)				
Tanker Transit (1) Combustion	8960	1408	533	87	17
Tanker Transit (1) Purging/Ballsting/ Venting	--	--	--	9080	--
Tanker Offloading	1616	216	36	3024	3
TOTAL:	10576	1624	569	12191	20

(1) Emissions calculated from Point Conception
(2) 2% weight sulfur fuel
(3) Assumes 1 20,000 DWT (120,000 BB1S (19,200M^3)), tanker making one round trip every 5 days.

(c) Energy - more energy consumption to heat and pump crude;

(d) Land Use - beach crossing plus potential conflict with Coastal Plan elements;

(e) Onshore - more localized short-term impacts (dust, noise, traffic conflicts due to onshore pipeline construction);

(f) Geologic - specific route would need to be surveyed for geologic hazards and to establish design criteria.

(2) Huntington Harbour

A second alternative would be to provide a landfall at Huntington Harbour. The impacts of this alternative are similar to the Huntington Beach alternative. A slightly longer offshore run would be required, and a reduced length of onshore line would be needed. The same impact assessment variations apply with the exception that the potential impact of oil spills and marine habitat disruption are heightened due to the location of the line in Huntington Harbour. It should be noted that an additional distribution pipeline will be required onshore because existing lines are now at capacity. Also, there is limited space for the onshore facility.

(3) Seal Beach

A third alternative is to make landfall at Seal Beach. Again, the existing distribution lines are at capacity or sufficiently undersized so as to be unable to accommodate this project. In this case, a shorter offshore pipeline route would result (13 mi or 20.9 km versus 17 mi or 27.4 km), but 11 mi (17.7 km) of new onshore pipeline would be needed to tie into the existing refinery system. While approximately 4 mi (6.4 km) of offshore pipeline could be eliminated, onshore and coastal zone impacts, including a probable beach crossing and other onshore short term effects due to pipeline construction are more penalizing. This alternative, like the other two, would require greater energy use for heating and pumping than the Long Beach proposal.

5.3 ALTERNATIVE ONSHORE FACILITIES

The impacts of onshore facilities, as addressed in Section 4, are generally mimimal and do not require mitigation. The Port of Long Beach distribution and supply sites are relatively small (one to three acres) and could be located at several locations in the industrialized port complex without any significant change in environmental impact.

The Huntington Harbour crew launch site is subject to some impacts, particularly traffic and parking congestion which could be mitigated by placement of the facility at a more industrialized area such as the Port of Long Beach or Los Angeles. While no specific sites are suggested because of the limited amount of space required, it is considered that a number of acceptable launch site alternatives exist which could eliminate any adverse impacts for this activity.

SECTION 6.0
IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

6.1 MINERAL RESOURCES

The Shell Beta project will represent an irreversible and irretrievable commitment of oil and gas resources which will be produced during the life of the project. Use of this resource by the present generation will deprive future generations of its use. This is seen as the major irreversible commitment of resources of the project. However, this loss is partially balanced by the fact that use of the resource now provides time to allow development of alternative energy sources.

6.2 ENERGY RESOURCES

Energy resources committed will include those expended for the development, production, transportation, and refining of the products drawn from the Shell Beta lease area, plus that expended due to processing losses. The efficiency of end-uses is not considered here because of the difficulty of relating production to any specific use.

The commitment of these energy resources will, of course, be more than offset by the energy that will be generated through the consumption of the recovered oil and gas resources.

6.3 LAND RESOURCES

The Shell Beta project will represent a commitment (of up to 35 years) of small parcels of previously man-disturbed land to the associated onshore facilities.

6.4 OTHER RESOURCES

Water, land, and mineral resources, as well as marine and terrestrial biota, will be affected to some degree, but this is not considered to be a totally irreversible change or irretrievable. Immediate offshore natural appearance has already been altered by previous development of state lands. Drilling operations may result in minor alterations of the offshore views, but this is also not considered to be irreversible. The project would, however, involve an irretrievable commitment of materials such as cement casing, drilling muds, and chemicals. Other materials, such as steel, may have salvage value and will be retrieved after the oil field is depleted and the platforms are removed.

Drilling and production inherently involve the possibility of an oil spill, and the effects of such an occurrence on the local environment cannot be disregarded. However, since oil spills are not certain to occur, they are seen as neither an inevitable impact nor as irreversible.

The potential for a spill does commit a variety of resources to protection of the environment and for cleanup. A listing of those committed resources can be found in the Technical Appendix; included are booms, absorbent materials, chemical dispersants, and transport vessels. Although some materials have multiple uses, most are single-purpose items related to the petroleum projects.

SECTION 7.0
THE RELATIONSHIP BETWEEN LOCAL SHORT-TERM USES OF THE ENVIRONMENT AND THE MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

The local short-term uses of the environment that would occur as a result of this project include the following:

(1) Nonrenewable resources in the form of crude oil and natural gas will be drawn from the earth for use as energy sources in the near-term. As a result, offshore reserves of these resources will be incrementally depleted and unavailable for use at some later time.

(2) Construction of the offshore drilling and production rigs and placement of the pipeline will be of a relatively limited duration, but will have the potential for adversely affecting the environment, primarily marine biologic species, marine traffic, and water quality.

(3) Longer-term use of the environment for day-to-day production will, of course, carry with it the major potential impact of oil spills with concomitant adverse effects in other areas of the environment. These impacts have been discussed previously in this report as well as by the BLM (1975, 1978).

(4) Onshore portions of the project will involve only a limited amount of land, all of which has been previously disturbed by man. It will, however, constitute a commitment of additional land beyond that presently designated for long-term associations with the production of oil.

Regarding the maintenance and enhancement of long-term productivity, the project will result in the following:

(1) Additional energy will be made available to the American economy for use as it sees fit. One of the potential uses will, of course, be to maintain and improve the quality of life of its citizens; another will be to help sustain the output of the economy and the nation at sought-for levels. A third could possibly be to provide the energy needed to discover other recoverable resources, or even alternate energy sources.

(2) Long-term productivity of certain biological species may be diminished by the project, particularly in the event of oil spills. This potential has been discussed earlier in this document, as well as on a broader scale in prior environmental analyses (BLM, 1975, 1978). In and of itself, the project is not expected to have long-term deleterious effects on any biological species, nor will it result in the extinction of any such species. In fact, the platform structure will most likely have beneficial impacts by providing a home, habitat, and feeding ground for a variety of marine species.

(3) Although commercial fishing activities could be affected by the project (through oil spills, snagged nets, etc.), the longer-term impact will be to attract fish to the area, thus enhancing sport-fishing activities, and, to a certain degree, commercial fishing.

(4) There will also be an unknown amount of long-term degradation of the environment due to the continuous introduction of small amounts of oil and other substances, such as trace amounts of heavy metals from drilling muds, etc., into the marine and coastal environment over the life of the Shell Beta operation. Evidence available at this time does not indicate any long-term adverse impacts on biological productivity as a result of the introduction of such substances into the environment; however, it is not possible at present to conclude that no adverse long-term impacts would result.

(5) The project will generate increased personal income as a result of new employment opportunities, royalties, and tax revenues to governmental agencies, as well as recovery of expenses and profits to the applicant. These monies will find their way back into the economy, and will thus contribute to the long-term health and productivity of local, state, national, and even international economies.

(6) Although the project will inherently add to the volume of basinwide pollutant emissions, it could have the long-term effect of improving air quality in the area, assuming that a net project benefit ratio is realized.

SECTION 8.0
GROWTH-INDUCING IMPACT OF THE PROPOSED ACTION

The Shell Beta project will have its most direct growth-inducing impact through the creation of new job opportunities. Previous discussions have acknowledged that while this impact on employment and population will occur, its effect, including growth inducement, on the Los Angeles/Orange County sub-region is seen as being relatively small and therefore negligible.

Likewise, the project will generate increased personal income, tax revenues, and profits which will, through their multiplier effect, be a source of additional growth-inducement throughout the region and the state. Again, the scope and significance of this effect is considered negligible, given the very large baseline figures that exist regarding personal income, tax revenues, and the like.

The continued availability of oil for conversion to energy will, at a minimum, contribute to the accommodation of growth and maintenance of a healthy economy by satisfying demands for energy.

The unitization of the Beta field will serve to limit the growth of petroleum related structures in San Pedro Bay. Further, proceeding with this project will not encourage or discourage development of other leaseholds within Lease Sale No. 35 or the upcoming Lease Sale No. 48. Each development proposal will be subject to separate review and will not necessarily be approved because of Shell's precedent. Further, based on very preliminary exploratory data from other tracts, there appears to be some question as to the potential for additional production in this immediate area.

SECTION 9.0

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State Agencies

California Air Resources Board
- Harmon Wong-Woo - Chief Stationary Source Control Division
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GEOTECHNICAL

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