CHAPTER 3 - EXISTING SETTING

INTRODUCTION

In order to determine the significance of the impacts associated with a proposed project, it is necessary to evaluate the project's impacts against the backdrop of the environment as it exists at the time the NOP/IS is published. The CEQA Guidelines defines "environment" as "the physical conditions that exist within the area which will be affected by a proposed project including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance" (CEQA Guidelines §15360; see also Public Resources Code §21060.5). Furthermore, a CEQA document must include a description of the physical environment in the vicinity of the project, as it exists at the time the notice of preparation is published, from both a local and regional perspective (CEQA Guidelines §15125). Therefore, the "environment" or "existing setting" against which a project's impacts are compared consists of the immediate, contemporaneous physical conditions at and around the project site (Remy, et al; 1996).

The following sections set forth the existing setting for each environmental topic analyzed in this report, i.e., air quality, energy resources, and hazards. In Chapter 4, potential adverse impacts from these identified environmental areas are then compared to the existing setting to determined whether the effects of the implementation of the proposed project is significant.

AIR QUALITY

The existing setting section for air quality is divided into two subsections. The first subsection describes the existing setting for the NOx RECLAIM market. The other subsection discusses the ambient air quality data in the district.

Existing RECLAIM NOx Market

Facilities within the RECLAIM program have the option of complying with their allocation allowance by either installing control equipment or purchasing RTCs from other facilities. From the start of the program in 1994, the price of NOx RTCs remained relatively stable until summer 2000, at which time an increased demand for power generation resulted in the electric power industry purchasing a large quantity of RTCs. This action caused the price of NOx RTCs for compliance year 2000 to increase in some instances from approximately $4,300 per ton traded in 1999 to more than $39,000 per ton traded.

A review of recent data indicates that increased demand for RTCs by power producers has played a significant role in the current situation. Power producers have purchased 67 percent of the NOx RTCs that were traded with price and that expired in December 2000. In contrast, power producers only account for approximately 14 percent of total RECLAIM allocations for Compliance Year 2000. Continued high demand from power producers would likely make it more difficult for other RECLAIM facilities to purchase needed RTCs and would increase pressure on RTC prices. At the same time, many RECLAIM facilities, relying on previous low RTC prices, did not have sufficient time to install controls after RTC prices climbed dramatically. The RECLAIM program predictably reached the "cross-over point" where emissions equal allocations. This also has an effect of increasing prices.

The RECLAIM market has started to respond to increased RTC prices. A number of facilities, including power producers, have filed permit applications to install controls that will significantly reduce emissions and associated the demand for RTCs. This may ultimately help RTC prices to drop. However, there is a lag time between the decision to install controls and actually operating the controls with associated reduced emissions. Unless refinements are made to the RECLAIM program, prices are likely to remain above the backstop level until controls become operational. Furthermore, significant increase in power-producing facilities RTC needs would necessitate large-scale installation of controls to stabilize RTC demand and supply.

The potential shortfall in RTC holdings, while partially due to widespread reliance on inexpensive RTCs, is largely associated with the unanticipated electricity crises facing California. Historically, power-producing facilities have been able to meet electric load demand running only some of their generating units and at low load factors. California's energy crises, however, has led the California Independent System Operator (ISO)[1] to request power-producing facilities to substantially increase their generation. Consequently, the power-producing facilities have increased their emissions substantially beyond historic levels and have deployed less efficient, uncontrolled generating units and will likely continue to do so for the next few years. The result has been that power-producing facilities have purchase large amounts of available RTCs, substantially driving up the price. Regardless of these purchases, one or more power-producing facilities may exceed their RECLAIM RTC holdings this year based on the demand for in-Basin electric generation to help meet statewide electricity demands.

The following describes the existing setting for facilities subject to RECLAIM. Specifically, this section presents the estimated RTC demand and supply for RECLAIM facilities through 2005. This information is divided between power-producing facilities ≥ 50 MW and for the remaining RECLAIM facilities. The changes to the RTC supply and demand projections due to the proposed project are compared to this existing setting in Chapter 4.

Table 3-1 presents the estimated RTC demand and supply through 2005 for power-producing facilities greater than 50 MW. As discussed in Chapter 2 and analyzed in Chapter 4 (Table 4-5), existing RTC supply and demand are assumed to differ from that which would be anticipated with implementation of the proposed project. The existing setting for power-producing facilities (as shown in Table 3-1) does not include the proposed project's Compliance Plan requirement or Mitigation Fee Program provision, nor additional MSERC and ASC credits entering the market from the proposed NOx credit generation rules (i.e., beyond existing MSERC and ASC rules).

As can be seen by the information presented in Table 3-1, RTC demand by power-producing facilities greater than 50 MW is estimated to exceed supply through at least 2005.

[1] The Independent System Operator (ISO) is responsible for overseeing the transmission of energy over the state's power grid. Energy consumption is accounted for on an hourly basis by the ISO. The ISO provides market participants non-discriminatory access to the transmission system while maintaining system reliability and security.

Table 3-1
Estimated RTC Demand and Supply for Power-producing Facilities ≥ 50 MW
- Assuming No Amendments -
(tons per day)

	RTC Demand and Supply	2001	2002	2003	2004	2005
Demand	Baseline NOx Emission Projections	19.63	19.58	20.24	20.86	21.39
Supply	Emission Reductions from Current Retrofit Projects	5.12	10.99	10.98	10.96	11.29
Supply	CARB Emission Bank	1.17	1.74	1.74	--	--
Supply	Utility Operator Offsets	--	--	--	1.74	1.74
Supply	RTC Holdings	6.71	6.61	5.45	5.80	5.78
	Estimated RTC Demand [1]	**6.63**	**0.24**	**2.07**	**2.36**	**2.58**
	Assuming that emissions in excess of a facility's annual allocation (as represented in Table 3-1 by a positive RTC demand [i.e., RTC shortfall]) are deducted from the facility's annual emissions allocations for the subsequent compliance year by the total amount the allocation was exceeded pursuant to Rule 2010(b)(A), the estimated RTC shortfall for power-producing facilities would be:					
	Estimated RTC Demand should Violations Occur [1, 2]	**--**	**6.87**	**8.94**	**11.30**	**13.88**

[1] Positive number indicates RTC shortfall; negative number means RTC supply exceeds demand.
[2] The values in this row represent RTC demand without additional emission reductions accounting for exceedances of annual allocations. Pursuant to CEQA Guidelines §15125, the existing setting assumes a baseline condition without the Governor's Executive Order D-24-01, since the NOP for the proposed project was published prior to the issuing of that Order.
The methodology for constructing this table is presented in Appendix E.

Table 3-2 presents the estimated RTC demand and supply through 2005 for RECLAIM facilities other than power-producing facilities greater than 50 MW. As discussed in Chapter 2 and analyzed in Chapter 4 (Table 4-6), existing RTC supply and demand are assumed to differ from that which would be anticipated with implementation of the proposed project. For the purposes of this CEQA analysis, the existing setting assumes no increased use of MSERCs and ASCs.

Table 3-2
Estimated RTC Demand and Supply for RECLAIM Universe
Other than Power-producing Facilities ≥ 50 MW
- Assuming No Amendments -
(tons per day)

	RTC Demand and Supply	2001	2002	2003	2004	2005
Demand	Baseline NOx Emission Projections	44.17	43.95	44.62	44.92	45.23
Supply	CARB Emission Bank	0.64	0.07	0.07	--	--
	Utility Operator Offsets	--	--	--	0.07	0.07
	Emission Reductions – Level 1	--	8.80	16.41	16.56	16.73
	Emission Reductions – Level 2	--	1.15	2.17	2.19	4.77
	RTC Holdings – RECLAIM Facilities	32.81	30.27	26.89	26.60	26.41
	RTC Holdings - non-RECLAIM Facilities	2.10	1.26	1.62	1.56	1.77
	Estimated Anticipated RTC Demand [1]	**8.62**	**2.40**	**-2.54**	**-2.06**	**-4.52**
	Assuming that emissions in excess of a facility's annual allocation (as represented in Table 3-2 by a positive RTC demand [i.e., RTC shortfall]) are deducted from the facility's annual emissions allocations for the subsequent compliance year by the total amount the allocation was exceeded pursuant to Rule 2010(b)(A), the estimated RTC shortfall for non-power-producing facilities would be:					
	Estimated RTC Demand should Violations Occur [1, 2]	**--**	**11.02**	**8.48**	**6.42**	**1.90**

[1] Positive number indicates RTC shortfall; negative number means RTC supply exceeds demand.
[2] The values in this row represent RTC demand without additional emission reductions accounting for exceedances of annual allocations.
The methodology for constructing this table is presented in Appendix E.

As can be seen by the information presented in Table 3-2, RTC demand by non-power-producing facilities is estimated to exceed supply through 2002; subsequent to 2002, RTC supply is anticipated to exceed demand. In the event that the estimated RTC shortfall results in facilities exceeding their RTC holdings for a given compliance year, then the exceedances are deducted from the facilities' annual emissions allocations for the subsequent compliance year. The last line in Table 3-2 shows the RTC shortages for non-power-producing facilities are substantially larger if the RTC shortfalls expected in 2001 are deducted from RTC holdings in future compliance years (pursuant to Rule 2010) as opposed to being otherwise reconciled.

1999 Ambient Air Quality Data

It is the responsibility of the SCAQMD to ensure that state and federal ambient air quality standards are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone, carbon monoxide (CO), nitrogen dioxide (NO2), particulate matter less than 10 microns (PM10), sulfur dioxide (SO2) and lead. These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. The California standards are more stringent than the federal standards and in the case of PM10 and SO2, far more stringent. California has also established standards for sulfate, visibility, hydrogen sulfide, and vinyl chloride. The state and national ambient air quality standards for each of these pollutants and their effects on health are summarized in Table 3-3.

The SCAQMD monitors levels of various criteria pollutants at 34 monitoring stations. The 1999 air quality data from SCAQMD's monitoring stations are presented in Table 3-4.

Ozone

Unlike primary criteria pollutants that are emitted directly from an emissions source, ozone is a secondary pollutant. It is formed in the atmosphere through a photochemical reaction of VOC, NOx, oxygen, and other hydrocarbon materials with sunlight.

Ozone is a deep lung irritant, causing the passages to become inflamed and swollen. Exposure to ozone produces alterations in respiration, the most characteristic of which is shallow, rapid breathing and a decrease in pulmonary performance. Ozone reduces the respiratory system's ability to fight infection and to remove foreign particles. People who suffer from respiratory diseases such as asthma, emphysema, and chronic bronchitis are more sensitive to ozone's effects. In severe cases, ozone is capable of causing death from pulmonary edema. Early studies suggested that long-term exposure to ozone results in adverse effects on morphology and function of the lung and acceleration of lung-tumor formation and aging. Ozone exposure also increases the sensitivity of the lung to bronchoconstrictive agents such as histamine, acetylcholine, and allergens.

The national ozone ambient air quality standard is exceeded far more frequently in the SCAQMD's jurisdiction than any other area in the United States[2]. In the past few years, ozone air quality has been the cleanest on record in terms of maximum concentration and number of days exceeding the standards and episode levels. Maximum 1-hour average and 8-hour average ozone concentrations in 1999 (0.17 ppm and 0.14 ppm) were 142 percent and 175 percent of the federal 1-hour and 8-hour standards, respectively. Ozone concentrations exceeded the 1-hour state standard at all monitored locations in 1999.

[2] It should be noted that in 1999 Houston, Texas exceeded the federal ozone standards on several occasions and reported the highest ozone concentration in the nation.

TABLE 3-3

Federal and State Ambient Air Quality Standards

	STATE STANDARD	FEDERAL PRIMARY STANDARD	MOST RELEVANT EFFECTS
AIR POLLUTANT	CONCENTRATION/ AVERAGING TIME	CONCENTRATION/ AVERAGING TIME	
Ozone	0.09 ppm, 1-hr. avg. >	0.12 ppm, 1-hr avg.>	(a) Short-term exposures: (1) Pulmonary function decrements and localized lung edema in humans and animals (2) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; (b) Long-term exposures: Risk to public health implied by altered connective tissue metabolism and altered pulmonary morphology in animals after long-term exposures and pulmonary function decrements in chronically exposed humans; (c) Vegetation damage; (d) Property damage
Carbon Monoxide	9.0 ppm, 8-hr avg. > 20 ppm, 1-hr avg. >	9 ppm, 8-hr avg.> 35 ppm, 1-hr avg.>	(a) Aggravation of angina pectoris and other aspects of coronary heart disease; (b) Decreased exercise tolerance in persons with peripheral vascular disease and lung disease; (c) Impairment of central nervous system functions; (d) Possible increased risk to fetuses
Nitrogen Dioxide	0.25 ppm, 1-hr avg. >	0.053 ppm, ann. avg.>	(a) Potential to aggravate chronic respiratory disease and respiratory symptoms in sensitive groups; (b) Risk to public health implied by pulmonary and extra-pulmonary biochemical and cellular changes and pulmonary structural changes; (c) Contribution to atmospheric discoloration
Sulfur Dioxide	0.04 ppm, 24-hr avg.> 0.25 ppm, 1-hr. avg. >	0.03 ppm, ann. avg.> 0.14 ppm, 24-hr avg.>	(a) Bronchoconstriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in persons with asthma
Suspended Particulate Matter (PM10)	30 $\mu g/m^3$, ann. geometric mean > 50 $\mu g/m^3$, 24-hr average>	50 $\mu g/m^3$, annual arithmetic mean > 150 $\mu g/m^3$, 24-hr avg.>	(a) Excess deaths from short-term exposures and exacerbation of symptoms in sensitive patients with respiratory disease; (b) Excess seasonal declines in pulmonary function, especially in children
Sulfates	25 $\mu g/m^3$, 24-hr avg. >=		(a) Decrease in ventilatory function; (b) Aggravation of asthmatic symptoms; (c) Aggravation of cardio-pulmonary disease; (d) Vegetation damage; (e) Degradation of visibility; (f) Property damage
Lead	1.5 $\mu g/m^3$, 30-day avg. >=	1.5 $\mu g/m^3$, calendar quarter>	(a) Increased body burden; (b) Impairment of blood formation and nerve conduction
Visibility-Reducing Particles	In sufficient amount to reduce the visual range to less than 10 miles at relative humidity less than 70%, 8-hour average (10am - 6pm)		Visibility impairment on days when relative humidity is less than 70 percent

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District

Carbon Monoxide

Source/ Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hour	Max. Conc. in ppm 8-hour		No. Days Standard Exceeded[a)] Federal ≤9.5 ppm 8-hr.	State >9.0 ppm 8-hr.
LOS ANGELES COUNTY							
1	Central LA	364	7	6.1		0	0
2	NW Coast LA Co	362	6	4.5		0	0
3	SW Coast LA Co	361	10	9.4		0	0
4	S Coast LA Co	358	7	6.6		0	0
6	W Sn Fernan V	365	9	9.3		0	0
7	E Sn Fernan V	362	9	9.0		0	0
8	W Sn Gabrl V	356	9	6.6		0	0
9	E Sn Gabrl V1	356*	5*	3.9*		0*	0*
9	E Sn Gabrl V2	--	--	--		--	--
10	Pomona/Wln	356	10	6.7		0	0
11	S Sn Gabrl V	363	7	5.6		0	0
12	S Cent LA Co 1	361	19	11.0		8	10
12	S Cent LA Co 2	349	19	11.7		6	6
13	Sta Clarita V	356	7	3.6		0	0
ORANGE COUNTY							
16	N Orange Co	364	11	5.3		0	0
17	Cent Orange Co	123*	8*	5.3*		0*	0*
18	N Coast Orange	359	8	6.4		0	0
19	Saddleback V 1	365	4	2.5		0	0
19	Saddleback V 2	--	--	--		--	--
RIVERSIDE COUNTY							
22	Norco/Corona	--	--	--		--	--
23	Metro Riv Co 1	354	7	4.4		0	0
23	Metro Riv Co 2	300*	7*	4.1*		0*	0*
24	Perris Valley	--	--	--		--	--
25	Lake Elsinore	--	--	--		--	--
29	Banning Airport	--	--	--		--	--
30	Coachella V1**	350	3	1.8		0	0
30	Coachella V2**	--	--	--	--	--	--
SAN BERNARDINO COUNTY							
32	NW SB V	--	--	--	--	--	--
33	SW SB V 1	--	--	--	--	--	--
33	SW SB V 2	--	--	--	--	--	--
34	Cent SB V 1	--	--	--	--	--	--
34	Cent SB V 2	358	5	4.0	0	0	0
35	E SB V	--	--	--	--	--	--
37	Cent SB Mtns	--	--	--	--	--	--

ABBREVIATIONS USED IN THE AREA NAMES: LA = Los Angeles, SB = San Bernardino, N = North, S = South, W = West, E = East, V = Valley, P = Pass, Cent = Central

ppm - Parts per million parts of air, by volume.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea Air Basin
a) - The federal 1-hour standard (1-hour average CO > 35 ppm) was not exceeded.

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

Ozone

Source/ Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hour	Max Conc. in ppm 8-hour	Fourth High Conc. ppm 8-hour	No. Days Standard Exceeded: Federal > .12 ppm 1-hr.	Federal > .08 ppm 8-hr.	State > .09 ppm 1-hr
LOS ANGELES COUNTY								
1	Central LA	362	0.13	0.11	0.079	1	2	13
2	NW Coast LA Co	365	0.12	0.08	0.069	0	0	4
3	SW Coast LA Co	362	0.15	0.09	0.066	1	1	1
4	S Coast LA Co	362	0.13	0.08	0.068	1	0	3
6	W Sn Fernan V	365	0.10	0.09	0.081	0	1	5
7	E Sn Fernan V	362	0.12	0.10	0.084	0	3	13
8	W Sn Gabrl V	361	0.12	0.10	0.086	0	4	15
9	E Sn Gabrl V1	339*	0.14*	0.10*	0.095*	2*	9*	24*
9	E Sn Gabrl V2	362	0.14	0.11	0.096	3	8	25
10	Pomona/Wln V1	358	0.14	0.10	0.089	2	10	19
11	S Sn Gabrl V	363	0.12	0.10	0.080	0	2	6
12	S Cent LA Co 1	363	0.12	0.06	0.041	0	0	1
12	S Cent LA Co 2	342*	0.16*	0.09*	0.083*	1*	2*	6*
13	Sta Clarita V	357	0.12	0.10	0.095	0	13	18
ORANGE COUNTY								
16	N Orange Co	365	0.12	0.09	0.078	0	1	6
17	Cent Orange Co	157*	0.10*	0.08*	0.061*	0*	0*	1*
18	N Coast Orange	350	0.10	0.08	0.070	0	0	1
19	Saddleback V 1	361	0.10	0.08	0.071	0	0	2
19	Saddleback V 2	--	--	--	--	--	--	--
RIVERSIDE COUNTY								
22	Norco/Corona	--	--	--	--	--	--	--
23	Metro Riv Co 1	359	0.14	0.11	0.104	3	27	38
23	Metro Riv Co 2	--	--	--	--	--	--	--
24	Perris Valley	365	0.11	0.10	0.091	0	7	10
25	Lake Elsinore	360	0.14	0.13	0.106	4	37	51
29	Banning Airport	358	0.14	0.13	0.114	5	33	55
30	Coachella V 1**	349	0.13	0.11	0.098	1	21	27
30	Coachella V 2**	358	0.13	0.11	0.089	1	7	13
SAN BERNARDINO COUNTY								
32	NW SB V	361	0.15	0.12	0.103	4	17	29
33	SW SB V 1	--	--	--	--	--	--	--
33	SW SB V 2	--	--	--	--	--	--	--
34	Cent SB V 1	365	0.14	0.10	0.098	4	16	26
34	Cent SB V 2	365	0.16	0.13	0.115	14	31	45
35	East SB V	365	0.15	0.13	0.115	12	39	59
37	Cent SB Mtns	365	0.17	0.14	0.133	30	90	93

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ppm - Parts per million parts of air, by volume.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea Air Basin.

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

Nitrogen Dioxide					
Source/ Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hour	Average Compared to Federal Standard[b)] AAM in ppm	No. Days Std. Exc'd State > 0.25 ppm 1-hour
LOS ANGELES COUNTY					
1	Central LA	347	0.21	0.0391	0
2	NW Coast LA Co	359	0.13	0.0291	0
3	SW Coast LA Co	356	0.13	0.0295	0
4	S Coast LA Co	359	0.15	0.0342	0
6	W Sn Fernan V	354	0.12	0.0287	0
7	E Sn Fernan V	343	0.18	0.0456	0
8	W Sn Gabrl V	362	0.16	0.0379	0
9	E Sn Gabrl V 1	327*	0.16*	0.0390*	0*
9	E Sn Gabrl V 2	357	0.14	0.0328	0
10	Pomona/Wln V	346	0.16	0.0503	0
11	S Sn Gabrl V	333*	0.16*	0.0391*	0
12	S Cent LA Co 1	343	0.18	0.0428	0
12	S Cent LA Co 2	148*	0.16*	0.0404*	0*
13	Sta Clarita V	141*	0.10*	0.0284*	0*
ORANGE COUNTY					
16	N Orange Co	364	0.16	0.0351	0
17	Cent Orange Co	154*	0.12*	0.0327*	0*
18	N Coast Orange Co	347	0.12	0.0209	0
19	Saddleback V 1	--	--	--	--
19	Saddleback V 2	--	--	--	--
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	--
23	Metro Riv Co 1	354	0.13	0.0225	0
23	Metro Riv Co 2	--	--	--	--
24	Perris Valley	--	--	--	--
25	Lake Elsinore	334*	0.11*	0.0200*	0
29	Banning Airport	361	0.31	0.0243	1
30	Coachella V 1**	350	0.07	0.0195	0
30	Coachella V 2**	--	--	--	--
SAN BERNARDINO COUNTY					
32	NW SB V	357	0.13	0.0398	0
33	SW SB V 1	--	--	--	--
33	SW SB V 2	--	--	--	--
34	Cent SB V 1	343	0.15	0.0388	0
34	Cent SB V 2	355	0.14	0.0358	0
35	E SB V	--	--	--	--
37	Cent SB Mtns	--	--	--	--

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ppm - Parts per million parts of air, by volume.
AAM - Annual arithmetic mean.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea Air Basin.
b) - The federal standard is annual arithmetic mean NO^2 greater than 0.0534 ppm. No location exceeded this standard.

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

Sulfur Dioxide

Source/ Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in ppm 1-hour[c)]	Max. Conc. in ppm 24-hour [c)]	Average Compared to Federal Standard[d)] AAM in ppm
LOS ANGELES COUNTY					
1	Central LA	333*	0.05*	0.010*	0.0023*
2	NW Coast LA Co	--	--	--	--
3	SW Coast LA Co	363	0.09	0.020	0.0040
4	S Coast LA Co	360	0.05	0.011	0.0027
6	W Sn Fernan V	--	--	--	--
7	E Sn Fernan V	346	0.01	0.003	0.0001
8	W Sn Gabrl V	--	--	--	--
9	E Sn Gabrl V 1	--	--	--	--
9	E Sn Gabrl V 2	--	--	--	--
10	Pomona/Wln V	--	--	--	--
11	S Sn Gabrl V	--	--	--	--
12	S Cent LA Co 1	--	--	--	--
12	S Cent LA Co 2	--	--	--	--
13	Sta Clarita V	--	--	--	--
ORANGE COUNTY					
16	N Orange Co	--	--	--	--
17	Cent Orange Co	--	--	--	--
18	N Coast Orange	363	0.02	0.008	0.0007
19	Saddleback V 1	--	--	--	--
19	Saddleback V 2	--	--	--	--
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	--
23	Metro Riv Co 1	358	0.03	0.011	0.0014
23	Metro Riv Co 2	--	--	--	--
24	Perris Valley	--	--	--	--
25	Lake Elsinore	--	--	--	--
29	Banning Airport	--	--	--	--
30	Coachella V 1**	--	--	--	--
30	Coachella V 2**	--	--	--	--
SAN BERNARDINO COUNTY					
32	NW SB V	--	--	--	--
33	SW SB V 1	--	--	--	--
33	SW SB V 2	--	--	--	--
34	Cent SB V 1	355	0.01	0.010	0.0018
34	Cent SB V 2	--	--	--	--
35	E SB V --	--	--	--	
37	Cent SB Mtns	--	--	--	--

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ppm - Parts per million parts of air, by volume.

AAM - Annual arithmetic mean.

* - Less than 12 full months of data. May not be representative.

-- - Pollutant not monitored.

** - Salton Sea Air Basin.

c) - The state standards are 1-hour average > 0.25 ppm and 24-hour average >0.04 ppm. No location exceeded state standards.

d) - The federal standard is annual arithmetic mean SO_2 greater than 80 $\mu g/m^3$ (0.03 ppm). No location exceeded this standard. The other federal standards (3-hour average > 0.50 ppm, and 24-hour average > 0.14 ppm) were not exceeded either

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

Suspended Particulates PM10[e)]

Source/ Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in µg/m3 24-hour	No. (%) Samples Exceeding Standard: Federal >150 µg/m3 24-hour	State >50 µg/m3 24-hour	Annual Averages[g)] AAM Conc. µg/m3	AGM Conc. µg/m3
LOS ANGELES COUNTY							
1	Central LA	60	88	0	19(33)	44.8	42.1
2	NW Coast LA Co	--	--	--	--	--	--
3	SW Coast LA Co	60	69	0	6(10)	35.6	33.4
4	S Coast LA Co	59	79	0	13(22)	38.9	36.4
6	W Sn Fernan V	--	--	--	--	--	--
7	E Sn Fernan V	60	82	0	21(35)	43.7	40.6
8	W Sn Gabrl V	--	--	--	--	--	--
9	E Sn Gabrl V 1	60	103	0	35(58)	56.3	51.5
9	E Sn Gabrl V 2	--	--	--	--	--	--
10	Pomona/Wln V	--	--	--	--	--	--
11	S Sn Gabrl V	--	--	--	--	--	--
12	S Cent LA Co 1	--	--	--	--	--	--
12	S Cent LA Co 2	--	--	--	--	--	--
13	Sta Clarita V	56	75	0	12(21)	38.4	34.5
ORANGE COUNTY							
16	N Orange Co	--	--	--	--	--	--
17	Cent Orange Co	39*	122*	0*	15(39)*	49.4*	43.4*
18	N Coast Orange	--	--	--	--	--	--
19	Saddleback V 1	60	111	0	6(10)	36.7	34.2
19	Saddleback V 2	33*	56*	0*	1(3)*	28.8*	27.6*
RIVERSIDE COUNTY							
22	Norco/Corona	56	136	0	31(55)	55.4	49.0
23	Metro Riv Co 1	64	153	1(2)	46(72)	72.3	64.9
23	Metro Riv Co 2	--	--	--	--	--	--
24	Perris Valley	60	112	0	30(50)	50.0	44.0
25	Lake Elsinore	--	--	--	--	--	--
29	Banning Airport	34*	86*	0*	4(12)*	34.5*	29.8*
30	Coachella V 1**	58	104	0	3(5)	28.8	26.1
30	Coachella V 2**	56	119	0	30(54)	52.7	49.8
SAN BERNARDINO COUNTY							
32	NW SB V	--	--	--	--	--	--
33	SW SB V 1	57	112	0	32(56)	55.3	49.9
33	SW SB V 2	55	183	1(2)	37(67)	65.9	58.6
34	Cent SB V 1	59	116	0	36(61)	60.2	54.3
34	Cent SB V 2	59	134	0	33(56)	56.5	50.6
35	E SB V	57	92	0	23(40)	46.6	40.5
37	Cent SB Mtns	57	47	0	0	27.1	23.6

ABBREVIATIONS USED IN THE AREA NAMES: LA = Los Angeles, SB = San Bernardino, N = North, S = South, W = West, E = East, V = Valley, P = Pass, Cent = Central

µg/m^3 - Micrograms per cubic meter of air.
AAM - Annual arithmetic mean. AGM - Annual geometric mean.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea Air Basin.
e) - PM10 samples were collected every 6 days using the size-selective inlet high volume sampler with quartz filter media
g) - Total suspended particulates, lead, and sulfate were determined from samples collected every 6 days by the high volume sampler method, on glass fiber filter media. Federal TSP standard superseded by PM_{10} standard, July 1, 1987.
h) - Federal PM10 standard is AAM > 50 µg/m^3; state standard is AGM > 30 µg/m^3

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

Suspended Particulates PM2.5[f)]					
				No. (%) Samples Exceeding Standard	Annual Averages[i)]
Source/ Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in $\mu g/m^3$ 24-hour	Federal >65 $\mu g/m^3$ 24-hour	AAM Conc. $\mu g/m^3$
LOS ANGELES COUNTY					
1	Central LA	136	69.3	2(2)	23.1
2	NW Coast LA Co	--	--	--	--
3	SW Coast LA Co	--	--	--	--
4	S Coast LA Co	148	66.9	1(1)	21.5
6	W Sn Fernan V	71*	79.0*	1(1)*	17.5*
7	E Sn Fernan V	106	79.5	1(1)	23.3
8	W Sn Gabrl V	95*	73.0*	1(1)*	20.6*
9	E Sn Gabrl V 1	144	81.3	3(2)	25.6
9	E Sn Gabrl V 2	--	--	--	--
10	Pomona/Wln V	--	--	--	--
11	S Sn Gabrl V	111	85.6	2(2)	25.7
12	S Cent LA Co 1	110	67.8	1(1)	24.2
12	S Cent LA Co 2	--	--	--	--
13	Sta Clarita V	--	--	--	--
ORANGE COUNTY					
16	N Orange Co	--	--	--	--
17	Cent Orange Co	115	68.7	2(2)	24.4
18	N Coast Orange	--	--	--	--
19	Saddleback V 1	--	--	--	--
19	Saddleback V 2	68*	56.6*	0*	16.8*
RIVERSIDE COUNTY					
22	Norco/Corona	--	--	--	--
23	Metro Riv Co 1	151	111.2	9(6)	30.9
23	Metro Riv Co 2	110	90.0	2(2)	26.9
24	Perris Valley	--	--	--	--
25	Lake Elsinore	--	--	--	--
29	Banning Airport	--	--	--	--
30	Coachella V 1**	--	--	--	--
30	Coachella V 2**	83*	29.6*	0*	12.6*
SAN BERNARDINO COUNTY					
32	NW SB V	--	--	--	--
33	SW SB V 1	96*	85.9*	2(2)*	25.7*
33	SW SB V 2	--	--	--	--
34	Cent SB V 1	121	98.0	3(3)	25.9
34	Cent SB V 2	104	121.5	4(4)	25.7
35	E SB V	--	--	--	--
37	Cent SB Mtns	--	--	--	--

ABBREVIATIONS USED IN THE AREA NAMES: LA = Los Angeles, SB = San Bernardino, N = North, S = South, W = West, E = East, V = Valley, P = Pass, Cent = Central

$\mu g/m^3$ - Micrograms per cubic meter of air.
AAM - Annual arithmetic mean. AGM - Annual geometric mean.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea Air Basin.
f) - PM2.5 federal standard was established effective September 16, 1997. PM2.5 samples were collected every 3 days using the size selective inlet high volume sampler.
i) - Federal PM2.5 standard is AAM > 15 $\mu g/m^3$

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

Particulates TSP[g)]				
			Annual Averages	
Source/ Receptor Area No.	Location of Air Monitoring Station	No. Days of Data	Max. Conc. in µg/m³ 24-hour	AAM Conc. µg/m³
LOS ANGELES COUNTY				
1	Central LA	60	138	73.7
2	NW Coast LA Co	56	108	50.9
3	SW Coast LA Co	55	113	63.9
4	S Coast LA Co	60	158	64.2
6	W Sn Fernan V	--	--	--
7	E Sn Fernan V	--	--	--
8	W Sn Gabrl V	57	109	55.1
9	E Sn Gabrl V 1	56	209	101.3
9	E Sn Gabrl V 2	--	--	--
10	Pomona/Wln V	--	--	--
11	S Sn Gabrl V	59	182	86.6
12	S Cent LA Co 1	59	176	90.9
12	S Cent LA Co 2	--	--	--
13	Sta Clarita V	--	--	--
ORANGE COUNTY				
16	N Orange Co	--	--	--
17	Cent Orange Co	--	--	--
18	N Coast Orange	--	--	--
19	Saddleback V 1	--	--	--
19	Saddleback V 2	--	--	--
RIVERSIDE COUNTY				
22	Norco/Corona	--	--	--
23	Metro Riv Co 1	60	261	120.0
23	Metro Riv Co 2	70	140	90.3
24	Perris Valley	--	--	--
25	Lake Elsinore	--	--	--
29	Banning Airport	--	--	--
30	Coachella V 1**	--	--	--
30	Coachella V 2**	--	--	--
SAN BERNARDINO COUNTY				
32	NW SB V	56	150	77.6
33	SW SB V 1	--	--	--
33	SW SB V 2	--	--	--
34	Cent SB V 1	60	232	106.3
34	Cent SB V 2	55	203	102.8
35	E SB V	--	--	--
37	Cent SB Mtns	--	--	--

µg/m³ - Micrograms per cubic meter of air.
AAM - Annual arithmetic mean. AGM - Annual geometric mean.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea Air Basin.
g) - Total suspended particulates, lead, and sulfate were from samples collected every 6 days by the high volume sampler method, on glass fiber filter media.

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

Lead[g)]

Source/ Receptor Area No.	Location of Air Monitoring Station	Max. Mo. Conc.[j)] µg/m^3	Max. Qtrly. Conc.[j)] µg/m^3
LOS ANGELES COUNTY			
1	Central LA	.0.13	0.07
2	NW Coast LA Co	--	--
3	SW Coast LA Co	0.05	0.04
4	S Coast LA Co	0.06	0.05
6	W SN Fernan V	--	--
7	E Sn Fernan V	--	--
8	W Sn Gabrl V	--	--
9	E Sn Gabrl V 1	--	--
9	E Sn Gabrl V 2	--	--
10	Pomona/Wln V	--	--
11	S Sn Gabrl V	0.21	0.09
12	S Cent LA Co 1	0.17	0.09
12	S Cent LA Co 2	--	--
13	Sta Clarita V	--	--
ORANGE COUNTY			
16	N Orange Co	--	--
17	Cent Orange Co	--	--
18	N Coast Orange	--	--
19	Saddleback V 1	--	--
19	Saddleback V 2	--	--
RIVERSIDE COUNTY			
22	Norco/Corona	--	--
23	Metro Riv Co 1	0.00	0.05
23	Metro Riv Co 2	0.05	0.04
24	Perris Valley	--	--
25	Lake Elsinore	--	--
29	Banning/San Gor P	--	--
29	Banning Airport	--	--
30	Coachella V 1**	--	--
30	Coachella V 2**	--	--
SAN BERNARDINO COUNTY			
32	NW SB V	0.07	0.05
33	SW SB V 1	--	--
33	SW SB V 2	--	
34	Cent SB V 1	--	--
34	Cent SB V 2	0.07	0.05
35	E SB V	--	--
37	Cent SB Mtns	--	--

µg/m^3 - Micrograms per cubic meter of air.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea or Majave Desert Air Basin.
g) - Total suspended particulates, lead, and sulfate were determined from samples collected every 6 days by the high volume sampler method, on glass fiber filter media.

j) - Federal lead standard is quarterly average 15 µg/m^3; state standard is monthly average 15 µg/m^3. No location exceeded lead standards. Special monitoring immediately downwind of stationary sources of lead was carried out at four locations in 1999. The maximum average concentration was 0.29 µg/m^3, recorded in Area 5, Southeast Los Angeles County, and the maximum quarterly average concentration was 0.23 µg/m^3, recorded in Area 1, Central Los Angeles.

Table 3-4
1999 Air Quality Data - South Coast Air Quality Management District
(continued)

		Sulfate[g)]	
			No. (%) Samples Exceeding Standard
Source/ Receptor Area No.	Location of Air Monitoring Station	Max. Conc. in µg/m^3 24-hour	State >=25 µg/m^3 24-hour
LOS ANGELES COUNTY			
1	Central LA	17.9	0
2	NW Coast LA Co	13.9	0
3	SW Coast LA Co	18.8	0
4	S Coast LA Co	13.7	0
6	W Sn Fernan V	--	--
7	E Sn Fernan V	--	--
8	W Sn Gabrl V	16.4	0
9	E Sn Gabrl V 1	17.8	0
9	E Sn Gabrl V 2	--	--
10	Pomona/Wln V	--	--
11	S Sn Gabrl V	25.6	1(2)
12	S Cent LA Co 1	15.6	0
12	S Cent LA Co 2	--	--
13	Sta Clarita V	--	--
ORANGE COUNTY			
16	N Orange Co	--	--
17	Cent Orange Co	--	--
18	N Coast Orange	--	--
19	Saddleback V 1	--	--
19	Saddleback V 2	--	--
RIVERSIDE COUNTY			
22	Norco/Corona	--	--
23	Metro Riv Co 1	10.7	0
23	Metro Riv Co 2	10.6	0
24	Perris Valley	--	--
25	Lake Elsinore	--	--
29	Banning Airport	--	--
30	Coachella V 1**	--	--
30	Coachella V 2**	--	--
SAN BERNARDINO COUNTY			
32	NW SB V	11.7	0
33	SW SB V 1	--	--
33	SW SB V 2	--	--
34	Cent SB V 1	12.4	0
34	Cent SB V 2	10.9	0
35	E SB V	--	--
37	Cent SB Mtns	--	--

µg/m^3 - Micrograms per cubic meter of air.
-- - Pollutant not monitored.
* - Less than 12 full months of data. May not be representative.
** - Salton Sea Air Basin.
g) - Total suspended particulates, lead, and sulfate were determined from samples collected every 6 days by the high volume sampler method, on glass fiber filter media.

In 1997, the U.S. EPA promulgated a new national ambient air quality standard for ozone. Soon thereafter, a court decision ordered that the U.S. EPA could not enforce the new standard until adequate justification for the new standard was provided. U.S. EPA appealed the decision to the Supreme Court. On February 27, 2001, the Supreme Court upheld U.S. EPA's authority and methods to establish clean air standards. The Supreme Court, however, ordered U.S. EPA to revise its implementation plan for the new ozone standard. Meanwhile, CARB and local air districts continue to collect technical information in order to prepare for an eventual SIP to reduce unhealthful levels of ozone in areas violating the new federal standard. California has previously developed a SIP for the current ozone standard, which has been approved by U.S. EPA for the South Coast Air Basin.

Carbon Monoxide

CO is a colorless, odorless gas formed by the incomplete combustion of fuels. CO competes with oxygen, often replacing it in the blood, thus reducing the blood's ability to transport oxygen to vital organs in the body. The ambient air quality standard for carbon monoxide is intended to protect persons whose medical condition already compromises their circulatory systems' ability to deliver oxygen. These medical conditions include certain heart ailments, chronic lung diseases, and anemia. Persons with these conditions have reduced exercise capacity even when exposed to relatively low levels of CO. Fetuses are at risk because their blood has an even greater affinity to bind with CO. Smokers are also at risk from ambient CO levels because smoking increases the background level of CO in their blood.

CO was monitored at 21 locations in the district in 1999. The national and state 8-hour CO standards were exceeded at two locations. The highest 8-hour average CO concentration of the year (11.7 ppm) was 123 percent of the federal standard. Source/Receptor Area No. 12, South Central Los Angeles County, reported the greatest number of the exceedances of the federal and state CO standards (eight and 10 days, respectively) in 1999.

Nitrogen Dioxide

NO2 is a brownish gas that is formed in the atmosphere through a rapid reaction of the colorless gas nitric oxide (NO) with atmospheric oxygen. NO and NO2 are collectively referred to as NOx. NO2 can cause health effects in sensitive population groups such as children and people with chronic lung diseases. It can cause respiratory irritation and constriction of the airways, making breathing more difficult. Asthmatics are especially sensitive to these effects. People with asthma and chronic bronchitis may also experience headaches, wheezing and chest tightness at high ambient levels of NO2. NO2 is suspected to reduce resistance to infection, especially in young children.

By 1991, exceedances of the federal standard were limited to one location in Los Angeles County. The Basin was the only area in the United States classified as nonattainment for the federal NO2 standard under the 1990 Clean Air Act Amendments. No location in the area of SCAQMD's jurisdiction has exceeded the federal standard since 1992 and the South Coast Air Basin was designated attainment for the national standard in 1998. In 1999, the maximum annual arithmetic mean (0.0503ppm) was 94 percent of the federal standard (the federal standard is annual arithmetic mean NO2 greater than 0.0534 ppm.). The more stringent state standard was exceeded on one day, with a maximum 1-hour average NO2 concentration (0.31 ppm) that was 124 percent of the state standard (0.25 ppm). Despite declining NOx emissions over the last decade, further NOx emissions reductions are necessary because NOx emissions are PM10 and ozone precursors.

Particulate Matter (PM10)

PM10 is defined as suspended particulate matter 10 microns or less in diameter and includes a complex mixture of man-made and natural substances including sulfates, nitrates, metals, elemental carbon, sea salt, soil, organics and other materials. PM10 may have adverse health impacts because these microscopic particles are able to penetrate deeply into the respiratory system. In some cases, the particulates themselves may cause actual damage to the alveoli of the lungs or they may contain adsorbed substances that are injurious. Children can experience a decline in lung function and an increase in respiratory symptoms from PM10 exposure. People with influenza, chronic respiratory disease and cardiovascular disease can be at risk of aggravated illness from exposure to fine particles. Increases in death rates have been statistically linked to corresponding increases in PM10 levels.

In 1999, PM10 was monitored at 21 locations in the district. There was one exceedance of the federal 24-hour standard (150 μg/m3), while the state 24-hour standard (50 μg/m3) was exceeded at 20 locations. The federal standard (annual arithmetic mean greater than 50 μg/m3) was exceeded in eight locations, and the state standard (annual geometric mean greater than 30 μg/m3) was exceeded at 17 locations.

In 1997, the U.S. EPA promulgated a new national ambient air quality standard for PM2.5, particulate matter 2.5 microns or less in diameter and a new PM10 standard as well. The PM2.5 standard complements existing national and state ambient air quality standards that target the full range of inhalable PM10. However, a court decision ordered that the U.S. EPA couldn't enforce the new PM10 standard until adequate justification for the new standard is provided. U.S. EPA is complying with the decision by considering separate fine (PM2.5) and coarse (PM2.5-10) standards. Meanwhile, CARB and local air districts continue to collect technical information in order to prepare for an eventual SIP to reduce unhealthful levels of PM2.5 in areas violating the new federal standards. California has previously developed a SIP for the current PM10 standard.

Sulfur Dioxide

SO2 is a colorless, pungent gas formed primarily by the combustion of sulfur-containing fossil fuels. Health effects include acute respiratory symptoms and difficulty in breathing for children. Though SO2 concentrations have been reduced to levels well below state and federal standards, further reductions in emissions of SO2 are needed to comply with standards for other pollutants (sulfate and PM10).

Lead

Lead concentrations once exceeded the state and national ambient air quality standards by a wide margin, but have not exceeded state or federal standards at any regular monitoring station since 1982. Though special monitoring sites immediately downwind of lead sources recorded very localized violations of the state standard in 1994, no violations were recorded at these stations since that time.

Sulfates

Sulfates are a group of chemical compounds containing the sulfate group, which is a sulfur atom with four oxygen atoms attached. Though not exceeded in 1993, 1996, 1997, and 1998, the state sulfate standard was exceeded at three locations in 1994 and one location in 1995 and 1999. There are no federal air quality standards for sulfate.

Visibility

Since deterioration of visibility is one of the most obvious manifestations of air pollution and plays a major role in the public's perception of air quality, the state of California has adopted a standard for visibility or visual range. Until 1989, the standard was based on visibility estimates made by human observers. The standard was changed to require measurement of visual range using instruments that measure light scattering and absorption by suspended particles. It has been determined that the calibration of the instruments used to measure visibility was faulty, and no reliable data are available for 1999.

Volatile Organic Compounds

It should be noted that there are no state or national ambient air quality standards for VOCs because they are not classified as criteria pollutants. VOCs are regulated, however, because reduction in VOC emissions reduces the rate of photochemical reactions that contribute to the formation of ozone. They are also transformed into organic aerosols in the atmosphere, contributing to higher PM10 and lower visibility levels.

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be hazardous. Benzene, for example, one hydrocarbon component of VOC emissions, is known to be a human carcinogen.

ENERGY RESOURCES

The following sections describe the existing setting relative to California's electricity and natural gas resources.

Electricity

The following discussion is subdivided into two sections. The first section presents an overview of California's electric system and its current constraints. The second describes current and forecasted electricity consumption for the state.[3]

Overview of California's Electric System

[3] The information presented here is taken nearly unaltered from referenced reports produced by the California Energy Commission, the California Public Utilities Commission, and the U.S. Department of Energy. References are included after each block of text.

The State's electric system has three major components: 1) generation, 2) transmission, and 3) distribution. Generation refers to the production of electricity at power plants or other facilities. California has about 1,000 generation facilities with 55,500 MW of capacity, including those run by gas and oil, nuclear power, hydro, biomass, wind, solar and cogeneration. California is able to import an additional 8,000 MW and, of these, about 4,500 MW are under contract as "firm" supplies. Transmission refers to the wires that run from generators to carry power throughout the State to distribution facilities. California has about 40,000 miles of power lines that connect utilities to the national and international electric power grid. Distribution refers to the wires and related facilities that run from customer premises to transmission substations (the sites where high voltage power is stepped down so that it can be delivered to customers on the distribution system). (CPUC, 2001)

Over the past twenty years California has transformed its electric system from one that was integrated and highly regulated to one that is unbundled and increasingly subject to competitive markets and federal oversight. As a result of the sale of the generating capacity the structure of the California electricity industry has shifted. In 1996, utilities in the state owned about 81 percent of the total generating capacity, with nonutilities (including independent electric power producers) owning the remaining 19 percent. In 1999, utilities owned about 46 percent of the total, with nonutilities owning the remaining 54 percent. Due to this shift, the utilities have become increasingly dependent on other suppliers of electric power to satisfy their legal obligation to serve all of their customers' demands. This makes them more vulnerable to prices charged by other electricity suppliers. (DOE, 2001)

Although the state retains regulatory control over utility distribution systems, the Federal Energy Regulatory Commission (FERC) regulates the transmission system operations and transmission rates. The FERC also regulates the terms and conditions of most power trades in California because most are now wholesale transactions rather than retail transactions that would be subject to state regulatory oversight. In addition, power sales and transmission are controlled mainly by two private, nonprofit organizations that have no duty to serve California's consumers or economy - the Independent Systems Operator (ISO) and the Power Exchange (PX). The ISO and the PX report to boards that are comprised of "stakeholders," who generally do not represent the public and many of whom have an interest in keeping wholesale electric prices high. These organizations do not have contact with the ultimate consumers of power and conduct much of their business in private. (CPUC, 2001)

Consumers' prices began escalating in southern California due to a combination of factors. Demand in the area had grown and local electricity supply sources had not been developed to meet them. Imports thus played a more important role. However, these imports could be limited due to the capacity of the transmission lines to bring the electricity into the State.

San Diego Gas & Electric (SDG&E) divested virtually all of its assets by the spring of 1999. As a result, SDG&E announced that it would pay off its stranded costs, ending the price-cap in July 1999. This allowed SDG&E to charge market prices and pass on to its customers the actual costs of the electricity. The other two investor-owned utilities in the state (i.e., PG&E and SCE) are, however, under severe constraints because deregulation does not currently allow them to pass on the actual costs to customers and they have to absorb the associated losses.

California has taken a number of actions to contain the situation. The state enacted legislation (AB 265) in September 2000 to re-cap rates at 6.5 cents per kilowatt-hour for SDG&E customers (to be retroactively effective for selected customers from June 1, 2000). Another law (AB 970) authorized various agencies in the state reduce the time necessary to issue permits to operate peaker power plants where necessary. In early January 2001, the state granted temporary rate relief to PG&E and SCE to reduce the losses they sustained. The State also has been buying power directly and making it available to the utilities at cost. The State is also negotiating long-term contracts with generators as well as the purchase of the PG&E and SCE transmission lines.

The Federal Government and the U.S. Department of Energy (DOE) have also been actively involved with the situation in California. FERC issued a set of directives aimed at fixing malfunctioning markets in California on December 15, 2000. The impact of these directives has been to permit PG&E and SCE to supply their electricity demands from the generating plants they still own, rather than having to sell their electricity on the PX.

In addition, DOE has issued several directives to electricity suppliers to continue supplying power to the utilities, despite the risk of the large debts that the utilities were amassing. Suppliers of natural gas, whose price has also risen sharply due a supply shortage, were also precluded from withholding deliveries to the utilities.

Despite these measures, a Stage 3 emergency was in force numerous times this winter. A Stage 3 emergency indicates that the State has less than 1.5 percent of electricity reserves. The DOE report identifies the following as the constraints leading to the shortage in electricity supply[4]:

- a lack of precipitation in the Northwest, reducing the already scarce amount of available hydroelectric capacity in the western States;
- the constrained capacity of the transmission lines to bring more electricity into the State; and
- the high level of planned and unplanned outages, due to the extended use of the power plants during the previous exceptionally hot summer months.

(DOE, 2001)

California customers have endured electricity outages and, in San Diego, huge increases in their bills as a result of price spikes in wholesale markets. According to the CPUC, the extent of the summer's wholesale price spikes cannot be explained by hot weather, increased natural gas prices, or increases in demand. Other problems - such as out-of-service power plants, transmission supply constraints and a dysfunctional power market - may have contributed to the problems. The state's short-term problems appear to evolve at least in part from past public policy choices regarding electricity supply combined with customer demand that has grown as a result of the state's robust economy. According to the CPUC, the high prices and outages of June 2000 were caused by a number of events and circumstances:

- new power supplies are inadequate to meet increasing demand;
- existing power plants are aging and in need of attention;

[4] The DOE report also indicates some power plants were unavailable because they had used their allocated emissions allowances, but the SCAQMD is unaware of any such circumstance.

- limited transmission facilities have also contributed to short supply, especially in San Diego and San Francisco;
- the State has reduced the role of energy efficiency and construction of renewable energy resources in recent years;
- California's economy has flourished, creating new demand and its high technology sector is highly dependent on electricity; and
- California's electric system is no longer consistently reliable.

The pricing system, in combination with inelastic customer demand and the ability of power sellers to withhold supply, results in wholesale prices that may bear no relationship to power producers' costs[5]. At the same time, no government body was compelling power plant construction or maintenance during this period of aging plants and short supplies.

In sum, power supply shortages, increased demand and a dysfunctional market are converging to undermine the state's ability to assure its businesses and citizens have clean, reliable and reasonably priced electricity. (CPUC, 2001)

Forecasted Electricity Consumption

Notwithstanding the preceding CPUC data, additional generating capacity is coming on-line to meet the state’s demand. Table 3-5 shows historical and forecast electricity consumption for major utilities. The data shown in Table 3-5 are for selected years and include loads served by self-generation, but do not include energy losses. During the 1980s, total statewide electricity consumption grew from 166,979 gigawatt-hour (GWh) in 1980 to 228,038 GWh in 1990, an annual growth rate of 3.2 percent. Sacramento Municipal Utility District (SMUD), SCE, and SDG&E were high growth areas. Electricity use from 1980 to 1990 grew as follows:

- in SMUD from 5,352 GWh to 8,358 GWh (4.6 percent per year),
- in SDG&E from 9,730 GWh to 14,798 GWh (4.3 percent per year),and
- in SCE from 59,624 GWH to 81,673 GWh (3.2 percent annually).

Growth in the PG&E (2.7 percent) and Los Angeles Department of Water and Power (LADWP) (2.2 percent) areas lagged behind the other three areas and the State as a whole. Consumption growth slowed in the early 1990s as a result of the severe economic recession that struck the State from 1990 to 1994. Southern California was hardest hit by the recession and that is reflected in the weak electric growth for southern California utilities, with SCE growing by one percent from 81,673 GWh in 1990 to 88,434 GWh in 1998 and LADWP increasing from 21,971 GWh to 23,004 GWh or 0.6 percent.

TABLE 3-5
Electricity Consumption by Utility Service Area
(GWh)

[5] In fact, the federal government has requested that power producers justify the prices charged in the last few months.

Year	PG&E	SMUD	SCE	LADWP	SDG&E	Other	Total State
1980	66,197	5,352	59,624	17,669	9,730	8,406	166,979
1990	86,806	8,358	81,673	21,971	14,798	14,432	228,038
1998	95,601	9,123	88,434	23,004	17,630	10,617	244,409
2004	109,219	10,460	100,822	24,985	20,539	13,541	279,565
2010	121,041	11,692	113,137	26,684	23,022	14,293	309,868
Annual Growth Rates (%)							
1980-90	2.7	4.6	3.2	2.2	4.3	5.6	3.2
1990-98	1.2	1.1	1.0	0.6	2.2	-3.8	0.9
1998-04	2.2	2.3	2.2	1.4	2.6	4.1	2.3
1998-10	2.0	2.1	2.1	1.2	2.2	2.5	2.0

Historic data through 1998

Over the forecast period, consumption is expected to grow at a stronger rate compared to the 1990s, but not as strong as 1980s growth. The forecast assumes steady, strong economic growth that translates into steady growth in electric consumption. Over the short term (1998-2004) consumption is projected to grow at 2.3 percent per year, and over the longer term (1998-2010) growth is expected to be two percent per year. The forecast growth is slower than 3.2 percent growth in the 1980s owing, in part, to continued savings from appliance and building standards and the shift to a less electricity intensive information economy.

The electricity data discussed above measured the amount of electricity customers used at their homes and businesses. Another measure of electricity use is the amount of electricity that must be provided by generators and supplied over the grid net energy for load. Net energy for load includes electric losses and excludes loads served by self-generation.

Table 3-6 shows historical and forecast net energy for load for major utilities and for selected years. The forecast growth rates for net energy for load are comparable to the growth rates for energy consumption.

TABLE 3-6
Net Energy for Load by Utility Service Area
(GWh)

Year	PG&E	SMUD	SCE	LADWP	SDG&E	Other	Total

							State
1980	71,861	5,695	63,370	20,055	10,419	9,028	180,428
1990	90,765	8,893	83,694	23,781	15,348	15,355	237,836
1998	98,000	9,707	90,303	24,302	18,449	11,457	252,218
2004	112,781	11,129	103,191	26,401	21,529	14,549	289,581
2010	125,739	12,440	116,344	28,330	24,188	15,381	322,421
		Annual	Growth	Rates	(%)		
1980-90	2.4	4.6	2.8	1.7	3.9	5.5	2.8
1990-98	1.0	1.1	1.0	0.3	2.3	-3 .6	0.7
1998-04	2.4	2.3	2.2	1.4	2.6	4.1	2.3
1998-10	2.1	2.1	2.1	1.3	2.3	2.5	2.1

Historic data through 1998

Statewide Peak Demand

Peak demand, expressed in megawatts (MW), measures the largest electric power requirement during a specified period of time, usually integrated over one clock hour. Peak demand is important in evaluating system reliability, determining congestion points on the electric grid, and identifying potential areas where additional transmission, distribution, and generation facilities may be needed.

California s peak demand typically occurs on a day in August between the hours of 3 and 5 p.m. High temperature leads to increased air conditioning use by residential and commercial customers. These increased air-conditioning loads in combination with industrial loads, commercial lighting and office equipment, and residential refrigerators create the peak demand use in California.

Table 3-7 below shows historical and forecast electric peak demand for major utilities and for selected years. The data shown in Table 3-7 are end use customer demand and do not include losses, but do include loads served by self-generation.

TABLE 3-7
End Use Peak Demand by Utility Service Area
(MW)

Year	**PG&E**	**SMUD**	**SCE**	**LADWP**	**SDG&E**	**Other**	**Total State**

1990	16,203	2,013	16,879	4,920	2,780	1,756	44,550
1999	19,417	2,531	18,359	5,115	3,318	2,002	50,743
2004	20,836	2,582	20,597	5,340	3,923	2,137	55,415
2010	23,034	2,859	22,871	5,604	4,367	2,300	61,034
Annual Growth Rates (%)							
1990-99	2.0	2.6	0.9	0.4	2.0	1.5	1.5
1999-04	1.4	0.4	2.3	0.9	3.4	1.3	1.8
1999-10	1.6	1.1	2.0	0.8	2.5	1.3	1.7

Historic Data through 1999

From 1900 to 1999 statewide peak demand grew at 1.5 percent a year, with peak demand in PG&E, SMUD, and SDG&E growing at a faster rate than peak demand in the State and peak demand in SCE and LADWP, as a result of the recession, growing slower than the State as a whole.

Peak demand is expected to grow at a slightly higher rate over the forecast period. In the short term (1999-2004) peak growth is projected to be 1.8 percent annually, and over the longer term of 1999-2010, annual peak growth of 1.7 percent is forecast.

The peak demand data discussed above measured the amount of electricity customers used at their homes and businesses. Another measure of electricity is the amount of electricity that must be provided by generators and supplied over the grid system peak demand. System peak demand includes line losses and excludes loads served by self-generation. The system peak demand is the load that the control area operator must meet with supply options.

TABLE 3-8
Noncoincident System Peak Demand by Utility Service Area
(MW)

Year	PG&E	SMUD	SCE	LADWP	SDG&E	Other	Total State
1990	17,250	2,195	17,647	5,336	2,973	1,854	47,255
1999	20,369	2,759	19,125	5,400	3,567	2,115	53,335
2004	21,914	2,815	21,513	5,638	4,235	2,258	58,371

2010	24,325	3,117	23,959	5,932	4,721	2,429	64,483
Annual Growth Rates (%)							
1990-99	1.9	2.6	0.9	0.1	2.0	1.5	1.4
1999-04	1.5	0.4	2.4	0.9	3.5	1.3	1.8
1999-10	1.6	1.1	2.1	0.9	2.6	1.3	1.7

Historic Data through 1999

The system peak demand is expected to grow the same as end use peak demand. From 1999 to 2004, total system peak is expected to increase at a 1.8 percent annual rate and, from 1999 to 2010, the projected annual growth is 1.7 percent. This forecast does not anticipate a major deployment of new distributed generation (which includes self-generation). Similarly, the forecast assumes no fundamental changes in electricity losses that would have resulted from changes in imports versus in-state generation. (CEC, 2000a)

To complement forecasting future electricity demand, the CEC has compiled an update on proposed power generating projects in California. As discussed in the CEC report, <u>Proposed Power Projects - An Overview, Update on Energy Commission's Review of California Power Projects</u>, the California CEC certified 12 power plants in the 1990s before the state's electricity generation industry was restructured. Of these, three were never built. Nine plants are now in operation producing 952 megawatts of generation; one of them has a Phase 2 project that is nearing completion and will add an additional 44 megawatts by May 2001. Since April 1999, the CEC has approved nine major power plant projects with a combined generation capacity of 6,278 megawatts. Six power plants, with a generation capacity of 4,308 megawatts are now under construction, with 2,368 megawatts expected to be on-line by the end of the year 2001. In addition, another 14 electricity generating projects, totaling 6,734 megawatts of generation are currently being considered for licensing by the Commission. (CEC, 2001a)

Natural Gas[6]

North America has a huge natural gas resource base. This resource base includes proven reserves that are ready to be produced, and an estimate of resources that could be developed and produced economically. With an estimated 975 trillion cubic feet (Tcf) in the U.S. (including nearly 160 Tcf of proven reserves) and 417 Tcf in Canada, this resource base can provide affordable natural gas supplies to serve the nation for the next 50 years at current demand levels. In addition to these resources, the natural gas industry is moving to develop and bring to market the large resource base located at Alaska’s North Slope and the Canadian fields located in the Beaufort Sea and McKenzie Delta regions. It is anticipated that, in six to ten years, 1,000 to 2,000 million cubic feet per day (MMcfd) in supply could be flowing to the U.S. from these regions, benefiting California and other regions.

[6] The information presented here is taken nearly unaltered from the referenced reports produced by the California Energy Commission.

Liquefied natural gas (LNG) is another economic natural gas supply source. LNG imports in recent years have been gradually building. In 1998, the U.S. received on average 234 million cubic feet per day (MMcfd). There are four LNG re-gasification facilities located on the East Coast with a present operational capacity of 1,235 MMcfd. While only two of the facilities are currently functioning, plans are being made to bring the others into operation. If this occurs, up to 2,565 MMcfd in LNG imports will be possible. Currently liquefaction facilities are being constructed in Trinidad and Venezuela to provide LNG to compete in the U.S. market. In addition to the sources mentioned above, there are other unconventional natural gas resources that will take many years to develop the technology to produce. Natural gas hydrates is one such unconventional source, consisting of gas molecules frozen between water molecules. Gas is also found in geopressured brines, underground salt-water reservoirs with large quantities of natural gas dissolved in the liquid. It is yet uncertain what the potential is for each of these unconventional resources, but it is thought to be many times greater than the present 975 trillion cubic feet (Tcf) relied upon today. (CEC, 2000b)

Four pipelines (El Paso Natural Gas, Transwestern Pipeline, Kern River Gas Transmission, and PG&E Gas Transmission-Northwest) deliver natural gas directly to California. These pipelines transport up to 7,000 MMcfd of natural gas to California from Canada, the Rocky Mountains and the Southwest. While each pipeline receives natural gas supply either directly from production facilities or from other pipelines, they also deliver gas to other states before reaching California. Thus, pipeline deliveries to California may be affected by the demands of customers upstream of the California border, including out-of-state power generators.

CEC staff believes that to meet average daily conditions, more interstate pipeline capacity will be needed to transport natural gas from these supply regions within the next five years. Several projects are being considered. Questar Pipeline Company, operator of a number of pipelines in the Rocky Mountain region, has received the approval of the FERC to convert the Four Corners Pipeline to transport natural gas rather than crude oil. With 90 MMcfd pipeline delivery to California, it extends from the San Juan Basin to Long Beach California and is expected to be operating in late 2001. Williams Companies has filed an application with the FERC to expand its Kern River system capacity by 125 MMcfd, to be operational in spring 2002. Another request for expansion will be filed by Kern River mid-2001 for a yet undisclosed capacity amount.

El Paso Natural Gas recently purchased the Plains All-American Pipeline, a crude oil pipeline extending from Santa Barbara, California to Texas. The plans are to convert the pipeline to transport natural gas to the California border and retire El Paso's older and less efficient Southern System. Initial capacity on this line could be as high as 500 MMcfd[7]. Finally, PG&E National Energy Group has announced an open season to determine the interest for expanding its PG&E Gas Transmission—NW pipeline capacity by 200 MMcfd[8]. Southern California Gas Company (SoCal Gas) has indicated that it will be adding 70 MMcfd in delivery capacity to SDG&E for use in the 2001 summer. North Baja Pipeline has filed with the FERC and its

[7] If El Paso does not retire its southern system, this would add up to 500 MMcfd in new delivery capacity to California.
[8] The new capacity would be to meet California s growing natural gas needs. The announcement indicated that up to 1000 MMcfd in new capacity additions to serve the Pacific Northwest and California would be considered over the next 10 years.

counterpart in Mexico to provide an initial 500 MMcfd capacity for Mexico and the SDG&E service area.

Table 3-9 summarizes the interstate pipeline delivery capacity picture to California. While natural gas pipeline delivery capacity to California is 7,000 MMcfd, there is less capacity available within the state to utilize that capacity. Currently there is a 350 MMcfd capacity imbalance at Topock and Needles, major points of interconnection between El Paso and SoCalGas, PG&E, and Mojave Pipeline. Even with projected growth of delivery capacity to 2002 increasing to 7,915 MMcfd, CEC staff is unaware of any proposals seeking to match delivery and receipt capacity at the California border.

Nearly 85 percent of gas consumed in the state comes from production outside the state. Half of the state's consumption is satisfied by production in the Southwest, with another quarter coming from Canada. Rocky Mountain production serves about 10 percent of the state's gas needs. Beyond the year 2000, California's natural gas use over the next decade is expected to increase from 6,400 MMcfd in 2000 to 7,500 MMcfd by 2010, a 1.5 percent increase on an annual basis. Virtually all of the increase stems from increased electric generation in California, with that sector experiencing growth in excess of 2.5 percent per year.

Currently, the SoCal Gas service area has flexibility to meet its natural gas customers needs. This is due to both to its receipt capacity of 3,500 MMcfd and its large natural gas storage capability. But during the past couple of years, the company has had to depend more often and for longer periods of time on its storage to meet summer natural gas demand. This was because its supply receipt points were operating at or near capacity during this time and more gas was needed to meet increased power plant natural gas needs. Without adequate storage when receipt capacity is running full to meet demand, SoCal Gas losses its flexibility to meet peak demand.

Storage injection to meet 2000 winter storage needs were delayed until September and October because of summer gas demand. Full storage was not accomplished due to the continued high electric gas demand and the El Paso pipeline eruption.

Table 3-9
Interstate Pipeline Delivery Capacity to California
(MMcfd)

PIPELINE	CURRENT CAPACITY	CAPACITY ADDITIONS	2002 TOTAL CAPACITY
PG&E Transmission	1920	200	2120
El Paso	3290	500	3790
Transwestern	1090	--	1090
Kern River	700	125	825
Southern Trails	--	90	90
TOTAL	**7000**	**915**	**7915**

1) PG&E Gas Transmission delivery capacity to California is impacted by its deliveries to the Tuscarora Pipeline, which has a rated capacity of 125 MMcfd. Cold weather in the Pacific Northwest can reduce deliveries to California by 350 MMcfd.
2) Kern River has filed with the FERC for 125 MMcfd in capacity additions but can increase its capacity by another 375 MMcfd by adding additional compression stations along its pipeline. Kern River is also exploring extending its pipeline into the Los Angeles basin with a 300 MMcfd pipeline lateral. The pipeline extension would not increase Kern River delivery capacity to California.
3) Southern Trails will also have the capacity to deliver up to 125 MMcfd to points inside the California border. It will have interties with other pipelines in California.
4) El Paso s Plains All American Pipeline conversion was assumed to be new capacity.

The growth in demand for the SoCal Gas system will be driven by electricity generation. The levels of natural gas needed for electricity generation will be dependant on how much new southwest generation is built in the next few years and the availability of southwest electricity imports into California. More electricity imports would reduce natural gas demand for electricity generation. Conversely, lower levels of imports would mean a higher need for natural gas for electricity generation.

Congestion is now occurring at Topock because of its desirability as a natural gas delivery point into the SoCal Gas system at the Arizona and California border. Additionally, since mid June SoCal Gas has been running at near capacity to receive natural gas from its various supply sources. This may be indicative that new receipt capacity is needed now. Expansion options would be at Wheeler Ridge (supply from PG&E, Mojave/Kern River and California production in the San Joaquin Valley), Topock (supply from El Paso) and Needles (supply from Transwestern). The Topock receipt point is always running full and may be the most appropriate location for capacity reinforcement.

Alternatively, the extension of interstate pipeline capacity into the SoCal Gas service could alleviate some supply delivery concerns in the service area. Both Southern Trails and Kern River pipeline system operators have proposed to provide natural gas delivery service into the Los Angeles Basin. The completion of these proposed projects potentially would increase the supply flexibility in the area, reducing the need for SoCal Gas to add new receipt capacity, and increase competition. Each of the pipeline projects could deliver both to SoCal Gas and directly to noncore consumers. (CEC, 2001b)

HAZARDS AND HAZARDOUS MATERIALS

Implementation of the proposed project may result in the increased use of CNG, LNG, and LPG as alternative fuels and ammonia (in SCR systems) for NOx control. As discussed in detail in the Initial Study, an incremental increase in the use of CNG, LNG, LPG would not have significant adverse hazard impacts. Though CNG, LNG, and LPG pose some different hazards during storage, handling, transport, and use than conventional fuels (e.g., diesel fuel), these clean fuels are widely used and their potential hazards are well understood and accounted for in building and fire codes and standard emergency planning. Existing emergency planning is anticipated to adequately minimize the risk associated with the substitution of natural gas or petroleum gas for diesel fuel. It was concluded in the Initial Study that the increased use of alternative clean fuels would not create significant adverse hazard impacts. Consequently, this EA does not further discuss these substances relative to hazards. The reader is referred to the Initial Study (Appendix B).

The following discusses the potential hazards associated with the increased transport, storage, and use of ammonia. Also included is a summary of the regulatory requirements intended to minimize the potential impacts associated with use of hazardous materials at industrial or commercial facilities.

Hazardous Properties of Ammonia

Ammonia is colorless gas with a strong odor that can be detected at concentrations below those that cause adverse effects. It is one of the most widely produced and used chemicals in the US. Large quantities are used in making fertilizers, plastics, dyes, textiles, detergents, pesticides, and in other industrial uses. Because of ammonia's widespread use, it is produced, transported, and stored in massive bulk quantities.

Ammonia used SCR systems can be transported and stored as either anhydrous (i.e.,pure) or aqueous ammonia (typically either 29 percent or 19 percent by weight). Aqueous ammonia at concentrations less than 20 percent is not considered a hazardous substance under federal Risk Management Program requirements (title 40 of the CFR, Part 68). Under current California Office of Emergency Services (OES) regulations implementing the California Accidental Release Program (CalARP) requirements, there is no threshold concentration of aqueous ammonia for exclusion from the program (California Health and Safety code Section 2770.1). On June 19, 1998, the California Office of Environmental Health Hazard Assessment (OEHHA) issued recommended changes to the list of regulated substances in the CalARP program that included a proposed change in aqueous ammonia applicability to solutions of 20 percent or greater, which would match the federal program. Thus, both the U.S. EPA and the OEHHA have determined that aqueous ammonia of less than 20 percent concentration does not present a significant toxic risk. However, California OES has not yet acted on the OEHHA's proposed change. Current SCAQMD policy with regard to permitting SCR systems requires the use of aqueous ammonia.

To analyze the potential offsite consequences of potential accidental releases of regulated substances, a concentration endpoint is needed. The endpoint used in Risk Management Plans (RMPs) under the California Accidental Release Prevention (CalARP) Program and U.S. EPA RMP requirements for regulated substances is the Emergency Response Planning Guideline Level 2 (ERPG-2), unless an ERPG-2 has not been developed for the substance. The American Industrial Hygiene Association develops ERPGs for hazardous substances. The ERPG-2 value is the maximum airborne concentration at which it is believed that nearly all individuals could be exposed for up to one hour without experiencing any irreversible or other serious health effects or symptoms that could impair an individual's ability to take protective action. Table 3-10 shows Emergency Response Planning Guidelines (ERPG) for ammonia.

Table 3-10
Emergency Response Planning Guidelines for Ammonia

Ammonia Concentrations	Responses to Exposure
25 ppm	No significant changes in pulse, blood pressure, and pulmonary function.*
50 ppm	Noted acclimation to odor: no significant physiological changes.*
100 ppm	With excursions to 200 ppm; caused no significant changes in vital functions; however, eye tearing and some discomfort were noted.*
200 ppm (ERPG-2)	The maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action.
1,000 ppm (ERPG-3)	The maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health effects.

American Industrial Hygiene Association (AIHA)
* 18 subjects, 8-hour days, for 6 weeks

Potential Hazards Associated with an Accidental Release of Ammonia

A hazard analysis generally considers the compounds or physical forces that can migrate off-site and result in acute health effects to individuals outside of a facility's boundaries. It should be noted that hazards exist to workers on-site. However, the workers have the benefit of training in fire and emergency response procedures, protective clothing, access to respiratory protection, and so forth. The general public does not have access to these safety precautions and measures in the event that the hazard situation occurs or migrates off-site. Therefore, workers could be exposed to hazards and still be protected because of training and personal protective equipment.

The potential hazards associated with industrial activities are a function of the materials being processed, processing systems, and procedures used to operate and maintain the facility. The hazards that are likely to exist are identified by the physical and chemical properties of the materials being handled and their process conditions. In regard to the proposed project, transport, storage and use of ammonia have the potential, under accidental upset conditions, to cause a toxic gas cloud.

Toxic gas clouds are releases of volatile chemicals (e.g., anhydrous ammonia, chlorine, hydrogen sulfide, etc.) that could form a cloud and migrate off-site, thus exposing individuals. This potential e hazard can be defined in terms of the distance that a release may travel or the number of individuals of the public potentially affected by maximum single events defined as "worst-case" scenarios. “Worst-case” scenarios represent the maximum extent of potential hazards that could occur within the process area that was evaluated, based on "worst-case" (generally low wind speed) meteorological conditions and assuming a complete release of materials.

Potential Risks associated with the Transportation of Hazardous Materials

The transportation of hazardous substances poses a potential for fires, explosions, and hazardous materials releases. In general, the greater the vehicle miles traveled, the greater the potential for an accident. Statistical accident frequency varies (especially for truck transport) and is related to the relative accident potential for the travel route since some freeways and streets are safer than others. The size of a potential release is related to the maximum volume of a hazardous substance that can be released in a single accident, should an accident occur, and the type of failure of the containment structure, e.g., rupture or leak. The potential consequences of the accident are related to the size of the release, the population density at the location of the accident, the specific release scenario, the physical and chemical properties of the hazardous material, and the local meteorological conditions.

The factors that enter into accident statistics include distance traveled and type of vehicle or transportation system. Factors affecting automobiles and truck transportation accidents include the type of roadway, presence of road hazards, vehicle type, maintenance and physical condition, and driver training. A common reference frequently used in measuring risk of an accident is the number of accidents per million miles traveled. Complicating the assessment of risk is the fact that some accidents can cause significant damage without injury or fatality.

Every time hazardous materials are moved from the site of generation, opportunities are provided for accidental (unintentional) release. A study conducted by the U.S. EPA indicates that the expected number of hazardous materials spills per mile shipped ranges from one in 100 million miles to one in one million miles, depending on the type of road and transport vehicle used. The U.S. EPA analyzed accident and traffic volume data from New Jersey, California, and Texas, using the Resource Conservation and Recovery Act Risk/Cost Analysis Model and calculated the accident involvement rates presented in Table 3-11.

Table 3-11
Truck Accident Rates For Cargo On Highways

Highway Type	Accidents Per 1,000,000 Miles
Interstate	0.13
U.S. and State Highways	0.45
Urban Roadways	0.73
Composite*	0.28

Source: U.S. Environmental Protection Agency, 1984.
* Average number for transport on interstates, highways, and urban roadways.

The U.S. EPA Accidental Release Information (ARIP) database lists 17 releases of liquid ammonia in California from 1988 to 1998. Over half of the releases were anhydrous ammonia releases primarily involving refrigeration units. Nationally, from 1986 to 1998, there were 872 reported releases of ammonia gas, liquid and vapor. Of those, 137 involved liquid ammonia and most of those were anhydrous not aqueous ammonia.

In the study completed by the U.S. EPA, cylinders, cans, glass, plastic, fiber boxes, tanks, metal drum/parts, and open metal containers were identified as usual container types. For each container type, the expected fractional release en route was calculated. The study concluded that the release rate for tank trucks is much lower than for any other container type

Some of the factors which need to be considered when determining the safest hazardous materials transportation routes include traffic volume, vehicle type, road capacity, pavement conditions, emergency response capabilities, spill records, adjacent land use, and population density. In managing the risk involved in the transportation of hazardous materials, all these factors must be considered.

The actual occurrence of an accidental release of a hazardous material cannot be predicted. The location of an accident or whether sensitive populations would be present in the immediate vicinity also cannot be identified. In general, the shortest and most direct route that takes the least amount of time would have the least risk of an accident. Hazardous material transporters do not routinely avoid populated areas along their routes, although they generally use approved truck routes that take population densities and residential areas into account.

Regulatory Background

There are many federal and state rules and regulations that facilities must comply with which serve to minimize the potential impacts associates with hazards at industrial or commercial facilities.

Under the Occupational Safety and Health Administration (OSHA) regulations [29 Code of Federal Regulations (CFR) Part 1910], facilities which use, store, manufacture, handle, process, or move highly hazardous materials must prepare a fire prevention plan. In addition, 29 CFR Part 1910.119, Process Safety Management of Highly Hazardous Chemicals, and Title 8 of the California Code of Regulations, General Industry Safety Order §5189, specify required prevention program elements to protect workers at facilities that have toxic, flammable, reactive or explosive materials. Prevention program elements are aimed at preventing or minimizing the consequences of catastrophic releases of the chemicals and include process hazard analyses, formal training programs for employees and contractors, investigation of equipment mechanical integrity, and an emergency response plan.

Section 112 (r) of the Clean Air Act Amendments of 1990 [42 U.S.C. 7401 et. Seq.] and Article 2, Chapter 6.95 of the California Health and Safety Code require facilities that handle listed regulated substances to develop Risk Management Programs (RMPs) to prevent accidental releases of these substances, U.S. EPA regulations are set forth in 40 CFR Part 68. In California, the California Accidental Release Prevention (CalARP) Program regulation (CCR Title 19, Division 2, Chapter 4.5) was issued by the Governor's Office Of Emergency Services (OES). RMPs consist of three main elements: a hazard assessment that includes off-site consequences analyses and a five-year accident history, a prevention program, and an emergency response program. RMPs for existing facilities were required to be submitted by June 21, 1999. Facilities that handle hazardous substances are also required to comply with the U.S. EPA's Emergency Planning and Community Right-to-Know Act.

The Hazardous Materials Transportation Act (HMTA) is the federal legislation that regulates transportation of hazardous materials. The primary regulatory authorities are the U.S. Department of Transportation, the Federal Highway Administration, and the Federal Railroad Administration. The HMTA requires that carriers report accidental releases of hazardous materials to the Department of Transportation at the earliest practical moment (49 CFR Subchapter C). Incidents which must be reported include deaths, injuries requiring hospitalization, and property damage exceeding $50,000. The California Department of Transportation (Caltrans) sets standards for trucks in California. The regulations are enforced by the California Highway Patrol.

California Assembly Bill 2185 requires local agencies to regulate the storage and handling of hazardous materials and requires development of a plan to mitigate the release of hazardous materials. Businesses that handle any of the specified hazardous materials must submit to government agencies (i.e., fire departments), an inventory of the hazardous materials, an emergency response plan, and an employee training program. The business plans must provide a description of the types of hazardous materials/waste on-site and the location of these materials. The information in the business plan can then be used in the event of an emergency to determine the appropriate response action, the need for public notification, and the need for evacuation.