SECTION 3
APPROACH TO ENVIRONMENTAL ANALYSIS

In reading this Initial Study and Negative Declaration, it is important to understand the uncertainty involved in predicting the future behavior of SDG&E or new plant owners, the legal framework in which this divestiture proposal exists, and the conservative nature of and bases for the assumptions used throughout the document to evaluate the environmental impacts of the project. Although the project itself—transfer of plant ownership from SDG&E to new, non-utility owners—is simple and straightforward, the projections, assumptions and methodology in this Initial Study are rather complex. This section outlines the approach to the environmental analysis in this document and the reasons for the assumptions employed.

3.1 RESTRUCTURING VERSUS DIVESTITURE

In 1996, the California Public Utilities Commission (CPUC) initiated and then suspended preparation of a policy-level Environmental Impact Report (EIR) to study the environmental effects of the entire electric industry restructuring process. The enactment of Assembly Bill 1890 (AB 1890) (Stats. 1996, Ch. 854) took precedence in planning the new electric market and rendered an EIR on restructuring unnecessary; with the enactment of AB 1890, the policy of introducing competition into California's electric generation sector in 1998 became law, and the implementation of laws enacted by the legislature is exempt from CEQA.

The divestiture of SDG&E's fossil-fueled plants is not called for in AB 1890, but rather is required as a condition of the CPUC's approval of the merger of Enova (the parent company of SDG&E) with Pacific Enterprises (which was the parent company of Southern California Gas Company) to become the merged firm of Sempra Energy (CPUC Decision No. D98-03-073). Under the merger order, the CPUC directed SDG&E to sell its fossil-fueled power plants by the end of 1999 in order to reduce the firm's market power in the San Diego service area (see Section 2, Project Description).

Restructuring itself is likely to lead to profound changes in how the state's electricity system operates. Divestiture, which is the sale of power plants, is intended to further facilitate and cement those changes by altering the incentives that participants, particularly in generation, face. This Initial Study does not analyze effects associated with the changes brought about by restructuring, since such changes have already been mandated and are occurring now. The Initial Study thus assumes the existence of the restructured market, and analyzes potential impacts associated with projected facilities operations under new owners in the restructured market as compared to SDG&E's projected operations (if the facilities were not sold) in the restructured market. However, because this Initial Study includes data on SDG&E's historical practices and levels of operation, as well as information about the current environmental setting, observations could be made concerning the effects of both restructuring and divestiture on the existing, or historical, environmental setting.

3.2 ANALYSIS YEARS

BASELINE SCENARIO (1999)

The manner in which SDG&E would be expected to operate the plants in 1999 is considered the environmental baseline for purposes of measuring the impacts of the project. In most respects, this 1999 SDG&E Baseline Scenario does not differ from the existing environmental setting. However, in order to reflect the ongoing changes in the electric industry resulting from restructuring (changes that will occur with or without the divestiture project), it is reasonable and informative to project the manner in which SDG&E would operate the plants in 1999 if the plants were not sold because 1999 is the first full year that utilities will operate under the restructured electric utility industry in California. The 1999 baseline assumptions and modeling results are described in Section 3.5.1.

ANALYTICAL MAXIMUM SCENARIO (1999)

In order to conservatively depict the greatest potential project impacts in 1999, the Baseline Scenario is compared to an analytically derived maximum capacity (the “Analytical Maximum”) at which each of the two fossil-fueled power plants (Encina and South Bay) proposed for sale could operate in 1999. The analytical maximum assumptions and modeling results are described in Section 3.5.2. No maximum capacity was considered for the 24th Street Terminal Refueling Facility as it is an oil transfer and storage facility and not a generation facility. In addition, the terminal will be sold together with the South Bay Power Plant and could thus be considered as part of the South Bay plant.

The year 1999 was selected as the project impact year for three primary reasons:

1. If the project is approved, the plants could be sold by 1999.

2. The year 1999 will be the first full year under restructuring of the electric industry in California.

3. SDG&E is currently precluded from selling power through Direct Access (i.e., direct service to retail customers outside its service territory) and, depending upon the timing of competitive transition charge (CTC) collection, could be precluded from that activity until March 31, 2002. New owners, on the other hand, could immediately take advantage of the direct access market—that is, selling directly to retail customers. The ability of new owners to immediately participate in the direct access market is a key factor in this Initial Study’s assumption that new owners will tend to operate at higher levels than would SDG&E (see Attachment C). Thus, a year prior to 2003—when SDG&E can sell power directly to any retail customer, thereby moving its operational characteristics closer to those of a new

owner—likely represents the greatest potential for environmental change caused by divestiture.

CUMULATIVE SCENARIO (2005)

This Initial Study analyzes cumulative impacts as of the year 2005. The year 2005 was selected for the cumulative analysis primarily because all air quality controls for oxides of nitrogen (NO_x), as required by the San Diego Air Pollution Control District under Rule 69, would be in place by that year. The cumulative impacts analysis is contained in Section 4.16 of this Initial Study.

The analysis considers the cumulative effects of a multitude of projects and factors, including proposed new power plants, projected increases in the demand for electricity, planned or proposed new electrical transmission facilities, and local projects proposed in the vicinities of the power plants. Many of these projects involve separate, project-specific environmental review and require governmental permits and approvals before implementation.

The cumulative analysis considers two possible scenarios, or variants: Variant 1 in which both the Encina and South Bay Power Plants continue in service, and Variant 2 in which the South Bay Power Plant would be shut down. (The assumptions for each variant are more thoroughly discussed at the end of this chapter, as well as in Section 4.16 of this Initial Study.) In order to conservatively depict the greatest potential cumulative impacts in 2005, cumulative Variant 1 continues to assume that the owners of the Encina and South Bay plants would operate the plants at their analytical maximum capacities.

Cumulative Variant 2 assumes that proposed new generation facilities (totaling 1,060 megawatts [MW]) have been constructed and are operating in the San Diego area, most likely at Otay Mesa. This new plant would not only accommodate local load growth, but also would be a load-following plant that displaces electric power imports from outside SDG&E's service area, which would otherwise be needed to meet demand in the area. The new plant may also export power to other service areas, including southward into Mexico.

The cumulative impacts analysis primarily compares the two 2005 Cumulative Scenarios to the 1999 Baseline Scenario. The reason that the Initial Study uses this approach instead of creating a 2005 Baseline Scenario for the analysis is to generally portray the maximum cumulative potential for environmental changes associated with the project. Furthermore, SDG&E has been ordered to divest the power plants as a condition of the merger, and thus is likely to divest them before 2005 either through this application or another process.

3.3 FACTORS THAT COULD PRODUCE CHANGE

This Initial Study considers whether SDG&E's proposed divestiture would likely lead to significant effects on the environment as a result of either (1) physical changes associated directly with the ownership transfer, or (2) distinguishable operational changes at the facilities proposed for sale, that are different or greater than would occur solely due to restructuring. Changes that are assumed reasonably foreseeable—i.e., the project being analyzed in this Initial Study—versus those that are not expected to occur, or would be too speculative to consider at this time, are identified in Section 3.4. The factors considered in determining whether divestiture would result in changes that could produce environmental impacts are discussed in the following bulleted items:

- *Amounts of Energy Generated at Each Divested Plant and Other Developed and Undeveloped Sites in California and the Western Region.* The plants proposed for divestiture generally have operated at less than maximum output. With divestiture, a new buyer of such a power plant could have an economic incentive to operate the facility at higher levels of generation, subject to permit requirements and applicable regulations. Many factors could cause the amount of energy generated at plants throughout California (not just the divested plants) to change. For example, a plant that is the primary income-generating (and energy-generating) asset of a new owner could run somewhat differently than when it was owned in common with the other plants within SDG&E's integrated system or service area, even if it were not retired or refurbished in some manner by the new owner. In addition, changes in fuel purchasing arrangements and the immediate availability of the "direct access" retail electricity sales market to new owners could tend to increase generation.

- *Amount and Timing of Construction, Refurbishment, Repowering, or Retirements of Divested Plants, or Other Developed or Undeveloped Sites in California and the Western Region.* A limited amount of new construction (of fences, driveways and the like) may be necessary to separate the power generating units, which would be divested, from on-site transmission and distribution equipment, ownership of which would be retained by SDG&E. In addition, the sale of SDG&E's plants to new owners could affect operations, which in turn could affect resource planning decisions at the divested plants and at other plants throughout California and the western grid. The new owners of the divested plants, facing financial conditions different than those of SDG&E (e.g., different assets and liabilities), could then choose to retire or add capital to their new properties. Under California Energy Commission (CEC) rules, power generating capacity could be increased by up to 15 percent per generating unit as part of any refurbishment or repowering, and cumulatively increased by up to 49 MW at a given power plant site, without requiring CEC approval. Additionally, any significant alteration to a power plant would trigger a "new-source review" (which includes a CEQA review) at the local Air Pollution Control District. Therefore, essentially any expansion or repowering of facilities at the plants would require issuance of new permits and accompanying environmental review. Changes in generation patterns may affect the scale or timing of construction, expansion or decommissioning of certain marginal generation facilities elsewhere.

- *Maintenance Practices at Each Divested Plant.* If plants were to change owners, the new owners would not have precisely the same operating experience, qualifications, financing, or corporate philosophy as SDG&E. New owners may have strong incentives to maintain their facilities in order to increase availability and resultant sales. A new company could implement measures at a plant that could change maintenance practices (e.g., replace several short-duration planned outages with one long one, or reduce total duration of planned outages), or defer maintenance to periods of forced outages. Forced outage durations could be shortened or lengthened, depending on the inventory of spare parts kept on site.

- *Pollution Control Technologies Employed or Installed by New Owners.* Within the restrictions imposed by the air district and permit conditions, new owners could potentially install pollution-control measures planned by SDG&E on an accelerated schedule, based upon the need to operate the plants at a greater capacity and to meet emission requirements sooner.

- *Employment Levels and Related Factors.* As the divested plants are sold, repowered, expanded, retired, or operated in their present forms, employment levels at the plants could be affected. AB 1890 requires that divested plants are operated and maintained by SDG&E for two years (and SDG&E has indicated that it intends to require new owners to recognize its employee unions). While no mandate exists that requires the plants to continue to operate after being sold unless they are "must-run" plants, all the SDG&E generation facilities are currently designated as "must-run" by the ISO. Changes such as these could affect local employment levels, which might have secondary environmental effects.

- *Extent and Character of Land Use.* To the extent that a divested plant site is constrained by surrounding sensitive land uses (e.g., nearby residential areas, recreation areas, or sensitive habitat), new construction at the plant site could increase potential conflicts with existing and potential future land uses.

- *Approach to Environmental Cleanup.* The change in ownership could affect the cleanup of power plant sites. Selling a power plant to a new entity could change how SDG&E approaches any ongoing environmental remediation activities at the site. Such changes could be beneficial. For example, cleanup could be accelerated to provide adequate room for both the new owner to upgrade the generating units and SDG&E to retain access and provide upgrades to retained transmission and distribution facilities, or simply as part of the purchase and sale transaction. Issues associated with the liability for environmental cleanup are expected to be resolved contractually between each new owner and SDG&E.

- *Permit Transfers for Divested Plants.* All permit conditions are assumed to be transferred to the new owners in their current form with all existing restrictions. However, some regulatory requirements for the SDG&E plants would cease to apply or would be substantially altered for plants sold to non-CPUC-regulated parties. The San Diego Air Pollution Control District (SDAPCD) has stated its intention to modify Rule 69, which currently applies to the SDG&E plants at Encina and South Bay, to place the new owners under an average daily nitrogen oxides (NO_x) emissions rate limit, rather than the annual total NO_x emissions cap that now applies to SDG&E. If SDG&E were to continue to own the plants, it would be subject to the declining NO_x emissions cap, but it could choose to burn residual fuel oil at the two steam plants for economic reasons, providing the San Diego Air Pollution Control District did not forecast an exceedance of state ambient air quality standard for ozone within the airshed at any time during the fuel oil burn (SDAPCD Rule 69). NO_x produced during oil burns would count against the cap. Whether or not SDG&E chose to burn oil would depend largely on the price differential between the cost of low-sulfur residual fuel oil and the cost of natural gas, as well as the difference in the cost of transporting the two fuels. The price of oil recently declined significantly compared to the price of natural gas, so for the first time in five years, oil burns by SDG&E are a possibility. However, burning oil produces more NO_x emissions per electrical unit than natural gas, and this factor would be a disincentive for SDG&E if it approaches its annual NO_x emission cap (as it has in recent years). A new air emissions permit and SDAPCD rule changes may cause the new owners to make different decisions (e.g., accelerated installation of selected catalytic reduction (SCR) on units, or changes in the decisionmaking process for selecting the fuel type used at the Encina and South Bay plants) than SDG&E would if the plants continued under SDG&E's ownership. Similarly, the new owners would also have to re-apply for permits that are not automatically transferred to a new owner by the permitting agency, such as the Regional Water Quality Control Board for an NPDES permit. The process of re-applying for these permits could also cause the new owners to make different operational and maintenance decisions that would SDG&E if it continued to own the plants.

3.4 ASSUMPTIONS REGARDING CHANGES RESULTING FROM DIVESTITURE

The environmental analysis in this Initial Study is based on assumptions of reasonably foreseeable changes that could result from divestiture, in terms of power plant operating characteristics, new construction, repowering or retirement of units, and employment levels. This section describes, based upon economic and operational analyses of SDG&E's proposed divestiture, the projected changes likely to result from divestiture compared to the changes expected to stem from restructuring alone, without divestiture. The economic and operational analyses (discussed in further detail in Attachment C and Attachment D) form the basis for the environmental analysis in this Initial Study.

For the two fossil-fueled plants, it can be reasonably foreseen that non-utility generators will operate these facilities differently than SDG&E would operate them without divestiture in a restructured environment. If it did not divest the two plants, SDG&E would be expected to continue to submit bid packages to the Power Exchange (PX) to run the more efficient units at high capacity levels and the less efficient units only when their capacity is needed, similar to the manner that SDG&E operated the plants prior to restructuring. In contrast, new owners would have incentives to operate their newly acquired plants in a more constant mode, particularly if the new owners do not own any other plants in the region. Furthermore, new owners could immediately sell power directly to users (through direct access) in addition to selling through the PX or other wholesale markets. By contrast, SDG&E is constrained to selling only to the PX prior to market valuation of the plants. Attachment C to this Initial Study was prepared primarily to answer the question of whether new plant owners would tend to generate more electricity than would SDG&E in a restructured setting. The analysis in Attachment C discusses three factors that may cause a tendency of new owners of the fossil-fueled plants to operate at higher levels, particularly during the transition period prior to 2002: (1) fuel procurement practices, such as the possibility that new owners would purchase natural gas at a lower cost per unit or in a different fashion than would SDG&E; (2) the ability of new owners immediately to participate in the direct access market, while SDG&E must initially sell all of its power through the PX; and (3) the shift from an annual NO_x emissions cap to an average daily NO_x emission rate (described further below).

It is noteworthy that SDG&E could eventually sell the plants even without the CPUC ordering the utility to do so; therefore, the physical and operational differences between restructuring with divestiture as currently proposed and without divestiture could, as a practical matter, be minimized or even eliminated, except in the period before market valuation of the plants. With restructuring and without divestiture of the Encina and South Bay facilities and CTs, the market value of the power generation facilities must by some means be established and approved by the CPUC no later than the end of 2001. Thus, implementation of restructuring itself could result in plants being sold after their market value is established. However, for environmental analysis purposes, this Initial Study analyzes how the plants would be operated by SDG&E in 1999 if they were retained by SDG&E.

Because SDG&E will be able to participate in the direct access market as of 2002 (or sooner if its plants' market values are approved by the CPUC), the tendency of new owners of the fossil-fueled plants to generate more than SDG&E lessens after the transition period. Thus, the environmental effects of divestiture that may be associated with increased generation, to the extent that such generation flows from the ability to participate in the direct access market, would be temporary.

At the time of preparation of this Initial Study, the identities of the purchasers of the plants are not known. However, the general characteristics of the buyers of the plants previously divested by Pacific Gas and Electric Company and Southern California Edison Company (Edison) are known. The greatest potential for increased generation at a fossil-fueled plant would exist if the plant were bought by a separate, independent entity that owns few or no other generation facilities within California. If a single entity buys several plants and/or owns other generating facilities (e.g., wind power, natural gas-fired, and/or hydroelectric plants) throughout the state, or to the extent that singly-owned plants are reconstituted into larger portfolios in the future, the tendency of such a new owner to operate the divested plants at higher levels than would SDG&E would decline, though not remarkably so due to the electric transmission import constraints that exist in the San Diego service area. In fact, based upon SDG&E's low historical utilization of the Encina and South Bay Power Plants and continuing load growth in the service area, it is very likely that the new owners of the SDG&E generation facilities will operate those facilities at higher capacity rates.

According to CEC forecasts, electricity demand is expected to increase throughout California in the future. Additional electric generation and/or transmission capacity will be needed to meet these future demands. It is not anticipated that this divestiture project will affect the future demand for electricity in California to any considerable degree.

This Initial Study assumes that each of the divested plants would operate within the parameters of its existing permits (e.g., water discharge permits and air emissions permits) because it is not reasonably foreseeable that operations would exceed those levels. Operations in excess of permitted levels or repowering would require new discretionary permits and environmental review.

The new owners would need to operate the plants in conformance with the San Diego County Air Pollution Control District (SDCAPCD) rules. The San Diego Air Basin is in nonattainment for ozone and PM-10. The SDCAPCD Rules 68 and 69 control NO_x emissions, a precursor to ozone, from power plants. Rule 68 limits the emissions of NO_x under certain conditions for SDG&E's

combustion turbines. Rule 69 regulates the use of fuel oil, limits the NO_x emissions from power plant steam boilers (such as those at the Encina and South Bay plants), and limits the NO_x emissions from stationary combustion turbine engines. These rules would continue to control NO_x emissions, with or without divestiture. However, as described in Section 4.5, Rule 69 has provisions for adjusting emissions limits for units that are transferred to another entity in which the existing owner (i.e., SDG&E) does not have a controlling interest. The new emissions limits would be based on performance (e.g., an average daily NO_x limit of 0.15 pounds per megawatt-hour) rather than the existing tons per year limit (the annual system-wide NO_x emissions cap).

The combustion turbines are only used for peak energy demand periods, with the exception of the CTs located at the South Bay and Encina Power Plants, which are also used to facilitate startup (i.e., black start) of the steam units. This analysis assumes the CTs would operate at the same or at slightly higher levels under divestiture. The operation level of the CTs would not change the employment or population levels associated with them, as the CTs require low inputs of labor to operate.

This analysis also assumes the 24th Street Terminal Refueling Facility, which is a receiving station for marine shipments of residual fuel oil for the South Bay Power Plant, would operate in the same manner with a new owner as it currently does under SDG&E ownership. It would continue to be used only in the event that fuel oil is needed at the plant. Since SDG&E leases the land, only the on-site equipment and the lease agreement would be transferred to the new owner.

Construction activities that are expected as a result of divestiture would be minor (i.e., construction of fences to separate properties being sold or retained). Nonphysical changes would include subdivision of the properties as necessary to complete the sales.

Increases in operations stemming from divestiture could result in a minimal increase in employment at the South Bay and Encina plants.

The precise manner in which SDG&E would operate the plants in the future restructured environment is difficult to predict. Under restructuring, SDG&E may operate its retained facilities at higher levels than historical levels of operation, and could operate those facilities up to their permit limits, providing it stays within the annual NO_x emissions cap. Although increased generation at the plants could occur without divestiture, there are grounds for believing that increased generation is more likely to occur with divestiture.

As the foregoing discussion indicates, the degree to which generation would increase at the plants slated for divestiture is highly uncertain. As shown in the analyses of Attachment C, the only conclusion that can be drawn concerning future operation of the fossil-fueled plants targeted for divestiture is that, overall, incentives exist that create a tendency for the new owner to operate a divested plant at higher levels than SDG&E would operate that plant in the future.

3.5 MODELING ASSUMPTIONS AND RESULTS

The primary impact analyses in this Initial Study consider the difference between SDG&E's projected operations of the power generation facilities at Encina, South Bay, and the 17 additional CTs located throughout San Diego County, and the projected analytical maximum operations of those plants (explained in Section 3.5.2, below). The level of operations at each plant is indicated by the plant's annual "capacity factor," that is, the ratio of actual energy production during a given time period compared to maximum possible energy production during that same time. The annual capacity factor of an individual unit (or, collectively, a plant) is a function of both the amount of time that the unit is operating and the amount of generation produced during that time. For instance, if a hypothetical unit were on and operating 100 percent of the time at 50 percent of its rated capacity, it would have a 50 percent capacity factor. Similarly, if a hypothetical unit were on and operating 50 percent of the time, but at 100 percent of its rated capacity, it would also have a 50 percent capacity factor. Combining these concepts, if a hypothetical unit were on and operating 50 percent of the hours of the year and at a 50 percent power level for each of the hours it was on, it would have an annual capacity factor of 25 percent.

The capacity factors used in this Initial Study and discussed below were derived using the SERASYM™ unit-specific, California-wide data set, which was processed by the SERASYM™ production cost model, to forecast plant operations. The computer modeling was conducted by Sierra Energy and Risk Assessment, Inc. (SERA), a California company that developed the model and has been running it for more than a decade. In developing modeling assumptions, SERA used the best and most reliable data available to the CPUC during the preparation of this Initial Study, although no model can precisely predict operations under, and conditions in, the restructured market. The key modeling assumptions used in deriving the capacity factors for the 1999 Baseline Scenario, the 1999 Analytical Maximum Scenario, and the 2005 Cumulative Analytical Maximum Scenarios are described below. An expanded list of modeling assumptions and a discussion of the modeling are presented in Attachment D to this Initial Study.

3.5.1 1999 BASELINE SCENARIO

Table 3.1 presents capacity factor estimates for operation of the Encina and South Bay facilities and the 17 additional CTs to be divested in a restructured setting in 1999 if they were not sold, but were retained by SDG&E ("1999 Baseline"). The major assumptions used in this baseline computer simulation include:

1. SDG&E continues to own and operate the Encina and South Bay plants and CTs, obtaining revenue through reliability contracts with the Independent System Operator (ISO) and by selling power from the facilities through the Power Exchange (PX).

2. Both the PX and the ISO continue to commit and dispatch the plants based on minimum variable cost of operation, consistent with the San Diego area reliability requirements and local distribution system voltage support requirements.

TABLE 3.1
SDG&E PROJECTED POWER PLANT ANNUAL CAPACITY FACTORS [a]

Plant	Unit	Type	Fuel	Net Capacity (MW)	1999 Baseline [b]	1999 Analytical Maximum [c]	2005 Without new 1,060 MW plant (Variant 1)	2005 With new 1,060 MW plant (Variant 2)
Encina	1	ST	NG	100	4.5	48.5	25.4	40.0
	2	ST	NG	103	4.0	48.5	24.2	40.7
	3	ST	NG	109	5.1	62.5	29.2	51.8
	4	ST	NG	299	16.3	50.8	46.9	62.2
	5	ST	NG	329	24.1	74.4	33.5	49.3
	CT	CT	NG	15	0.1	0.3	3.2	2.3
Annual Plant Capacity				955 [d]	14.9	59.0	34.9	51.0
South Bay	1	ST	NG	145	35.0	84.3	54.5	N/A
	2	ST	NG	149	33.8	76.7	41.4	N/A
	3	ST	NG	174	32.2	75.0	53.7	N/A
	4	ST	NG	222	0.7	35.7	20.9	N/A
	CT	CT	JF	15	0.0	0.0	0.0	N/A
Annual Plant Capacity				705 [d]	22.5	63.3	39.8	N/A
New Otay Mesa	1	CC	NG	960	NA	NA	NA	90.5
1,060 MW Plant	2	CT	NG	100	NA	NA	NA	6.1
Annual Plant Capacity				1,060	NA	NA	NA	82.5
Division		CT	DF	14	0.0	0.0	0.0	0.0
El Cajon		CT	NG	15	0.2	0.4	3.4	2.4
Kearny 1	1	CT	NG	16	0.2	0.3	3.8	2.6
Kearny 2	A	CT	NG	15	0.1	0.3	3.5	2.5
	B	CT	NG	15	0.1	0.3	3.1	2.3
	C	CT	NG	15	0.2	0.4	3.5	2.5
	D	CT	NG	14	0.2	0.3	3.3	2.3
Kearny 3	A	CT	NG	16	0.2	0.4	3.6	2.6
	B	CT	NG	15	0.1	0.3	3.4	2.3
	C	CT	NG	15	0.2	0.4	3.7	2.8
	D	CT	NG	15	0.2	0.4	3.4	2.4
Miramar 1	A	CT	NG	18	0.2	0.4	4.0	2.8
	B	CT	NG	18	0.3	0.4	4.0	2.9
Naval Station		CT	NG	22	0.3	0.4	4.4	3.1
Naval Tr. Ctr		CT	NG	15	0.2	0.4	3.5	2.7
North Island	1	CT	DF	18	0.0	0.0	0.0	0.0
	2	CT	NG	18	0.1	0.2	2.2	1.6
Annual Plant Capacity				274 [e]	0.2	0.3	3.1	2.2

a Capacity factor is the ratio of energy actually produced by a generating unit to the maximum energy it could possibly produce (that is, its rated generating capacity) in the same time period.
b Baseline is the manner in which SDG&E would be expected to operate the plants in 1999.
c Analytical maximum is the analytically derived maximum capacity under a set of assumptions described in Section 3.5.2.
d Net capacity for entire plant.
e Net capacity for 17 CTs being sold as a package.

NOTE: The capacity factors were derived using the SERASYM™ unit-specific, California-wide data set, which was processed by the SERASYM™ production cost model to forecast plant operations.

UNIT TYPES: CT combustion turbine; ST steam turbine

FUELS: NG natural gas; DF diesel fuel; JF jet fuel

NA = not applicable

SOURCE: Sierra Energy and Risk Assessment, Inc., and ESA, 1998.

3. SDG&E does not install any new pollution control equipment on units at the Encina or South Bay plants until 2000 pursuant to SDG&E's latest compliance schedule filed with the SDAPCD.

4. The NO_x caps associated with Rule 69 are kept in place because SDG&E continues to own the plants.

5. The CEC's recently adopted forecast of natural gas prices for all regions of California are employed for all gas-fired plants, and the CEC's companion inflation forecast series is used to adjust other generation costs, including maintenance.

6. The hourly demand loads for San Diego in 1999 employ a load shape derived from five years of historical load shape as modified to reflect the CEC's latest annual energy and peak load forecast for SDG&E's service area.

7. Simultaneous electric transmission import limits into San Diego County are raised by 550 MW to total approximately 2,450 MW.

8. Low sulfur (0.5 percent) residual fuel oil may be burned, up to the NO_x emissions cap, when natural gas is not available or is uneconomic.

3.5.2 1999 ANALYTICAL MAXIMUM SCENARIO

As discussed above in Section 3.4, divestiture of the power plants is expected to create a tendency for new owners to operate the Encina and South Bay plants at higher levels than in the 1999 Baseline Scenario. However, it is not possible to determine with any precision at which plant (or plants) operations would increase, or the degree to which operations would increase at either plant. The 1999 Analytical Maximum Scenario calculated by the computer model is intended to capture the maximum possible change in operations that could occur from divestiture. Table 3.1 presents capacity factor estimates for operation of the two plants in 1999 at their Analytical Maximum capacities.

The Analytical Maximum capacity factors for the Encina and South Bay plants and the 17 additional CTs represent the highest capacities at which the plants could operate, taking into account limiting factors such as: the rated capacities of the units; the capacity of the gas pipeline system supplying the plants; scheduled and forced outages of units for maintenance; contractual limitations, including must-take contracts that favor power generated by qualifying facilities (QFs) and nuclear facilities; and demand constraints (i.e., the finite demand for electricity at any particular time on any given day). The 1999 Analytical Maximum Scenario reflects the assumptions outlined in Section 3.5.1 above for the 1999 Baseline Scenario and, additionally, assumes for the Encina and South Bay plants and the gas-fired CTs that the new owner(s) can purchase natural gas at a 25 percent discount from the least expensive supply of gas assumed to be available to fuel California power plants. The purpose of this assumption was to remove, to a great degree, the cost of fossil fuel from the new owner's decision whether and when to generate power. Although it is extremely unlikely that such a reduced gas price could be obtained, this assumption further strengthens the conservative, comprehensive nature of the impacts analysis.

The model was run with both plants receiving the lowest gas price. However, because of occasional gas delivery system constraints in the San Diego service area, sometimes there is an economic incentive to burn fuel oil during periods of high demand for electricity. Up to 5 percent of fuel use could be oil rather than natural gas. Therefore, oil as a secondary fuel source was also evaluated for the 1999 Analytical Maximum Scenario to more accurately reflect the range of options available to new owners and to again strengthen the conservative approach taken to project the potential impact of divestiture.

In order to fully account for any and all effects on the environment, the Initial Study's project impact analyses assume that the new owners would operate the divested plants at the 1999 Analytical Maximum capacities. However, for the reasons discussed above, operations are not expected to reach these levels at each plant, and operations may not reach such levels at either plant. It is merely the possibility that operations could increase within this range of capacity factors that is evaluated in this Initial Study.

3.5.3 2005 CUMULATIVE ANALYTICAL MAXIMUM SCENARIO

The capacity factor estimates for the 2005 Cumulative Analytical Maximum scenario are also presented in Table 3.1. Two variants of the 2005 Cumulative Analytical Maximum analysis were run. The variants and the assumptions used in the analysis of each are more thoroughly discussed in Section 4.16 of this Initial Study. These 2005 capacity factor estimates in Table 3.1 were derived in the same manner as those for the 1999 Analytical Maximum Scenario, with the following additional key assumptions:

2005 CUMULATIVE VARIANT 1

1. The Encina and South Bay plants continue to operate.

2. All of the units at the South Bay plant have SCR installed to comply with San Diego air quality limits in 2005.

3. The new plant owners at Encina install SCR for all of the units in order to comply with San Diego air quality limits in 2005.

4. New generation currently under construction in Nevada is added and the High Grove and San Bernardino power plants in Southern California are repowered consistent with CEC siting requirements and South Coast Air Quality Management District permit procedures. A new 480-MW plant is constructed in the San Francisco area, and the Hunters Point Power Plant is decommissioned.

5. The owner of the El Segundo Generating Station in Southern California produces 70 MW of generation at all times to replace the base-load in the existing El Segundo Refinery adjacent to the power station.

6. Projected transmission upgrades are assumed to increase the power importation capacity to the San Diego area so that the total importation capacity would be 2,850 MW (an increase of 400 MW above the 1999 importation capacity).

2005 CUMULATIVE VARIANT 2

Assumptions 2 through 6 above remain constant, with Assumption 1 replaced as follows:

1. The South Bay Power Plant is retired and replaced with a new plant (Otay Mesa), with a total generating capacity of 1,060 MW, to satisfy existing electricity needs plus the projected cumulative increase in demand for electricity within the SDG&E service area.