APPENDICES

Fuels REPORT

CALIFORNIA
ENERGY
COMMISSION

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APPENDIX A

STATE ENERGY SUPPLY AND DEMAND STATISTICS: HISTORIC AND FORECASTED

TABLE A-1

HISTORICAL
PRIMARY ENERGY RECEIPTS AND DELIVERIES
(Trillions of Btu)

ORIGIN / ENERGY TYPE	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
California Receipts											
Natural Gas	346	350	344	374	346	388	397	421	464	462	433
Petroleum	1,834	1,976	1,964	1,991	2,021	2,113	2,198	2,229	2,308	2,423	2,329
Natural Gas Plant Liquids	59	57	60	62	64	59	54	48	51	50	34
Hydropower	92	57	144	134	164	119	177	232	180	132	171
Geothermal and Other	74	74	60	80	101	113	91	130	134	170	210
Subtotal California	2,405	2,514	2,572	2,641	2,696	2,792	2,917	3,060	3,137	3,237	3,177
Other States Receipts											
Natural Gas	1,144	1,104	1,046	1,215	1,253	1,340	1,148	1,024	1,059	1,122	907
Petroleum	433	637	1,377	1,701	1,708	1,718	1,363	1,342	1,476	1,334	1,690
Liquified Petroleum Gas	5	6	6	6	4	5	2	6	16	16	16
Coal	191	217	166	196	224	239	248	219	208	153	196
Hydropower	118	52	93	57	100	134	207	216	271	217	251
Nuclear	51	87	81	96	51	36	37	43	138	176	297
Subtotal Other States	1,942	2,103	2,769	3,271	3,340	3,472	3,005	2,850	3,168	3,018	3,357
Foreign Receipts											
Natural Gas	395	392	352	396	324	269	319	293	283	377	335
Petroleum	1,758	2,080	1,150	949	719	376	254	327	345	267	266
Liquified Petroleum Gas	3	1	2	3	3	2	4	2	11	12	12
Subtotal Foreign	2,156	2,473	1,504	1,348	1,046	647	577	622	639	656	613
Total Receipts											
Natural Gas	1,885	1,846	1,742	1,985	1,923	1,997	1,864	1,738	1,806	1,961	1,675
Petroleum	4,025	4,693	4,491	4,641	4,448	4,207	3,815	3,898	4,129	4,024	4,285
Liquified Petroleum Gas	67	64	68	71	71	66	60	56	78	78	62
Coal	191	217	166	196	224	239	248	219	208	153	196
Hydropower	210	109	237	191	264	253	384	448	451	349	422
Nuclear	51	87	81	96	51	36	37	43	138	176	297
Geothermal and Other	74	74	60	80	101	113	91	130	134	170	210
Grand Total Receipts	6,503	7,090	6,845	7,260	7,082	6,911	6,499	6,532	6,944	6,911	7,147
EXPORT / ENERGY TYPE											
Export											
Petroleum	687	715	704	611	602	666	673	629	653	515	570
Liquified Petroleum Gas	2	6	4	6	7	5	4	6	21	28	12
Total Export	689	721	708	617	609	671	677	635	674	543	582
STORAGE / ENERGY TYPE											
Change											
Natural Gas	43	33	-2	-40	-61	-59	-62	51	-19	-20	-4
Petroleum	-68	121	-195	4	113	-107	-35	-77	-34	-57	6
Coal	-1	10	-4	-2	3	2	-4	5	--	-2	1
Liquified Petroleum Gas	-1	0	-1	1	2	0	-1	2	-1	0	0
Total Change	-27	164	-202	-37	57	-164	-102	-19	-54	-79	3
DELIVERIES / ENERGY TYPE											
Deliveries											
Natural Gas	1,842	1,813	1,744	2,025	1,984	2,056	1,926	1,687	1,825	1,981	1,679
Petroleum											
Motor Gasoline	1,307	1,397	1,405	1,447	1,372	1,321	1,340	1,415	1,415	1,473	1,541
Aviation Fuels	336	372	387	381	363	348	335	357	392	426	440
Distillate Fuels	303	381	410	404	386	424	411	464	489	531	556
Residual Fuels	915	1,144	1,023	1,081	929	798	519	467	523	547	527
Misc. Fuels	545	563	757	713	683	757	572	643	691	589	645
Subtotal Petroleum	3,406	3,857	3,982	4,026	3,733	3,648	3,177	3,346	3,510	3,566	3,709
Liquified Petroleum Gas	66	58	65	64	62	61	57	48	58	50	50
Coal	192	207	170	198	221	237	252	214	208	155	195
Hydropower	210	109	237	191	264	253	384	448	451	349	422
Nuclear	51	87	81	96	51	36	37	43	138	176	297
Geothermal and Other	74	74	60	80	101	113	91	130	134	170	210
Grand Total Deliveries	5,841	6,205	6,339	6,680	6,416	6,404	5,924	5,916	6,324	6,447	6,562

TABLE A-2

HISTORICAL
DELIVERIES BY SECTOR
(Trillions of Btu)

SECTOR/ENERGY TYPE	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Electric Utility											
Natural Gas	302	364	312	458	534	678	571	486	599	683	442
Petroleum											
Distillate	0	0	0	0	0	0	2	2	2	2	2
Residual	596	774	619	640	391	284	99	65	22	28	38
Subtotal	596	774	619	640	391	284	101	67	24	30	40
Coal	135	141	110	138	152	165	187	188	182	128	171
Hydropower	210	109	237	191	264	253	384	448	451	349	422
Nuclear	51	87	81	96	51	36	37	43	138	176	297
Geothermal and Other	74	74	60	80	101	113	91	130	134	170	210
Total	1,368	1,549	1,419	1,603	1,493	1,529	1,371	1,362	1,528	1,536	1,582
Electricity Delivered	520	527	545	567	566	591	578	584	611	641	659
Conversion Loss	800	976	821	983	870	893	754	704	797	775	861
Transmission Loss	48	46	53	53	57	45	39	74	120	120	62
Total Loss	848	1,022	874	1,036	927	938	793	778	917	895	923
Residential End User											
Electricity	154	162	174	182	176	183	179	187	200	199	200
Natural Gas	610	569	584	621	557	518	559	515	502	510	478
Petroleum											
Distillate Fuel Oil	5	7	7	7	1	1	1	1	1	6	6
Subtotal Petroleum	5	7	7	7	1	1	1	1	1	6	6
Liquified Petroleum Gas	9	9	14	18	18	16	16	15	15	15	15
Subtotal Residential	777	747	779	828	752	718	755	718	718	730	699
Commercial End User											
Electricity	194	187	191	198	204	197	197	203	213	220	245
Natural Gas	183	187	174	177	165	178	187	173	172	197	193
Petroleum											
Motor Gasoline	11	13	16	14	10	8	8	8	8	8	8
Distillate Fuel Oil	9	13	13	10	21	30	29	27	27	13	13
Residual Fuel Oil	25	27	25	28	43	40	35	20	20	25	24
Subtotal Petroleum	45	53	54	52	74	78	72	55	55	46	45
Liquified Petroleum Gas	2	2	3	3	3	3	3	3	3	4	4
Subtotal Commercial	424	429	422	430	446	456	459	434	443	467	487
Industrial End User											
Electricity	172	178	180	187	186	211	202	194	198	222	214
Natural Gas	747	693	674	769	728	682	609	513	552	591	566
Petroleum											
Motor Gasoline	8	6	5	6	9	7	7	7	7	7	8
Distillate Fuel Oil	78	104	110	138	105	112	127	103	103	103	108
Residual Fuel Oil	106	107	90	89	85	59	55	46	46	55	53
Other Petroleum	544	561	756	711	681	754	569	640	689	586	642
Subtotal Petroleum	736	779	961	944	880	932	758	796	845	751	811
Liquified Petroleum Gas	54	47	47	41	39	39	35	27	37	29	28
Coal	57	66	60	60	69	72	65	26	26	27	24
Subtotal Industrial	1,766	1,762	1,922	2,001	1,902	1,966	1,669	1,556	1,658	1,620	1,643
Transportation End User											
Petroleum											
Motor Gasoline	1,288	1,378	1,384	1,427	1,353	1,306	1,325	1,400	1,400	1,458	1,525
Aviation Fuels	336	372	387	381	363	348	335	357	392	426	440
Distillate Fuel Oil	211	257	280	249	259	281	252	331	356	407	427
Residual Fuel Oil	188	236	289	324	410	385	330	336	435	439	412
Lube Oil	1	1	1	2	2	3	3	3	2	3	3
Subtotal Petroleum	2,024	2,244	2,341	2,383	2,387	2,353	2,245	2,427	2,585	2,733	2,807
Liquified Petroleum Gas	1	1	1	2	2	3	3	3	3	2	3
Subtotal Transportation	2,025	2,245	2,342	2,385	2,389	2,356	2,248	2,430	2,588	2,735	2,810
Total End User	4,993	5,183	5,465	5,644	5,489	5,466	5,131	5,138	5,407	5,552	5,639
				TOTAL END USER DELIVERIES							
End User Deliveries											
Electricity	520	527	545	567	566	591	578	584	611	641	659
Natural Gas	1,540	1,449	1,432	1,567	1,450	1,378	1,355	1,201	1.226	1,298	1,237
Petroleum											
Motor Gasoline	1,307	1,397	1,405	1,447	1,372	1,321	1,340	1,415	1,415	1,473	1,541
Aviation Fuels	336	372	387	381	363	348	335	357	392	426	440
Distillate Fuels	303	381	410	404	386	424	409	462	487	529	554
Residual Fuels	319	370	404	441	538	514	420	402	501	519	489
Misc. Fuels	545	563	757	713	683	757	572	643	691	589	645
Subtotal Petroleum	2,810	3,083	3,363	3,386	3,342	3,364	3,076	3,279	3,486	3,336	3,669
Liquified Petroleum Gas	66	58	65	64	62	61	57	48	58	50	50
Coal	57	66	60	60	69	72	65	26	26	27	24
Total End User	4,993	5,183	5,465	5,644	5,489	5,466	5,131	5,138	5,407	5,552	5,639

TABLE A-3

PROJECTED
PRIMARY ENERGY RECEIPTS AND DELIVERIES
(Trillions of Btu)

ORIGIN/ENERGY TYPE	1987	1992	1999	2007
California Receipts				
Natural Gas	437	618	504	444
Petroleum	2,438	2,378	2,318	2,143
Natural Gas Plant Liquids	34	35	26	24
Hydropower	159	166	174	178
Geothermal	265	320	312	320
Wind	6	8	8	8
Solar	6	8	10	9
Biomass	73	132	173	246
Subtotal California	3,418	3,665	3,525	3,372
Other States Receipts				
Natural Gas	866	827	1,136	1,381
Petroleum	1,702	1,707	1,639	1,342
Liquified Petroleum Gas	16	16	24	28
Coal	427	393	371	453
Hydropower	101	110	116	125
Nuclear	359	371	380	364
Subtotal Other States	3,471	3,424	3,666	3,693
Foreign Receipts				
Natural Gas	466	496	576	694
Petroleum	326	325	736	1,647
Liquified Petroleum Gas	12	12	12	12
Subtotal Foreign	804	833	1,324	2,253
Total Receipts				
Natural Gas	1,769	1,941	2,216	2,519
Petroleum	4,466	4,410	4,693	5,132
Liquified Petroleum Gas	62	63	62	64
Coal	427	393	371	453
Hydropower	260	276	290	303
Nuclear	359	371	380	364
Geothermal	265	320	312	320
Wind	6	8	8	8
Solar	6	8	10	9
Biomass	73	132	173	246
Grand Total Receipts	7,693	7,922	8,515	9,418
EXPORT/ENERGY TYPE				
Petroleum	697	692	670	812
Liquified Petroleum Gas	12	12	12	12
Total Export	709	704	682	824
DELIVERIES/ENERGY TYPE				
Natural Gas	1,769	1,941	2,216	2,519
Petroleum				
Motor Gasoline	1,505	1,414	1,480	1,619
Aviation Fuels	472	522	558	591
Distillate Fuels	576	608	681	764
Residual Fuels	490	487	520	571
Misc. Fuels	726	687	784	775
Subtotal Petroleum	3,769	3,718	4,023	4,320
Liquified Petroleum Gas	50	51	50	52
Coal	427	393	371	453
Hydropower	260	276	290	303
Nuclear	359	371	380	364
Geothermal	265	320	312	320
Wind	6	8	8	8
Solar	6	8	10	9
Biomass	73	132	173	246
Grand Total Deliveries	6,984	7,166	7,833	8,594

TABLE A-4

PROJECTED
DELIVERIES BY SECTOR
(Trillions of Btu)

SECTOR/ENERGY DEMAND	1987	1992	1999	2007
Electric Utility				
Natural Gas	431	467	665	858
Petroleum				
Distillate	2	3	3	3
Residual	0	0	0	0
Subtotal Petroleum	2	3	3	3
Coal(26)	398	365	343	425
Hydropower	260	276	290	303
Nuclear	359	371	380	364
Geothermal	265	320	312	320
Wind	6	8	8	8
Solar	6	8	10	9
Biomass	73	132	173	246
Total	1,800	1,950	2,184	2,536
Electricity Delivered	665	737	843	951
Conversion Loss	1,085	1,165	1,298	1,528
Transmission Loss	50	48	43	57
Total Loss	1,135	1,213	1,341	1,585
Residential End User				
Electricity	206	234	274	312
Natural Gas	558	564	579	602
Petroleum				
Distillate Fuel Oil	6	7	7	8
Subtotal Petroleum	6	7	7	8
Liquified Petroleum Gas	15	15	16	17
Subtotal Residential	785	820	876	939
Commercial End User				
Electricity	230	253	288	321
Natural Gas	208	212	228	241
Petroleum				
Motor Gasoline	8	8	9	9
Distillate Fuel Oil	14	14	16	19
Residual Fuel Oil	24	24	30	28
Subtotal Petroleum	46	46	55	56
Liquified Petroleum Gas	4	4	4	4
Subtotal Commercial	488	515	575	622
Industrial End User				
Electricity	229	250	281	318
Natural Gas	572	698	744	808
Petroleum				
Motor Gasoline	8	8	8	9
Distillate Fuel Oil	110	110	130	146
Residual Fuel Oil	54	54	57	63
Other Petroleum	726	687	784	775
Subtotal Petroleum	898	859	979	993
Liquified Petroleum Gas	29	29	27	28
Coal	29	28	28	28
Subtotal Industrial	1,757	1,864	2,059	2,185
Transportation End User				
Petroleum				
Motor Gasloline	1,489	1,398	1,463	1,601
Aviation Fuels	472	522	558	591
Distillate Fuel Oil	444	474	525	588
Residual Fuel Oil	412	409	433	480
Subtotal Petroleum	2,817	2,803	2,979	3,260
Liquified Petroleum Gas	2	3	3	3
Subtotal Transportation	2,819	2,806	2,982	3,263
Total End User	5,849	6,005	6,492	7,009
TOTAL END USE DELIVERIES				
Electricity	665	737	843	951
Natural Gas	1,338	1,474	1,551	1,661
Petroleum(34)				
Motor Gasoline	1,505	1,414	1,480	1,619
Aviation Fuels	472	522	558	591
Distillate Fuels	574	605	678	761
Residual Fuels	490	487	520	571
Mis. Fuels	726	687	784	775
Subtotal Petroleum	3,767	3,715	4,020	4,317
Liquified Petroleum Gas	50	51	50	52
Coal	29	28	28	28
Total End User	5,849	6,005	6,492	7,009

APPENDIX B

NATURAL GAS DEMAND

APPENDIX B

NATURAL GAS DEMAND

I. Introduction

This appendix presents the staff's natural gas demand forecast prepared for the 1987 Biennial Fuels Report. Public Resources Code 25310 requires the Commission to prepare long term natural gas demand forecasts as part of a comprehensive supply and demand outlook for the principal fossil fuels.

The natural gas demand forecast represents the efforts of three offices within the Energy Forecasting and Planning Division. The Demand Forecasting Office has prepared the residential, commercial and industrial demand forecasts. The Electric Resources Planning Office has prepared the basic electric generation requirements for determining the natural gas demand for electric generation. Finally, the Fossil Fuels Planning Office has converted the basic electric generation requirements into natural gas demand and integrated it with the residential, commercial and industrial forecasts into a comprehensive whole.

Table B-1 summarizes the staff's natural gas demand forecast by sector through to 2007. The summary represents the total potential natural gas demand for California except for C. P. National and Southwest Gas Corporation service areas (basically Bishop, Needles and North and South Shore Lake Tahoe). The forecast includes utility and nonutility serviced gas requirements.

Overall the forecast indicates a flat demand in the near-term with an overall 1.3 percent growth rate. Largest growth occurs in the industrial, and cogeneration sectors. Industrial growth is primarily the result of potential thermal enhanced oil recovery natural gas requirements. More reliance on California generated electricity has increased the natural gas demand for cogeneration. Further information on these forecasts is provided in the following sections.

The remainder of this Appendix is divided into two parts which provide further details and documentation of the natural gas demand forecast. Part I covers the residential, commercial, and industrial demand sectors. Part II describes the demand for gas in electricity generation. These discussions cover the underlying methodology and assumptions and compare the forecast with previous CEC forecasts.

TABLE B-1

CALIFORNIA SUMMARY[1]

FORECASTED POTENTIAL NATURAL GAS DEMAND BY SECTOR
mmcfd

Year	Residential	Commercial	Industrial	Other[2]	Cogeneration[3]	UEG [4]	Total
1985	1,397	499	1,269	42	88	1,750	5,045
1990	1,462	542	1,736	50	483	674	4,947
1995	1,496	570	1,820	52	559	814	5,311
2000	1,531	597	1,907	54	637	1,149	5,875
2007	1,578	629	2,079	56	707	1,535	6,584

[1]Includes utility and nonutility served gas requirements except for C.P. National and Southwest Gas Corporation service areas.

[2]Includes agricultural and unclassified.

[3]Incremental fuel requirement.

[4]Includes conventional oil and gas fired utility boilers and gas turbines.

II. Residential, Industrial, Commercial and Agricultural Sector Demand for Natural Gas

A. Summary

Section II of this Appendix presents forecasts of California natural gas demand for the residential, commercial, industrial and agricultural sectors. The California Energy Commission (CEC) staff prepared the forecasts in support of the second Biennial Fuels Report (BFR 2) proceedings. The forecasts present future gas consumption for the Pacific Gas and Electric, Southern California Gas and San Diego Gas and Electric service areas. Gas consumption includes California gas utility sales and producer/marketer use and sales. The forecasts exclude gas use in support of electrical generation by utilities and incremental fuel requirements for electrical generation by cogenerators. The forecasts rely on the economic/demographic projections used by staff for the Common Forecasting Methodology (CFM) 7 electricity demand forecasts. Projections of gas prices and gas use in support of Thermally Enhanced Oil Recovery (TEOR) are from the September 1986 Biennial Fuels Report (BFR 1).

Table B-2 summarizes the forecast for the three service areas and statewide. In this table "commercial" comprises the commercial building and TCU (transportation, communications and utilities) sectors which are shown separately in the tables in the body of the report. "Industrial" comprises process industries, assembly industries, and mining and extraction. "Other" comprises agriculture and unclassified.

Staff forecasts statewide gas demand to grow at an average annual rate of 2.7 percent between 1985 and 1992. Over the 22 year period through 2007, the forecast statewide growth rate is about 1.4 percent. Staff forecasts the Southern California service area to have the highest growth rate for demand. Growth in TEOR consumption is the primary cause of the Southern California Gas service area having the highest growth rate. Growth in TEOR demand accounts for about 43 percent of the statewide forecast growth through 2007. The staff expects 80 percent of TEOR use will occur in the Southern California Gas service area based on a California Public Utilities Commission Decision 86-01-025 on service areas in Kern County for TEOR.

Tables B-3 and B-4 compare the forecast presented here for BFR 2 with the similar forecast for BFR 1. For the comparison in Table B-3, the adjusted numbers for the current forecast for BFR 2 do not include TEOR use or California gas producer/marketer deliveries to customers other than utilities as these uses were not included in the comparable forecast for BFR 1. These deliverables by gas producers/marketers were assumed to continue at 1985 levels for the purposes of Table B-3. The results of Table B-3 suggest on a comparable basis the present forecast is lower than previous forecasts for each service area. Table B-3 indicates the present forecast is about 13 percent less for 2005.

TABLE B-2

FORECAST OF NATURAL GAS CONSUMPTION
BY GAS UTILITY SERVICE AREA*
(millions of therms** per year)

PACIFIC GAS AND ELECTRIC SERVICE AREA

Year	Residential	Commercial	Industrial	Other	Total
1985	2,166	852	2,213	86	5,317
1992	2,122	936	2,598	108	5,764
1999	2,162	995	2,769	112	6,038
2007	2,241	1,050	3,160	116	6,568
Average Annual Growth Rate (%)					
1985-1992	-.29	.88	2.32	3.30	1.16
1985-1999	-.01	1.11	1.61	1.90	.91
1985-2007	.16	.95	1.63	1.37	.96

SOUTHERN CALIFORNIA GAS SERVICE AREA

Year	Residential	Commercial	Industrial	Other	Total
1985	2,870	938	2,603	62	6,473
1992	3,174	1,052	4,147	74	8,448
1999	3,246	1,132	4,430	80	8,927
2007	3,414	1,203	4,762	82	9,461
Average Annual Growth Rate (%)					
1985-1992	1.45	1.65	6.88	2.56	3.88
1985-1999	.95	1.35	3.87	1.84	2.32
1985-2009	.79	1.14	2.78	1.28	1.74

* Includes all natural gas demand with the service area not associated with electrical generation.
** Therm = 100,000 Btu.

TABLE B-2 (Continued)

SAN DIEGO GAS AND ELECTRIC SERVICE AREA

Year	Residential	Commercial	Industrial	Other	Total
1985	317	126	43	11	497
1992	369	137	39	13	558
1999	375	148	41	14	578
2007	391	157	45	15	608
		Average Annual Growth Rate			
1985-1992	2.16	1.20	-1.39	2.42	1.64
1985-1999	1.20	1.16	- .34	1.74	1.09
1985-2007	.96	1.00	0.21	1.42	.92

STATEWIDE SUMMARY

Year	Residential	Commercial	Industrial	Other	Total
1985	5,353	1,915	4,860	160	12,288
1992	5,665	2,126	6,748	195	14,770
1999	5,823	2,275	7,240	206	15,544
2007	6,047	2,409	7,967	214	16,638
		Average Annual Growth Rate (%)			
1985-1992	.81	1.50	4.80	2.87	2.66
1985-1999	.60	1.24	2.89	1.82	1.69
1985-2007	.56	1.05	2.27	1.33	1.39

TABLE B-3

COMPARISON OF STAFF BFR 1 AND BFR 2
RESIDENTIAL, COMMERCIAL, INDUSTRY, AND AGRICULTURE
NATURAL GAS FORECASTS
(millions of therms per year)

	PGandE		SCG		SDG&E	
	BFR 1	BFR 2*	BFR 1	BFR 2*	BFR 1	BFR 2
1990	4,995	4,598	6,343	5,540	571	548
2005	5,787	5,150	7,213	6,307	652	600

* Adjusted by removing TEOR use and 1985 levels of gas producers/ marketing direct sales and use.

TABLE B-4

AVERAGE ANNUAL GROWTH FOR 22 YEAR FORECAST PERIOD
(Percent)

	Residential		Commercial Building		Process Industry		Assembly Industry	
	BFR 1	BFR2	BFR 1	BFR 2	BFR 1	BFR 2	BFR 1	BFR 2
PGandE	.3	.2	.9	1.0	1.7	1.0	5.1	1.6
SCG	.8	.8	1.4	1.1	1.9	1.2	4.3	1.3
SDG&E	1.3	1.0	2.1	.9	4.9	0.7	3.2	.1

The primary cause for the lower forecast for these sectors for BFR 2, excluding TEOR, is lower growth in the forecast for industrial gas demand, particularly for the assembly industries (Table B-4). The annual growth rates of future gas demand for the residential and commercial sectors show less change between the two forecasts. The assembly model forecast is lower due in part to lower value of shipment projections. The current forecast has 10 percent lower total value of shipments for assembly industries for 2005 in constant dollars than the previous forecast. Major contributors to the lower assembly forecast are the chemical and primary metal industries where projections of both value of shipments and energy intensity are substantially lower than the assumptions used in the previous forecasts.

B. Introduction

This part of the appendix presents the CEC staff forecast of natural gas consumption (utility sales plus gas from other sources) for end uses other than electrical generation. The staff forecast of natural gas demand by utilities and cogenerators for electrical generation is provided separately. The purpose of these forecasts is to assist the preparation of the Commission's second Biennial Fuels Report.

Background

The CEC staff forecast demand for electricity and natural gas in the residential, commercial, industrial and agricultural sectors using models which simultaneously forecast demand for each energy type. Recent documentation of the residential, commercial, and assembly industry energy demand models is available.[1] Additional documentation on these and the other sector models is in preparation (expected to be available by the end of August 1987).

The forecast includes all consumption for the sectors in California except gas sales by the gas utilities C. P. National and Southwest Gas Corporation. These sales account for about 0.3 percent of California demand.

Methodology

The staff prepared the natural gas forecasts using the models and data used to develop the Common Forecasting Methodology (CFM) 7 electrical demand forecast. Section D, Input Assumptions, provides additional information. The forecasts reflect reduced demand due to the conservation savings presented in Section E of the same document.

The historical data base of consumption for the forecast relies on the sales reported by the gas utilities as well as sales and use reported by California gas producers (see Section F, Historic Gas Consumption). These sales and use, as reported by the gas utilities and producers, include gas used to support electrical generation in cogeneration. As the forecasts presented here address end use demand such as process heat and space conditioning for the various sectors excluding electrical generation, the historical data were appropriately reduced by estimates of incremental gas use in cogeneration (see Section F).

As discussed in Section D, gas used in support of Thermally Enhanced Oil Recovery (TEOR) was forecast at the levels of the BFR 1 projections. Staff allocated 80 percent of the TEOR use to Southern California Gas (SCG) service area and 20 percent to PGandE service area. This split is consistent with estimates of the impact of the CPUC decision 86-01-025 in specifying Kern County service areas for TEOR. The forecasts for TEOR are included as part of mining and extraction.

C. Forecast Results

The following eight tables provide the results of the forecast for the utility service areas and statewide. The 1977 through 1985 values are historical data. The historical and forecast values reflect California gas utility sales and producer sales and use less incremental gas use in support of electrical generation in cogeneration. Table B-27 of Section F provides historic incremental fuel requirements for cogeneration. "TCU" includes consumption for transportation, communication, utilities, and some portion related to national defense. Commercial, TCU, process, and assembly values include a portion of consumption reported as unclassified by the utilities. For each forecast the first table provides the forecast in energy units and the second table provides the forecast in volume units.

The Forecast of Natural Gas Consumption

Pacific Gas and Electric Service Area

TABLE B-5

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

MAY 1987 BASELINE GAS FORECAST

PACIFIC GAS AND ELECTRIC GEOGRPHICAL REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	2593.200	890.914	121.729	.000	1841.215	621.277	242.900	81.300	34.265	6426.800
1978	2292.900	746.050	126.401	.000	1639.365	546.624	233.800	77.500	20.860	5683.500
1979	2489.000	766.536	127.571	.000	2161.037	457.096	250.000	94.600	17.360	6363.200
1980	2298.100	721.820	114.230	.000	2103.766	375.129	248.600	76.600	6.755	5945.000
1981	2079.400	675.047	118.115	.000	2024.082	337.601	226.400	64.900	7.455	5533.000
1982	2225.700	730.460	119.066	.000	1631.558	350.930	214.000	58.000	40.985	5370.700
1983	2093.400	693.666	107.841	.000	1500.087	277.341	161.600	50.600	32.165	4916.700
1984	2036.300	689.728	108.675	.000	1443.140	282.103	221.300	49.300	55.755	4886.300
1985	2165.900	726.079	125.578	.000	1669.318	302.986	241.100	54.600	31.640	5317.200
1986	2174.071	742.114	120.612	.000	1565.985	314.580	305.347	69.587	32.339	5324.633
1987	2157.615	809.572	121.746	.000	1594.801	313.032	369.693	69.441	35.278	5471.179
1988	2139.002	804.250	123.191	.000	1624.726	314.752	433.940	70.164	35.046	5545.071
1989	2120.611	798.369	124.324	.000	1646.730	315.745	498.187	70.019	34.790	5608.776
1990	2103.544	794.707	125.253	.000	1663.460	318.103	562.534	70.757	34.631	5672.988
1991	2113.655	801.124	126.595	.000	1679.324	325.252	566.803	71.502	34.910	5719.167
1992	2122.392	808.690	127.729	.000	1694.170	332.709	570.875	72.255	35.240	5764.060
1993	2127.242	814.782	128.761	.000	1708.043	338.708	575.145	72.515	35.505	5800.701
1994	2132.347	822.238	129.586	.000	1721.993	344.962	579.315	72.784	35.830	5839.055
1995	2138.661	827.170	130.722	.000	1734.154	349.963	583.486	73.064	36.045	5873.264
1996	2143.430	835.566	131.340	.000	1929.736	356.190	587.756	73.351	36.411	6093.780
1997	2149.051	843.057	132.475	.000	1763.891	361.887	591.926	73.647	36.738	5952.672
1998	2155.108	851.117	133.608	.000	1779.822	367.806	596.097	73.951	37.089	5994.597
1999	2162.198	860.397	134.537	.000	1794.637	373.905	600.267	74.263	37.493	6037.698
2000	2176.569	864.229	135.465	.000	1810.644	379.895	604.537	75.084	37.660	6084.083
2001	2182.846	868.969	136.806	.000	1824.520	386.089	608.708	75.913	37.867	6121.719
2002	2189.554	873.895	137.734	.000	1840.601	392.258	612.879	76.752	38.081	6161.753
2003	2197.725	879.936	138.766	.000	1857.847	398.787	617.049	76.752	38.345	6205.206
2004	2206.592	886.132	139.693	.000	1868.568	405.071	621.220	76.752	38.615	6242.642
2005	2217.173	892.477	141.034	.000	1883.712	411.547	625.390	76.752	38.891	6286.976
2006	2228.618	899.438	141.859	.000	1893.599	418.067	629.561	76.752	39.194	6327.088
2007	2241.346	906.659	143.097	.000	2101.911	424.660	633.632	76.752	39.509	6567.566

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	-2.23	-2.52	.39	.00	-1.22	-8.59	-.09	-4.85	-.99	-2.34
1985 - 1992	-.29	1.55	.24	.00	.21	1.35	13.10	4.08	1.55	1.16
1985 - 1999	-.01	1.22	.49	.00	.52	1.51	6.73	2.22	1.22	.91
1985 - 2007	.16	1.01	.60	.00	1.05	1.55	4.49	1.56	1.01	.96

TABLE B-6

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

MAY 1987 BASELINE GAS FORECAST

PACIFIC GAS AND ELECTRIC GEOGRPHICAL REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	677.	233.	32.	0.	481.	162.	63.	21.	9.	1677.
1978	598.	195.	33.	0.	428.	143.	61.	20.	5.	1483.
1979	650.	200.	33.	0.	564.	119.	65.	25.	5.	1661.
1980	600.	188.	30.	0.	549.	98.	65.	20.	2.	1552.
1981	543.	176.	31.	0.	528.	88.	59.	17.	2.	1444.
1982	581.	191.	31.	0.	426.	92.	56.	15.	11.	1402.
1983	546.	181.	28.	0.	392.	72.	42.	13.	8.	1283.
1984	531.	180.	28.	0.	377.	74.	58.	13.	15.	1275.
1985	565.	190.	33.	0.	436.	79.	63.	14.	8.	1388.
1986	567.	194.	31.	0.	409.	82.	80.	18.	8.	1390.
1987	563.	211.	32.	0.	416.	82.	96.	18.	9.	1428.
1988	558.	210.	32.	0.	424.	82.	113.	18.	9.	1447.
1989	553.	208.	32.	0.	430.	82.	130.	18.	9.	1464.
1990	549.	207.	33.	0.	434.	83.	147.	18.	9.	1481.
1991	552.	209.	33.	0.	438.	85.	148.	19.	9.	1493.
1992	554.	211.	33.	0.	442.	87.	149.	19.	9.	1504.
1993	555.	213.	34.	0.	446.	88.	150.	19.	9.	1514.
1994	557.	215.	34.	0.	449.	90.	151.	19.	9.	1524.
1995	558.	216.	34.	0.	453.	91.	152.	19.	9.	1533.
1996	559.	218.	34.	0.	504.	93.	153.	19.	10.	1590.
1997	561.	220.	35.	0.	460.	94.	154.	19.	10.	1554.
1998	562.	222.	35.	0.	465.	96.	156.	19.	10.	1565.
1999	564.	225.	35.	0.	468.	98.	157.	19.	10.	1576.
2000	568.	226.	35.	0.	473.	99.	158.	20.	10.	1588.
2001	570.	227.	36.	0.	476.	101.	159.	20.	10.	1598.
2002	571.	228.	36.	0.	480.	102.	160.	20.	10.	1608.
2003	574.	230.	36.	0.	485.	104.	161.	20.	10.	1620.
2004	576.	231.	36.	0.	488.	106.	162.	20.	10.	1629.
2005	579.	233.	37.	0.	492.	107.	163.	20.	10.	1641.
2006	582.	235.	37.	0.	494.	109.	164.	20.	10.	1651.
2007	585.	237.	37.	0.	549.	111.	165.	20.	10.	1714.

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	-2.23	-2.52	.39	.00	-1.22	-8.59	-.09	-4.85	-.99	-2.3
1985 - 1992	-.29	1.55	.24	.00	.21	1.35	13.10	4.08	1.55	1.1
1985 - 1999	-.01	1.22	.49	.00	.52	1.51	6.73	2.22	1.22	.9
1985 - 2007	.16	1.01	.60	.00	1.05	1.55	4.49	1.56	1.01	.9

Forecast of Natural Gas Consumption

Southern California Gas Company Service Area

TABLE B-7

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

MAY 1987 BASELINE GAS FORECAST

SOUTHERN CALIFORNIA GAS REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	3078.000	827.614	82.220	.000	1264.657	1000.940	897.700	74.400	35.770	7261.300
1978	3142.000	879.190	92.187	.000	1134.669	962.903	874.500	64.600	53.550	7203.600
1979	3321.700	881.800	89.000	.000	1181.000	909.600	917.800	70.800	.000	7371.700
1980	3183.800	801.800	90.200	.000	1239.500	871.000	929.200	65.100	.000	7180.60
1981	2783.900	783.000	91.000	.000	1255.900	841.500	853.200	71.300	.000	6679.80
1982	3005.500	833.776	96.701	.000	1115.007	637.777	802.800	60.600	1.540	6553.70
1983	2747.200	778.595	84.050	.000	1138.249	581.451	597.900	47.400	2.555	5977.40
1984	2544.600	748.266	81.158	.000	1054.226	582.155	838.400	52.200	2.695	5903.70
1985	2869.800	851.412	86.122	.000	992.294	601.322	1009.600	53.800	8.750	6473.10
1986	3071.664	832.273	88.000	.000	1007.266	643.257	1282.783	60.414	8.553	6994.21
1987	3098.077	925.501	89.220	.000	1015.701	643.786	1555.863	61.041	9.511	7398.70
1988	3111.068	926.698	90.446	.000	1024.525	643.783	1829.146	61.659	9.524	7696.84
1989	3121.672	928.132	91.772	.000	1036.212	643.442	2102.220	62.287	9.538	7995.27
1990	3133.945	929.347	92.789	.000	1045.043	644.884	2375.405	62.919	9.551	8293.88
1991	3154.193	942.127	93.814	.000	1056.307	655.132	2392.937	63.558	9.682	8367.75
1992	3174.025	957.524	95.034	.000	1070.143	666.691	2410.664	64.204	9.841	8448.12
1993	3190.400	967.101	95.852	.000	1083.356	675.911	2428.304	64.856	9.939	8515.71
1994	3206.580	977.218	96.963	.000	1098.744	685.277	2445.933	65.515	10.043	8586.27
1995	3223.724	986.651	97.981	.000	1110.502	693.599	2463.458	66.185	10.140	8652.23
1996	3237.866	996.439	98.691	.000	1136.309	702.000	2481.094	66.860	10.240	8729.50
1997	3253.401	1006.591	99.705	.000	1138.536	710.389	2498.827	67.544	10.345	8785.33
1998	3268.846	1018.457	100.625	.000	1152.934	719.886	2516.353	68.235	10.467	8855.80
1999	3285.706	1030.333	101.238	.000	1167.085	728.968	2533.982	68.932	10.589	8926.83
2000	3310.535	1036.290	102.062	.000	1180.885	736.338	2551.622	69.637	10.650	8998.01
2001	3319.564	1043.733	103.381	.000	1197.048	744.941	2569.147	70.349	10.726	9058.88
2002	3329.785	1050.764	104.411	.000	1208.929	752.680	2586.777	71.061	10.799	9115.20
2003	3343.857	1059.103	105.329	.000	1224.246	761.445	2604.406	71.061	10.884	9180.33
2004	3358.449	1067.426	106.242	.000	1236.896	769.576	2622.035	71.061	10.970	9242.65
2005	3376.315	1075.651	107.169	.000	1251.823	777.354	2639.665	71.061	11.055	9310.09
2006	3395.382	1084.536	108.180	.000	1266.628	785.847	2657.190	71.061	11.146	9379.97
2007	3414.416	1093.684	108.905	.000	1292.193	794.498	2674.917	71.061	11.240	9460.91

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	-.87	.35	.58	.00	-2.99	-6.17	1.48	-3.97	-16.14	-1.4
1985 - 1992	1.45	1.69	1.42	.00	1.08	1.49	13.24	2.56	1.69	3.8
1985 - 1999	.97	1.37	1.16	.00	1.17	1.38	6.79	1.79	1.37	2.3
1985 - 2007	.79	1.14	1.07	.00	1.21	1.27	4.53	1.27	1.14	1.7

TABLE B-8

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

MAY 1987 BASELINE GAS FORECAST

SOUTHERN CALIFORNIA GAS REGION

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	803.	216.	21.	0.	330.	261.	234.	19.	9.	1895.
1978	820.	229.	24.	0.	296.	251.	228.	17.	14.	1880.
1979	867.	230.	23.	0.	308.	237.	240.	18.	0.	1924.
1980	831.	209.	24.	0.	324.	227.	243.	17.	0.	1874.
1981	727.	204.	24.	0.	328.	220.	223.	19.	0.	1743.
1982	784.	218.	25.	0.	291.	166.	210.	16.	0.	1711.
1983	717.	203.	22.	0.	297.	152.	156.	12.	1.	1560.
1984	664.	195.	21.	0.	275.	152.	219.	14.	1.	1541.
1985	749.	222.	22.	0.	259.	157.	264.	14.	2.	1689.
1986	802.	217.	23.	0.	263.	168.	335.	16.	2.	1825.
1987	809.	242.	23.	0.	265.	168.	406.	16.	2.	1931.
1988	812.	242.	24.	0.	267.	168.	477.	16.	2.	2009.
1989	815.	242.	24.	0.	270.	168.	549.	16.	2.	2087.
1990	818.	243.	24.	0.	273.	168.	620.	16.	2.	2165.
1991	823.	246.	24.	0.	276.	171.	625.	17.	3.	2184.
1992	828.	250.	25.	0.	279.	174.	629.	17.	3.	2205.
1993	833.	252.	25.	0.	283.	176.	634.	17.	3.	2223.
1994	837.	255.	25.	0.	287.	179.	638.	17.	3.	2241.
1995	841.	258.	26.	0.	290.	181.	643.	17.	3.	2258.
1996	845.	260.	26.	0.	297.	183.	648.	17.	3.	2278.
1997	849.	263.	26.	0.	297.	185.	652.	18.	3.	2293.
1998	853.	266.	26.	0.	301.	188.	657.	18.	3.	2311.
1999	858.	269.	26.	0.	305.	190.	661.	18.	3.	2330.
2000	864.	270.	27.	0.	308.	192.	666.	18.	3.	2348.
2001	866.	272.	27.	0.	312.	194.	671.	18.	3.	2364.
2002	869.	274.	27.	0.	316.	196.	675.	19.	3.	2379.
2003	873.	276.	27.	0.	320.	199.	680.	19.	3.	2396.
2004	877.	279.	28.	0.	323.	201.	684.	19.	3.	2412.
2005	881.	281.	28.	0.	327.	203.	689.	19.	3.	2430.
2006	886.	283.	28.	0.	331.	205.	694.	19.	3.	2448.
2007	891.	285.	28.	0.	337.	207.	698.	19.	3.	2469.

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	-.87	.35	.58	.00	-2.99	-6.17	1.48	-3.97	-16.14	-1.43
1985 - 1992	1.45	1.69	1.42	.00	1.08	1.49	13.24	2.56	1.69	3.88
1985 - 1999	.97	1.37	1.16	.00	1.17	1.38	6.79	1.79	1.37	2.32
1985 - 2007	.79	1.14	1.07	.00	1.21	1.27	4.53	1.27	1.14	1.74

Forecast of Natural Gas Consumption

San Diego Gas and Electric Service Area

TABLE B-9

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

MAY 1987 BASELINE GAS FORECAST

SAN DIEGO GAS AND ELECTRIC

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	299.100	105.479	13.240	.000	14.881	28.011	2.300	9.600	7.490	480.100
1978	313.700	95.717	18.216	.100	15.456	27.931	1.700	5.100	7.980	485.900
1979	357.000	101.222	15.115	.100	15.115	26.582	1.900	10.300	3.465	530.800
1980	313.400	89.118	13.392	.100	15.452	23.899	1.000	10.100	2.240	468.700
1981	289.100	84.406	13.407	.000	12.160	25.463	1.300	8.300	2.765	436.900
1982	317.800	81.400	16.905	.000	12.209	30.876	1.800	3.600	11.410	476.000
1983	296.400	87.886	13.981	.000	7.838	20.335	2.100	6.000	4.060	438.600
1984	283.500	81.717	14.518	.000	7.790	24.875	2.700	5.200	6.300	426.600
1985	317.300	110.240	15.761	.000	7.377	33.132	2.500	7.200	3.990	497.500
1986	352.512	106.155	17.733	.000	7.963	28.843	2.750	8.397	3.842	528.195
1987	357.842	113.109	17.945	.000	7.809	28.866	2.750	8.484	4.094	540.899
1988	359.723	113.502	18.264	.000	7.718	28.816	2.750	8.570	4.108	543.451
1989	362.149	113.747	18.582	.000	7.625	27.694	2.750	8.657	4.117	545.321
1990	364.820	114.139	18.795	.000	7.518	27.667	2.750	8.745	4.131	548.464
1991	366.437	116.112	19.113	.000	7.350	28.029	2.750	8.834	4.203	552.828
1992	368.533	118.131	19.325	.000	7.282	28.458	2.750	8.923	4.276	557.677
1993	369.319	119.426	19.538	.000	7.341	28.734	3.000	9.014	4.322	560.695
1994	370.010	120.971	19.644	.000	7.418	29.012	3.000	9.106	4.378	563.540
1995	371.084	122.293	19.856	.000	7.472	29.253	3.000	9.198	4.426	566.583
1996	371.584	123.454	19.963	.000	7.518	29.493	3.000	9.293	4.468	568.772
1997	372.849	124.845	20.069	.000	7.573	29.740	3.000	9.388	4.519	571.983
1998	374.115	126.470	20.281	.000	7.641	30.036	3.000	9.483	4.577	575.605
1999	375.093	128.073	20.387	.000	7.704	30.315	3.000	9.580	4.635	578.788
2000	378.063	128.741	20.706	.000	7.813	30.686	3.250	9.678	4.660	583.597
2001	379.501	129.535	20.918	.000	7.935	31.120	3.250	9.777	4.688	586.723
2002	380.554	130.268	21.343	.000	8.046	31.505	3.250	9.876	4.715	589.558
2003	383.045	131.156	21.555	.000	8.169	31.941	3.250	9.876	4.747	593.740
2004	384.099	131.987	21.662	.000	8.285	32.344	3.250	9.876	4.777	596.281
2005	386.686	132.803	21.980	.000	8.396	32.722	3.250	9.876	4.807	600.520
2006	388.890	133.704	22.086	.000	8.514	33.135	3.250	9.876	4.839	604.295
2007	391.285	134.626	22.405	.000	8.633	33.556	3.250	9.876	4.873	608.503

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	.74	.55	2.20	.00	-8.40	2.12	1.05	-3.53	-7.57	.45
1985 - 1992	2.16	.99	2.96	.00	-.19	-2.15	1.37	3.11	.99	1.64
1985 - 1999	1.20	1.08	1.86	.00	.31	-.63	1.31	2.06	1.08	1.09
1985 - 2007	.96	.91	1.61	.00	.72	.06	1.20	1.45	.91	.92

TABLE B-10

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

MAY 1987 BASELINE GAS FORECAST

SAN DIEGO GAS AND ELECTRIC

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	78.	28.	3.	0.	4.	7.	1.	3.	2.	125.
1978	82.	25.	5.	0.	4.	7.	0.	1.	2.	127.
1979	93.	26.	4.	0.	4.	7.	0.	3.	1.	139.
1980	82.	23.	3.	0.	4.	6.	0.	3.	1.	122.
1981	75.	22.	3.	0.	3.	7.	0.	2.	1.	114.
1982	83.	21.	4.	0.	3.	8.	0.	1.	3.	124.
1983	77.	23.	4.	0.	2.	5.	1.	2.	1.	114.
1984	74.	21.	4.	0.	2.	6.	1.	1.	2.	111.
1985	83.	29.	4.	0.	2.	9.	1.	2.	1.	130.
1986	92.	28.	5.	0.	2.	8.	1.	2.	1.	138.
1987	93.	30.	5.	0.	2.	8.	1.	2.	1.	141.
1988	94.	30.	5.	0.	2.	8.	1.	2.	1.	142.
1989	95.	30.	5.	0.	2.	7.	1.	2.	1.	142.
1990	95.	30.	5.	0.	2.	7.	1.	2.	1.	143.
1991	96.	30.	5.	0.	2.	7.	1.	2.	1.	144.
1992	96.	31.	5.	0.	2.	7.	1.	2.	1.	146.
1993	96.	31.	5.	0.	2.	7.	1.	2.	1.	146.
1994	97.	32.	5.	0.	2.	8.	1.	2.	1.	147.
1995	97.	32.	5.	0.	2.	8.	1.	2.	1.	148.
1996	97.	32.	5.	0.	2.	8.	1.	2.	1.	148.
1997	97.	33.	5.	0.	2.	8.	1.	2.	1.	149.
1998	98.	33.	5.	0.	2.	8.	1.	2.	1.	150.
1999	98.	33.	5.	0.	2.	8.	1.	3.	1.	151.
2000	99.	34.	5.	0.	2.	8.	1.	3.	1.	152.
2001	99.	34.	5.	0.	2.	8.	1.	3.	1.	153.
2002	99.	34.	6.	0.	2.	8.	1.	3.	1.	154.
2003	100.	34.	6.	0.	2.	8.	1.	3.	1.	155.
2004	100.	34.	6.	0.	2.	8.	1.	3.	1.	156.
2005	101.	35.	6.	0.	2.	9.	1.	3.	1.	157.
2006	102.	35.	6.	0.	2.	9.	1.	3.	1.	158.
2007	102.	35.	6.	0.	2.	9.	1.	3.	1.	159.

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	.74	.55	2.20	.00	-8.40	2.12	1.05	-3.53	-7.57	.45
1985 - 1992	2.16	.99	2.96	.00	-.19	-2.15	1.37	3.11	.99	1.64
1985 - 1999	1.20	1.08	1.86	.00	.31	-.63	1.31	2.06	1.08	1.09
1985 - 2007	.96	.91	1.61	.00	.72	.06	1.20	1.45	.91	.92

Forecast of Natural Gas Consumption

Statewide

TABLE B-11

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF THERMS PER YR)

MAY 1987 BASELINE GAS FORECAST

CALIFORNIA TOTAL

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	5970.300	1824.007	217.189	.000	3120.753	1650.227	1142.900	165.300	77.525	14168.200
1978	5748.600	1720.957	236.804	.100	2789.490	1537.458	1110.000	147.200	82.390	13373.000
1979	6167.700	1749.558	231.686	.100	3357.152	1393.278	1169.700	175.700	20.825	14265.700
1980	5795.300	1612.738	217.822	.100	3358.718	1270.028	1178.800	151.800	8.995	13594.300
1981	5152.400	1542.453	222.522	.000	3292.141	1204.564	1080.900	144.500	10.220	12649.700
1982	5549.000	1645.636	232.673	.000	2758.774	1019.583	1018.600	122.200	53.935	12400.400
1983	5137.000	1560.147	205.871	.000	2646.174	879.128	761.600	104.000	38.780	11332.700
1984	4864.400	1519.710	204.351	.000	2505.157	889.132	1062.400	106.700	64.750	11216.600
1985	5353.000	1687.730	227.462	.000	2668.989	937.439	1253.200	115.600	44.380	12287.800
1986	5598.247	1680.542	226.345	.000	2581.213	986.680	1590.880	138.398	44.191	12846.496
1987	5613.534	1848.182	228.911	.000	2618.311	985.684	1928.307	138.965	48.599	13410.493
1988	5609.793	1844.449	231.901	.000	2656.969	987.351	2265.836	140.393	48.501	13785.194
1989	5604.432	1840.248	234.678	.000	2690.566	986.882	2603.158	140.963	48.391	14149.317
1990	5602.309	1838.192	236.836	.000	2715.922	990.654	2940.688	142.421	48.337	14515.359
1991	5634.285	1859.364	239.522	.000	2742.981	1008.413	2962.490	143.894	48.893	14639.843
1992	5664.949	1884.345	242.088	.000	2771.595	1027.858	2984.288	145.383	49.550	14770.056
1993	5686.961	1901.310	244.151	.000	2798.740	1043.352	3006.448	146.385	49.996	14877.344
1994	5708.937	1920.427	246.193	.000	2828.155	1059.252	3028.248	147.404	50.499	14989.114
1995	5733.469	1936.113	248.559	.000	2852.128	1072.815	3049.944	148.447	50.911	15092.386
1996	5752.880	1955.459	249.994	.000	3073.563	1087.683	3071.850	149.504	51.420	15392.352
1997	5775.302	1974.494	252.248	.000	2910.000	1102.015	3093.754	150.579	51.921	15310.313
1998	5798.068	1996.044	254.515	.000	2940.397	1117.729	3115.450	151.669	52.487	15426.359
1999	5822.998	2018.803	256.162	.000	2969.426	1133.188	3137.250	152.775	53.086	15543.687
2000	5865.167	2029.260	258.232	.000	2999.343	1146.919	3159.409	154.399	53.361	15666.090
2001	5881.911	2042.237	261.106	.000	3029.502	1162.151	3181.105	156.039	53.702	15767.752
2002	5899.893	2054.928	263.488	.000	3057.575	1176.443	3202.905	157.689	54.036	15866.956
2003	5924.627	2070.195	265.650	.000	3090.263	1192.173	3224.705	157.689	54.437	15979.739
2004	5949.140	2085.546	267.596	.000	3113.750	1206.991	3246.505	157.689	54.841	16082.058
2005	5980.174	2100.931	270.183	.000	3143.931	1221.622	3268.305	157.689	55.245	16198.081
2006	6012.891	2117.678	272.125	.000	3168.741	1237.048	3290.001	157.689	55.686	16311.859
2007	6047.047	2134.969	274.408	.000	3402.737	1252.714	3311.800	157.689	56.140	16637.504

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	-1.35	-.97	.58	.00	-1.94	-6.82	1.16	-4.37	-6.74	-1.76
1985 - 1992	.81	1.59	.89	.00	.54	1.32	13.20	3.33	1.59	2.66
1985 - 1999	.60	1.29	.85	.00	.76	1.36	6.77	2.01	1.29	1.69
1985 - 2007	.56	1.07	.86	.00	1.11	1.33	4.52	1.42	1.07	1.39

TABLE B-12

CALIFORNIA ENERGY COMMISSION

FORECAST OF NATURAL GAS CONSUMPTION BY GAS UTILITY SERVICE AREA
(MILLIONS OF CUFT PER DAY)

MAY 1987 BASELINE GAS FORECAST

CALIFORNIA TOTAL

YEAR	RESIDEN-TIAL	COMM BLDGS.	TCU	STREET LIGHT.	PROCESS INDUST.	ASSEMBLY INDUST.	MINING & EXTRACT.	AGRIC & WAT. PUMP	UNCLASS-IFIED	TOTAL CONSUMPTION
1977	1558.	476.	57.	0.	815.	431.	298.	43.	20.	3698.
1978	1500.	449.	62.	0.	728.	401.	290.	38.	22.	3490.
1979	1610.	457.	60.	0.	876.	364.	305.	46.	5.	3723.
1980	1513.	421.	57.	0.	877.	331.	308.	40.	2.	3548.
1981	1345.	403.	58.	0.	859.	314.	282.	38.	3.	3302.
1982	1448.	430.	61.	0.	720.	266.	266.	32.	14.	3237.
1983	1341.	407.	54.	0.	691.	229.	199.	27.	10.	2958.
1984	1270.	397.	53.	0.	654.	232.	277.	28.	17.	2928.
1985	1397.	440.	59.	0.	697.	245.	327.	30.	12.	3207.
1986	1461.	439.	59.	0.	674.	258.	415.	36.	12.	3353.
1987	1465.	482.	60.	0.	683.	257.	503.	36.	13.	3500.
1988	1464.	481.	61.	0.	693.	258.	591.	37.	13.	3598.
1989	1463.	480.	61.	0.	702.	258.	679.	37.	13.	3693.
1990	1462.	480.	62.	0.	709.	259.	768.	37.	13.	3789.
1991	1471.	485.	63.	0.	716.	263.	773.	38.	13.	3821.
1992	1479.	492.	63.	0.	723.	268.	779.	38.	13.	3855.
1993	1484.	496.	64.	0.	730.	272.	785.	38.	13.	3883.
1994	1490.	501.	64.	0.	738.	276.	790.	38.	13.	3912.
1995	1496.	505.	65.	0.	744.	280.	796.	39.	13.	3939.
1996	1502.	510.	65.	0.	802.	284.	802.	39.	13.	4017.
1997	1507.	515.	66.	0.	760.	288.	807.	39.	13.	3996.
1998	1513.	521.	66.	0.	767.	292.	813.	40.	14.	4026.
1999	1520.	527.	67.	0.	775.	296.	819.	40.	14.	4057.
2000	1531.	530.	67.	0.	783.	299.	825.	40.	14.	4089.
2001	1535.	533.	68.	0.	791.	303.	830.	41.	14.	4115.
2002	1540.	536.	69.	0.	798.	307.	836.	41.	14.	4141.
2003	1546.	540.	69.	0.	807.	311.	842.	41.	14.	4171.
2004	1553.	544.	70.	0.	813.	315.	847.	41.	14.	4197.
2005	1561.	548.	71.	0.	821.	319.	853.	41.	14.	4228.
2006	1569.	553.	71.	0.	827.	323.	859.	41.	14.	4257.
2007	1578.	557.	72.	0.	888.	327.	864.	41.	15.	4342.

AVERAGE ANNUAL GROWTH RATE (%)

1977 - 1985	-1.35	-.97	.58	.00	-1.94	-6.82	1.16	-4.37	-6.74	-1.76
1985 - 1992	.81	1.59	.89	.00	.54	1.32	13.20	3.33	1.53	2.66
1985 - 1999	.60	1.29	.85	.00	.76	1.36	6.77	2.01	1.24	1.69
1985 - 2007	.56	1.07	.86	.00	1.11	1.33	4.52	1.42	1.03	1.39

D. Input Assumptions

Most input assumptions for the gas demand forecast are the same as those documented separately for the electricity demand forecast for CFM 7.[2] This chapter describes the assumptions used to forecast demand in support of TEOR. For ease of reference, this section also provides gas price assumptions used in the forecast.

TEOR Gas Demand

Projections from BFR 1 provide the assumptions for gas demand in support of TEOR.[3] The BFR 1 analysis projected continued development of the heavy oil fields and consequent expansion of TEOR projects will cause fuel demand for meeting steaming requirements to increase from 230 trillion Btu in 1984 to 351 trillion Btu in 1990. Fuel requirements were expected to increase gradually to 390 trillion Btu by 2005.

Natural gas is the preferred fuel of TEOR operators because of its clean combustion characteristics and cost. However, the analysis projected oil will continue to supply about 20 percent of TEOR energy needs after 1990 with gas supplying the remainder of the TEOR energy needs. With these assumptions the BFR 1 analysis projected the following gas demand for TEOR.

Year	Millions of Therms/Year	Mmcf/Day
1985 (actual)	1,191	311
1990	2,821	736
1997	3,028	790
2005	3,112	812

As noted previously, staff allocated 80 percent of this demand to the SCG service area and 20 percent to the PGandE service area.

Natural Gas Prices

CEC staff prepares its own gas supply and price forecasts. In developing the forecasts, staff used information obtained directly from the utilities and pipelines, from their filings with regulatory agencies (including the CEC), from California Public Utilities Commission (CPUC) decisions, and from various industry trade journals. Staff used a grass roots approach to develop each format. Each potential supply source was evaluated in terms of reserve, production capability, regulatory requirements, and cost of purchase and transport. A case is then developed for each service area to match the forecasted demand. This demand includes all of the residential, commercial, industrial, and electric generation requirements.

For each supply case, purchase and transport costs to bring each source to California are determined. California gas utility cost to distribute the gas to the customer are then estimated. Costs are then summarized by

utility to determine total revenue requirements to purchase and distribute the gas. These costs are then allocated to the end users using CPUC rate making policies and guidelines.

The gas price forecast used for this preliminary natural gas and electricity demand forecast was adopted for the first Biennial Fuels Report dated September 1986. Specific details regarding assumptions and methodologies are provided in Appendix F of that report. The following tables provide the historical and forecasted natural gas prices for the residential and commercial sectors and by two-digit SIC for the industrial sector.

TABLE B-13

PACIFIC GAS & ELECTRIC COMPANY
NATURAL GAS PRICE BY SECTOR
MED. PRICE MED. SUPPLY CASE*
1985 DOLLARS PER MILLION BTU

YEAR	SIC 20	SIC 22	SIC 23	SIC 25	SIC 26	SIC 27	SIC 28	SIC 30	SIC 32	SIC 33	SIC 34	SIC 35	SIC 36	SIC 37	SIC 38	SIC 39	COMM	RES
1977	3.54	3.52	3.50	3.50	3.55	3.51	3.54	3.49	3.53	3.49	3.49	3.52	3.50	3.48	3.51	3.50	3.52	2.91
1978	3.57	3.54	3.50	3.50	3.59	3.52	3.57	3.51	3.57	3.52	3.52	3.54	3.51	3.52	3.52	3.50	3.53	2.88
1979	3.68	3.76	3.83	3.83	3.64	3.81	3.68	3.81	3.67	3.79	3.82	3.76	3.82	3.81	3.79	3.83	3.78	3.22
1980	5.14	5.21	5.06	5.06	5.32	5.11	5.25	5.13	5.32	5.17	5.15	5.11	5.10	5.17	5.15	5.08	5.14	4.59
1981	5.17	5.39	5.38	5.38	5.29	5.39	5.27	5.38	5.34	5.36	5.38	5.28	5.38	5.38	5.39	5.38	5.35	4.43
1982	5.83	5.88	5.92	5.92	5.80	5.91	5.83	5.91	5.82	5.90	5.92	5.88	5.91	5.91	5.90	5.92	5.89	4.70
1983	5.99	6.06	6.22	6.24	5.96	6.13	5.90	6.25	6.07	6.23	6.25	6.12	6.20	6.19	6.06	6.18	6.05	5.06
1984	5.51	6.62	6.59	6.59	5.42	6.43	5.37	6.25	5.72	6.39	6.58	6.17	6.57	6.51	5.84	6.43	6.19	5.38
1985	4.58	6.38	6.41	6.41	4.41	6.11	4.80	5.40	4.60	5.48	5.78	5.76	6.20	5.48	5.40	6.30	5.72	5.19
1986	3.15	4.02	4.90	4.90	2.65	4.56	3.08	4.66	3.08	4.41	4.65	4.00	4.67	4.57	4.40	4.90	4.21	4.53
1987	3.61	4.44	5.29	5.29	3.13	4.96	3.54	5.05	3.54	4.82	5.05	4.43	5.07	4.97	4.81	5.29	4.62	4.89
1988	4.01	4.75	5.50	5.50	3.58	5.21	3.95	5.29	3.95	5.09	5.29	4.74	5.31	5.22	5.08	5.50	4.91	5.07
1989	4.46	5.19	5.93	5.93	4.04	5.65	4.41	5.73	4.40	5.52	5.72	5.18	5.74	5.66	5.51	5.93	5.35	5.46
1990	4.89	5.57	6.25	6.25	4.50	5.99	4.84	6.06	4.83	5.87	6.06	5.56	6.08	6.00	5.87	6.25	5.72	5.74
1991	4.94	5.59	6.25	6.25	4.56	6.00	4.89	6.07	4.88	5.89	6.07	5.58	6.08	6.01	5.88	6.25	5.74	5.74
1992	4.98	5.61	6.24	6.24	4.62	6.00	4.94	6.07	4.93	5.89	6.07	5.60	6.08	6.01	5.89	6.24	5.75	5.73
1993	5.06	5.69	6.33	6.33	4.69	6.08	5.01	6.15	5.00	5.97	6.15	5.68	6.16	6.09	5.97	6.33	5.83	5.81
1994	5.12	5.74	6.37	6.37	4.76	6.13	5.07	6.20	5.07	6.02	6.20	5.73	6.21	6.14	6.02	6.37	5.88	5.85
1995	5.28	5.93	6.59	6.59	4.90	6.33	5.23	6.40	5.22	6.22	6.40	5.92	6.42	6.34	6.21	6.59	6.07	6.04
1996	5.36	5.99	6.63	6.63	5.00	6.38	5.32	6.45	5.31	6.28	6.45	5.98	6.47	6.39	6.27	6.63	6.13	6.09
1997	5.49	6.12	6.76	6.76	5.13	6.51	5.45	6.58	5.44	6.41	6.58	6.11	6.60	6.52	6.40	6.76	6.26	6.19
1998	5.61	6.24	6.89	6.89	5.24	6.64	5.56	6.71	5.55	6.53	6.71	6.24	6.72	6.65	6.52	6.89	6.39	6.31
1999	5.73	6.35	6.99	6.99	5.36	6.74	5.68	6.81	5.67	6.63	6.81	6.34	6.82	6.75	6.63	6.99	6.49	6.40
2000	5.87	6.51	7.17	7.17	5.50	6.92	5.82	6.99	5.82	6.81	6.99	6.51	7.00	6.92	6.80	7.17	6.66	6.56
2001	6.02	6.66	7.32	7.32	5.64	7.07	5.97	7.14	5.96	6.96	7.13	6.65	7.15	7.07	6.95	7.32	6.81	6.70
2002	6.16	6.83	7.51	7.51	5.78	7.25	6.11	7.32	6.11	7.14	7.32	6.82	7.34	7.26	7.13	7.51	6.98	6.87
2003	6.30	6.97	7.64	7.64	5.91	7.38	6.25	7.45	6.24	7.27	7.45	6.96	7.47	7.39	7.26	7.64	7.12	6.99
2004	6.47	7.13	7.81	7.81	6.08	7.55	6.42	7.63	6.41	7.44	7.62	7.13	7.64	7.56	7.43	7.81	7.28	7.15
2005	6.61	7.30	8.01	8.01	6.21	7.74	6.56	7.81	6.55	7.62	7.81	7.30	7.83	7.74	7.61	8.01	7.46	7.31
2006	6.77	7.47	8.19	8.19	6.36	7.92	6.72	7.99	6.71	7.79	7.99	7.47	8.01	7.92	7.78	8.19	7.63	7.47
2007	6.93	7.64	8.38	8.38	6.52	8.10	6.88	8.17	6.87	7.97	8.17	7.65	8.19	8.10	7.96	8.38	7.81	7.66

* 1977-1985 (HISTORIC DEMAND)

TABLE B-14

SOUTHERN CALIFORNIA GAS COMPANY
NATURAL GAS PRICE BY SECTOR
MED. PRICE MED. SUPPLY CASE*
1985 DOLLARS PER MILLION BTU

YEAR	SIC 20	SIC 22	SIC 23	SIC 25	SIC 26	SIC 27	SIC 28	SIC 30	SIC 32	SIC 33	SIC 34	SIC 35	SIC 36	SIC 37	SIC 38	SIC 39	COMM	RES
1977	2.82	2.82	2.82	2.82	2.83	2.82	2.82	2.82	2.83	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.94
1978	3.12	3.12	3.12	3.12	3.13	3.12	3.12	3.12	3.13	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.12	2.86
1979	3.45	3.41	3.66	3.66	3.31	3.59	3.39	3.52	3.41	3.48	3.59	3.62	3.59	3.50	3.63	3.65	3.53	3.47
1980	4.46	4.58	4.12	4.13	4.72	4.26	4.61	4.41	4.64	4.48	4.25	4.21	4.27	4.41	4.20	4.16	4.37	4.21
1981	4.20	4.29	4.05	4.06	4.33	4.13	4.30	4.21	4.34	4.24	4.12	4.10	4.14	4.20	4.09	4.07	4.19	4.03
1982	5.36	5.38	5.24	5.25	5.45	5.28	5.40	5.33	5.40	5.35	5.29	5.27	5.29	5.34	5.27	5.25	5.32	4.81
1983	6.60	6.50	7.30	7.20	5.90	7.00	6.40	6.80	6.40	6.40	6.90	7.10	7.00	6.60	7.00	7.20	6.90	5.95
1984	6.30	6.40	7.60	7.50	5.60	7.10	5.10	6.80	6.20	6.60	6.90	7.30	7.20	6.60	7.20	7.50	7.10	5.95
1985	5.80	5.70	7.30	7.10	4.90	7.00	4.70	6.40	5.50	6.00	6.50	7.10	6.30	6.20	6.90	7.20	6.40	5.56
1986	4.07	3.82	5.54	5.54	3.01	5.05	3.66	4.55	3.74	4.23	5.02	5.26	5.04	4.41	5.30	5.43	4.63	5.14
1987	4.29	4.10	5.45	5.44	3.47	5.06	3.98	4.68	4.05	4.43	5.04	5.23	5.06	4.57	5.26	5.36	4.73	5.02
1988	4.64	4.49	5.60	5.59	3.96	5.28	4.39	4.97	4.45	4.76	5.26	5.42	5.28	4.87	5.44	5.53	5.01	5.14
1989	5.04	4.92	5.87	5.86	4.46	5.60	4.83	5.33	4.89	5.15	5.58	5.71	5.60	5.24	5.73	5.81	5.37	5.38
1990	5.46	5.36	6.18	6.18	4.95	5.95	5.28	5.72	5.34	5.56	5.93	6.05	5.95	5.64	6.06	6.13	5.75	5.66
1991	5.53	5.43	6.23	6.23	5.03	6.01	5.36	5.79	5.42	5.63	5.99	6.10	6.01	5.70	6.12	6.18	5.81	5.70
1992	5.54	5.46	6.20	6.20	5.09	5.99	5.39	5.79	5.45	5.64	5.97	6.08	5.99	5.71	6.10	6.15	5.81	5.67
1993	5.64	5.55	6.30	6.29	5.17	6.09	5.48	5.88	5.54	5.73	6.07	6.18	6.09	5.80	6.19	6.25	5.90	5.76
1994	5.73	5.64	6.40	6.40	5.26	6.19	5.57	5.98	5.63	5.83	6.17	6.28	6.19	5.90	6.30	6.36	6.00	5.86
1995	5.87	5.79	6.55	6.55	5.40	6.34	5.71	6.13	5.78	5.98	6.32	6.43	6.34	6.05	6.45	6.51	6.15	5.99
1996	6.03	5.94	6.74	6.74	5.53	6.51	5.86	6.29	5.92	6.13	6.49	6.61	6.51	6.21	6.63	6.69	6.32	6.16
1997	6.19	6.10	6.93	6.93	5.67	6.70	6.02	6.47	6.08	6.30	6.68	6.80	6.69	6.38	6.81	6.88	6.49	6.34
1998	6.32	6.23	7.06	7.06	5.80	6.82	6.15	6.60	6.21	6.43	6.80	6.93	6.82	6.51	6.94	7.01	6.62	6.46
1999	6.48	6.38	7.23	7.23	5.95	6.99	6.30	6.76	6.37	6.59	6.97	7.10	6.99	6.67	7.11	7.18	6.78	6.60
2000	6.68	6.57	7.49	7.49	6.11	7.23	6.49	6.98	6.56	6.80	7.21	7.34	7.23	6.89	7.36	7.43	7.01	6.84
2001	6.84	6.73	7.66	7.66	6.27	7.40	6.65	7.14	6.72	6.96	7.38	7.51	7.40	7.05	7.53	7.61	7.17	7.00
2002	7.05	6.93	7.94	7.94	6.43	7.66	6.84	7.38	6.91	7.18	7.63	7.78	7.66	7.28	7.80	7.88	7.41	7.25
2003	7.23	7.11	8.15	8.14	6.59	7.85	7.01	7.57	7.09	7.36	7.83	7.98	7.85	7.46	8.00	8.08	7.60	7.43
2004	7.45	7.32	8.42	8.41	6.77	8.11	7.22	7.80	7.30	7.59	8.08	8.24	8.10	7.69	8.26	8.35	7.84	7.67
2005	7.70	7.55	8.77	8.77	6.94	8.42	7.44	8.09	7.52	7.85	8.40	8.57	8.42	7.97	8.60	8.69	8.13	7.99
2006	7.93	7.77	9.07	9.07	7.12	8.70	7.65	8.35	7.73	8.09	8.68	8.86	8.70	8.22	8.89	8.98	8.39	8.26
2007	8.17	8.00	9.38	9.38	7.30	8.98	7.87	8.61	7.96	8.34	8.96	9.15	8.98	8.47	9.19	9.29	8.66	8.54

* 1977-1985 (HISTORIC DEMAND)

TABLE B-15

SAN DIEGO GAS & ELECTRIC COMPANY
NATURAL GAS PRICE BY SECTOR
MED. PRICE MED. SUPPLY CASE*
1985 DOLLARS PER MILLION BTU

YEAR	SIC 20	SIC 22	SIC 23	SIC 25	SIC 26	SIC 27	SIC 28	SIC 30	SIC 32	SIC 33	SIC 34	SIC 35	SIC 36	SIC 37	SIC 38	SIC 39	COMM	RES
1977	3.29	3.25	3.25	3.25	3.25	3.25	3.30	3.25	3.29	3.25	3.25	3.25	3.26	3.29	3.25	3.25	3.27	3.39
1978	3.83	3.73	3.73	3.73	3.73	3.73	3.86	3.73	3.82	3.73	3.73	3.77	3.75	3.83	3.73	3.73	3.78	3.31
1979	3.69	3.72	3.72	3.72	3.72	3.72	3.69	3.72	3.69	3.72	3.72	3.71	3.73	3.69	3.72	3.72	3.70	3.54
1980	4.83	4.26	4.26	4.26	4.26	4.26	4.98	4.26	4.80	4.26	4.26	4.50	4.33	4.82	4.26	4.26	4.56	4.03
1981	5.09	5.23	5.23	5.23	5.23	5.23	5.07	5.23	5.06	5.23	5.23	5.16	5.22	5.05	5.23	5.23	5.14	4.44
1982	6.72	6.47	6.47	6.47	6.47	6.47	6.79	6.47	6.71	6.47	6.47	6.57	6.50	6.72	6.47	6.47	6.60	5.19
1983	7.30	7.70	7.70	7.70	7.70	7.70	7.20	7.70	7.30	7.70	7.70	7.60	7.70	7.30	7.70	7.70	7.40	6.47
1984	7.30	8.10	8.10	8.10	8.10	8.10	8.10	8.10	7.00	8.10	8.10	7.60	7.90	7.20	8.10	8.10	7.30	6.74
1985	5.96	6.59	6.59	6.59	6.59	6.59	6.28	6.59	5.81	6.59	6.59	6.15	6.40	5.81	6.59	6.59	6.21	5.61
1986	3.81	4.88	4.88	4.88	4.88	4.88	3.56	4.88	3.81	4.88	4.88	4.43	4.78	3.78	4.88	4.88	4.29	4.46
1987	4.30	5.26	5.26	5.26	5.26	5.26	4.08	5.26	4.28	5.26	5.26	4.86	5.17	4.26	5.26	5.26	4.73	4.84
1988	4.72	5.50	5.50	5.50	5.50	5.50	4.55	5.50	4.69	5.50	5.50	5.17	5.43	4.67	5.50	5.50	5.06	5.04
1989	5.22	5.93	5.93	5.93	5.93	5.93	5.07	5.93	5.19	5.93	5.93	5.62	5.86	5.17	5.93	5.93	5.53	5.44
1990	5.69	6.31	6.31	6.31	6.31	6.31	5.57	6.31	5.65	6.31	6.31	6.03	6.25	5.63	6.31	6.31	5.96	5.79
1991	5.71	6.25	6.25	6.25	6.25	6.25	5.61	6.25	5.67	6.25	6.25	6.01	6.20	5.65	6.25	6.25	5.94	5.74
1992	5.73	6.21	6.21	6.21	6.21	6.21	5.64	6.21	5.69	6.21	6.21	5.99	6.17	5.67	6.21	6.21	5.93	5.69
1993	5.84	6.33	6.33	6.33	6.33	6.33	5.75	6.33	5.80	6.33	6.33	6.11	6.28	5.78	6.33	6.33	6.04	5.81
1994	5.89	6.35	6.35	6.35	6.35	6.35	5.81	6.35	5.85	6.35	6.35	6.14	6.31	5.84	6.35	6.35	6.08	5.83
1995	6.03	6.47	6.47	6.47	6.47	6.47	5.96	6.47	5.99	6.47	6.47	6.27	6.43	5.97	6.47	6.47	6.21	5.94
1996	6.21	6.71	6.71	6.71	6.71	6.71	6.13	6.71	6.17	6.71	6.71	6.48	6.66	6.15	6.71	6.71	6.42	6.15
1997	6.37	6.88	6.88	6.88	6.88	6.88	6.28	6.88	6.32	6.88	6.88	6.65	6.83	6.31	6.88	6.88	6.58	6.31
1998	6.48	6.96	6.96	6.96	6.96	6.96	6.40	6.96	6.44	6.96	6.96	6.74	6.92	6.42	6.96	6.96	6.68	6.38
1999	6.63	7.10	7.10	7.10	7.10	7.10	6.55	7.10	6.58	7.10	7.10	6.89	7.06	6.57	7.10	7.10	6.83	6.51
2000	6.82	7.33	7.33	7.33	7.33	7.33	6.73	7.33	6.77	7.33	7.33	7.10	7.28	6.75	7.33	7.33	7.03	6.71
2001	6.98	7.48	7.48	7.48	7.48	7.48	6.89	7.48	6.92	7.48	7.48	7.25	7.43	6.91	7.48	7.48	7.19	6.84
2002	7.18	7.74	7.43	7.43	7.43	7.43	7.08	7.74	7.13	7.74	7.74	7.48	7.69	7.11	7.74	7.74	7.41	7.07
2003	7.34	7.88	7.88	7.88	7.88	7.88	7.24	7.88	7.28	7.88	7.88	7.63	7.83	7.27	7.88	7.88	7.56	7.18
2004	7.54	8.10	8.10	8.10	8.10	8.10	7.44	8.10	7.48	8.10	8.10	7.84	8.05	7.46	8.10	8.10	7.77	7.38
2005	7.77	8.40	8.40	8.40	8.40	8.40	7.66	8.40	7.71	8.40	8.40	8.12	8.35	7.69	8.40	8.40	8.03	7.66
2006	7.98	8.65	8.65	8.65	8.65	8.65	7.87	8.65	7.92	8.65	8.65	8.35	8.60	7.90	8.65	8.65	8.25	7.88
2007	8.20	8.90	8.90	8.90	8.90	8.90	8.08	8.90	8.14	8.90	8.90	8.59	8.85	8.11	8.90	8.90	8.49	8.11

* 1977-1985 (HISTORIC DEMAND)

E. Conservation Program Savings

Tables B-16, B-17, and B-18 provide a summary of impacts for statewide standards, utility-administered programs and public agency programs. The staff forecasts reflect lower demand due to the savings presented in these tables.

TABLE B-16

Summary of Conservation Program Savings Estimates
Utility Service Area: Pacific Gas and Electric
(millions of therms per year)

Sector/Program	Savings 1985	1992	1999	2007
Residential				
Standards				
1975 HCD Bldg Stds	150	294	437	562
1978 T24 Bldg Stds	8	24	39	53
1983 T24 Bldg Stds	6	38	69	99
1976-82 Appl Stds	46	148	264	391
1984 T20 Appl Stds	0	2	15	29
Programs				
Solar Retrofit	4	6	9	10
Misc. Retrofit Programs	134	307	335	346
Other Programs	36	77	127	127
TOTAL SECTOR	385	896	1,296	1,616
Commercial				
Standards				
1977 T24 Comm Bldg Stds	3	13	23	33
1984 T24 Office Stds	0	-6	-12	-18
1985-86 T24 2nd Tier	0	0	0	0
1976-82 T20 Equip	2	4	4	4
1984 T20 Equip Stds	0	3	6	8
Programs				
Energy Mgmt Ser/Incentives	7	13	23	33
Facility Loans and Grants	8	13	11	9
Other Programs	0	0	0	0
TOTAL SECTOR	20	41	43	46
Industrial				
Standards				
1978 T24 Bldg Stds	22	22	23	22
Programs				
Other Programs	28	33	37	37
TOTAL SECTOR	50	55	60	59
TOTAL SAVINGS	455	992	1,399	1,721

TABLE B-17

Summary of Conservation Program Savings Estimates
Utility Service Area: Southern California Gas
(millions of therms per year)

Sector/Program	Savings 1985	1992	1999	2007
Residential				
Standards				
1975 HCD Bldg Stds	161	337	493	627
1978 T24 Bldg Stds	11	33	56	74
1983 T24 Bldg Stds	6	39	68	95
1976-82 Appl Stds	63	216	374	537
1984 T20 Appl Stds	0	85	99	110
Programs				
Solar Retrofit	8	10	12	12
Misc. Retrofit Programs	84	150	172	188
Other Programs	42	82	131	131
TOTAL SECTOR	378	869	1,317	1,685
Commercial				
Standards				
1977 T24 Comm Bldg Stds	5	23	44	70
1984 T24 Office Stds	0	-1	-3	-6
1985-86 T24 2nd Tier	0	0	0	0
1976-82 T20 Equip	3	6	7	7
1984 T20 Equip Stds	1	6	11	15
Programs				
Energy Mgmt Ser/Incentives	12	31	27	21
Facility Loans and Grants	10	15	13	11
Other Programs	0	0	0	0
TOTAL SECTOR	32	80	98	119
Industrial				
Standards				
1978 T24 Bldg Stds	38	39	37	34
Programs				
Other Programs	0	0	0	0
TOTAL SECTOR	38	39	37	34
TOTAL SAVINGS	448	988	1,452	1,838

TABLE B-18

Summary of Conservation Program Savings Estimates
Utility Service Area: San Diego Gas and Electric
(millions of therms per year)

Sector/Program	Savings 1985	1992	1999	2007
Residential				
Standards				
1975 HCD Bldg Stds	35	73	101	126
1978 T24 Bldg Stds	2	6	9	12
1983 T24 Bldg Stds	1	6	10	13
1976-82 Appl Stds	7	28	50	75
1984 T20 Appl Stds	0	0	1	2
Programs				
Solar Retrofit	1	2	2	2
Misc. Retroft Programs	7	19	23	26
Other Programs	12	24	35	35
TOTAL SECTOR	64	157	230	291
Commercial				
Standards				
1977 T24 Comm Bldg Stds	1	3	5	7
1984 T24 Office Stds	0	0	1	1
1985-86 T24 2nd Tier	0	0	0	0
1976-82 T20 Equip	1	1	2	2
1984 T20 Equip Stds	0	1	1	2
Programs				
Energy Mgmt Ser/Incentives	2	3	3	2
Facility Loans and Grants	1	2	2	1
Other Programs	0	0	0	0
TOTAL SECTOR	5	11	13	16
Industrial				
Standards				
1978 T24 Bldg Stds	6	6	6	6
Programs				
Other Programs	1	2	2	2
TOTAL SECTOR	7	8	8	8
TOTAL SAVINGS	76	176	251	315

F. Historic Gas Consumption

This section describes how the staff derived information on the end use of natural gas in California for the years 1977 to 1985. The staff used this information to calibrate its forecasts of consumption of gas by geographical regions and by end use sector within each region.

End users have generally obtained natural gas in one of three ways. The source of gas for most of California's gas consumers is the gas utility company. Another major source of natural gas, particularly for large industrial customers, is from a major gas marketer or producer with pipelines nearby. Recently, gas producers and marketers located outside California have furnished gas to end users through the pipeline systems of California gas utilities. This third source of gas was not significant in the historical period 1977-1985. As basis for the forecasts the staff used the historical data of the first two sources: utility sales of natural gas to end users and gas distributions made by natural gas producers and marketers in California.

Tables B-19, B-20, and B-21 show the historical consumption of natural gas for the PGandE, SCG, and SDG&E gas service areas used for the staff forecast. The tables do not include sales to electric utilities for electrical generation. The following two sections explain how these tables were developed. The first section describes how the staff obtained information on sales of natural gas by gas utilities. The second section covers gas distributions by producers and marketers. A third section presents staff estimates of incremental gas use in cogeneration.

TABLE B-19

PGE SERVICE AREA
MILLIONS OF THERMS

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985
RESIDENTIAL (U)*	2593.20	2292.90	2489.00	2298.10	2079.40	2225.70	2093.40	2036.30	2165.90
COMMERCIAL (U)									
Buildings	874.60	736.60	759.50	719.10	672.90	712.30	680.80	667.40	719.20
Other	119.50	124.80	126.40	113.80	117.60	115.90	105.40	104.40	123.10
Total	994.10	861.40	885.90	832.90	790.50	828.20	786.20	771.80	842.30
INDUSTRIAL									
M&C** -SIC13 (U)	26.70	22.90	27.50	22.40	18.20	16.40	14.00	13.80	15.00
SIC13 (U)***	1.10	0.70	0.70	0.80	1.30	15.10	16.10	32.80	188.30
SIC13 (PM)****	215.10	210.20	221.82	225.36	206.90	182.46	131.50	174.72	67.82
Subtotal SIC13	216.20	210.90	222.52	226.16	208.20	197.56	147.60	207.52	256.12
Total M&C+SIC13	242.90	233.80	250.02	248.56	226.40	213.96	161.60	221.32	271.12
Process (U)	1514.20	1356.40	1873.60	1822.70	1677.50	1253.10	1025.80	996.00	1256.70
PM Indust	37.83	35.21	31.42	42.46	101.75	146.83	140.00	96.00	85.00
PM Refin.	238.60	200.50	197.00	219.50	226.50	179.80	328.00	341.00	357.00
PM Other	16.92	26.54	39.21	21.25	22.04	25.58	4.00	4.00	1.00
Subtotal PM	293.35	262.25	267.62	283.21	350.29	352.22	472.00	441.00	443.00
Total Process	1807.55	1618.65	2141.22	2105.91	2027.79	1605.32	1497.80	1437.00	1699.70
Assembly (U)	604.30	532.30	451.40	375.70	340.60	339.30	272.60	277.90	305.80
Company A ****	0.00	0.00	0.00	0.00	0.00	5.66	15.28	29.06	50.55
Company B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00
PM Chem.	5.25	7.45	1.55	2.05	2.10	7.30	7.50	9.00	16.50
Subtotal PM	5.25	7.45	[illegible]	2.05	2.10	12.96	22.78	42.06	71.05
Total Assembly	609.55	539.75	452.95	377.75	342.70	352.26	295.38	319.96	376.85
Total Industry	2660.00	2392.20	2844.19	2732.22	2596.89	2171.54	1954.78	1978.28	2347.67
AG/WATERPUMP (U)	80.40	76.90	94.00	76.00	64.60	57.70	50.60	49.30	54.60
PM Ag.	0.90	0.60	0.60	0.60	0.30	0.30	0.00	0.00	0.00
Total Ag/Water	81.30	77.50	94.60	76.60	64.90	58.00	50.60	49.30	54.60
UNCLASSIFIED (U)	97.90	59.60	49.60	19.30	21.30	117.10	91.90	159.30	90.40
PM Unclass.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Unclass.	97.90	59.60	49.60	19.30	21.30	117.10	91.90	159.30	90.40
Subtotal (U)	5911.90	5203.10	5871.70	5447.90	4993.40	4852.60	4350.60	4337.20	4919.00
Subtotal PM	514.60	480.50	491.59	511.22	559.59	547.94	626.28	657.78	581.87
TOTAL	6426.50	5683.60	6363.29	5959.12	5552.99	5400.54	4976.88	4994.98	5500.87

NOTES:
* (U) = Utility Sales from QFER Form 4 and Form 4A submittals.
** M&C = Mining and Extraction and Construction Industry.
*** PM = Gas Producers and Gas Marketers data from QFER Form 10.
**** Company A and Company B = Sales by two gas marketer companies requesting confidentiality.

TABLE B-20

SCG SERVICE AREA
MILLIONS OF THERMS

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985
RESIDENTIAL (U)*	3078.00	3142.00	3321.70	3183.80	2783.90	3005.50	2747.20	2544.60	2869.80
COMMERCIAL (U)									
Buildings	810.30	850.70	881.80	801.80	783.00	835.40	781.80	752.80	854.50
Other	80.50	89.20	89.00	90.20	91.00	96.60	83.90	81.00	85.60
Total	890.80	939.90	970.80	892.00	874.00	932.00	865.70	833.80	940.10
INDUSTRIAL									
M&C** -SIC13 (U)	32.90	30.90	27.70	24.60	20.40	12.60	7.50	8.30	9.10
SIC13 (U)***	58.10	57.80	149.00	105.40	164.90	120.00	37.90	52.80	92.30
SIC13 (PM)****	806.70	785.80	741.08	799.24	667.90	670.24	552.50	777.28	932.18
Subtotal SIC13	864.80	843.60	890.08	904.64	832.80	790.24	590.40	830.08	1024.48
Total M&C+SIC13	897.70	874.50	917.78	929.24	853.20	802.84	597.90	838.38	1033.58
Process (U)	966.40	846.90	921.10	970.70	903.30	762.80	730.80	664.20	623.00
PM Indust	52.97	49.82	43.98	59.44	142.45	205.57	145.00	159.00	163.00
PM Refin.	195.20	164.00	161.00	179.60	185.40	147.10	269.00	279.00	292.00
PM Other	23.68	37.16	54.89	29.75	30.86	35.82	60.00	41.00	36.00
Subtotal PM	271.85	250.97	259.87	268.79	358.71	388.48	474.00	479.00	491.00
Total Process	1238.25	1097.87	1180.97	1239.49	1262.01	1151.28	1204.80	1143.20	1114.00
Assembly (U)	974.70	924.30	908.10	869.00	841.60	638.20	581.90	584.00	593.70
PM Chem.	5.25	7.45	1.55	2.05	2.10	7.30	7.50	9.00	16.50
Subtotal PM	5.25	7.45	1.55	2.05	2.10	7.30	7.50	9.00	16.50
Total Assembly	979.95	931.75	909.65	871.05	843.70	645.50	589.40	593.00	610.20
Total Industry	2218.20	2029.62	2090.62	2110.54	2105.71	1796.78	1794.20	1736.20	1724.20
AG/WATERPUMP (U)	74.40	64.60	70.80	65.10	71.30	60.60	47.40	52.20	53.80
PM Ag.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Ag/Water	74.40	64.60	70.80	65.10	71.30	60.60	47.40	52.20	53.80
UNCLASSIFIED (U)	102.20	153.00	0.00	0.00	0.00	4.40	7.30	7.70	25.00
PM Unclass.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Unclass.	102.20	153.00	0.00	0.00	0.00	4.40	7.30	7.70	25.00
Subtotal (U)	6177.50	6159.40	6369.20	6110.60	5659.40	5536.10	5025.70	4747.60	5206.80
Subtotal PM	1083.80	1044.22	1002.50	1070.08	1028.71	1066.02	1034.00	1265.28	1439.68
TOTAL	7261.30	7203.62	7371.70	7180.68	6688.11	6602.12	6059.70	6012.88	6646.48

NOTES:
* (U) = Utility Sales from QFER Form 4 and Form 4A submittals.
** M&C = Mining and Extraction and Construction Industry.
*** PM = Gas Producers and Gas Marketers data from QFER Form 10.

TABLE B-21

SDG&E GAS SERVICE AREA
MILLIONS OF THERMS

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985
RESIDENTIAL (U)*	299.10	313.70	357.00	313.40	289.10	317.80	296.40	283.50	317.30
COMMERCIAL (U)									
Buildings	96.40	86.70	97.10	86.90	81.60	70.70	87.70	80.70	113.90
Other	12.10	16.50	14.50	13.00	12.90	14.40	13.20	17.30	22.10
Total	108.50	103.20	111.60	99.90	94.50	85.10	100.90	98.00	136.00
INDUSTRIAL									
M&C** -SIC13 (U)	2.30	1.70	1.90	1.00	1.30	1.80	2.10	2.70	2.50
SIC13 (U)***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SIC13 (PM)****	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal SIC13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total M&C+SIC13	2.30	1.70	1.90	1.00	1.30	1.80	2.10	2.70	2.50
Process (U)	13.60	14.00	14.50	15.00	11.70	10.40	7.40	7.20	7.10
PM Indust	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM Refin.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal PM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Process	13.60	14.00	14.50	15.00	11.70	10.40	7.40	7.20	7.10
Assembly (U)	25.60	25.30	25.50	23.20	24.50	26.30	19.20	37.50	47.00
PM Chem.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal PM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Assembly	25.60	25.30	25.50	23.20	24.50	26.30	19.20	37.50	47.00
Total Industry	41.50	41.00	41.90	39.20	37.50	38.50	28.70	47.40	56.60
AG/WATERPUMP (U)	7.60	4.00	9.20	8.50	7.80	3.30	5.30	4.50	6.50
PM Ag.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Ag/Water	7.60	4.00	9.20	8.50	7.80	3.30	5.30	4.50	6.50
UNCLASSIFIED (U)	21.40	22.80	9.90	6.40	7.90	32.60	11.60	18.00	11.40
PM Unclass.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Unclass.	21.40	22.80	9.90	6.40	7.90	32.60	11.60	18.00	11.40
Subtotal (U)	478.10	484.70	529.60	467.40	436.80	477.30	442.90	451.40	527.80
Subtotal PM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	478.10	484.70	529.60	467.40	436.80	477.30	442.90	451.40	527.80

NOTES:
* (U) = Utility Sales from QFER Form 4 and Form 4A submittals.
** M&C = Mining and Extraction and Construction Industry.
*** PM = Gas Producers and Gas Marketers data from QFER Form 10.

Gas Sales by Utilities

Tables B-22, B-23 and B-24 show sales of natural gas by end use sector for the gas utilities in the PGandE, SCG, and SDG&E service areas. The tables exclude sales by gas producers and gas marketers. Staff gathered most of the data from Quarterly Fuel and Energy Reports (QFER) Form 4 that the utilities submitted. Form 4 details monthly sales of gas by Standard Industrial Classification (SIC) code. Data on consumption in the SDG&E planning area for 1985 came from QFER Form 7 (Annual Sales of Gas by SIC code and CPUC priority code) because the company modified its SIC code reporting procedures for Form 4 during the year. In 1982 PGandE changed its SIC code reporting procedures. This change may be responsible for what seem to be changes in consumption trends between the two periods 1977 to 1981 and 1982 to 1985.

TABLE B-22

PGE SERVICE AREA
SALES BY GAS UTILITIES
MILLIONS OF THERMS

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985
RESIDENTIAL	2593.20	2292.90	2489.00	2298.10	2079.40	2225.70	2093.40	2036.30	2165.90
COMMERCIAL									
Buildings	874.60	736.60	759.50	719.10	672.90	712.30	680.80	667.40	719.20
Other	119.50	124.80	126.40	113.80	117.60	115.90	105.40	104.40	123.10
Total	994.10	861.40	885.90	832.90	790.50	828.20	786.20	771.80	842.30
INDUSTRIAL									
M&C* minus SIC13	26.70	22.90	27.50	22.40	18.20	16.40	14.00	13.80	15.00
SIC13	1.10	0.70	0.70	0.80	1.30	15.10	16.10	32.80	188.30
Total	27.80	23.60	28.20	23.20	19.50	31.50	30.10	46.60	203.30
Process	1514.20	1356.40	1873.60	1822.70	1677.50	1253.10	1025.80	996.00	1256.70
Assembly	604.30	532.30	451.40	375.70	340.60	339.30	272.60	277.90	305.80
Total Industry	2118.50	1888.70	2325.00	2198.40	2018.10	1592.40	1298.40	1273.90	1562.50
AG & WP	80.40	76.90	94.00	76.00	64.60	57.70	50.60	49.30	54.60
UNCLASSIFIED	97.90	59.60	49.60	19.30	21.30	117.10	91.90	159.30	90.40
TOTAL	5884.10	5179.50	5843.50	5424.70	4973.90	4821.10	4320.50	4290.60	4715.70

Notes
* M&C = Mining and Extraction and Construction

TABLE B-23

SCG PLANNING AREA
SALES BY GAS UTILITIES
MILLIONS OF THERMS

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985
RESIDENTIAL	3078.00	3142.00	3321.70	3183.80	2783.90	3005.50	2747.20	2544.60	2869.80
COMMERCIAL									
Buildings	810.30	850.70	881.80	801.80	783.00	835.40	781.80	752.80	854.50
Other	80.50	89.20	89.00	90.20	91.00	96.60	83.90	81.00	85.60
Total	890.80	939.90	970.80	892.00	874.00	932.00	865.70	833.80	940.10
INDUSTRIAL									
M&C* minus SIC13	32.90	30.90	27.70	24.60	20.40	12.60	7.50	8.30	9.10
SIC13	58.10	57.80	149.00	105.40	164.90	120.00	37.90	52.80	92.30
Total	91.00	88.70	176.70	130.00	185.30	132.60	45.40	61.10	101.40
Process	966.40	846.90	921.10	970.70	903.30	762.80	730.80	664.20	623.00
Assembly	974.70	924.30	908.10	869.00	841.60	638.20	581.90	584.00	593.70
Total Industry	2032.10	1859.90	2005.90	1969.70	1930.20	1533.60	1358.10	1309.30	1318.10
AG & WP	74.40	64.60	70.80	65.10	71.30	60.60	47.40	52.20	53.80
UNCLASSIFIED	102.20	153.00	0.00	0.00	0.00	4.40	7.30	7.70	25.00
TOTAL	6177.50	6159.40	6369.20	6110.60	5659.40	5536.10	5025.70	4747.60	5206.80

Note
* M&C = Mining and Extraction and Construction

TABLE B-24

SDG&E GAS SERVICE AREA
MILLIONS OF THERMS

SECTOR	1977	1978	1979	1980	1981	1982	1983	1984	1985
RESIDENTIAL (U)*	299.10	313.70	357.00	313.40	289.10	317.80	296.40	283.50	317.30
COMMERCIAL (U)									
Buildings	96.40	86.70	97.10	86.90	81.60	70.70	87.70	80.70	113.90
Other	12.10	16.50	14.50	13.00	12.90	14.40	13.20	17.30	22.10
Total	108.50	103.20	111.60	99.90	94.50	85.10	100.90	98.00	136.00
INDUSTRIAL									
M&C** -SIC13 (U)	2.30	1.70	1.90	1.00	1.30	1.80	2.10	2.70	2.50
SIC13 (U)***	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SIC13 (PM)****	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal SIC13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total M&C+SIC13	2.30	1.70	1.90	1.00	1.30	1.80	2.10	2.70	2.50
Process (U)	13.60	14.00	14.50	15.00	11.70	10.40	7.40	7.20	7.10
PM Indust	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM Refin.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PM Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal PM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Process	13.60	14.00	14.50	15.00	11.70	10.40	7.40	7.20	7.10
Assembly (U)	25.60	25.30	25.50	23.20	24.50	26.30	19.20	37.50	47.00
PM Chem.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal PM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Assembly	25.60	25.30	25.50	23.20	24.50	26.30	19.20	37.50	47.00
Total Industry	41.50	41.00	41.90	39.20	37.50	38.50	28.70	47.40	56.60
AG/WATERPUMP (U)	7.60	4.00	9.20	8.50	7.80	3.30	5.30	4.50	6.50
PM Ag.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Ag/Water	7.60	4.00	9.20	8.50	7.80	3.30	5.30	4.50	6.50
UNCLASSIFIED (U)	21.40	22.80	9.90	6.40	7.90	32.60	11.60	18.00	11.40
PM Unclass.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Unclass.	21.40	22.80	9.90	6.40	7.90	32.60	11.60	18.00	11.40
Subtotal (U)	478.10	484.70	529.60	467.40	436.80	477.30	442.90	451.40	527.80
Subtotal PM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	478.10	484.70	529.60	467.40	436.80	477.30	442.90	451.40	527.80

NOTES:
* (U) = Utility Sales from QFER Form 4 and Form 4A submittals.
** M&C = Mining and Extraction and Construction Industry.
*** PM = Gas Producers and Gas Marketers data from QFER Form 10.

Gas Sales and Use by Gas Producers and Marketers

Table B-25 shows sales by gas producers and gas marketers. This information was obtained from QFER Form 10 (Sales and Distribution of Gas by Producers and Marketers). Producers and marketers who report on these forms include their own use of gas as well as gas sold to other companies. Any company delivering more than 50 million cubic feet per month for any month is required to report their activities on the Form 10. Statewide totals were separated into SCG planning area and PGandE planning area by using information from Form 10A. No reported sales by gas producers or marketers occurred in the SDG&E planning area. Sales were assigned to SCG or PGandE planning areas by using QFER Form 10A. Form 10A resembles Form 10 but it is submitted annually and includes a reference to the county where the sales or delivery occurred. Except for oil and gas extraction (SIC 13) staff allocated the gas of producers between the PGandE and SCE service areas based on the county of origin and utility sales for the sector in that county.

The reference to SIC 13 in Table B-25 refers to natural gas burned in oil and gas production. Table B-26 numerically shows how it was allocated to the two gas planning areas. First, total use of SIC 13 was calculated from QFER Form 4 and Form 10. Next, it was distributed between PGandE and SCG planning areas with 20 percent of the total assigned to PGandE as discussed in Section B. SCG received 80 percent of the total. Finally, staff calculated for each planning area how much gas for SIC 13 was distributed by gas producers and marketers. Tables B-19 and B-20 show the final distribution of the use of gas for SIC 13 in the PGandE and SCG planning areas.

TABLE B-25

GAS PRODUCER MARKETER SALES
MILLIONS OF THERMS

	1977	1978	1979	1980	1981	1982	1983	1984	1985
SCG									
PM SIC13	806.70	785.80	741.08	799.24	667.90	670.24	552.50	777.28	932.18
PM Indust	52.97	49.82	43.98	59.44	142.45	205.57	145.00	159.00	163.00
PM Refin.	195.20	164.00	161.00	179.60	185.40	147.10	269.00	279.00	292.00
PM Other	23.68	37.16	54.89	29.75	30.86	35.82	60.00	41.00	36.00
PM Chem.	5.25	7.45	1.55	2.05	2.10	7.30	7.50	9.00	16.50
PM Ag/WP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCG TOTAL	1083.80	1044.22	1002.50	1070.08	1028.71	1066.02	1034.00	1265.28	1439.68
PGE GAS									
PM SIC13	215.10	210.20	221.82	225.36	206.90	182.46	131.50	174.72	67.82
PM Indust	37.83	35.21	31.42	42.46	101.75	146.83	140.00	96.00	85.00
PM Refin.	238.60	200.50	197.00	219.50	226.50	179.80	328.00	341.00	357.00
PM Other	16.92	26.54	39.21	21.25	22.04	25.58	4.00	4.00	1.00
Company A*	0.00	0.00	0.00	0.00	0.00	5.66	15.28	29.06	50.55
Company B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00
PM Chem.	5.25	7.45	1.55	2.05	2.10	7.30	7.50	9.00	16.50
PM Ag/WP	0.90	0.60	0.60	0.60	0.30	0.30	0.00	0.00	0.00
PGE TOTAL	514.60	480.50	491.59	511.22	559.59	547.94	626.28	657.78	581.87
STATEWIDE									
PM SIC13	1021.80	996.00	962.90	1024.60	874.80	852.70	684.00	952.00	1000.00
PM Indust	90.80	85.02	75.40	101.90	244.20	352.40	285.00	255.00	248.00
PM Refin.	433.80	364.50	358.00	399.10	411.90	326.90	597.00	620.00	649.00
PM Other	40.60	63.70	94.10	51.00	52.90	61.40	64.00	45.00	37.00
Company A	0.00	0.00	0.00	0.00	0.00	5.66	15.28	29.06	50.55
Company B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00
PM Chem.	10.50	14.90	3.10	4.10	4.20	14.60	15.00	18.00	33.00
PM Ag/WP	0.90	0.60	0.60	0.60	0.30	0.30	0.00	0.00	0.00
STATEWIDE TOTAL	1598.40	1524.72	1494.10	1581.30	1588.30	1613.96	1660.28	1923.06	2021.55

Note:
*Company A and Company B are pseudonyms used to protect the confidentiality of certain companies.

TABLE B-26

ALLOCATION OF SIC 13 TO PGE AND SCG GAS SERVICE AREAS
MILLIONS OF THERMS

	1977	1978	1979	1980	1981	1982	1983	1984	1985
1. GAS SALES AND USE FOR SIC 13 BY PRODUCER MARKETERS (QFER FORM 10) AND UTILITIES (QFER FORM 4)									
PM FORM 10	1021.80	996.00	962.90	1024.60	874.80	852.70	684.00	952.00	1000.00
PGE FORM 4	1.10	0.70	0.70	0.80	1.30	15.10	16.10	32.80	188.30
SCG FORM 4	58.10	57.80	149.00	105.40	164.90	120.00	37.90	52.80	92.30
TOTAL	1081.00	1054.50	1112.60	1130.80	1041.00	987.80	738.00	1037.60	1280.60
2. DISTRIBUTION OF TOTAL SIC13 GAS SALES AMONG PGE AND SCG SERVICE AREAS									
PGE (20% TOTAL)	216.20	210.90	222.52	226.16	208.20	197.56	147.60	207.52	256.12
SCG (80% TOTAL)	864.80	843.60	890.08	904.64	832.80	790.24	590.40	830.08	1024.48
TOTAL	1081.00	1054.50	1112.60	1130.80	1041.00	987.80	738.00	1037.60	1280.60
3. CALCULATION OF PM SALES IN PGE AND SCG SERVICE AREAS									
PGE 20%-PGE FORM 4	215.10	210.20	221.82	225.36	206.90	182.46	131.50	174.72	67.82
SCG 80%-SCG FORM 4	806.70	785.80	741.08	799.24	667.90	670.24	552.50	777.28	932.18
TOTAL PM SALES	1021.80	996.00	962.90	1024.60	874.80	852.70	684.00	952.00	1000.00

Incremental Gas Use in Cogeneration

As the QFER historical demand data include gas used in cogeneration to generate electricity, staff adjusted the QFER data to develop values for the demand excluding electrical generation. These historical levels are then consistent with the staff models which forecast demand due to space conditioning, process use and other basic demands for each sector. Table B-27 presents staff estimates used to adjust downward the QFER data.

The values of Table B-27 are staff estimates of the incremental amount of gas used in cogeneration in support of electrical generation beyond the gas required for process heat or other end use based on ER 6 submittals by the utilities. The estimates assume an incremental heat rate of 6,000 Btu/kWh. The historical data in Section 2, Forecast Results, reflect demand excluding the gas levels of Table B-27.

TABLE B-27

Estimated Incremental Gas Supporting
Electrical Generation in Cogeneration
(millions of therms per year)

Pacific Gas and Electric Service Area

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Commercial	.0	.0	.0	.0	.8	1.3	2.9	5.0	7.6
TCU	.0	.0	.0	.0	.0	.0	.0	.0	.0
Process	.0	.0	.0	10.1	12.6	17.6	32.4	32.7	64.6
Assembly	.0	.0	.0	4.0	6.6	11.2	24.9	51.0	81.4
Mining & Extraction	.0	.0	.0	.0	.0	.0	.0	.0	30.0
Total	.0	.0	.0	14.1	20.0	30.6	60.2	108.7	183.6

Southern California Gas Service Area

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Commercial	.0	.0	.0	.0	.0	2.5	4.6	6.0	8.3
TCU	.0	.0	.0	.0	.0	.0	.0	.0	.0
Process	.0	.0	.0	.0	6.1	37.5	68.7	91.2	128.5
Assembly	.0	.0	.0	.0	2.2	8.4	9.0	12.0	12.6
Mining & Extraction	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total	.0	.0	.0	.0	8.3	48.4	82.3	109.2	123.4

San Diego Gas and Electric Service Area

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Commercial	.0	.0	.0	.4	.4	1.6	5.0	5.6	8.1
TCU	.0	.0	.0	.0	.0	.0	.0	.0	.0
Process	.0	.0	.0	.0	.0	.0	.0	.0	.0
Assembly	.0	.0	.0	.0	.0	.0	.0	15.7	15.7
Mining & Extraction	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total	.0	.0	.0	.4	.4	1.6	5.0	25.5	31.0

FOOTNOTES - APPENDIX B, SECTION II

1. California Energy Commission, California Energy Demand: 1985-2005, Volume II, Electricity Demand Forecasting Methods, Staff Report, P300-87-004 (July 1987).

2. California Energy Commission, California Energy Demand: 1987 - 2007.

   Volume III: The PGandE Planning Area Forms, Publication No. P300-87-005 (July 1987)

   Volume IV: The SMUD Planning Area Forms, Publication No. P300-87-006 (July 1987)

   Volume V: The SCE Planning Area Forms, Publication No. P300-87-007 (July 1987)

   Volume VI: The LADWP Planning Area Forms, Publication No. P300-87-008 (July 1987)

   Volume VII: The SDG&E Planning Area Forms, Publication No. P300-87-009 (July 1987)

   Volume VIII: The BGP Planning Area Forms, Publication No. P300-87-010 (July 1987)

3. California Energy Commission, Biennial Fuels Report Appendices, Appendix B, Publication No. P300-86-007A (September 1986).

III. Demand For Gas In Electricity Generation

A. Introduction

Natural gas is an important and valuable fuel used to meet California's electricity needs. Of the 1800 billion cubic feet (bcf) of California's 1985 natural gas consumption electric generation accounted for approximately 35 percent. Based on this level of consumption for electric generation California ranks second in the nation after Texas.

Part III of the Appendix describes the Commission staff's forecast of electric generation natural gas requirements for the 1987 Biennial Fuels Report, compares it to the forecast provided in the September 1986 Biennial Fuels Report and comments on the differences.

Nearly all of California's present gas fired electric generation capability could readily be switched to fuel oil. Most new gas fired units also include dual-fuel capability. Therefore, while this report describes the fuel requirements for these units as gas demand, these fuel requirements could be satisfied partially or totally with oil.

B. Natural Gas Requirement

The electric generation natural gas demand forecast for the 1987 Biennial Fuels Report relies on staff's simulation of the electric utility system which was carried out primarily to develop preliminary electricity prices for CFM 7. The results of these simulations are presented by year in Tables B-28, B-29 and B-30 for PGandE, SoCalGas and SDG&E natural gas service areas.

For each service area, the gas requirements have been subdivided into three distinct groupings: cogeneration, combustion turbines and utility boilers. A total gas requirement for each year is also provided.

For cogeneration, only incremental fuel requirements for electricity generation are reported. Cogeneration facilities consume more fuel than facilities designed to provide only the desired quantity of process heat. The difference in fuel requirements between these two facilities referred to is defined as the incremental fuel requirement.

Combustion turbines include baseload, intermediate, and peaking facilities, but not cogeneration. This category also includes highly efficient steam injection combustion turbines which are presumed to become available in the mid-to-late 1990s.

The natural gas requirements for electric generation presented in Tables B-28 - B-30 are staff's estimates of gas requirements within the discrete service areas. These requirements include self generation, third party generation for utility purchase, and utility generation. The respective gas utility may not provide all the gas service to meet these requirements. Both utility and nonutility gas as well as oil may be used to satisfy the fuel demand represented by this forecast.

TABLE B-28

PG&E NATURAL GAS SERVICE AREA
POTENTIAL NATURAL GAS REQUIREMENTS FOR ELECTRIC GENERATION[1]
mmcfd

Year	Cogeneration[2]	Combustion Turbines	Utility Boilers	Total
1985[3]	17	2	716	735
1990	184	9	265	458
1995	216	14	282	512
2000	269	38	339	646
2005	307	56	424	787
2007	322	66	466	854

[1]Source: CEC staff CFM 7 revised electricity price forecast ELFIN data sets, October 1987. Includes SCE's Coolwater facilities.

[2]Incremental fuel requirements for electricity generation.

[3]Historic data based on 1986 California Gas Report.

TABLE B-29

SOCALGAS NATURAL GAS SERVICE AREA
POTENTIAL NATURAL GAS REQUIREMENTS FOR ELECTRIC GENERATION[1]
mmcfd

Year	Cogeneration[2]	Combustion Turbines	Utility Boilers	Total
1985[3]	46	47	856	949
1990	262	0	344	606
1995	289	0	437	726
2000	309	31	563	903
2005	322	17	590	1,029
2007	326	149	596	1,071

[1]Source: CEC staff CFM 7 revised electricity price forecast ELFIN data sets, October 1987. Excludes SCE's Coolwater facilities.

[2]Incremental fuel requirements for electricity generation.

[3]Historic data based on 1986 California Gas Report.

TABLE B-30

SDG&E NATURAL GAS SERVICE AREA
POTENTIAL NATURAL GAS REQUIREMENTS FOR ELECTRIC GENERATION[1]
mmcfd

Year	Cogeneration[2]	Combustion Turbines	Utility Boilers	Total
1985[3]	35	-	97	132
1990	37	0	56	93
1995	54	0	81	135
2000	59	14	164	237
2005	59	88	147	294
2007	59	97	157	313

[1]Source: CEC staff CFM 7 revised electricity price forecast ELFIN data sets, October 1987.

[2]Incremental fuel requirements for electricity generation.

[3]Historic data based on 1986 California Gas Report.

PGandE

Overall potential natural gas requirements for electric generation in PGandE's service area are forecasted to grow from 735 mmcfd in 1985 to 854 mmcfd in 2007. The use of PGandE's gas and oil fired boilers are forecasted to decline substantially in the near term with gradual growth in the long term, but growth does not lead demand to surpass current requirements.

Substantial near-term growth in cogeneration more than offset the decline in use of utility boilers.

SoCalGas

Potential electric generation gas requirements in SoCalGas' service area are forecasted to grow from 949 mmcfd in 1985 to 1071 mmcfd in 2007. The use of electric utility boilers to meet the demand for electricity declines by more than half in the next few years. This decline is then reversed, but growth does not lead demand to surpass current needs. There is also a substantial early growth in cogeneration and a long term growth in the use of combustion turbines.

SDG&E

Forecasted gas demand in SDG&E service area for electric generation declines in the near term, then increases substantially. Cogeneration and utility boiler requirements and combustion turbine fuel needs increase dramatically during the forecast period.

Comparison of Electric Generation Forecasts

Tables B-31 and B-32 provide a statewide comparison of the forecasted gas/oil requirements for electric generation in the years 1995 and 2005. These tables compare the Biennial Fuels Report published in September 1986 (BFR 1) the October 1987 Committee Draft of the Biennial Fuels Report and the current forecast, for the 1987 Biennial Fuels Report (CFM 7 RPF). The tables display the demand forecast by electric utility service area and by the generic generation sectors of cogeneration, combustion turbines and utility boilers.

The tables show that the current forecast represents an increase in potential UEG gas requirements over BFR 1. Overall potential gas requirements in the current forecast are 20 percent higher in 1995 and 50 percent higher than the BFR 1 forecast in 2005.

In 1995, cogeneration and utility boiler requirements are about 60 percent higher in the current forecast. Combustion turbine requirements are down substantially. In 2005, combustion turbine requirements are 20 percent higher than the BFR 1 forecast and utility boiler requirements are 60 percent higher. Cogeneration gas requirements in the current forecast are 40 percent higher than BFR 1.

TABLE B-31

1995 STATEWIDE COMPARISON
ELECTRIC GENERATION OIL/GAS REQUIREMENTS FORECAST
mmcfd

Electric Utility Service Area	Cogeneration[1]			Combustion Turbines			Utility Boilers			Total		
	BFR 1	Draft BFR 2	CFM 7 RPF	BFR 1	Draft BFR 2	CFM 7 RPF	BFR 1	Draft BFR 2	CMF 7 RPF	BFR 1	Draft BFR 2	CFM 7 RPF
PG&E	135	181	216	30	11	14	199	444	282	364	636	512
SCE	166	293	262	21	0	0	364	409	345	551	702	607
LADWP	18	12	27	0	0	0	109	157	92	127	169	119
SDG&E	27	25	54	0	30	0	83	74	81	110	129	135
TOTAL	346	511	559	51	41	14	755	1,084	800	1,152	1,636	1,373

[1]Incremental fuel requirement for electricity generation.

BFR 1: September 1986 Biennial Fuels Report.

Draft BFR 2: Committee Draft 1987 Biennial Fuels Report, October 1987.

CFM 7 RPF: CFM 7 revised electricity price forecast, ELFIN production cost model data sets, October 1987.

TABLE B-32

2005 STATEWIDE COMPARISON
ELECTRIC GENERATION OIL/GAS REQUIREMENTS FORECAST
mmcfd

Electric Utility Service Area	Cogeneration[1]			Combustion Turbines			Utility Boilers			Total		
	BFR 1	Draft BFR 2	CFM 7 RPF	BFR 1	Draft BFR 2	CFM 7 RPF	BFR 1	Draft BFR 2	CMF 7 RPF	BFR 1	Draft BFR 2	CFM 7 RPF
PG&E	180	198	269	21	280	38	205	525	339	406	1,003	646
SCE	224	293	274	48	173	31	331	508	477	603	1,074	782
LADWP	18	12	35	0	2	0	65	225	86	83	239	121
SDG&E	31	25	59	0	143	14	71	145	164	102	313	237
TOTAL	453	528	637	69	598	83	672	1,503	1,066	1,194	2,629	1,786

[1]Incremental fuel requirement for electricity generation.

BFR 1: September 1986 Biennial Fuels Report.

Draft BFR 2: Committee Draft 1987 Biennial Fuels Report, October 1987.

CFM 7 RPF: CFM 7 revised electricity price forecast, ELFIN production cost model data sets, October 1987.

There is a great deal of uncertainty in any forecast of UEG gas demand in California. This uncertainty arises because California meets its electricity customer demands by using a number of diverse resources. These resources include gas and oil generation, nuclear, coal, geothermal and hydroelectric generation, imports from the southwest and Pacific northwest and PURPA defined qualifying facilities.

The forecast of UEG gas demand depends quite strongly on the mix of generating equipment, or "resource plan." The availability of resources other than oil and gas units is subject to large uncertainties. For example, demand for electricity in areas which export to California continue to grow, reducing availability for purchase by California. These changes make it difficult to estimate precisely the amount of energy California will be able to import from these areas in the future. Because of reevaluation for need and economic viability, future coal and nuclear facilities used in this or other planning periods may be added to or deleted from the staff's resource plan.

Changes in the availability of nongas resources strongly affects forecasted gas and oil generation. This impact occurs because oil and gas units tend to be relied on more heavily in response to shortages in other generating capacity. To illustrate the impact of resource changes it takes about 10 mmcf to generate one gigawatt hour. If there is a 5000 GWH downward shift in energy available from a potential source (about equivalent to a 800 MW facility), conceivably gas consumption could increase 50,000 mmcf annually or about 140 mmcfd.

The following section provides a detailed discussion of the underlying assumptions for the BFR 1 and BFR 2 electric generation forecasts. Contrasts by generic resource type for each service area highlight the differences in assumptions that lead to the increased reliance on conventional oil and gas generation.

C. Methodology and Assumptions

Introduction

In August 1987, the California Energy Commission staff presented its Draft BFR 2 forecast of gas requirements for the utility electric generation (UEG) system (hereafter referred to as "Draft BFR 2"). The staff based that forecast on the resource plan results it developed for the preliminary CFM 7 electricity price forecast.[1] This section describes an updated UEG gas forecast, based on the staff's revised CFM 7 electricity price forecast results,[2] and compares this new UEG forecast (hereafter referred to as "CFM 7 RPF") to both the Draft BFR 2 forecast and the 1986 adopted BFR 1 forecast (hereafter referred to as "BFR 1").

Summary Results

The CFM 7 RPF forecast is based on the following general resource plan assumptions:

- The staff's preliminary CFM 7 electricity demand forecast;[3]
- Resources from the Commission-adopted Electricity Supply Planning Assumptions Report (ESPAR);[4]

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[1] The CEC is currently in the process of developing its 1988 Electricity Report. A preliminary step in that process requires the CEC staff and California's electric utilities to file demand forecasts following Common Forecasting Methodology 7 (CFM 7). Electricity prices are one of the variables the staff and utility must forecast in developing a demand forecast.

[2] The staff has developed a revised CFM 7 electricity price forecast which addresses a number of the criticisms and concerns raised in the staff's and other parties' CFM 7 demand issues statements.

[3] California Energy Demand: 1987-2007; Staff Reports Prepared for Consideration in the 1988 Electricity Report, June, 1987.

[4] The Commission adopted supply planning assumptions in its 1986 Electricity Report (ER 6). Although the staff is currently reviewing and considering revising those assumptions, that work is in an early stage.

- Additional nonfirm energy from the Pacific Northwest beyond what was included in the ESPAR, based on average-year availability;[5]

- Capacity and energy purchases from the Pacific Northwest associated with a Third AC line on the Pacific Intertie (known as the California-Oregon Transmission Project or COTP);[6]

- Additional capacity from qualifying facilities (QFs) based on the staff's ER 6 long-range projections;[7]

- Self-generation additions after 1997 based on the staff's forecast in its preliminary CFM 7 electricity demand forecast;[8] and

- "Conditional" conservation savings based on the staff's preliminary CFM 7 electricity demand forecast.[9]

Given these loads and resources, the staff made decisions regarding the need for additional resources based primarily on whether capacity would be required for reliability. The type of resource was then decided, based upon relative cost, the potential for accompanying fuel savings, and environmental implications.

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5 The Commission also adopted an "additionally developed" amount of nonfirm energy from the Pacific Northwest in ER 6 (See Chapter 4, pages 4-6 to 4-7). That amount was in addition to the nonfirm energy adopted as part of ESPAR.

6 The judgement regarding whether to include COTP in the resource plans must be made consistently for all service areas. The decision to build COTP may ultimately be made based upon how likely it is that the municipal proponents would proceed to build the project without investor-owned utility participation. For present purposes, the staff assumed they would.

7 The staff prepared a short-range forecast of QFs (through 1990) based on the probability of success of known projects. That forecast was included among the adopted supply planning assumptions in ER 6. The staff also prepared a long-range forecast of QFs (1991-1997) derived from the economic potential of different technologies. Much of this QF capacity was projected to be self generation. The Commission did not adopt the long-range projections, instead designating them forecasts of potential (ER 6, Table 4-1).

8 Staff used the self-generation forecast consistent with the ER 6 long-range QF forecast through 1997. From 1998 through 2007, the staff added self-generation increments according to the staff CFM 7 projections (Form E-1.3).

9 These figures came from the staff's CFM 7 Form E-9.3.

In contrast, the Draft BFR 2 forecast assumed the Commission's adopted ER 6 demand forecast and resources likely to be available as found in ESPAR. Accordingly, after 1990, the plans show no QF additions, no self-generation additions, no incremental conservation effects, and no PNW transmission upgrades. The staff added either conventional gas turbines or steam-injected gas turbines to meet future capacity requirements. In its August 1987 testimony, the staff characterized this Draft BFR 2 outlook as an upper bound on future UEG requirements because future additions were presumed to be gas fired.

The BFR 1 forecast is, on the other hand, a lower bound. The resource plans from which that forecast came assumed utilities CFM 6 resources and the staff's CFM 6 demand forecast. Because utilities CFM 6 resource plans were based on higher demand forecasts, the resulting gas requirements projections in BFR 1 were lower than utilities.

Utility - Specific Comparisons

Northern California Planning Area (NCPA)

Table B-33 compares generation by resource type for the three gas demand forecasts. The following differences are noteworthy:

- The CFM 7 RPF forecast shows higher oil- and gas-fired cogeneration than either of the previous forecasts. The CFM 7 RPF projections are a result of more careful specifications of QFs' fuel type;

- Although the gas-fired share of total QF generation differs significantly, the total amount of generation from QFs in the BFR 1 forecast agrees with the CFM 7 RPF amount;

- The two most recent forecasts assume PGandE will not continue its geothermal resource program. Likely to be a available utility-owned, third party and municipal utilities' resource additions will more than meet the planning areas's needs;

- The CFM 7 RPF projections of Northwest imports are higher than either of the previous projections. Again, this is the result of the staff's more careful specification of available resources.

TABLE B-33

PACIFIC GAS AND ELECTRIC COMPANY
COMPARISON OF ELECTRIC GENERATION
SOURCES AMONG RESOURCE PLANS
GWh

Generation Type	1995 BFR 1	1995 Draft BFR 2	1995 CFM 7 RPF	2005 BFR 1	2005 Draft BFR 2	2005 CFM 7 RPF
Nuclear	17,185	15,036	15,522	17,366	15,623	15,639
Coal	723	668	859	777	744	931
Oil/Gas(1)	5,309	16,291	9,160	7,197	30,177	15,534
QF Gas/Oil(2)	8,601	10,571	11,810	12,470	10,852	16,826
QF Other(3)	16,076	9,416	12,372	21,249	9,416	15,477
Geothermal (Utility)	15,269	12,982	12,883	16,468	12,982	13,378
Imports	7,722	6,539	10,169	10,529	6,724	13,040
Hydro	29,246	27,852	27,788	29,478	28,088	27,836
TOTAL	100,131	99,355	100,563	115,534	114,606	118,661

Note: May not sum due to rounding.

Draft BFR 2 Source: CEC Fuels Planning Committee "Biennial Fuels Report, Committee Draft", Appendix C, October 1987, P300-86-016A.

CFM 7 RPF Source: CFM 7 Revised Electricity Price Forecast, ELFIN Production Cost Model data sets, October 1987.

(1) Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
(2) Includes all QF cogeneration which uses natural gas, including utility cogeneration.
(3) Includes QF biomass, geothermal, small hydro, solar and wind.

Southern California Edison (SCE)

Table B-34 shows the summary results by generation type for the CFM 7 RPF resource plan compared to BFR 1 results and the Draft BFR 2 figures.

The major differences these results reflect in the resource plan are:

- While, compared to the Draft BFR 2 results, higher QF capacity is now projected, the gas- and oil-fired proportion of that capacity is relatively lower;

- To import generic firm Southwest coal purchases, SCE would need a Southwest transmission upgrade; i.e, a second Devers-Palo Verde transmission line, but its planned construction could be deferred for several years;

- In the CFM 7 RPF forecast, the SCE-CDWR contract is assumed to be renewed after 2004, whereas it had been assumed terminated in the Draft BFR 2.

- The CFM 7 RPF reflects SCE's statement that it does not plan to retire San Onofre 1 in 2004.

Los Angeles Department of Water Power (LADWP)

QFs are not a major factor in the LADWP area. The only change in the co-generation category is to account for self-generation additions consistent with the staff's CFM 7 forecast. The reduced nuclear and imported generation shown in Table B-35 for 2005 reflect a presumed recall of shares of the Palo Verde unit.

For the CFM 7 RPF resource plan, the staff assumed that LADWP would continue to pursue an oil and gas displacement policy by participating in out-of-state coal projects. These units are assumed to provide cycling duty, normally provided by the oil and gas system. Hence, LADWP gas-fired generation drops to only 11 percent of total generation. In fact, this low level of in-basin generation may be infeasible, although LADWP does assume even lower levels.

San Diego Gas and Electric (SDG&E)

The San Diego Gas and Electric resource plan reflects a near-term strategy of purchases from other utilities. In the long term, the staff resource plan adds gas-fired combustion turbines and combined cycles. Although it is questionable whether this Commission would approve of such a plan, the corresponding gas use is consistent with what's shown in SDG&E CFM 7 resource plan Table B-34 through 1999, and considerably more moderate than

TABLE B-34

SOUTHERN CALIFORNIA EDISON
COMPARISON OF ELECTRIC GENERATION
SOURCES AMONG RESOURCE PLANS
GWh

Generation Type	1995 BFR 1	1995 Draft BFR 2	1995 CFM 7 RPF	2005 BFR 1	2005 Draft BFR 2	2005 CFM 7 RPF
Nuclear	15,269	15,005	14,990	13,282	15,005	15,001
Coal	11,663	11,698	11,425	11,662	11,538	11,616
Oil/Gas(1)	15,110	14,926	11,980	14,640	32,219	25,426
QF Gas/Oil(2)	10,773	18,311	16,611	10,773	18,337	17,624
QF Other(3)	7,898	8,254	12,063	20,804	8,253	13,652
Geothermal (Utility)	59	63	63	59	63	63
Imports	18,699	11,159	13,020	20,281	4,507	12,798
Hydro	9,894	9,749	9,155	10,538	7,388	9,288
TOTAL	89,365	89,165	89,307	102,039	97,310	105,468

Note: May not sum due to rounding.

Draft BFR 2 Source: CEC Fuels Planning Committee "Biennial Fuels Report, Committee Draft", Appendix C, October 1987, P300-86-016A.

CFM 7 RPF Source: CFM 7 Revised Electricity Price Forecast, ELFIN Production Cost model data sets, October 1987.

(1) Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
(2) Includes all QF cogeneration which uses natural gas, including utility cogeneration.
(3) Includes QF biomass, geothermal, small hydro, solar and wind.

TABLE B-35

LOS ANGELES DEPARTMENT OF WATER AND POWER
COMPARISON OF ELECTRIC GENERATION
SOURCES AMONG RESOURCE PLANS
GWh

Generation Type	1995 BFR 1	1995 Draft BFR 2	1995 CFM 7 RPF	2005 BFR 1	2005 Draft BFR 2	2005 CFM 7 RPF
Nuclear	1,936	1,978	1,978	794	1,978	762
Coal	11,835	9,836	12,342	17,877	9,836	19,208
Oil/Gas(1)	4,564	6,473	3,580	2,624	9,397	3,105
QF Gas/Oil(2)	976	682	1,492	976	682	2,255
QF Other(3)	0	199	164	0	199	164
Geothermal (Utility)	196	0	0	1,228	0	0
Imports	3,785	4,232	4,101	2,370	3,868	1,943
Hydro	1,816	2,365	2,575	1,829	2,247	2,682
TOTAL	25,108	25,765	26,232	27,698	28,207	30,119

Note: May not sum due to rounding.

Draft BFR 2 Source: CEC Fuels Planning Committee "Biennial Fuels Report, Committee Draft", Appendix C, October 1987, P300-86-016A.

CFM 7 RPF Source: CFM 7 Revised Electricity Price Forecast, ELFIN Production Cost model data sets, October 1987.

(1) Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
(2) Includes all QF cogeneration which uses natural gas, including utility cogeneration.
(3) Includes QF biomass, geothermal, small hydro, solar and wind.

what is shown in the California Gas Report for 2005. Although QFs are a small fraction of the SDG&E generation system, there was a large increase in gas-fired QFs in the CFM 7 RPF plan. Again, the increase stems from the staff's using the long-range QF forecast developed in ER 6 and the self-generation forecast developed in the staff's CFM 7 filing. Table B-36 compares the results of the three resource plans.

TABLE B-36

SAN DIEGO GAS AND ELECTRIC COMPANY
COMPARISON OF ELECTRIC GENERATION
SOURCES AMONG RESOURCE PLANS
GWh

Generation Type	1995 BFR 1	1995 Draft BFR 2	1995 CFM 7 RPF	2005 BFR 1	2005 Draft BFR 2	2005 CFM 7 RPF
Nuclear	2,718	2,897	2,897	2,718	2,897	2,897
Coal	497	0	0	2,159	0	0
Oil/Gas(1)	3,074	4,145	3,016	2,624	12,022	9,204
QF Gas/Oil(2)	3,246	1,357	3,316	3,740	1,357	3,861
QF Other(3)	614	240	251	776	240	318
Geothermal (Utility)	263	263	263	1,331	263	263
Imports	5,114	6,608	6,291	4,774	1,217	2,458
Hydro	0	0	0	310	0	0
TOTAL	15,526	15,510	16,034	18,432	17,996	19,001

Note: May not sum due to rounding.

Draft BFR 2 Source: CEC Fuels Planning Committee "Biennial Fuels Report, Committee Draft", Appendix C, October 1987, P300-86-016A.

CFM 7 RPF Source: CFM 7 Revised Electricity Price Forecast, ELFIN Production Cost model data sets, October 1987.

(1) Includes conventional oil- and gas-fired utility boilers, peaking units and advanced steam injection gas turbines (STIG).
(2) Includes all QF cogeneration which uses natural gas, including utility cogeneration.
(3) Includes QF biomass, geothermal, small hydro, solar and wind.

APPENDIX C

NATURAL GAS SUPPLY AND PRICE FORECAST DOCUMENTATION

APPENDIX C

NATURAL GAS SUPPLY AND PRICE FORECAST DOCUMENTATION

I. Introduction

This appendix documents the basic assumptions and methodologies used to prepare the natural gas supply and price forecasts presented in the 1987 Biennial Fuels Report (BFR).

II. Natural Gas Supply Forecast

A summary of the supply forecast is provided in Table C-1. This statewide supply forecast includes nonutility and utility supply. Staff has drawn heavily from information presented at the natural gas supply hearings in preparing the supply forecast.

The forecast gives the potential available supply from the most likely future natural gas supply areas for California. These supply areas include California, Canada, Southwest USA, Rocky Mountains, and the Gulf Coast.

Pipeline systems have been utilized as a focal point for preparing the supply forecast. Supply would be carried but not necessarily owned by the indicated pipeline. The forecast includes potential available supply under all possible contract terms and no attempt has been made to quantify

purchases by such terms or conditions as spot, transport, third party, or pipeline supply.

TABLE C-1

AVAILABLE SUPPLY FORECAST SUMMARY
(mmcfd)

Source	1990	1995	2000	2007
California	1,572	1,557	1,278	1,159
Southwest	2,011	1,934	2,020	2,411
Canada	1,193	1,211	1,217	1,217
Rocky Mountains	81	345	690	690
Mexico	75	90	100	90
Unspecified		153	564	1,007
TOTAL	4,932	5,290	5,869	6,574

A. California Production

The California production forecast was prepared in three segments, Northern California, Southern California and offshore California including state and federal waters.

1. Northern California. Production forecasts for Northern California correspond to Division of Oil and Gas (DOG) District 6. A summary of this forecast is provided in Table C-2. The forecast is based on anticipated production from proven reserves, new reserve additions and production of sanitary landfill gas.

TABLE C-2

AVAILABLE SUPPLY FORECAST
FROM NORTHERN CALIFORNIA RESOURCES
(mmcfd)

Year	PGandE Purchases	Nonutility Supply	Total Production
1990	357	62	419
1995	184	24	208
2000	182	28	208
2007	210	34	244

Production from existing reserves was determined on the basis of maximum production capability. This capability was determined by reviewing the peak production months for the past several years. The maximum monthly peak capability was annualized and then for each successive year reduced by 18 percent until existing proven reserves had been exhausted. Production from new reserves were based on a historic average of 100 Bcf per year in reserve additions. A production decline curve was applied to obtain annual production.[1]

Production forecasts were then divided into two supply components: producer sales to PGandE for resale and nonutility supply. This latter category could be either nonutility uses by the producer or direct sales to end users. Allocation between the two supply components was based on historic DOG District 6 production and PGandE purchases as provided to the CEC by PG&E in QFER Form 6A.

2. Southern California. Production from Southern California natural gas resources includes all production in California other than DOG District 6 and production from California waters in Southern California (DOG districts 1, 2 and 3). A summary of forecasted Southern California production is provided in Table C-3. It consists of production from proved reserves, reserves to be added in the future, and sanitary landfill gas.

TABLE C-3

AVAILABLE SUPPLY FORECAST
FROM SOUTHERN CALIFORNIA RESOURCES
(mmcfd)

Year	Utility System Supply	Nonutility Supply	Total Production
1990	357	506	863
1995	346	438	784
2000	270	379	649
2007	232	325	557

Onshore Southern California net natural gas production from proved reserves was assumed to continue at 1986 levels of 225.6 Bcf for the next five years. In recent years production has increased from 164 Bcf in 1980 to 245.1 Bcf in 1985 with an average of 215.6 Bcf, which is approximately the 1986 production level. After 1992, production from currently proved reserves is assumed to decline in succeeding years by 10 percent per year until present proved reserves are fully exhausted. Reserve additions have averaged 230 Bcf per year. It was assumed this level of reserve additions will continue.

In estimating new reserve additions, the staff considered (1) estimate of potential natural gas reserves made by the Potential Gas Committee, (2) present reserve holdings of EPNG and Transwestern in basins which have been their traditional supply areas, and (3) historic trends in reserve additions. The staff assumed that 75 percent of the Probable, 50 percent of the Possible, and 25 percent of the Speculative gas reserves identified by the Potential Gas Committee for the San Juan, Anadarko, and Permian Basins would be proven over the next 20 years. Portions of these reserves were assigned to supply California based on the proportions of current reserve holdings dedicated to California. The resulting estimate of future reserve additions were then allocated as yearly additions reflecting current plans and future needs for reserve additions through 2007.

C. Canada

Natural gas supplies from Canada are delivered to both PGandE and SoCalGas service areas under long term export/import licenses. Table C-6 provides a summary of forecasted supply from Canada.

TABLE C-6

AVAILABLE SUPPLY FORECAST FROM CANADA
(mmcfd)

	1990	1995	2000	2007
PGandE Max. License	1,000	1,000	1,000	1,000
SoCal Gas Max. License	217	217	217	217
Total	1,217	1,217	1,217	1,217

The basis of the Canadian forecast is expert witness testimony provided by Dr. G. C. Watkins, Datametrics Ltd. and sponsored by the CEC.[4] This testimony indicates available Canadian gas supplies will be more than sufficient to continue meeting SoCal and PGandE import licenses.

D. Rocky Mountains

The Rocky Mountain area of Utah, Colorado, Idaho, Wyoming and possibly Montana might emerge as a major future supply area. The area is relatively near to California and has large undedicated proven reserves and substantial undiscovered potential resources. Table C-7 provides a summary of staff's forecasted available supply from the Rocky Mountain area.

TABLE C-7

AVAILABLE SUPPLY FORECAST
FROM THE ROCKY MOUNTAIN AREA
(mmcfd)

	1990	1995	2000	2007
California Share	81	345	690	690

The methodology to develop the supply forecast consisted of several steps. The first was to develop a deliverability and wellhead price supply/curve. Then, available supply was determined based on burner tip prices net back to the wellhead. A portion of the available supply was allocated to California.

The Rocky Mountain available supply forecast is based on information obtained from the Biennial Fuels Report Supply Hearings held on May 18-29, 1987. V.A. Kuuskraa of Lewin and Associates provided staff-sponsored testimony on potential natural gas resources in the Rocky Mountains at various wellhead prices.[5] Mark Doelger, a geologist with Barlow and Hahn, Inc. and representing the State of Wyoming, provided additional resource, drilling and production information.[6]

E. Gulf Coast

Natural gas supplies for California from the Gulf Coast are not expected to be a reliable long term supply option. Testimony received from John Brickhill of Foster Associates, sponsored by the CEC, indicated that while there are currently substantial uncommitted reserves and excess production in the Gulf Coast, production will decline substantially in the 1990s even with new reserve additions.[7] Moreover, demand for Gulf Coast gas in its nearest markets - Louisiana and Texas - is expected to increase as onshore production in these areas declines. This increased demand together with the expected decline in production will leave little Gulf Coast gas available for export to California.

F. Unspecified Available Supplies

In addition to the potentially available supplies discussed in this report, there are additional resources which may become available to California.[8] These resources include production from Northern and Central California offshore, Mexican gas, and additional supplies from Canada, the

Rocky Mountains, the Southwest and the Gulf Coast. Unspecified available supplies needed to balance supply and demand are summarized in Table C-8.

TABLE C-8

AVAILABLE SUPPLY FORECAST FROM
UNSPECIFIED SOURCES
(mmcfd)

	1990	1995	2000	2007
Supply	0	153	564	1,007

Analysis sponsored by the CEC indicates there are potential additional supplies from Canada which could average 200 mmcfd in the late 1990s and 400 mmcfd after 2000 (see footnote 4). Staff analysis indicates that the Rocky Mountains could potentially provide an additional 400 mmcfd to meet the unspecified requirements. The availability of the additional Canadian and Rocky Mountain supplies as well as others will depend on such factors as regional competition for supply, transportation availability, and new technology development. The large uncertainties inherent in these factors make it impossible to specify which additional supplies or what quantities will become available in the later years of the forecast.

III. Natural Gas Price Forecast

This section discusses assumptions and procedures used to determine an end-use price forecast for the 1987 Biennial Fuels Report. Table C-9 provides a summary of the price forecast by sector and utility. Tables at

the end of the text provide additional information on specific details concerning the price forecast.

The general procedures followed were to first determine wellhead prices. To these were added transportation costs to obtain a delivered price at the California border. Individual utility distribution costs were then added to obtain a total cost of acquiring and delivering natural gas to the end-use customer. End-use prices were then determined by applying CPUC end-use pricing policies. The following discusses the procedures followed in more detail.

TABLE C-9

NATURAL GAS END USE PRICE FORECAST
1987 $/mmBtu

	1990	1995	2000	2007
PG&E				
Residential	5.70	6.53	7.24	8.04
Commercial	5.98	6.81	7.57	8.51
Industrial	5.41	6.04	6.78	7.84
UEG	4.64	5.07	5.76	6.86
System Average	5.37	6.01	6.68	7.62
SoCal Gas				
Residential	6.08	6.89	7.63	8.51
Commercial	6.28	7.06	7.85	8.88
Industrial	5.31	5.87	6.61	7.73
UEG	4.86	5.33	6.04	7.20
System Average	5.58	6.18	6.86	7.87
SDG&E				
Residential	6.01	6.83	7.50	8.33
Commercial	6.08	6.84	7.55	8.55
Industrial	5.89	6.59	7.31	8.33
UEG	4.64	5.07	5.76	6.86
System Average	5.48	5.99	6.45	7.38

A. Wellhead Prices

In the long term, wellhead prices were assumed to follow forecasted oil prices. To meet the cost of service assumption described in "End-Use Prices" part of this section, the deregulated wellhead price was adjusted to provide a reasonable cost of service contribution by the industrial sector. After considering industrial burner tip prices, controlled wellhead prices, and transport costs, it was determined that deregulated wellhead prices would be approximately 82 percent of the forecasted low sulfur content residual fuel oil forecast. Old gas was assumed to remain controlled with wellhead prices only escalating with inflation. Imported gas at the Canadian border was uniformly set to provide a California border price competitive with El Paso and Transwestern supplies. Unspecified available supplies were priced at the border price equal to the highest cost gas.

B. Natural Gas Transportation Costs.

Staff selected a variety of approaches for determining transportation rates for gas. The approach selected depended primarily upon the quality of available data. A summary of the methodology used to compute transportation rates follows:

El Paso & Transwestern. Staff used the December 1984 El Paso general rate case filing before FERC to identify the major cost elements.[9] The following assumptions were applied to the various cost elements identified in the general rate case filing. Annual capital outlays were limited to approximately 1 percent of total pipeline assets and operation and

maintenance costs were assumed to be constant in real terms. Pipeline assets were straight line depreciated over the expected life. These assumptions result in overall cost decreases. First year costs for Transwestern were based on a rate settlement effective on February 1, 1986. It was presumed the Transwestern first year transport cost would escalate at the same rate as forecasted for El Paso. Average unit transportation rates were determined by applying the throughput levels discussed earlier.

PGT. Staff used the most recent filing before FERC and assumed costs to remain constant in real terms.[10] The pipeline system has been almost completely depreciated and any small decrease in depreciation and capital costs over time will be offset by increases in operating costs. Full throughput levels were assumed for all years.

Rocky Mountain. Short term and long term transportation rates were developed for Rocky Mountain supplies. Staff assumed existing rates in the range of $.80-$1.15 mmBtu would continue until 1995.[11] At that time, a Rocky Mountain pipeline system was assumed operational. The Rocky Mountain transportation rates were based upon a staff analysis of a Rocky Mountain pipeline, using a levelized rate basis.[12]

California Offshore. Cost data available in the 1985 California Gas Report working papers was used to forecast the transportation cost of a base supply level. All gas supplies above this level were assumed to have a transport rate of $1.00/mmBtu.

Pacific Interstate-Pan Alberta. Staff relied upon data available in the 1986 California Gas Report for developing the SoCal Gas transportation rates for Canadian natural gas.

C. Distribution Costs.

The CEC approach to forecasting natural gas utility distribution costs includes a complete analysis of all key cost components. Assumptions are made regarding each of the following cost components:

- Capital outlay (plant additions)
- Working capital requirements
- Depreciation
- The cost of debt and stock (capital costs)
- The ratio of debt to stock (capital structure)
- Operation and maintenance costs
- Income and other taxes
- Miscellaneous costs
- Conservation costs.

As Table C-10 indicates, distribution costs for California gas utilities are expected to increase by slightly less than 1 percent per year in real terms. This is a major change from the 9 percent real growth rate in distribution costs experienced by California gas utilities between 1976-1984. Distribution costs have actually decreased during 1986-87 and may continue this trend or remain flat over the near term.

TABLE C-10

ANNUAL FORECASTED DISTRIBUTION COSTS
1987$ in Millions

	PG&E	SoCal	SDG&E
1987	1,053	1,333	126
1990	1,108	1,353	134
1995	1,131	1,450	142
2000	1,178	1,542	149
2005	1,213	1,645	155
2007	1,233	1,670	158

The general restructuring of the natural gas market in California includes one of the most intensive cost cutting efforts California gas utilities have ever experienced. Efficiencies are necessary if California natural gas utilities are to compete with other suppliers for the lucrative TEOR market and maintain large industrial customers. Cognizant of this fact, the CPUC has mandated major efficiencies through the rate setting mechanism.

It is difficult at this early stage of market restructuring to determine just how far California's natural gas utilities can cut costs. Potentially, there could be considerable long term efficiency improvements, particularly if the current trend to increased competition prevails. Staff's forecast of distribution costs does not explicitly assume any major efficiencies by utilities. Distribution costs could potentially remain flat or increase at much less than 1 percent per year, depending on the degree of competition that utilities experience. However, the rising gas prices forecasted for the 1990s should also result in increased outlays for energy conservation measures.

D. End-Use Prices

There are two key assumptions underlying the natural gas end-use price forecast. The first is that end-use prices are set based on cost of service. The second is that industrial and utility electric generation (UEG) end-use prices reflect oil prices. There is a corollary cost of service assumption concerning transported gas. This is that the gas utility under cost of service rates would receive the same margin contributions whether gas was transported or directly sold to a customer.

Industrial rates were set equal to the CEC forecasted low sulfur residual fuel oil price and UEG gas rates were set at 95 percent. Residential rates were initially set equal to 90 percent of the system average delivered price and commercial rates equal to the system average delivered price.

These initial rate projections were applied to forecasted demand to obtain revenue collections. The sum of the revenues collected were compared with revenue requirements. If there was an over collection, then all rates were uniformly reduced. On the other hand, if revenues were under collected, only residential and commercial rates were increased.

Natural gas demand served by gas utilities was determined by removing the nonutility demand from the total utility service area demand forecast found in Appendix C.

Nonutility natural gas demand is the requirement for natural gas service that would be satisfied by the nonutility supply discussed earlier in this Appendix under California production.

California natural gas marketer reports[13] filed with the CEC were used to determine the proportion of nonutility supply that would serve the commercial sector and process, assembly and mining industries. It was assumed these proportions would remain constant throughout the forecast period. The following provides estimates of nonutility supply serving the various sectors.

TABLE C-11

NONUTILITY NATURAL GAS DEMAND
(mmcfd)

	1987	1990	1995	2000	2005	2007
PG&E Service Area						
Commercial	1	1	0	0	0	0
Process Industry	48	34	13	15	18	19
Assembly Industry	6	5	2	2	2	2
Mining	32	22	9	11	13	13
SCG Service Area						
Commercial	25	31	27	23	22	20
Process Industry	84	104	90	78	74	67
Assembly Industry	32	39	34	29	28	25
Mining	270	332	288	249	236	214

C. NATURAL GAS SUPPLY, DEMAND AND PRICE TABLES

In the following tables unspecified supplies have been identified as "Northwest" in Northern California and "Canada (New)" in Southern California. The designation was done for ease in analysis and does not imply the gas supply would come from these sources.

TABLE C-12

NATURAL GAS WELL_HEAD PRICES
1987 BIENNIAL FUELS REPORT
1987 DOLLARS PER MMBTU

YEAR	S102	S103	S104 POST 1974	S104 1973-74	S104 & S106 PRE 1973	S107	S108	S109	CANADA BORDER
1987	1.60	2.00	1.88	1.71	0.64	3.00	3.00	2.[illegible]	1.88
1988	2.09	2.43	2.11	1.71	0.64	3.43	3.37	2.65	2.38
1989	2.73	2.94	2.36	1.71	0.64	3.92	3.79	2.65	3.02
1990	3.57	3.57	2.65	1.71	0.64	4.48	4.26	2.65	3.83
1991	3.69	3.69	2.65	1.71	0.64	4.47	4.25	2.65	3.93
1992	3.81	3.81	2.65	1.71	0.64	4.46	4.23	2.65	4.03
1993	3.93	3.93	2.65	1.71	0.64	4.46	4.22	2.65	4.13
1994	4.06	4.06	2.65	1.71	0.64	4.45	4.20	2.65	4.24
1995	4.19	4.19	2.65	1.71	0.64	4.44	4.19	2.65	4.35
1996	4.34	4.34	2.65	1.71	0.64	4.59	4.34	2.65	4.51
1997	4.49	4.49	2.65	1.71	0.64	4.76	4.49	2.65	4.67
1998	4.64	4.64	2.65	1.71	0.64	4.92	4.64	2.65	4.84
1999	4.80	4.80	2.65	1.71	0.64	5.09	4.80	2.65	5.02
2000	4.97	4.97	2.65	1.71	0.64	5.27	4.97	2.65	5.20
2001	5.11	5.11	2.65	1.71	0.64	5.41	5.11	2.65	5.33
2002	5.26	5.26	2.65	1.71	0.64	5.56	5.26	2.65	5.47
2003	5.41	5.41	2.65	1.71	0.64	5.71	5.41	2.65	5.61
2004	5.57	5.57	2.65	1.71	0.64	5.87	5.57	2.65	5.76
2005	5.73	5.73	2.65	1.71	0.64	6.03	5.73	2.65	5.91
2006	5.89	5.89	2.65	1.71	0.64	6.19	5.89	2.65	6.06
2007	6.06	6.06	2.65	1.71	0.64	6.36	6.06	2.65	6.22

TABLE C-13

CALIFORNIA UNIT BORDER COST
MED. SUPPLY AND MED. PRICE CASE
1987 BIENNIAL FUELS REPORT
1987 DOLLARS PER MMBTU

SOURCE	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
ONSHORE - NORTH	1.76	2.23	2.81	3.57	3.69	3.81	3.93	4.06	4.19	4.34	4.49	4.64	4.80
ONSHORE - SOUTH	2.41	2.87	3.42	4.10	4.14	4.19	4.24	4.29	4.33	4.48	4.65	4.80	4.97
OFFSHORE	3.30	3.19	3.44	4.25	4.44	4.58	4.69	4.81	4.88	5.01	5.12	5.24	5.40
EL PASO	2.24	2.63	3.09	3.70	3.84	3.94	4.21	4.33	4.51	4.68	4.73	4.94	5.02
TRANSWESTERN	2.60	3.03	3.48	4.03	4.17	4.24	4.49	4.58	4.65	4.76	4.94	5.01	5.21
PAC INTERSTATE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTHWEST	0.00	0.00	0.00	4.80	4.88	4.97	5.06	5.16	5.10	5.26	5.38	5.50	5.60
CANADA (PGT)	2.45	3.07	3.60	3.93	4.03	4.13	4.23	4.34	4.45	4.61	4.77	4.94	5.12
CANADA (SCG)	3.68	3.92	4.40	4.86	4.86	4.86	4.86	4.87	4.87	4.97	5.07	5.19	5.32
CANADA (NEW)	0.00	0.00	0.00	0.00	0.00	0.00	5.06	5.16	5.10	5.26	5.38	5.50	5.60
ROCKY MTN (PGT)	2.95	3.42	4.03	4.80	4.88	4.97	5.06	5.16	5.08	5.07	5.20	5.27	5.43
ROCKY MTN (EPNG)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.08	5.07	5.20	5.27	5.43
MEXICO	0.00	0.00	0.00	4.39	4.54	4.64	4.87	4.97	5.10	5.26	5.38	5.50	5.60
INDONESIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH SLOPE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SNG COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOUTH AMERICA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AUSTRALIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIGESTER-MANURE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAN LAND FILL	1.88	2.18	2.53	2.93	2.98	3.02	3.07	3.13	3.20	3.29	3.37	3.46	3.55

SOURCE	2000	2001	2002	2003	2004	2005	2006	2007
ONSHORE - NORTH	4.97	5.11	5.26	5.41	5.57	5.73	5.89	6.06
ONSHORE - SOUTH	5.14	5.28	5.43	5.58	5.74	5.90	6.06	6.23
OFFSHORE	5.56	5.68	5.82	5.95	6.10	6.25	6.39	6.55
EL PASO	5.22	5.27	5.43	5.63	5.79	5.93	5.96	6.31
TRANSWESTERN	5.39	5.53	5.70	5.85	6.03	6.23	6.33	6.61
PAC INTERSTATE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTHWEST	5.77	5.87	5.99	6.12	6.26	6.41	6.55	6.72
CANADA (PGT)	5.30	5.43	5.57	5.71	5.86	6.01	6.16	6.32
CANADA (SCG)	5.45	5.58	5.70	5.82	5.95	6.06	6.21	6.37
CANADA (NEW)	5.77	5.87	5.99	6.12	6.26	6.41	6.55	6.72
ROCKY MTN (PGT)	5.60	5.74	5.89	6.04	6.20	6.36	6.52	6.69
ROCKY MTN (EPNG)	5.60	5.74	5.89	6.04	6.20	6.36	6.52	6.69
MEXICO	5.77	5.87	5.99	6.12	6.26	6.41	6.55	6.72
INDONESIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOK INLET	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH SLOPE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SNG COAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOUTH AMERICA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AUSTRALIA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DIGESTER-MANURE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SAN LAND FILL	3.64	3.73	3.82	3.92	4.01	4.12	4.22	4.33

TABLE C-14

NORTHERN CALIFORNIA SUPPLY
MED. SUPPLY CASE
MMCFD

SOURCE	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
ONSHORE - NORTH	448	406	380	352	325	293	286	239	166	172	176	171	156
ONSHORE - SOUTH	0	0	0	0	0	0	0	0	0	0	0	0	0
OFFSHORE	0	0	0	0	0	0	0	0	0	0	0	0	0
EL PASO	528	482	440	423	376	392	388	420	367	421	452	466	478
TRANSWESTERN	0	0	0	0	0	0	0	0	0	0	0	0	0
PAC INTERSTATE	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	76	69	75	79	153	139	33	0	0
CANADA (PGT)	773	850	936	985	1000	1000	1000	1000	1000	1000	1000	995	963
CANADA (SCG)	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (NEW)	0	0	0	0	0	0	0	0	0	0	0	0	0
ROCKY MTN (PGT)	43	55	68	81	102	136	169	199	276	328	390	462	536
ROCKY MTN (EPNG)	0	0	0	0	0	0	0	0	0	0	0	0	0
MEXICO	0	0	0	15	15	15	18	18	18	18	18	18	20
INDONESIA	0	0	0	0	0	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0	0	0	0	0	0
SAN LAND FILL	1	2	3	5	7	9	12	15	18	18	18	18	18
TOTAL	1793	1795	1827	1861	1901	1914	1948	1970	1998	2096	2087	2130	2171

SOURCE	2000	2001	2002	2003	2004	2005	2006	2007
ONSHORE - NORTH	164	165	170	173	179	183	188	192
ONSHORE - SOUTH	0	0	0	0	0	0	0	0
OFFSHORE	0	0	0	0	0	0	0	0
EL PASO	454	478	518	537	552	582	597	619
TRANSWESTERN	0	0	0	0	0	0	0	0
PAC INTERSTATE	0	0	0	0	0	0	0	0
NORTHWEST	8	19	8	21	31	31	46	99
CANADA (PGT)	1000	1000	1000	1000	1000	1000	1000	1000
CANADA (SCG)	0	0	0	0	0	0	0	0
CANADA (NEW)	0	0	0	0	0	0	0	0
ROCKY MTN (PGT)	536	538	533	543	548	554	561	579
ROCKY MTN (EPNG)	0	0	0	0	0	0	0	0
MEXICO	20	20	20	18	18	18	18	18
INDONESIA	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0
SAN LAND FILL	18	18	18	18	18	18	18	18
TOTAL	2200	2238	2267	2310	2346	2386	2428	2525

TABLE C-15

SOUTHERN CALIFORNIA SUPPLY
MED. SUPPLY CASE
MMCFD

SOURCE	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
ONSHORE - NORTH	0	0	0	0	0	0	0	0	0	0	0	0	0
ONSHORE - SOUTH	282	309	332	351	349	348	357	346	340	331	317	297	270
OFFSHORE	186	203	256	290	337	416	501	561	565	580	516	473	451
EL PASO	1176	1126	1130	1089	1072	1061	999	1028	1045	1031	1006	990	1016
TRANSWESTERN	480	481	497	499	511	501	519	513	522	546	559	556	556
PAC INTERSTATE	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (PGT)	0	0	0	0	0	0	0	0	0	0	0	0	0
CANADA (SCG)	184	191	199	208	211	212	217	217	211	217	217	217	217
CANADA (NEW)	0	0	0	0	0	0	9	15	0	45	220	387	446
ROCKY MTN (PGT)	0	0	0	0	0	0	0	0	0	0	0	0	0
ROCKY MTN (EPNG)	0	0	0	0	0	0	0	0	69	82	97	118	154
MEXICO	0	0	0	60	60	60	72	72	72	72	72	72	80
INDONESIA	0	0	0	0	0	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0	0	0	0	0	0
SAN LAND FILL	6	6	6	6	6	6	6	6	6	6	6	6	6
TOTAL	2314	2316	2420	2503	2546	2604	2680	2758	2830	2910	3010	3116	3196

SOURCE	2000	2001	2002	2003	2004	2005	2006	2007
ONSHORE - NORTH	0	0	0	0	0	0	0	0
ONSHORE - SOUTH	264	259	256	252	251	251	249	226
OFFSHORE	419	393	406	400	397	391	374	358
EL PASO	1010	1116	1154	1196	1229	1238	1268	1256
TRANSWESTERN	556	557	558	559	557	532	534	536
PAC INTERSTATE	0	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	0	0	0	0
CANADA (PGT)	0	0	0	0	0	0	0	0
CANADA (SCG)	217	217	217	217	217	217	217	217
CANADA (NEW)	556	569	557	611	625	711	744	908
ROCKY MTN (PGT)	0	0	0	0	0	0	0	0
ROCKY MTN (EPNG)	154	152	153	147	142	136	129	111
MEXICO	80	80	80	72	72	72	72	72
INDONESIA	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0
SAN LAND FILL	6	6	6	6	6	6	6	6
TOTAL	3262	3349	3387	3460	3496	3554	3593	3690

TABLE C-16

TOTAL CALIFORNIA SUPPLY
MED. SUPPLY CASE
MMCFD

SOURCE	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
ONSHORE - NORTH	448	406	380	352	325	293	286	239	166	172	176	171	156
ONSHORE - SOUTH	282	309	332	351	349	348	357	346	340	331	317	297	270
OFFSHORE	186	203	256	290	337	416	501	561	565	580	516	473	451
EL PASO	1704	1608	1570	1512	1448	1453	1387	1448	1412	1452	1458	1456	1494
TRANSWESTERN	480	481	497	499	511	501	519	513	522	546	559	556	556
PAC INTERSTATE	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTHWEST	0	0	0	0	76	69	75	79	153	139	33	0	0
CANADA (PGT)	773	850	936	985	1000	1000	1000	1000	1000	1000	1000	995	963
CANADA (SCG)	184	191	199	208	211	212	217	217	211	217	217	217	217
CANADA (NEW)	0	0	0	0	0	0	9	15	0	45	220	387	446
ROCKY MTN (PGT)	43	55	68	81	102	136	169	199	276	328	390	462	536
ROCKY MTN (EPNG)	0	0	0	0	0	0	0	0	69	82	97	118	154
MEXICO	0	0	0	75	75	75	90	90	90	90	90	90	100
INDONESIA	0	0	0	0	0	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0	0	0	0	0	0
SAN LAND FILL	7	8	9	11	13	15	18	21	24	24	24	24	24
TOTAL	4107	4111	4247	4364	4447	4518	4628	4728	4828	5006	5097	5246	5367

SOURCE	2000	2001	2002	2003	2004	2005	2006	2007
ONSHORE - NORTH	164	165	170	173	179	183	188	192
ONSHORE - SOUTH	264	259	256	252	251	251	249	226
OFFSHORE	419	393	406	400	397	391	374	358
EL PASO	1464	1594	1672	1733	1781	1820	1865	1875
TRANSWESTERN	556	557	558	559	557	532	534	536
PAC INTERSTATE	0	0	0	0	0	0	0	0
NORTHWEST	75	75	75	75	75	75	75	99
CANADA (PGT)	933	944	933	946	956	956	971	1000
CANADA (SCG)	217	217	217	217	217	217	217	217
CANADA (NEW)	556	569	557	611	625	711	744	908
ROCKY MTN (PGT)	536	538	533	543	548	554	561	579
ROCKY MTN (EPNG)	154	152	153	147	142	136	129	111
MEXICO	100	100	100	90	90	90	90	90
INDONESIA	0	0	0	0	0	0	0	0
COOK INLET	0	0	0	0	0	0	0	0
NORTH SLOPE	0	0	0	0	0	0	0	0
SNG COAL	0	0	0	0	0	0	0	0
SOUTH AMERICA	0	0	0	0	0	0	0	0
AUSTRALIA	0	0	0	0	0	0	0	0
DIGESTER-MANURE	0	0	0	0	0	0	0	0
SAN LAND FILL	24	24	24	24	24	24	24	24
TOTAL	5462	5587	5654	5770	5842	5940	6021	6215

TABLE C-17

PACIFIC GAS & ELECTRIC
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P4	P5	TOTAL
1987	556	231	185	103	189	172	357	1793
1988	551	231	188	138	192	189	306	1795
1989	546	231	192	157	197	211	293	1827
1990	542	232	196	184	201	232	274	1861
1991	544	235	200	192	205	237	288	1901
1992	546	238	202	198	208	241	281	1914
1993	548	241	207	204	215	247	286	1948
1994	549	243	210	210	212	251	295	1970
1995	551	246	214	216	219	256	296	1998
1996	552	252	238	222	240	275	317	2096
1997	553	252	221	230	226	267	338	2087
1998	555	254	223	246	228	269	355	2130
1999	557	257	225	261	230	271	370	2171
2000	560	259	228	269	233	274	377	2200
2001	562	261	229	271	234	275	406	2238
2002	564	262	231	284	235	276	415	2267
2003	566	265	233	287	238	279	442	2310
2004	568	266	235	300	240	280	457	2346
2005	571	268	237	307	241	282	480	2386
2006	574	271	238	315	243	283	504	2428
2007	577	276	260	322	262	296	532	2525

TABLE C-18

SOUTHERN CALIFORNIA GAS
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P3C	P4	P5	TOTAL
1987	809	250	98	114	182	16	181	457	2107
1988	812	248	97	155	183	12	216	389	2112
1989	815	248	98	261	186	12	257	322	2199
1990	818	249	99	262	190	12	303	332	2265
1991	823	254	100	267	192	12	305	349	2302
1992	828	261	104	273	201	12	323	348	2350
1993	833	265	107	279	207	13	339	372	2415
1994	837	271	111	285	215	13	354	396	2482
1995	841	276	114	289	221	13	368	424	2546
1996	845	281	117	293	229	16	383	450	2614
1997	849	286	119	297	233	15	395	482	2676
1998	853	292	122	303	239	14	408	531	2762
1999	858	296	125	306	244	13	418	562	2822
2000	864	299	127	309	249	12	429	582	2871
2001	866	302	129	311	254	12	439	615	2928
2002	869	306	132	315	258	12	445	623	2960
2003	873	310	133	317	262	12	453	657	3017
2004	877	314	136	319	267	12	460	664	3049
2005	881	317	137	322	270	12	466	695	3100
2006	886	319	139	324	274	12	472	701	3127
2007	891	326	144	326	284	12	496	733	3212

TABLE C-19

SAN DIEGO GAS & ELECTRIC
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P4	P5	TOTAL
1987	93	29	7	20	11	4	43	207
1988	94	29	7	29	11	4	30	204
1989	95	28	7	33	11	4	43	221
1990	95	28	7	37	11	4	56	238
1991	96	28	7	41	11	4	57	244
1992	96	29	7	44	11	4	63	254
1993	96	29	7	47	11	4	71	265
1994	97	30	7	50	11	4	77	276
1995	97	30	7	54	11	4	81	284
1996	97	30	7	56	11	4	91	296
1997	97	31	7	59	11	4	125	334
1998	98	31	7	59	11	4	144	354
1999	98	31	7	59	12	4	163	374
2000	99	32	7	59	12	4	178	391
2001	99	32	7	59	12	4	208	421
2002	99	33	7	59	12	4	213	427
2003	100	33	7	59	12	4	228	443
2004	100	33	7	59	12	4	232	447
2005	101	34	8	59	13	4	235	454
2006	102	34	8	59	13	4	246	466
2007	102	34	8	59	13	4	258	478

TABLE C-20

CALIFORNIA SUMMARY
ANNUAL AVERAGE NATURAL GAS DEMAND BY PRIORITY
MMCFD

YEAR	P1 RES	P1 OTH	P2	P3A	P3B	P3C	P4	P5	TOTAL
1987	1458	510	290	237	382	16	357	857	4107
1988	1457	508	292	322	386	12	409	725	4111
1989	1456	507	297	451	394	12	472	658	4247
1990	1455	509	302	483	402	12	539	662	4364
1991	1463	517	307	500	408	12	546	694	4447
1992	1470	528	313	515	420	12	568	692	4518
1993	1477	535	321	530	433	13	590	729	4628
1994	1483	544	328	545	438	13	609	768	4728
1995	1489	552	335	559	451	13	628	801	4828
1996	1494	563	362	571	480	16	662	858	5006
1997	1499	569	347	586	470	15	666	945	5097
1998	1506	577	352	608	478	14	681	1030	5246
1999	1513	584	357	626	486	13	693	1095	5367
2000	1523	590	362	637	494	12	707	1137	5462
2001	1527	595	365	641	500	12	718	1229	5587
2002	1532	601	370	658	505	12	725	1251	5654
2003	1539	608	373	663	512	12	736	1327	5770
2004	1545	613	378	678	519	12	744	1353	5842
2005	1553	619	382	688	524	12	752	1410	5940
2006	1562	624	385	698	530	12	759	1451	6021
2007	1570	636	412	707	559	12	796	1523	6215

TABLE C-21

PACIFIC GAS & ELECTRIC COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
1987 DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1987	4.39	4.47	3.78	2.50	2.50	3.74
1988	4.96	5.07	4.32	3.07	3.07	4.31
1989	5.37	5.56	4.86	3.78	3.78	4.83
1990	5.70	5.98	5.41	4.64	4.64	5.37
1991	5.88	6.16	5.53	4.71	4.71	5.49
1992	6.02	6.30	5.64	4.79	4.79	5.61
1993	6.23	6.50	5.78	4.86	4.86	5.75
1994	6.38	6.65	5.90	4.95	4.95	5.87
1995	6.53	6.81	6.04	5.07	5.07	6.01
1996	6.59	6.88	6.15	5.21	5.21	6.11
1997	6.73	7.03	6.29	5.34	5.34	6.23
1998	6.89	7.20	6.45	5.47	5.47	6.37
1999	7.06	7.38	6.61	5.61	5.61	6.52
2000	7.28	7.60	6.80	5.76	5.76	6.70
2001	7.33	7.68	6.91	5.90	5.90	6.79
2002	7.44	7.81	7.06	6.05	6.05	6.92
2003	7.58	7.97	7.22	6.20	6.20	7.06
2004	7.72	8.12	7.37	6.36	6.36	7.21
2005	7.81	8.23	7.52	6.52	6.52	7.33
2006	7.86	8.31	7.65	6.69	6.69	7.44
2007	8.04	8.51	7.84	6.86	6.86	7.62

TABLE C-22

SOUTHERN CALIFORNIA GAS COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
1987 DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1987	5.24	5.15	3.76	2.57	2.57	4.20
1988	5.36	5.37	4.17	3.18	3.18	4.53
1989	5.63	5.73	4.69	3.93	3.93	4.96
1990	6.08	6.28	5.31	4.86	4.86	5.58
1991	6.28	6.47	5.42	4.95	4.95	5.72
1992	6.38	6.57	5.51	5.03	5.03	5.80
1993	6.72	6.87	5.66	5.11	5.11	6.01
1994	6.82	6.98	5.76	5.21	5.21	6.09
1995	6.89	7.06	5.87	5.33	5.33	6.18
1996	7.03	7.22	6.02	5.46	5.46	6.30
1997	7.14	7.34	6.15	5.61	5.61	6.43
1998	7.29	7.50	6.30	5.75	5.75	6.55
1999	7.40	7.63	6.44	5.89	5.89	6.68
2000	7.63	7.85	6.61	6.04	6.04	6.86
2001	7.63	7.89	6.73	6.19	6.19	6.93
2002	7.73	8.01	6.88	6.36	6.36	7.07
2003	7.89	8.19	7.04	6.51	6.51	7.22
2004	8.03	8.35	7.20	6.68	6.68	7.38
2005	8.21	8.53	7.38	6.85	6.85	7.54
2006	8.20	8.57	7.51	7.02	7.02	7.64
2007	8.51	8.88	7.73	7.20	7.20	7.87

TABLE C-23

SAN DIEGO GAS & ELECTRIC COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
1987 DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1987	4.71	4.56	4.33	2.98	2.98	4.14
1988	5.06	4.99	4.77	3.46	3.46	4.57
1989	5.44	5.45	5.25	4.01	4.01	4.94
1990	6.01	6.08	5.89	4.64	4.64	5.48
1991	6.24	6.28	6.06	4.71	4.71	5.62
1992	6.35	6.39	6.17	4.79	4.79	5.69
1993	6.65	6.63	6.38	4.86	4.86	5.84
1994	6.72	6.71	6.47	4.95	4.95	5.90
1995	6.83	6.84	6.59	5.07	5.07	5.99
1996	6.97	6.98	6.74	5.21	5.21	6.10
1997	7.02	7.06	6.83	5.34	5.34	6.10
1998	7.16	7.21	6.97	5.47	5.47	6.20
1999	7.27	7.34	7.10	5.61	5.61	6.29
2000	7.50	7.55	7.31	5.76	5.76	6.45
2001	7.46	7.57	7.34	5.90	5.90	6.48
2002	7.57	7.70	7.49	6.05	6.05	6.62
2003	7.70	7.85	7.64	6.20	6.20	6.74
2004	7.86	8.02	7.81	6.36	6.36	6.90
2005	7.95	8.14	7.94	6.52	6.52	7.05
2006	7.91	8.18	7.99	6.69	6.69	7.14
2007	8.33	8.55	8.33	6.86	6.86	7.38

TABLE C-24

PACIFIC GAS & ELECTRIC COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
CURRENT DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1987	4.39	4.47	3.78	2.50	2.50	3.74
1988	5.17	5.29	4.51	3.20	3.20	4.50
1989	5.85	6.05	5.29	4.12	4.12	5.26
1990	6.49	6.81	6.15	5.28	5.28	6.11
1991	7.00	7.33	6.58	5.60	5.60	6.53
1992	7.61	7.96	7.13	6.05	6.05	7.09
1993	8.14	8.49	7.55	6.35	6.35	7.51
1994	8.73	9.10	8.07	6.78	6.78	8.04
1995	9.36	9.76	8.66	7.27	7.27	8.62
1996	9.83	10.27	9.18	7.77	7.77	9.12
1997	10.52	10.99	9.84	8.35	8.35	9.74
1998	11.29	11.79	10.56	8.96	8.96	10.43
1999	12.12	12.67	11.35	9.63	9.63	11.19
2000	13.10	13.68	12.23	10.36	10.36	12.05
2001	13.82	14.48	13.04	11.13	11.13	12.81
2002	14.70	15.42	13.94	11.95	11.95	13.67
2003	15.70	16.50	14.95	12.84	12.84	14.62
2004	16.76	17.62	16.01	13.81	13.81	15.65
2005	17.77	18.73	17.10	14.83	14.83	16.68
2006	18.74	19.82	18.23	15.95	15.95	17.74
2007	20.08	21.26	19.57	17.14	17.14	19.03

TABLE C-25

SOUTHERN CALIFORNIA GAS COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
CURRENT DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1987	5.24	5.15	3.76	2.57	2.57	4.20
1988	5.59	5.60	4.35	3.32	3.32	4.72
1989	6.13	6.24	5.10	4.28	4.28	5.40
1990	6.92	7.15	6.05	5.53	5.53	6.35
1991	7.47	7.69	6.46	5.89	5.89	6.81
1992	8.06	8.30	6.97	6.36	6.36	7.33
1993	8.78	8.98	7.39	6.67	6.67	7.85
1994	9.34	9.55	7.88	7.13	7.13	8.34
1995	9.88	10.13	8.42	7.64	7.64	8.86
1996	10.49	10.77	8.98	8.15	8.15	9.40
1997	11.16	11.47	9.61	8.77	8.77	10.05
1998	11.94	12.28	10.31	9.42	9.42	10.73
1999	12.71	13.10	11.06	10.11	10.11	11.47
2000	13.73	14.13	11.90	10.87	10.87	12.34
2001	14.39	14.88	12.69	11.67	11.67	13.07
2002	15.27	15.83	13.59	12.57	12.57	13.97
2003	16.34	16.96	14.58	13.48	13.48	14.95
2004	17.43	18.12	15.63	14.50	14.50	16.02
2005	18.68	19.41	16.78	15.58	15.58	17.15
2006	19.55	20.43	17.91	16.74	16.74	18.21
2007	21.26	22.18	19.31	17.99	17.99	19.66

TABLE C-26

SAN DIEGO GAS & ELECTRIC COMPANY
NATURAL GAS PRICE FORECAST BY SECTOR
CURRENT DOLLARS PER MILLION BTU

YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COGENERATION	ELECTRIC GENERATION	SYSTEM AVERAGE
1987	4.71	4.56	4.33	2.98	2.98	4.14
1988	5.28	5.20	4.97	3.61	3.61	4.77
1989	5.92	5.94	5.72	4.37	4.37	5.38
1990	6.84	6.92	6.70	5.28	5.28	6.24
1991	7.43	7.47	7.22	5.60	5.60	6.69
1992	8.03	8.07	7.80	6.05	6.05	7.19
1993	8.68	8.66	8.34	6.35	6.35	7.63
1994	9.20	9.19	8.86	6.78	6.78	8.08
1995	9.79	9.81	9.45	7.27	7.27	8.59
1996	10.40	10.42	10.05	7.77	7.77	9.10
1997	10.97	11.04	10.67	8.35	8.35	9.53
1998	11.73	11.81	11.42	8.96	8.96	10.16
1999	12.48	12.60	12.20	9.63	9.63	10.80
2000	13.49	13.58	13.15	10.36	10.36	11.60
2001	14.07	14.27	13.85	11.13	11.13	12.22
2002	14.96	15.22	14.79	11.95	11.95	13.08
2003	15.95	16.26	15.81	12.84	12.84	13.96
2004	17.06	17.42	16.95	13.81	13.81	14.98
2005	18.09	18.53	18.05	14.83	14.83	16.04
2006	18.86	19.49	19.05	15.95	15.95	17.02
2007	20.81	21.35	20.81	17.14	17.14	18.44

TABLE C-27

PACIFIC GAS & ELECTRIC
1987 BIENNIAL FUELS REPORT
SELECTED INPUT DATA
1987 DOLLARS

YEAR	PURCHASE COSTS K$/DAY	PURCHASE COSTS $/MMBTU*	DISTRIBUTION COSTS K$/DAY	DISTRIBUTION COSTS $/MMBTU*	TOTAL COSTS K$/DAY	TOTAL COSTS $/MMBTU*	SUPPLY MMCFD	POWER PLANT GAS PRICE $/MMBTU	INDUSTRIAL GAS PRICE $/MMBTU
1987	4150	2.20	2886	1.54	7036	3.74	1793	2.50	3.14
1988	5174	2.73	2960	1.57	8134	4.31	1795	3.07	3.64
1989	6322	3.28	2970	1.55	9292	4.83	1827	3.78	4.22
1990	7455	3.81	3036	1.56	10491	5.37	1861	4.64	4.88
1991	7945	3.97	3038	1.53	10983	5.49	1901	4.71	4.96
1992	8243	4.09	3040	1.52	11283	5.61	1914	4.79	5.04
1993	8695	4.25	3068	1.50	11763	5.75	1948	4.86	5.12
1994	9076	4.38	3087	1.50	12163	5.87	1970	4.95	5.21
1995	9533	4.53	3099	1.48	12632	6.01	1998	5.07	5.34
1996	10305	4.67	3147	1.43	13452	6.11	2096	5.21	5.48
1997	10502	4.78	3162	1.45	13664	6.23	2087	5.34	5.62
1998	11070	4.94	3187	1.43	14257	6.37	2130	5.47	5.76
1999	11656	5.11	3203	1.41	14859	6.52	2171	5.61	5.91
2000	12214	5.28	3228	1.40	15442	6.68	2200	5.76	6.06
2001	12705	5.39	3243	1.38	15948	6.77	2239	5.90	6.21
2002	13207	5.55	3263	1.37	16470	6.92	2267	6.05	6.37
2003	13839	5.70	3283	1.36	17122	7.06	2310	6.20	6.53
2004	14429	5.84	3307	1.35	17736	7.19	2346	6.36	6.69
2005	15049	6.00	3323	1.33	18372	7.33	2386	6.52	6.86
2006	15629	6.13	3350	1.32	18979	7.44	2428	6.69	7.04
2007	16836	6.34	3377	1.28	20213	7.62	2525	6.86	7.22

* ASSUMES 1050 BTU PER CUBIC FOOT.

TABLE C-28

SOUTHERN CALIFORNIA GAS
SELECTED INPUT DATA[B]
1987 DOLLARS

YEAR	PURCHASE COSTS K$/DAY	PURCHASE COSTS $/MMBTU*	DISTRIBUTION COSTS K$/DAY	DISTRIBUTION COSTS $/MMBTU*	TOTAL COSTS K$/DAY	TOTAL COSTS $/MMBTU*	SUPPLY MMCFD	POWER PLANT GAS PRICE $/MMBTU	INDUSTRIAL GAS PRICE $/MMBTU
1987	5635	2.55	3651	1.65	9286	4.20	2107	2.57	3.14
1988	6445	2.91	3597	1.63	10042	4.53	2112	3.18	3.64
1989	7793	3.38	3655	1.59	11448	4.96	2199	3.93	4.22
1990	9550	4.02	3707	1.56	13257	5.58	2265	4.86	4.88
1991	10008	4.14	3801	1.58	13809	5.72	2302	4.95	4.96
1992	10487	4.25	3825	1.55	14312	5.80	2350	5.03	5.04
1993	11332	4.47	3889	1.54	15221	6.01	2415	5.11	5.12
1994	11931	4.58	3937	1.51	15868	6.09	2482	5.21	5.21
1995	12531	4.69	3972	1.49	16503	6.18	2546	5.33	5.34
1996	13252	4.83	4046	1.48	17298	6.30	2614	5.46	5.48
1997	13961	4.97	4085	1.46	18046	6.43	2676	5.61	5.62
1998	14863	5.13	4135	1.43	18998	6.55	2762	5.75	5.76
1999	15603	5.27	4174	1.41	19777	6.68	2822	5.89	5.91
2000	16439	5.45	4225	1.40	20664	6.86	2871	6.04	6.06
2001	17059	5.55	4252	1.38	21311	6.93	2929	6.19	6.21
2002	17677	5.69	4283	1.38	21960	7.07	2960	6.36	6.37
2003	18512	5.84	4344	1.38	22856	7.22	3017	6.51	6.53
2004	19209	6.00	4401	1.38	23610	7.38	3049	6.68	6.69
2005	20039	6.16	4507	1.39	24546	7.54	3100	6.85	6.86
2006	20572	6.27	4505	1.38	25077	7.64	3127	7.02	7.04
2007	21975	6.52	4575	1.36	26550	7.88	3212	7.20	7.22

* ASSUMES 1050 BTU PER CUBIC FOOT.

TABLE C-29

SAN DIEGO GAS & ELECTRIC
SELECTED INPUT DATA[B]
1987 DOLLARS

YEAR	PURCHASE COSTS K$/DAY	PURCHASE COSTS $/MMBTU*	DISTRIBUTION COSTS K$/DAY	DISTRIBUTION COSTS $/MMBTU*	TOTAL COSTS K$/DAY	TOTAL COSTS $/MMBTU*	SUPPLY MMCFD	POWER PLANT GAS PRICE $/MMBTU	INDUSTRIAL GAS PRICE $/MMBTU
1987	554	2.55	346	1.60	900	4.14	207	2.98	3.14
1988	623	2.91	356	1.67	979	4.57	204	3.46	3.64
1989	783	3.38	363	1.57	1146	4.94	221	4.01	4.22
1990	1004	4.02	366	1.47	1370	5.48	238	4.64	4.88
1991	1061	4.14	379	1.48	1440	5.62	244	4.71	4.96
1992	1133	4.25	384	1.44	1517	5.69	254	4.79	5.04
1993	1243	4.47	381	1.37	1624	5.84	265	4.86	5.12
1994	1327	4.58	382	1.32	1709	5.90	276	4.95	5.21
1995	1398	4.69	388	1.30	1786	5.99	284	5.07	5.34
1996	1501	4.83	393	1.27	1894	6.10	296	5.21	5.48
1997	1743	4.97	395	1.13	2138	6.10	334	5.34	5.62
1998	1905	5.13	397	1.07	2302	6.20	354	5.47	5.76
1999	2068	5.27	401	1.02	2469	6.29	374	5.61	5.91
2000	2239	5.45	407	0.99	2646	6.45	391	5.76	6.06
2001	2452	5.55	412	0.93	2864	6.48	421	5.90	6.21
2002	2550	5.69	416	0.93	2966	6.62	427	6.05	6.37
2003	2718	5.84	418	0.90	3136	6.74	443	6.20	6.53
2004	2816	6.00	422	0.90	3238	6.90	447	6.36	6.69
2005	2935	6.16	424	0.89	3359	7.05	454	6.52	6.86
2006	3066	6.27	428	0.88	3494	7.14	466	6.69	7.04
2007	3270	6.52	432	0.86	3702	7.38	478	6.86	7.22

* ASSUMES 1050 BTU PER CUBIC FOOT.

FOOTNOTES - APPENDIX C

1. Eighteen percent reduction applied to existing reserves and the production decline curve applied to new reserves is based on work papers prepared by H. Bertholf in support of testimony provided for the CEC in the CPUC LNG proceedings, March 1978.

2. John Peirson, Outlook for Natural Gas Production, Offshore California, testimony in the 1987 Biennial Fuels Report Proceedings, June 5, 1987.

3. El Paso: FERC Form 15 for Calendar year 1986.
Transwestern: FERC Form 15 for Calendar year 1981. Yearly deliverability for 1983 was equated to 1987. Each succeeding year was adjusted similiarly. Projected end of year reserves for 1982 in FERC Form 15 for 1981 equalled end of year reserves for 1986 in FERC Form 15 for Calendar year 1986. It appears the latter Form 15 is projecting reduced sales rather than deliverability, therefore the use of the earlier Form 15.

4. Dr. G.C. Watkins, California: Prospects for Natural Gas Imports, testimony in the 1987 Biennial Fuels Report Proceedings, Docket No. 87-BFR-1.

5. V.A. Kuuskraa, Rocky Mountain Region: Natural Gas Supply and Price Forecast, testimony in the 1987 Biennial Fuels Report Proceedings, Docket No. 87-BFR-1.

6. Mark Doelger, written supplemental testimony dated June 11, 1987 provided for the 1987 Biennial Fuels Report Proceeding, Docket No. 87-BFR-1.

7. John Brickhill, Gulf Coast Region: Natural Gas Supply and Price Forecast, testimony provided in the 1987 Biennial Fuels Report Proceedings, Docket No. 87-BFR-1.

8. In the detailed supply Tables C-13,14,15 following the text, unspecified available supply is designated as Northwest supplies for Northern California and Canada (new) for Southern California.

9. El Paso Natural Gas Co., Notice of Change in Rates, Docket No. RP85-58, filed before the Federal Energy Regulatory Commission, December 1984.

10. Pacific Gas Transmission Co., Notice of Change in Rates, Dockets No. RP 86-62-000, filed before the Federal Energy Regulatory Commission.

11. James T. Jensen, Transportation Rates for Natural Gas Pipelines Serving California, testimony provided in the 1987 Biennial Fuels Report Proceedings, Docket No. 87-BFR-1.

12. The PGandE filings to FERC on the proposed Rocky Mountain pipeline and Kern River Gas Transmission Company FERC filings provided information on the generic new pipeline to deliver the long term forecasted supplies.

13. Quarterly Fuels and Energy Report Form 10A for 1985.

APPENDIX D

NATURAL GAS COMPETITION

APPENDIX D

NATURAL GAS COMPETITION

The natural gas industry is becoming market-driven. This is not to say that it is becoming totally or even largely unregulated. Rather, the industry is becoming market-driven in that the major determinant of gas prices is competition of gas with competing energy sources, along with competition among gas suppliers. This competition determines gas prices at the wellhead, now that wellhead price regulation is largely a thing of the past. With competitive wellhead prices, market forces are a major determinant of gas prices even for residential gas users, who are "captive" customers of their local utility.

Other hallmarks of the new competitive atmosphere in the gas industry are apparent. A unified national market has developed, where gas can be moved from any region to any other. With the nationwide gas market has come a large "spot" market of short-term sales at market-based prices (in contrast to traditional long-term sales at fixed prices). The spot market thrives due to the recent widespread availability of gas transportation services (contract carriage) for gas not owned by the transporting utilities or pipeline companies. With simultaneous interfuel and interregional competition, the price of gas in California can be affected by the price of coal in the Midwest or the availability of hydroelectric power in the Northwest.

Despite great progress, unresolved issues still hinder the transition toward a market-driven gas industry. Probably at the top of the list is the prevalence of outdated contracts between gas producers and interstate pipeline companies. These long-term contracts, signed when gas market conditions were very different from now, lack the flexibility to adapt to today's competitive market conditions and changed regulatory structure.

The principal problem with many of the outdated contracts is the "take-or-pay" provision. A take-or-pay provision requires the gas purchaser (usually a pipeline company) to take delivery of a specified amount of gas, or pay for it anyway. In the late 1970s and early 1980s most pipeline companies signed long-term contracts to buy high-cost gas with take-or-pay terms. Much of this high-cost gas is not competitive at current prices. Actions by the Federal Energy Regulatory Commission (FERC) exacerbated the problem by providing means for the pipelines' customers to avoid buying the high-cost gas, even though the pipelines contracted for the gas on behalf of those same customers. Many pipeline companies are now faced with take-or-pay liabilities as high as hundreds of millions of dollars because they cannot market the gas. El Paso Natural Gas Co. and Transwestern Pipeline Co., two of the interstate pipeline companies serving California, accumulated net take-or-pay liability in 1986 of $645 and $144 million, respectively.

Estimating how much California gas consumers will have to pay due to take-or-pay liability is extremely difficult, if not impossible. How much liability California's pipeline suppliers will accrue in the future is

unclear. What will be done to reform outdated contracts, and when, is speculative.

What fraction of its current and future liability for take-or-pay costs each pipeline will actually pay is also highly uncertain. In the past, pipelines have settled many take-or-pay claims for 10 to 20 percent of the liability. Moreover, what fraction of pipeline payments to settle take-or-pay claims will be passed along to the pipeline's customers, and what fraction will be borne by the pipeline's shareholders, is also unclear.

With all these uncertainties, it is difficult to know how concerned California should be with take-or-pay costs. California gas consumers potentially could end up paying significantly more for gas due to take-or-pay costs. In any event, California may not be able to do much to reduce these costs, because of primary federal jurisdiction. Although the size of the bill is not yet clear, the CPUC is now considering how the take-or-pay costs should be allocated among ratepayer classes in percentage terms.

Another factor hindering the transition to a market-driven gas industry is limited and uneven access to interstate transmission capacity. Under federal regulations, interstate pipeline companies are not required to transport gas owned by others. Some of these companies restrict access to transportation services, especially firm transportation, to the pipeline's traditional gas sales customers. This exercise of monopoly power restricts competition in gas supply.

The trend is toward greater willingness of pipeline companies to offer transportation services. Many companies, however, are not yet ready to embrace the practice of unrestricted eligibility for transportation. The principle reason cited for this reluctance is that transportation exacerbates the take-or-pay problem of any pipeline whose obligation to buy gas exceeds its ability to resell it. If a pipeline offers transportation services to one of its sales customers, it provides a means for the customer to buy gas from someone other than the pipeline and then have the pipeline deliver the gas. As the pipeline's sales market shrinks, its fixed obligations to buy gas from producers under take-or-pay arrangements become more burdensome. For this reason, some pipeline companies maintain that a solution to the take-or-pay problem is a prerequisite to making transportation services available to all.

Recent gas regulatory actions. Since the Commission's first Biennial Fuels Report was released, several significant federal and state regulatory actions have increased the competitiveness of the gas market. In December 1985 the CPUC adopted its proposed new regulatory structure, which was described in the previous Biennial Fuels Report. The new structure acknowledges the benefits of competition and seeks to exploit them. The CPUC structure separates utility gas customers into a "core" group of mostly small customers lacking immediate alternatives to burning gas, and a "noncore" group of mostly large customers capable of shifting to alternative fuels such as oil. Gas sales and transportation services are offered separately only to the noncore group. Noncore customers are

free to buy gas from nonutility sources, and contract with the utility to deliver it.

A CPUC proceeding is underway to establish utility rates under the new regulatory structure. The rates will be based on a utility's costs to provide each service. After adopting rates, which is anticipated to occur in late 1987, the CPUC intends to consider further refinements to the new regulatory structure. The CPUC identified a number of issues concerning utility gas supply and utility system reliability for investigation (Order Instituting Investigation No. 87-03-036, March 25, 1987; Decision 87-10-043, October 16, 1987).

The FERC has continued to take steps to increase competition in the gas industry. In August 1987 the FERC issued Order 500, an interim rule and statement of policy designed, among other things, to facilitate and encourage the resolution of take-or-pay contractual disputes. The order allows certain pipelines to directly bill their customers for one-quarter to one-half of the pipelines' costs of settling pipelines' take-or-pay liabilities with producers, as long as the pipelines agree to absorb an equal portion of settlement costs. Any remaining settlement costs may be added to gas costs and recovered through the pipelines' commodity rates.

In addition, Order 500 seeks to limit the incurrence of future take-or-pay liability. One provision outlines principles by which pipelines may include in their rates charges for maintaining future gas supplies, as a substitute for take-or-pay provisions. Another provision seeks to prevent

the buildup of take-or-pay charges when gas sales by pipelines are replaced by pipeline transportation of gas. In that case, producers would have to credit the transporting pipeline as if it had instead bought the gas.

In April 1987 the FERC proposed a method to make it easier for producers and interstate pipelines to terminate traditional supply arrangements under which certain gas is permanently committed (or "dedicated") to specific markets. In May 1987 the FERC issued a proposed rule to set standards of conduct for pipelines and their marketing affiliates. The purpose is to prevent anticompetitive practices in which pipelines give preferential treatment to their affiliates compared to other pipeline customers.

APPENDIX E

CEC STAFF BFR II
OIL PRICE FORECAST

APPENDIX E

CEC STAFF BFR II OIL PRICE FORECAST

I. Introduction

The California Energy Commission regularly develops 20-year crude oil price forecasts in recognition that crude oil prices are a major determinant of the prices of electricity, natural gas, and petroleum products and a major factor in evaluating the cost effectiveness of conservation programs and alternative energy sources. In California, the price of natural gas is also an important component in determining electricity costs, as many utilities have the capability to burn both natural gas and fuel oil.

II. Petroleum Price Forecast

A. Crude Oil Price Forecast

The staff oil price forecast is unchanged from the forecast contained in the September 1986 Biennial Fuels Report (BFR). This forecast incorporates several important assumptions about the international oil market. In particular, this forecast assumes that the relatively low level of prices that has prevailed since early 1986 will limit oil supplies produced by countries that are not members of the Organization of Petroleum Exporting Countries (OPEC), leading to increased reliance on OPEC oil supplies. Lower oil prices are also expected to lead to

increased worldwide oil consumption. The simultaneous decrease of non-OPEC supply and increased worldwide oil consumption will cause a recovery of oil prices to 1985 levels by 1990 as the current world surplus of crude oil is eliminated and OPEC gains increased ability to impose price increases through production controls.

As shown in Table E-1, forecasted crude oil prices are expected to rise relatively rapidly in the short-term to about $28 per barrel in 1990. The rate of price increase will slow from 1990 through 1995 and then pick up through the remainder of the forecast period. The growth rate of prices is expected to quicken in the late 1990s as the increased market share of the OPEC members gives them enhanced power over prices. The rate of increase, however, will still be relatively moderate over the long term, as OPEC attempts to avoid increasing oil prices to levels that could lead to a sharply reduced market share for OPEC. By the end of the forecast period, 2007, inflation-adjusted crude oil prices are expected to be $41.50 per barrel. This will still not attain the highest price reached in 1981 following the second OPEC-induced price hike. At that time, the refiners' acquisition cost of imported oil was about $46 per barrel (in 1987 dollars).

The forecast of increasing prices reflects the CEC staff expectation that OPEC will continue to function in a cohesive manner and gradually regain market control. In the short-term, staff believes OPEC can return prices to their 1985 levels by 1990 with relatively gradual changes in non-OPEC production or world oil consumption. OPEC's production and its share of

TABLE E-1

HISTORICAL WORLD OIL PRICES

Year	Price
1972	7.86
1973	9.41
1974	26.54
1975	27.02
1976	24.85
1977	25.32
1978	23.64
1979	32.38
1980	46.42
1981	46.26
1982	39.51
1983	33.21
1984	31.44
1985	28.61
1986	14.43
PROJECTED[a]	
1987	18.38
1988	21.21
1989	24.47
1990	28.25
1991	28.70
1992	29.17
1993	29.63
1994	30.11
1995	30.86
1996	31.63
1997	32.42
1998	33.24
1999	34.06
2000	34.91
2001	35.78
2002	36.68
2003	37.60
2004	38.54
2005	39.50
2006	40.49
2007	41.50

a. Weighted-average international price of a barrel of crude oil in 1987 dollars.

Source: Prices for 1972-1986 are refiners' acquisition costs of imported crude in 1987 dollars from Monthly Energy Review, U.S. Department of Energy.

total world oil production is expected to grow throughout the forecast period.

To develop its 20-year forecast of world oil prices, staff has conducted an independent analysis of the major issues affecting the world oil market, surveyed a panel of international experts and reviewed other independent forecasts. The following sections of the staff report contain an analysis of the major issues and a summary of other oil price forecasts.

B. Analysis of International Oil Market

The CEC staff analysis of the major issues affecting international oil prices leads to several conclusions. First, the current low level of prices is probably temporary. The combination of moderately growing world oil consumption, increased OPEC cohesiveness and an eventual decline of non-OPEC production will probably result in prices nearly recovering to 1985 levels between now and 1990. After 1990, oil prices are forecasted to increase much more moderately. Slow, rather than rapid, growth in demand and the desire of key OPEC members to ensure a market for their crude oil well into the next century will moderate growth in oil prices.

<u>OPEC's ability to affect prices.</u> This forecast assumes that the key factor in determining the future course of oil prices is OPEC's ability to maintain cohesiveness and exercise production restraint. Throughout the forecast period, OPEC should be able to increase market share as demand

increases and non-OPEC oil supplies decline. As the organization's market share grows, OPEC will probably be able to exercise increasingly greater control over prices.

This forecast assumes OPEC's success in reestablishing official prices at the $18 per barrel level, from a 1986 price which at times was under $13 per barrel, demonstrates OPEC's determination and ability to maintain cohesiveness and to exercise production restraint under the most difficult circumstances of reduced demand that the cartel is likely to face for the foreseeable future. OPEC was able to raise prices during a seasonal low point in demand, after most winter oil purchases had been made and before the start of the summer driving season. OPEC also faced widespread inventory reductions which acted to reduce demand during the early part of this year. The staff forecast also assumes that it is OPEC's intent to return to price levels that existed prior to Saudi Arabia's 1985 decision to increase production. OPEC's desire to return to this price level reflects the organization's belief that this price level will not interfere with its desire to dominate a greater proportion of the world oil export market.

The staff analysis supports the conclusion that a return of oil prices to 1985 levels by 1990 will not prevent OPEC from increasing its market share. Although oil prices in 1985 were higher than now, they were not high enough to prevent demand from slowly increasing or keep U.S. oil production from flattening. Also, in 1985, both U.S. and North Sea production were forecasted to begin to decline within the next five to ten

years. The decline in U.S. production was expected to accelerate as Alaskan production flattened and eventually began to sharply decline. This previously forecasted decline in U.S. and North Sea production was expected to be a harbinger of an overall decline in non-OPEC production. With oil prices now lower than expected in 1985, the decline in non-OPEC production is even more likely.

OPEC, however, will face several significant problems if they are to be successful in raising prices. First, if OPEC allows prices to increase too quickly, the long term demand for OPEC oil will be reduced. Second, one member, most likely Saudi Arabia, must act as a swing producer, varying its own production to meet the always frequent changes in demand. Third, production discipline must generally be maintained by all OPEC members.

Too rapid price hikes could lead to a replay of the early 1980s, when conservation, fuel switching, and growth of substitute sources of energy, including non-OPEC oil, drastically reduced OPEC's market share. Within OPEC, the producers with large reserves, Saudi Arabia, Kuwait and Venezuela, have a special interest in keeping prices low enough so these countries can ensure a market that allows them to produce at high levels over a relatively long period.

In the past, OPEC has depended on a swing producer to ensure price stability. A swing producer is necessary because oil demand is very volatile and OPEC cannot quickly adjust production quotas to meet the

daily and seasonal changes in demand. Saudi Arabia was the swing producer until late 1985, when it abandoned the swing producer role and increased its production. The Saudis appear to have resumed the swing producer role again. Acting as the organization's swing producer is not without risk. If OPEC prices are too high, demand for oil falls and the swing producer's production and revenues are apt to decline. Alternately, widespread production by members in excess of their quotas also puts pressure on the swing producer to reduce its level of exports to maintain prices. If the swing producer is being significantly harmed the role may be abandoned with the likely result of a decline in oil prices.

Throughout the organization's history over-production has been a common problem. Cheating on individual quotas, combined with shrinking demand for OPEC oil, led to the sharp oil price decline that began in late 1985. However, a significant amount of over-production by member countries appears to be less likely now. Saudi Arabia's 1985 decision to abandon its quota and increase production has brought home to OPEC members the possible dangers of exceeding production quotas. While minor cheating is occurring and is likely to continue, the sharp decline in oil prices has probably increased the understanding that member nations have for the fragility of OPEC and the limits to Saudi patience. Members are now more likely to restrain production and stay within or close to production quotas.

If OPEC can enlist the help of non-OPEC producers, the organization's burden of maintaining production discipline is reduced. To date, OPEC has

had some success in gaining assistance from non-OPEC producers. However, chances for more widespread cooperative efforts are unlikely. OPEC hoped to gain the assistance of the North Sea producers, especially Norway and the United Kingdom. OPEC's so-called "market share" strategy initiated in late 1985 depended on the lower prices to convince the North Sea producers to join in the cartel's efforts to restrict production. Among the North Sea producers, only Norway has reduced production, while the others ignored calls for joint action.

OPEC has enjoyed some success in gaining the support of other countries, primarily those whose energy industry is a large portion of the overall economy, such as Mexico and Egypt. The Soviet Union, an important oil exporter and the world's largest producer, has also pledged to assist OPEC. The Soviet economy was significantly hurt by falling prices as the Soviets rely on oil exports to earn a large portion of their hard currency needs. Despite pledges, however, the actual cooperation is not always gained. Soviet production remains above 1986 levels.

OPEC has had little success gaining the support of small producers. For producers with a relatively small oil industry cooperation in raising prices has many negative drawbacks, namely the risk of increasing the price of energy to the non-oil economy. Even for a large producer such as the United Kingdom, the oil portion of the economy is relatively small. The risks of reducing production are not worth the relatively small benefits that would accrue to these producers.

$28.25 per barrel in 1990 provides approximately $14 billion in additional oil revenues.

The recent depreciation of the dollar has exacerbated the financial problems of OPEC members. Since OPEC earns dollars from most of the organizations's oil sales, the depreciation of the dollar has reduced the purchasing power of OPEC's members. OPEC's Secretariat estimates that the depreciation of the dollar has reduced the purchasing power of OPEC by 8 percent within the last year. This may be offset to some degree as member countries reduce imports from countries with appreciating currencies and turn to U.S. supplied goods. For some goods, however, no effective substitutes exist.

While the behavior of OPEC is probably the most important factor to assess when forecasting oil prices, other issues must also be considered.

Impact of lower oil prices on petroleum demand. Rapid increases in oil consumption caused by lower oil prices would be likely to lead to higher oil prices than the staff forecasts. However, while world oil demand growth was somewhat rapid during 1986, slightly over 2 percent, the rate of increase has slowed to less than 1 percent annually. The slowing of oil demand growth can be attributed to two main factors. The first is the significant recovery in prices that has occurred during the latter half of 1986. Second, a significant portion of the oil demand increase during 1986 resulted from inventory building as buyers took advantage of the low

prices. This is a one-time gain that is not likely to be repeated at forecasted price levels.

In the United States, oil demand growth in 1986 was strong, increasing almost 3 percent. Special factors in the United States contributed to the high demand during 1986. As oil prices became more competitive, residual oil temporarily displaced the natural gas used by power plants. Also, fear of terrorism and the weak dollar kept many tourists at home, hence gasoline demand was unusually strong.

In the short term, a number of other factors, both in the United States and abroad, are expected to operate to restrain demand growth. The elevated levels of petroleum and petroleum product inventories held during 1986 are being worked off. The reduction has been estimated as being especially sharp during early 1987 as inventories were reduced in the widespread expectation that OPEC would not be able to support the announced level of prices. This inventory reduction will act to restrain the overall increase in demand for oil during 1987. As the inventories are worked off, the growth in oil demand should accelerate, most likely during the latter half of 1987 or 1988 by the latest.

An important component for forecasting demand is the expected rate of energy demand growth in less developed countries (LDCs). Historically, demand has increased more rapidly in the non-OPEC developing countries than in the developed world. Energy demand is expected to continue growing more rapidly in the LDCs than in the developed world even though

involvement of other nations and endangering the flow of oil from the Persian Gulf. The likelihood of an interruption and its duration depends, in part, on the reaction of the superpowers and other countries in the region.

Given current events and trends, a widening of the conflict cannot be ruled out. Possible scenarios for expanded combat range from the land war spilling over into a third country, most likely Kuwait, to attacks on shipping that trigger a superpower reaction. A scenario that is less threatening to Persian Gulf shipping and oil production is a gradual winding down of the war as the high costs reduce the will of both countries to continue combat. Chances of a negotiated settlement in the short-term are not good, absent a major change in leadership in either of the combatants.

C. Delphi IV Oil Price Forecast

Since 1983, the CEC has used the Delphi survey method as an important tool in preparing its oil price forecasts. In the Delphi survey process, a panel of experts is selected and each panelist's opinions regarding future changes in oil prices and related economic variables are systematically polled through a series of questionnaires.

During Spring of 1987 the California Energy Commission conducted its Delphi IV survey of international experts from the energy industry, government, banking and financial institutions and private economic

consulting firms. The Delphi IV survey was tabulated from the responses of 33 panelists. The panel was asked to estimate a most likely forecast as well as high and low price scenarios. Panelists were also asked to identify the extent to which various factors contributed to their low and high prices scenarios. The averages of the price forecasts provided by the panelists are displayed in Table E-2.

TABLE E-2

COMPARISON OF STAFF FORECAST AND DELPHI IV RESULTS
(1987$/barrel)

Year	Delphi IV Alternative Price Forecasts			Staff
	Most Likely	High	Low	Forecast
1990	18.57	24.43	16.09	28.25
1995	22.74	34.93	18.52	30.86
2007	37.07	88.19	25.43	41.50

The major difference between the average forecast provided by Delphi IV and the staff forecast is the growth in oil prices between now and 1990. Panelists expect prices to grow only slightly between now and 1990, while staff expects OPEC to raise prices to 1985 levels. Both staff and the Delphi IV panelists forecast moderate price increases from 1990 to 2007, although the projected rate of price increase for the Delphi IV panelists is greater than the staff's.

In comparing Delphi IV with past Delphi surveys, it is apparent that recent events significantly affect the response of the panelists. The sensitivity of the surveys to recent events can be seen in comparing

Delphi III and IV as shown in Table E-3. Delphi IV was conducted in April 1987, after prices had begun to move up in response to OPEC's latest round of production cuts and price agreements. OPEC appeared to be regaining power in world oil markets and prices were increasing. The Delphi III survey was conducted in July 1986, during a period of slack demand. Oil prices had dipped below $10 per barrel and OPEC had just adjourned without an agreement. Although only nine months after Delphi III, the average Delphi IV forecast of prices in 1987 is $17.62 per barrel, compared to $16.51 for Delphi III. The Delphi IV forecast is closer to the staff's forecast of $18.38 per barrel. The forecast for the year 2005 increased from $30.90 per barrel in Delphi III to $34.14 per barrel in Delphi IV. The apparent importance that panelists place on immediate events may induce inaccuracies in the long-term forecast. The considerable short-term variation in the world oil market is often not indicative of a long-term trend. Examples are the low world oil prices found during the summer of 1986 or the peak reached in 1981. Both events were used as a basis for oil prices forecasts, which have been proven to be inaccurate.

There is considerable variation among the responses received in the Delphi survey (see Table E-3). This variation among oil price forecasters reflects the lack of consensus about the future direction of oil prices. This uncertainty, as measured by the standard deviation of the forecasts, increases the further away the time period being forecasted. There are some changes in the relative degree of uncertainty when comparing Delphi III and IV. Panelists from Delphi III had greater uncertainty about the

Table E-3

RESULTS FROM DELPHI III AND IV SURVEYS

	Average Prices		Standard Deviation	
Year	Delphi IV	Delphi III	Delphi IV	Delphi III
1987	17.59	16.51	.81	1.51
1990	18.57	17.96	2.18	2.76
1995	22.74	21.51	4.17	4.62
2000	27.99	25.89	7.51	6.76
2005	34.14	30.90	12.57	9.94
2007	37.07	a	15.30	a

a. Not available.

near-term forecasts than Delphi IV panelists. The uncertainty probably reflected the confusion engendered by the events occurring when Delphi III was conducted. Delphi IV panelists exhibited much greater uncertainty about the long-term (from 2000 to 2007) than the Delphi III panelists.

There was, however, remarkable agreement among the Delphi respondents that OPEC's actions would be the major factor in determining the future path of oil prices. When asked what factor would be most likely to cause deviations from their forecast, the most often cited answer was adherence, or lack thereof, by OPEC to strict production quotas.

D. Review of Independent Forecasts

Staff reviewed independent oil prices forecasts of other organizations. These forecasts included some that were officially adopted by the sponsoring agency as well as others that were used for analytical and illustrative purposes only. Perhaps because of the difficulty of developing accurate forecasts, the number of entities developing forecasts, especially long-term forecasts, appears to have declined. Many of the available forecasts extend only over the short-term (through 1990).

Generally, these other independent forecasts were similar to the average forecast from Delphi IV. That is, the forecasters expected lower prices than staff in the short-run while forecasting moderately increasing prices through the long-term. Table E-4 displays representative forecasts from different types of entities that forecasted prices through the year 2000.

The differences between the forecasts reflects a combination of factors. Some of the differences rest on varying assumptions about economic growth, non-OPEC reserves and the sensitivity of petroleum demand to price. Differences in these assumptions tend to produce relatively minor differences between the forecasts. However, the major differences between forecasts reflect different assumptions about OPEC behavior. Some forecasts project that OPEC will take advantage of its growing share of the crude oil market to sharply increase prices. Other forecasts assume that OPEC will restrain price growth to maintain a larger share of the

energy market and ensure demand for its production far into the next century.

TABLE E-4

REPRESENTATIVE OIL PRICE FORECASTS
(1987$/barrel)

Organization	1990	1995	2000
National Petroleum Council			
Higher Price Case	22	28	36
Lower Price Case	14	17	21
U.S. Department Of Energy	17.8	26.6	33
SRI International	22	29	28[b]

a. Not available

b. SRI is forecasting an oil price for 2007 of $30 per barrel.

Sources: National Petroleum Council, Factors Affecting U.S. Oil and Gas Outlook, February 1987.

Energy Information Administration, U.S. Department of Energy, Annual Energy Outlook 1986, February 1987.

SRI International, Petroleum Price Forecasting System, April 1987.

None of the forecasts reviewed by staff expect major changes in the international oil market such as the dissolution of OPEC without a replacement cartel or an emerging technology that will severely reduce the demand for oil. Without exception, the forecasts that were reviewed expect OPEC to play a major role in setting petroleum prices throughout the forecast period.

E. Product Price Forecasts

The CEC's petroleum product price forecast is based on the assumption that over the long run, stable historical relationships between crude oil prices and selected petroleum product prices will continue. No price projections for leaded gasoline have been made. The combination of EPA lead reduction rules and the continuing replacement of vehicles fueled with leaded gasoline should result in the phaseout of leaded regular gasoline. Table E-5, in $/gallon, and Table E-6, in $/million Btu, present the price projections for major products in California for the period 1987-2007.

There does exist the possibility that regulatory actions would change the historical relationship between the price of crude oil and petroleum product prices in California. Regulations designed to protect air quality could increase fuel production costs for California refiners. It is not clear how large these costs might be, or if the costs could be passed on to consumers. International competition in the petroleum products market may restrain the ability of refiners to pass higher costs on to consumers.

TABLE E-5

PETROLEUM PRODUCT PRICE PROJECTIONS
(1987$/gallon* - excluding taxes)

Year	Diesel (#2)		Regular Unleaded	
	Retail	Wholesale	Retail	Wholesale
1987	0.70	0.54	0.75	0.62
1988	0.77	0.61	0.82	0.69
1989	0.85	0.68	0.90	0.77
1990	0.93	0.77	1.00	0.86
1991	0.94	0.78	1.01	0.87
1992	0.95	0.79	1.02	0.88
1993	0.97	0.80	1.03	0.89
1994	0.98	0.81	1.04	0.90
1995	0.99	0.83	1.06	0.92
1996	1.01	0.84	1.08	0.94
1997	1.03	0.86	1.10	0.96
1998	1.05	0.88	1.12	0.98
1999	1.07	0.90	1.14	1.00
2000	1.09	0.92	1.16	1.02
2001	1.11	0.94	1.18	1.04
2002	1.13	0.96	1.21	1.06
2003	1.15	0.98	1.23	1.08
2004	1.17	1.00	1.25	1.11
2005	1.19	1.02	1.28	1.13
2006	1.22	1.05	1.30	1.15
2007	1.24	1.07	1.33	1.18

TABLE E-5 (Continued)

	Premium Unleaded Retail	Premium Unleaded Wholesale	Jet Fuel Wholesale	Residual (#6) Fuel Oil <.25% S	Residual (#6) Fuel Oil .25-.5% S
1987	0.89	0.69	0.58	20.11	19.16
1988	0.96	0.76	0.65	23.31	22.20
1989	1.04	0.84	0.72	27.00	25.71
1990	1.13	0.93	0.81	31.26	29.77
1991	1.14	0.94	0.82	31.77	30.25
1992	1.15	0.96	0.83	32.29	30.75
1993	1.16	0.97	0.84	32.82	31.25
1994	1.18	0.98	0.85	33.35	31.77
1995	1.20	1.00	0.87	34.20	32.57
1996	1.21	1.02	0.89	35.07	33.40
1997	1.23	1.03	0.90	35.96	34.25
1998	1.25	1.05	0.92	36.88	35.13
1999	1.27	1.07	0.94	37.82	36.02
2000	1.30	1.09	0.96	38.78	36.93
2001	1.32	1.12	0.98	39.76	37.87
2002	1.34	1.14	1.00	40.77	38.83
2003	1.36	1.16	1.02	41.81	39.82
2004	1.39	1.18	1.04	42.87	40.83
2005	1.41	1.21	1.07	43.96	41.87
2006	1.43	1.23	1.09	45.07	42.93
2007	1.46	1.25	1.11	46.22	44.02

Note: *Residual fuel oil prices are in dollars per barrel. Wholesale prices are at the refinery/terminal; retail prices are for self-serve.

TABLE E-6

PETROLEUM PRODUCT PRICE PROJECTIONS
(1987$/million Btu)

Year	Diesel (#2) Retail	Diesel (#2) Wholesale	Regular Unleaded Retail	Regular Unleaded Wholesale
1987	5.08	3.91	6.00	4.97
1988	5.55	4.37	6.56	5.51
1989	6.09	4.91	7.21	6.14
1990	6.72	5.53	7.97	6.86
1991	6.80	5.61	8.06	6.95
1992	6.88	5.68	8.15	7.04
1993	6.96	5.76	8.24	7.13
1994	7.03	5.84	8.34	7.22
1995	7.16	5.96	8.49	7.36
1996	7.29	6.09	8.64	7.51
1997	7.42	6.22	8.80	7.66
1998	7.56	6.35	8.96	7.82
1999	7.70	6.49	9.13	7.98
2000	7.84	6.63	9.30	8.14
2001	7.98	6.77	9.47	8.31
2002	8.13	6.92	9.65	8.48
2003	8.29	7.07	9.84	8.65
2004	8.44	7.22	10.02	8.84
2005	8.61	7.38	10.22	9.02
2006	8.78	7.55	10.41	9.22
2007	8.94	7.72	10.62	9.41

APPENDIX F

METHANOL AND ALTERNATIVE FUELS

APPENDIX F

METHANOL AND ALTERNATIVE FUELS

I. Introduction

As an alternative to petroleum based fuels, methanol has become an increasingly important fuel for its potential to improve energy security and air quality. Recent reports from the US Department of Energy and the California Energy Commission urge reduced dependence on petroleum to avoid the severe economic problems experienced in the 1970s. Methanol was identified as an alternative to petroleum particularly for transportation uses.

While the energy security benefits of introducing methanol fuels are important, a growing body of evidence strongly suggests that methanol can substantially improve California's air quality. Indeed, several of the state's air quality agencies consider methanol as an integral part of their emissions control strategies. These benefits may also extend to the area of toxic control, specifically in reducing benzene emissions.

California's pioneering efforts in methanol have demonstrated to others that this state has a firm commitment to energy security and improved air quality. The public interest and future potential of this fuel have prompted some in the oil industry to cooperate with the state by establishing fueling stations for dispensing methanol. In addition the automobile manufacturers have accelerated their research programs for

methanol fueled vehicles. Bus manufacturers have also supplied methanol powered buses to several transit agencies in the country. Although some companies remain cautious, a developing private-public movement has created a momentum that has improved the prospects for this fuel.

This analysis will focus on the air quality issues associated with methanol, the potential methanol supply to California, and the future demand assuming certain behavior of methanol prices.

II. Methanol As an Air Quality Control Strategy

The federal Clean Air Act requires states to meet clean air standards by the end of 1987 to avoid the imposition of sanctions. These sanctions could include halting new construction and restricting federal highway funding in nonattainment areas. The South Coast Air Basin (SCAB), which has the worst air quality in the state, and four other areas (Sacramento, Fresno, Ventura, and Kern Counties) will be designated as nonattainment areas at the end of 1987. After seven years of research, development, and demonstration by CEC, methanol has shown that, if widely used, it offers pollution control benefits.

California's demonstration fleet of methanol cars were tested using the standardized Federal emissions test procedures. Selected vehicles of these test fleets consistently met all of California's emission standards for hydrocarbon (HC), oxides of nitrogen (NOx), and carbon monoxide (CO).[1]

Figure F-1 shows the results of these tests along with the emissions standards represented by the solid line in each graph.

Tests were also conducted on these cars for evaporative hydrocarbon emissions. Again, the California methanol fleet met all federal and state standards (see Figure F-2). The most notable improvement in controlling evaporative emissions came from fuel injected vehicles. In both methanol and gasoline vehicles not equipped with fuel injection, the predominant source of evaporative emissions is the fuel bowls in the carburetor. Although fuel injector clogging has made consumers somewhat wary of this technology, automobile manufacturers are shifting to fuel injection systems for new vehicles. Evaporative emissions will thus become a smaller source of hydrocarbon emissions for both methanol and gasoline powered vehicles.[2]

Formaldehyde emissions have frequently raised concerns whenever methanol is proposed, since the pollutant is a suspected cancer causing agent and can contribute to ozone formation. The current generation of methanol vehicles have shown higher formaldehyde emissions than similar gasoline cars.[3] Work is progressing on improved catalyst control systems to bring formaldehyde emissions down to the level of comparable gasoline cars. In recent tests, two advanced lean-burn methanol technology vehicles have demonstrated the ability to meet this level of formaldehyde emissions.[4]

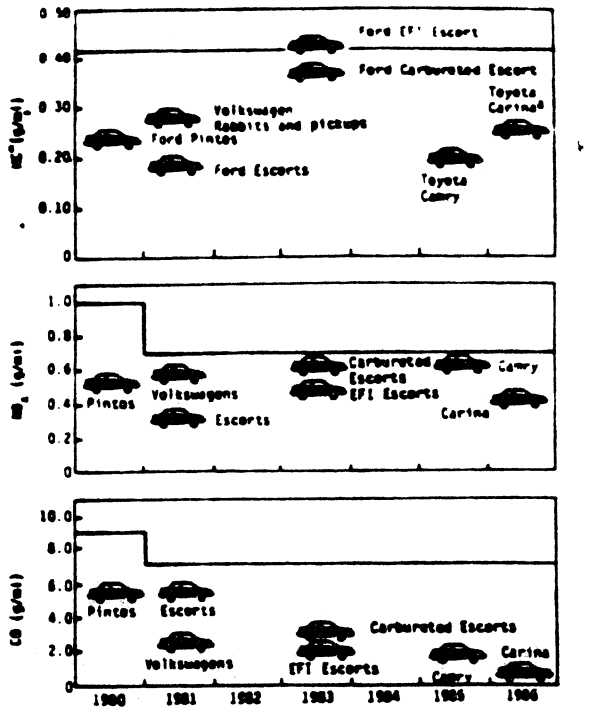


Figure F-1. California Methanol Vehicles Meet or Exceed Stringent California Emission Standards for HC, CO, and NO_x.[5]

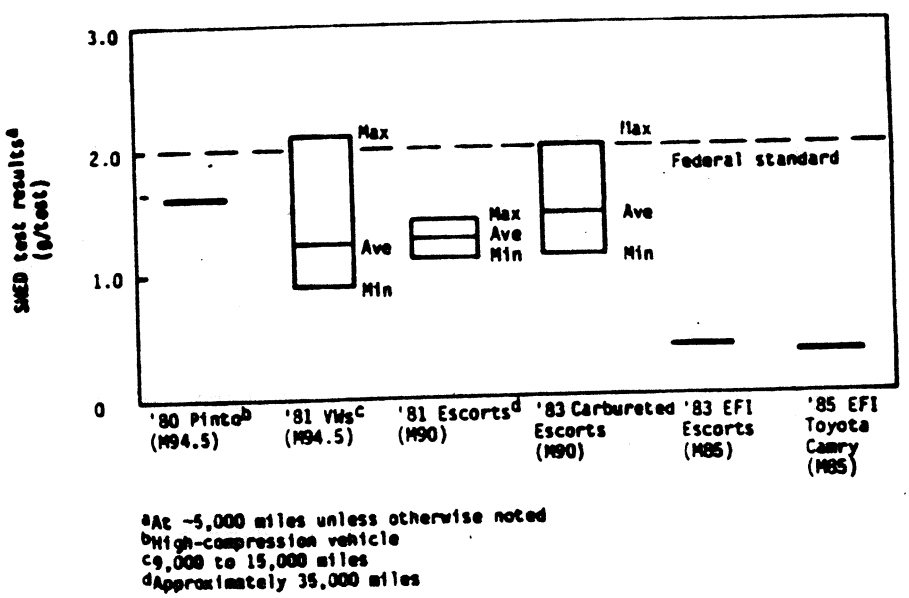


Figure F-2. California Methanol Vehicles Achieve the 2.0 Gram Per Test Evaporation Emission Standard[6]

The overall ozone forming potential of a methanol vehicle is compared with a similarly equipped gasoline vehicle in Figure F-3. This figure shows that of the two, the impact of emissions from gasoline vehicle can be worse than that of a methanol vehicle. The shaded areas represent the chemical agents that have a medium to high potential for ozone formation. Unburned methanol is the predominant exhaust pollutant for methanol vehicles, and its ozone forming potential is very low. On the whole gasoline exhaust has a medium reactivity potential for forming ozone, whereas methanol exhaust has a low reactivity potential, even with a higher formaldehyde fraction in the methanol exhaust.[7]

While the emissions from methanol and gasoline vehicles can be directly measured, secondary pollutants such as ozone must be calculated because they are formed in the atmosphere through a complex series of chemical reactions. Using sophisticated models which incorporate the known chemical reactions in sunlight and in the presence of other pollutant emissions, researchers simulated the impacts to the air quality in the South Coast Air Basin of widespread methanol vehicle substitution. One early simulation showed that 100 percent substitution of methanol vehicles results in an 18 percent improvement in peak one-hour ozone for a typical smoggy day.[9] According to another estimate, significant methanol vehicle use combined with other pollution control strategies will reduce peak ozone from 0.33 parts per million (ppm) to under 0.20 ppm, bringing the South Coast Air Basin significantly closer to the National Ambient Air Quality Standard (NAAQS) for ozone of 0.12 ppm.[10] In fact a 100 percent

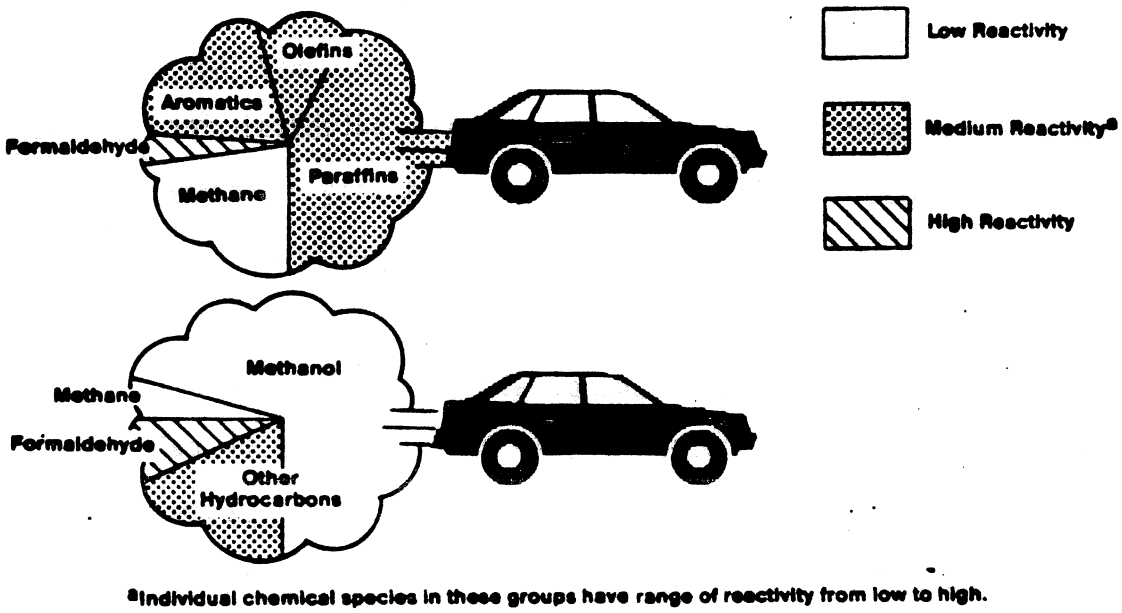


Figure F-3. The Chemical Composition of Gasoline and Methanol Vehicle Exhaust With Their Corresponding Reactivities (Ozone-forming Potential)[8]

substitution to methanol vehicles will reduce reactive hydrocarbon emissions by 170 tons per day - an amount nearly equal to all other hydrocarbon reduction strategies proposed in the South Coast Air Quality Management Plan.[11]

An area of controversy, however, relates to the effect of multi-day episodes. The South Coast Air Basin experiences a number of days during the smoggy season in which portions of the air mass can take two or three days to move through the basin. During these multi-day episodes the unburned emission have longer exposure to sunlight and may eventually photohemically react to form ozone than they would for a single day. The University of California, Riverside performed smog chamber tests to simulate multi-day events for methanol vehicles in the future. This study found that the ozone benefits of methanol decrease significantly on simulated second and third days.[12]

However, all smog chambers suffer from the same methodological shortcoming of not accepting fresh emissions that vehicles normally emit on the second and third days of an episode period. In fact studies in smog chambers are "stagnant air" studies and cannot incorporate other basic meteorological phenomena such as wind speed and direction, emissions entrainment inversion layer effects, and other important real world variables, which are all necessary to project the future levels of ozone in any air basin. The Air Resources Board (ARB), in cooperation with other members of the Three Agency Methanol Task Force, is currently conducting a detailed multi-day air quality computer modeling study in an attempt to adequately

account for multi-day episode effects that occur in the South Coast Air Basin. The results of this study will be available in 1988.

In other applications the use of methanol to substitute for diesel fuel results in substantially reduced NOx and particulate emissions. Figure F-4 shows the dramatic drop in particulate emissions from the two methanol buses operating in the CEC demonstration program in Marin County to a federally certified, diesel fueled transit bus.[13]

The certified emission test results become particularly significant given the recently adopted federal regulations which restrict particulate emissions from buses and heavy duty diesel trucks to 0.1 grams per brake horsepower hour by 1991. Continued use of diesel technology by the transit and trucking industry will force major improvements to comply with this regulation. Major manufacturers have developed particulate traps, although the durability of this equipment has yet to be shown. In addition to the traps the Environmental Protection Agency (EPA) and the South Coast Air Quality Management District (SCAQMD) have adopted regulations that may require the use of cleaner diesel fuels to achieve future standards. Because traps and cleaner diesel fuels will add to the operating costs of diesel heavy duty vehicles, heavy duty methanol vehicles may actually prove less expensive to operate than diesel vehicles. These comparative costs and the uncertainty of meeting the EPA and SCAQMD regulations have induced several manufacturers to increase methanol engine technology development.

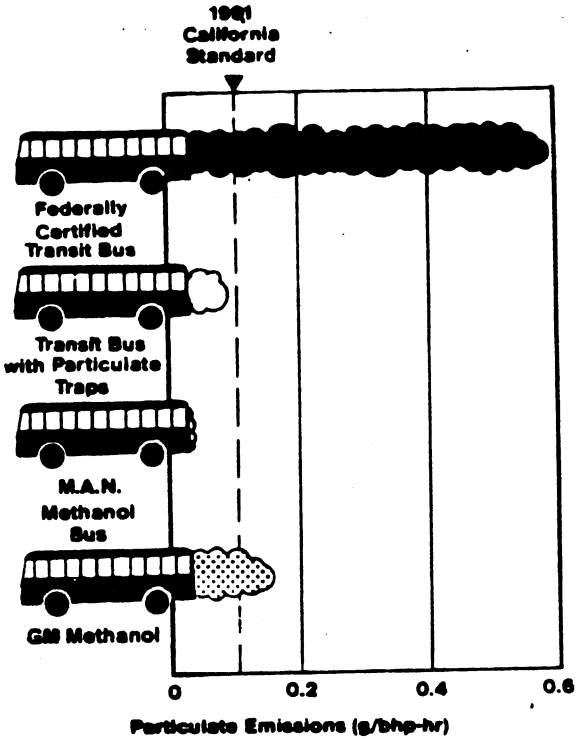


Figure F-4. Particulate emissions reductions achievable with methanol use in heavy-duty engines[14]

III. Methanol As a Toxic Control Strategy

The exhausts from gasoline and diesel fueled vehicles contain hundreds of organic compounds (commonly termed hydrocarbons), which are either present in the fuel or created through the combustion process in the engine. Among these compounds are a number of suspected or known toxic air contaminants such as benzene, a known carcinogen. Since benzene is classified as a toxic air contaminants under both federal and state law, the ARB is required to develop a control plan to reduce its presence in the environment. Emissions from methanol vehicles show levels of benzene roughly one-seventh the levels found for gasoline.[15] Thus, the displacement of gasoline with methanol has the potential of significantly decreasing benzene emissions. Table F-1 provides a list of compounds suspected or known toxins and the source for these emissions.

In contrast to the specie by specie considerations represented in the case of benzene, methanol may prove to be more effective from an air toxic control perspective when the synergistic effects of emissions associated with gasoline components are considered. The EPA has recently reviewed animal studies which indicate that, in addition to the earlier assertion that aromatics (e.g., benzene, toluene, and xylene) were the primary cancer causing components of gasoline, paraffinic compounds now appear to be suspected carcinogens.[17] This would suggest that adequate controls of toxic substances may rest with gasoline displacement since the synergistic effects of hundreds of organic compounds acting simultaneously may create

TABLE F-1

Motor Vehicle Emissions Currently

Under Review Or Identified As Hazardous Or Toxic Pollutant[16]

Compound	FUEL				HAZARDOUS POLLUTANT LIST			
					State reg.		Federal reg.	
	M100	M85	Gasoline	Diesel	Compounds Listed Under AB 1807	Identified as Toxic Under AB 1807	Clean Air Act Candidate Hazardous Air Pollutant	Clean Air Act Listed Hazardous Air Pollutant
Formaldehyde	X	X	X	X	X		X	
Acetaldehyde		X	X	X	X		X	
Benzene		tr*	X	X	X	X		X
Xylene		tr	X		X		X	
Acrolein		tr	X		X		X	
PAH**		tr	X	X	X		X	
1,3 Butadiene		tr	X				X	
Gasoline vapors		X***	X				X	

* tr- trace amounts- Denotes reduced levels which are roughly 7 times lower than those levels found for gasoline

** Polycyclic Aromatic Hydrocarbons

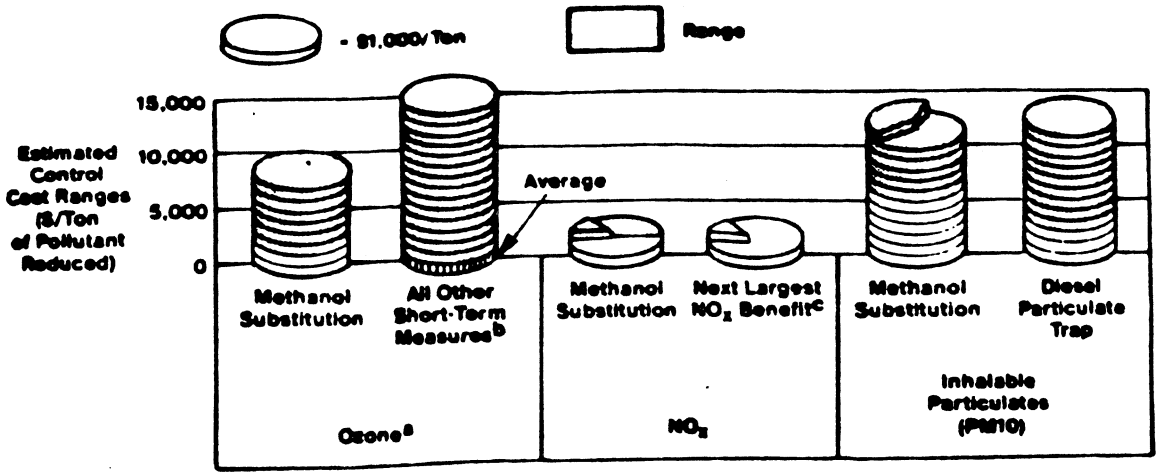
*** Measurements show that gasoline vapors associated with M85 are two to four times lower than more levels found for gasoline

hazardous air quality conditions for humans. While the initial considerations of methanol for toxic substances control look promising, more detailed analysis is still required to determine the extent of any benefits and cost effectiveness.

IV. The Cost Effectiveness Of Methanol As An Air Pollutant Control Strategy

Methanol substitution compares favorably with the cost of other pollution control strategies. Methanol's cost effectiveness in both light and heavy duty vehicle applications is similar to that of other emission control strategies which the South Coast Air Quality Management District has either implemented or placed under review. Based upon 1985 gasoline and methanol prices, methanol in light duty vehicles is somewhat more expensive per ton of reactive hydrocarbon reduced than the current inspection and maintenance program for gasoline vehicles. However, it is much less than the cost of other hydrocarbon reduction strategies which may run as high as $15,000 per ton (see Figures F-5 and F-6). In addition methanol cost effectiveness may benefit from proposed regulations on benzene controls or reduced volatility measures for gasoline which will raise the gasoline cost at the pump.[18]

A comparison of the cost of using methanol in heavy duty vehicles with the cost of pollution controls for diesel vehicles suggests some advantages for methanol. As indicated in an earlier section, diesel, a major



[a]For ozone, costs are expressed as cost /ton of "reactive" hydrocarbons (ROGs) removed from inventory.

[b]Light-duty vehicle control has varied from $400/ton of ROG for three-way catalysts to about $1,700/ton of ROG for current I&M.

[c]Light-duty NO_x vehicle control has varied from 0 to about $1,200/ton.

Figure F-5. Methanol's Cost Effectiveness is Comparable to Other Pollutant Control Strategies[19]

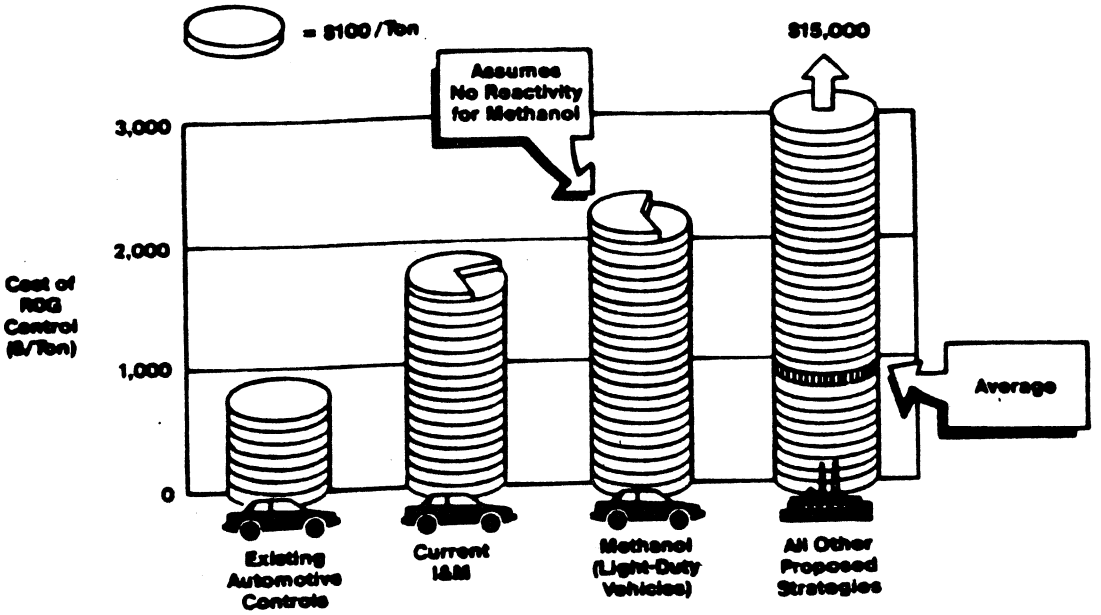


Figure F-6. Methanol's Cost Effectiveness in Light Duty Vehicles as a Hydrocarbon Control Strategy Compared With Other Strategies[20]

contributor to particulate and NOx emissions, must be controlled by unproven traps, electronic controls, and engine derating. If cleaner diesel fuels are also required, the cost may run as high as ten cents per gallon. An estimate of the costs with traps and cleaner fuels is $12,000 per ton of particulates eliminated.[21] In contrast methanol in similar heavy duty engines would cost $6,000 per ton.[22]

The combination of reducing NOx and particulates makes methanol an attractive air pollution control strategy. For diesel vehicles lowering NOx emissions will raise particulate levels and vice versa. Thus, engine manufacturers must add two separate controls to diesel engines whereas methanol can take care of both NOx and particulates in a simplified way.

In the next two years new cost effectiveness analyses will include recent prices for gasoline and methanol, ranges of methanol prices, and the added cost of benzene or aromatic controls and volatility reduction. As discussed in the next section, methanol prices to California are expected to drop as economies of scale are realized. At the same time greater gasoline controls and cleaner diesel fuels will raise the price of these fuels by an average of three and ten cents per gallon respectively. While the current lower gasoline prices make methanol look less cost effective, impending regulations, expected higher gasoline and diesel prices, and expected lower methanol prices could dramatically change the relative cost effectiveness of methanol.

V. Anticipated Methanol Supply

Given the benefits of methanol for air quality and energy security, the potential for greater methanol use as a transportation fuel poses questions of supply and availability. The prospects for meeting any future increase in methanol demand for transportation rest on the rate of methanol vehicle penetration.

The world's methanol producers currently face the problem of overcapacity. In 1986, the total capacity of the world's methanol plants was rated at seven billion gallons, which exceeded world demand by 1.65 billion gallons. By 1990, this excess supply could grow to 2.6 billion gallons barring unforeseen surges in methanol demand.[23]

Despite this overcapacity, new methanol production plants are under construction in several parts of the world. These seemingly superfluous plants add to an already saturated market and appear less than rational from a purely economic perspective. Accepting this condition, sponsors of these new methanol plants apparently view the current methanol glut as transitory. They may anticipate a greater demand for methanol from transportation and chemical uses, and thus, their product will become more highly valued. Alternatively, they may have lower production costs and can grab market shares by underselling other producers. Still another view is that Third World countries may see methanol production as an opportunity to attract investors and promote their own economic growth.

The continued growth of methanol capacity may also reflect the producer's decision to convert remote natural gas to methanol. To directly use the remote natural gas resources requires building costly pipelines or liquified natural gas facilities. In most cases these facilities would render remote natural gas uneconomic with conventional natural gas. Several studies suggest that a methanol production plant built at the remote site or on a floating barge may offer an alternative, economic use of this currently unusable gas. The Atlantic Richfield Company and Standard Oil of Ohio have indicated that their long term development plans include methanol production plants as an option for their North Slope natural gas.

A study prepared for the US Department of Energy and the Environmental Protection Agency analyzed these remote natural gas resources and estimated production costs for methanol. Assuming that the world's vented, flared, or reinjected gas were converted to methanol, approximately 50 billion gallons would be produced annually. However, these 50 billion gallons have widely varying production costs. The study estimated that these costs range from 20 to 60 cents per gallon. Table F-2 provides a list of countries where the first five billion gallons of methanol are cheapest and the potential production costs.[24]

In the short term producers generally intend to sell methanol to cover only variable costs. This strategy reflects the overcapacity condition of the world methanol market. While distressing for plant owners, the limited return on fixed costs is representative of a young industry that

TABLE F-2

ESTIMATED DELIVERED PRICE OF METHANOL TO CALIFORNIA
(1985 Dollars)

Country	Price[b] (cents per gallon)
Mexico	18.88
Trinidad	21.10[b]
Canada	24.14
Argentina	26.17
Chile	26.42
Brazil	28.34
Malaysia	30.51
Taiwan	30.56
China	30.79
Arab Emirates	32.12
Burma	32.12
Bahrain	33.24
Saudi Arabia	34.20[b]
India	34.25
Algeria	34.93
United States	35.67

a) Unless otherwise noted, prices are estimated from Jack Faucett Associates, Methanol Prices During Transition, (California Energy Commission, Sacramento, CA, 1987).

b) The Pace Consultants, Methanol Analysis, prepared for Yankee Energy, November, 1985.

has grown in capacity more quickly than demand conditions warrant. Under these market conditions, producers with the lowest variable costs are favored. As suggested in Table F-2, methanol will probably come from Mexico, South America, the Pacific Rim, and Canada. US producers suffer from high feedstock and maintenance costs resulting in less competitive methanol product.

These estimated costs point toward an opportunity to obtain cheaper methanol than what is available to California currently. For California's methanol program, the state purchases the fuel at 49 cents per gallon delivered to San Pedro and Richmond. This price includes 15 to 20 cents per gallon for transporting methanol by rail, the most expensive method of moving fuel. However, since the demand for methanol is so low, more cost effective choices are not available. Higher volume demand for methanol would take advantage of barges and tankers which could reduce the cost of transporting the fuel to two to five cents per gallon. Combining the reduced transportation costs with methanol from one of the lowest cost, methanol producing countries such as Trinidad would suggest a delivered cost to California of about 22 to 26 cents per gallon, substantially below the 49 cents per gallon paid currently.

The prospects of using domestic coal resources as a methanol feedstock are feasible only in the long term. Using current technology, a dedicated coal to methanol plant could produce methanol for 62 cents to 65 cents per

gallon, or twice the spot prices posted earlier in 1987 at the Gulf Coast. To reduce this cost, the Tennessee Valley Authority and the Electric Power Research Institute proposed building an add-on methanol manufacturing unit to integrated gasification/combined cycle plants. This process uses a portion of the gas from the coal gasification unit and converts it to methanol; the remaining usable gases go to the combined cycle power plant for electricity generation. Estimates of the methanol production costs vary from 30 cents to 35 cents per gallon at the facility, well within the range of methanol produced from some remote natural gas sites, but still more expensive than the most likely short term sources for methanol.[25]

Thus, with the availability of remote natural gas and the vast domestic coal reserves, methanol production will not be constrained by limited feedstock resources. Instead, like all other energy resources, methanol availability depends on the price that consumers are willing to pay.

VI. Transitions to Methanol Use

Despite the promise of methanol fuel for transportation, increasing the demand for methanol will require some lowering of a number of barriers. Overcoming these barriers requires the assumption of perceived undue economic risks to consumers, manufacturers, distributors, and producers. Clear market signals to lower these barriers would help in increasing demand. The key signal is the competitive price of methanol relative to petroleum based fuels. As suggested in the previous section, greater volumes of methanol shipped to California would in the short term lower

the prices considerably. One estimate took the existing California price and under four progressive stages of methanol market penetration, calculated a market price for methanol. Table F-3 gives a detailed breakdown of the costs going into the price for methanol. Given these stages, methanol prices will become much lower in stages two through four relative to gasoline.

A comparison of the methanol prices with gasoline prices suggests that methanol has the potential to become cost competitive. Assuming that Stage III from Table F-3 occurs in the year 2000, the projected price of gasoline in constant dollars is $1.32 per gallon (based upon the CEC basecase oil price projections), while the equivalent methanol price is 93 cents per gallon. These comparisons are presented only to indicate that methanol has some potential for achieving a cost advantage relative to gasoline. Further study on the cost comparisons is needed before fully understanding and predicting the cost differences.

A transition strategy to methanol fuels has not been fully identified although two methods seem to present compelling arguments. The first is the blending of methanol with gasoline in three to five percent concentrations. If all gasoline sold in California in 1986 included a five percent blend, approximately 615 million gallons of methanol would have been sold.

TABLE F-3

ESTIMATED METHANOL PRICES AS VOLUME INCREASES[26]

Sacramento Costs and Margins Assuming California-Wide Transition
(Premium Unleaded Rack Price = 61¢, Retail Price = 100¢)

	Stage				
	0	1	2	3	4
California Cars Using M85	500	50,000	500,000	1,000,000	1,500,000
Percent Market	—	1%	7%	15%	20%
M85 Volume (gal/year)	500,000	50 MM	500 MM	1B	1.5B
Rack Price of Methanol (¢/gal)	27	24	26	26	31
Cost of Bulk Delivery (¢/gal)	17 (Rail)	6 (Barge)	6	2 (Ship)	2
Bay Area Storage (¢/gal)	5	3	2	2	1
Total (¢/gal)	49	33	34	30	34
Blended M85 Cost (¢/gal)	50.9	37.3	38.1	34.7	38.1
Delivery to Sacramento (¢/gal)	3 (Truck)	3	0.5 (Pipeline)	0.5	0.5
Sacramento Terminalling and Retail Delivery (¢/gal)	0	0	1.5	1.5	1.0
Taxes (U.S. and State) (¢/gal)	9	9	9	9	9
Required Retail Margin (¢/gal)	9	9	9	9	9
Total (¢/gal)	71.9	58.3	58.1	54.7	57.6
Equivalent Gasoline Price (¢/gal)	122.2	99.1	98.8	93.0	97.9
Implied M85 Wholesale Net Margin (¢/gal) from Sales at Premium Unleaded Retail Price	-22.2	0.9	1.2	7.0	2.1

Recent rulings by the Environmental Protection Agency (EPA) could enhance the marketability of gasoline blends. The EPA ordered a reduction in the lead content of gasoline by 1988, forcing refiners to find alternative octane enhancers. The major oil companies have indicated that they can adapt their processing to make up for the loss in octane. However, smaller refiners and blenders lack the resources to add processing options and could rely on purchased octane enhancers such as methanol, ethanol, or Methyl Tertiary Butyl Ether (MTBE). These alcohol based enhancers, collectively known as oxygenates, were all used in the past in gasoline with varying degrees of success.

More recently, other governmental actions may also have positive consequences for gasoline blends. Citing the need to meet Clean Air Act standards, Colorado will require oxygenates in about 70 percent of the state's gasoline. In addition a federal government task force headed by Vice President George Bush recommended both neat alcohol and gasoline blends for transportation as a strategy to attain air quality standards.

Currently, the favored oxygenate blending component is MTBE which is produced from methanol and isobutylene. In contrast to methanol and ethanol blends, MTBE does not increase the volatility problems of gasoline. In addition the industry has considerable experience in handling this blending agent and uses MTBE as the primary oxygenate blend in Europe. While many producers are gearing up for maximum production, the availability of isobutylene, which is a refinery byproduct, will limit the quantity of MTBE produced. Nevertheless, industry watchers foresee

the demand for MTBE to steadily rise and may squeeze the methanol surplus dry.[27]

Another gasoline blend under consideration is a formulation known as the "DuPont Waiver". This blend, consisting of five percent methanol, 2.5 percent ethanol, and corrosion inhibitors, was approved by the EPA in 1986. The EPA required that the blend comply with industry established volatility standards which requires rigorous quality control. Although the component costs of this fuel is less than MTBE, the special handling procedures have backed many fuel distributors away. Past experience with illegal "splash" blending of methanol into gasoline has made consumers wary of methanol/gasoline blends in some parts of the country.

If one objective is to bring higher quantities of methanol into the fuels market, methanol or MTBE blends may achieve this purpose. However, the overall goal of California's methanol program is to maximize neat methanol use. While oxygenates in gasoline blends may have lower emissions than gasoline, the greatest benefits to air quality come from neat methanol fuel use. Blends are thus considered a short term means to a long term end.

The second transition strategy is the flexible fuel vehicle (FFV). The FFV is equipped with a device that can detect the relative amount of methanol in any fuel mixture. It signals an on-board computer that adjusts the operation of the car to run on the specified fuel. With these devices drivers of FFV's could travel to any area without regard to the

locations of methanol fueling stations. This flexibility will become important to consumers during the transition period when only a small network of fueling stations will exist in the state.

The FFV transition strategy could bring certain benefits to consumers. For example, the FFV's that are owned by the CEC show marked improvement in performance when running on methanol, a characteristic that is confirmed by Ford Motor Company under standardized federal test procedures. While all the reasons why consumers purchase the premium fuels are not clear, some evidently perceive upgraded vehicle performance with the use of premium fuels. Methanol could compete with this consumer sector, and FFV's offer them an opportunity to make this choice. In fact a second benefit extends other choices to the consumer. From a cost conscious consumer's perspective, the ability to choose fuels based on the lowest price adds considerably to the utility of FFV's. Indeed, the added competition among the different transportation fuels may in the long run benefit all consumers in keeping all fuel prices lower. A third benefit helps the state with its goal of reducing petroleum dependence for transportation. Because the FFV helps to lower market barriers for methanol, it may lead to an increased demand for the fuel at a much higher level than if the state provided costly and marginally effective incentives through tax credits and subsidies.

The one uncertainty with FFV's is that consumers may not use any methanol. Since consumers have decades of experience with gasoline, a new fuel faces an uphill task of gaining consumer confidence. The next task for the

FIGURE F-7

POST 1990 METHANOL PRICE BEHAVIOR

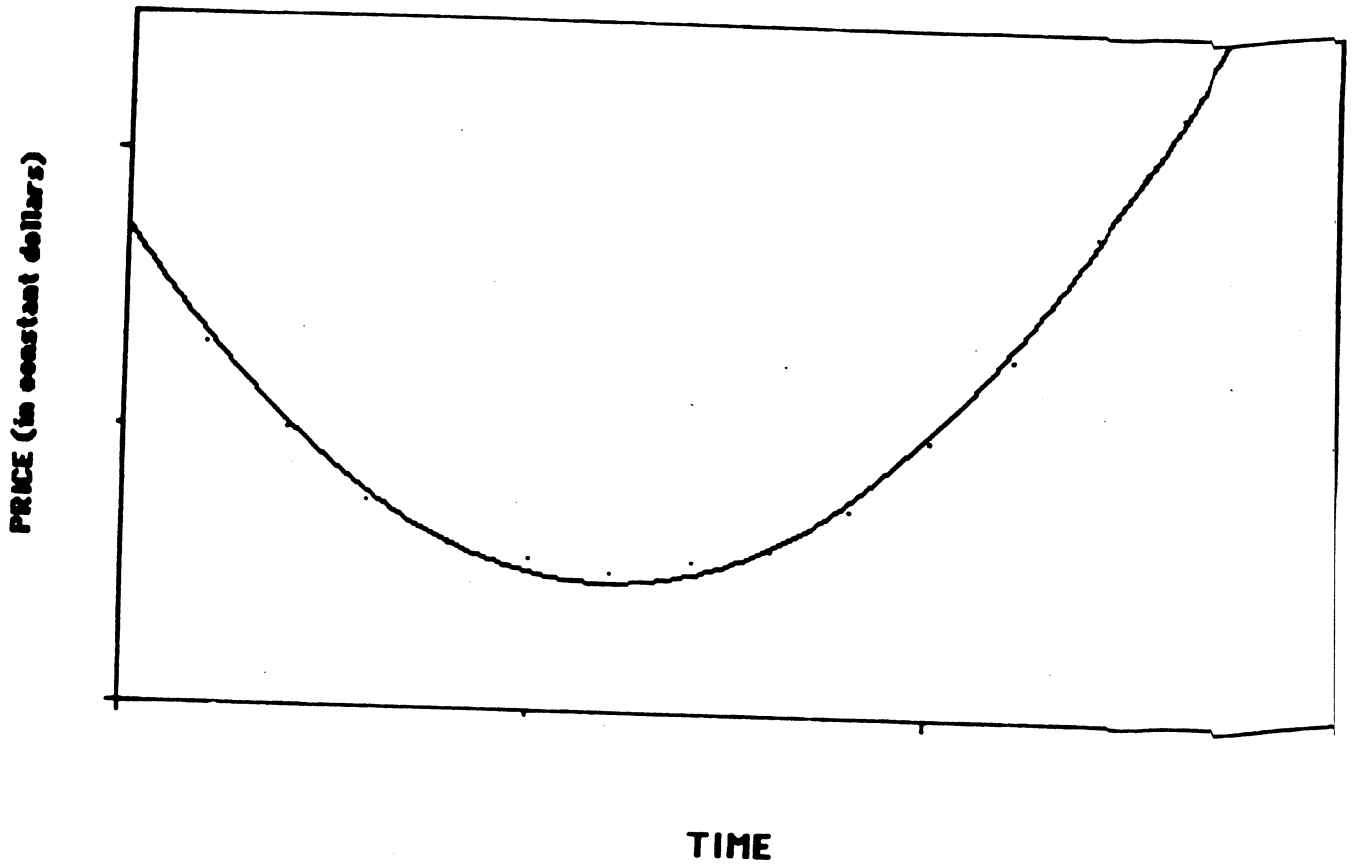


TABLE F-4

METHANOL DEMAND USING LOW METHANOL PRICES [28]

	Price per Gallon Delivered FOB Los Angeles ($ 1986)	Demand (millions of gallons)
1988	$0.49	0.8
1992	$0.35	1
1999	$0.25 - 0.35	680
2007	$0.25 - 0.35	18995

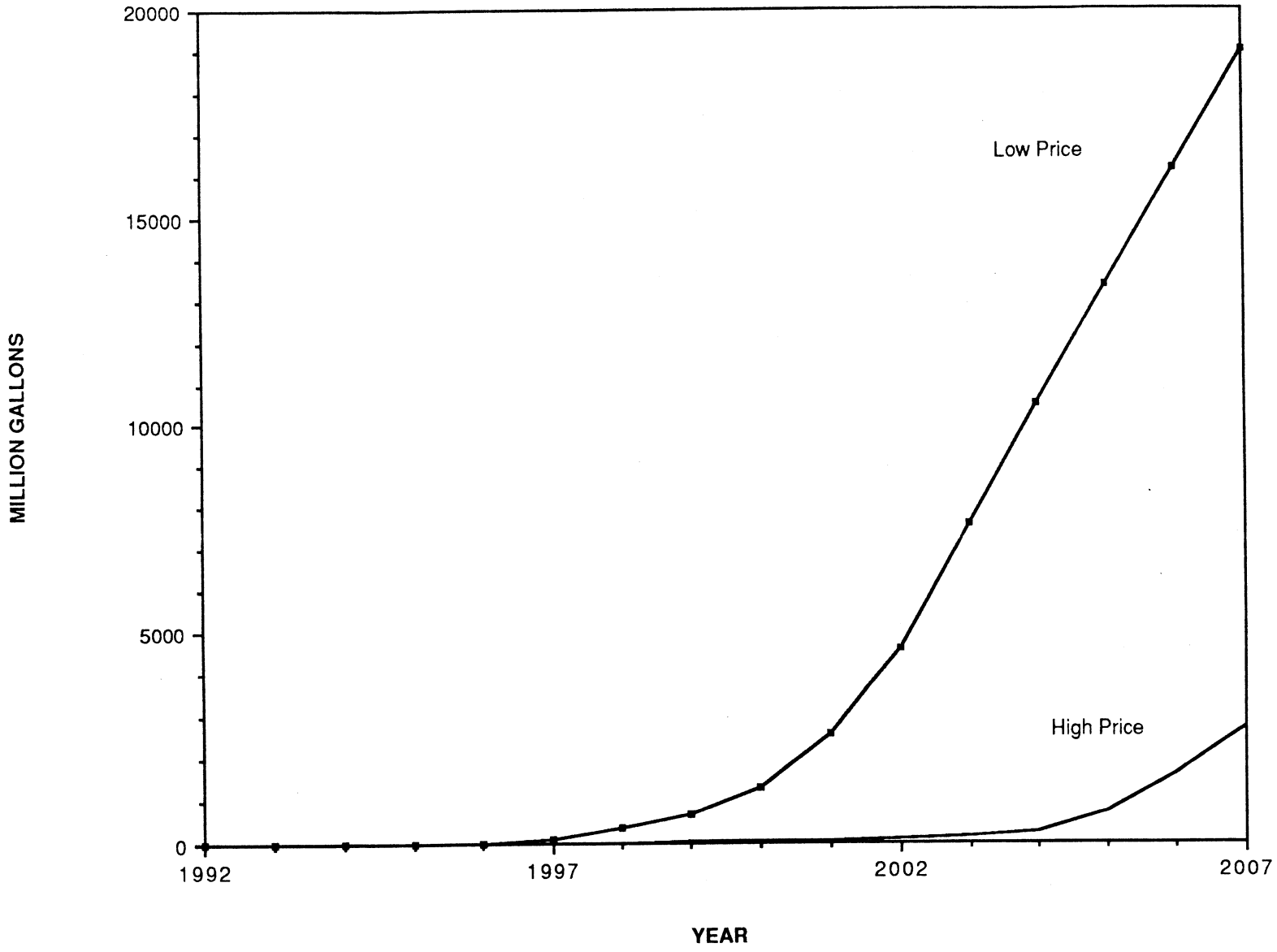
TABLE F-5

METHANOL DEMAND USING HIGH METHANOL PRICES[29]

	Price per Gallon Delivered FOB Los Angeles ($ 1986)	Demand (millions of gallons)
1988	$0.49	0.8
1992	$0.35	1
1999	$0.45	26.8
2007	$0.56	2768.2

FIGURE F-8

ESTIMATED METHANOL FUEL DEMAND[30]



Source: Energetics, Inc., Letter Report to CEC, August 17, 1987.

The two forecasts present two distinctly different alternatives and reflect the infancy of methanol demand analysis. Interpreting the consumers' preferences for performance to quantitative measures in a model is a jump that requires considerably more data and research. Future work in this area is planned particularly with respect to the transitions from a petroleum dominated transportation system to a system with greater fuels diversity.

VIII. Natural Gas Vehicles

The use of natural gas also offers advantages for aiding fuels diversity in transportation. Italy, New Zealand, Canada, and the United States have the most advanced programs, accounting for nearly half a million vehicles in service. Other countries have also determined that natural gas vehicles have a high potential including the Soviet Union, Argentina, Columbia, Trinidad, Bangladesh, India, and Thailand.[31]

The natural gas for these vehicles can be stored in either compressed form or liquefied form in cryogenic containers. The compressed natural gas (CNG) vehicles store fuel at 2400 to 3000 pounds per square inch (psi) in steel or aluminum cylinders that are placed in the trunks of sedans or attached to the frame beneath larger vehicles. Unfortunately, these cylinders add considerable weight, which reduces the vehicle's efficiency and take up significant storage space. Only two cylinders typically are placed in CNG sedans to limit the added weight and yet keep reasonable range capability. Light duty pickup trucks and vans can accept two or

three cylinders and not exceed gross vehicle weight limits. With these cylinder capacities, CNG vehicles have one-third to one-half the range of a similar gasoline car.

Liquified natural gas (LNG), which by volume contains a higher energy content than CNG, requires storage in heavily insulated (cryogenic) tanks to prevent significant loss of natural gas due to boil off. These tanks are equipped with vents to allow the boil off to escape rather than building pressure inside the vessel. If an LNG vehicle remains idle, the vaporized natural gas must be vented to the atmosphere and therefore lost as fuel. Due to the cryogenic tanks and the specialized fueling stations, LNG for vehicles is a tremendously expensive investment.

Refueling CNG vehicles requires a compressor to fill the natural gas at 2400 psi in the storage tanks. Processes that tap directly into the compressor take three to five hours for complete refueling. Fast fill methods involve a rack of large volume cylinders that store natural gas at somewhat higher pressures than for the vehicle's cylinders. This method reduces refueling to three to five minutes. In many fleet applications, the refueling stations use a combined slow fill operation for a majority of their cars and a fast fill for the cars that cannot be taken out of service for extended periods.

These refueling stations comprise a major expense for the CNG fleet operators. The compressors typically cost about $200,000 with the fast fueling capability adding a small margin. The actual operation of these

compressors have proven costly as well. An estimate of electrically driven compressors would increase the cost of natural gas 10 to 20 cents per gasoline equivalent gallon. If the compressors were operated on natural gas, the operating cost is reduced to 6 to 15 cents per gasoline equivalent gallon. Because of this high compressor operating cost, fuel savings of natural gas compared to gasoline diminishes somewhat. Adding the compressor costs to natural gas, the gasoline equivalent price is 70 to 80 cents per gallon, which still is lower than the current retail gasoline price.[32]

In general emissions from natural gas vehicles are cleaner than comparable gasoline vehicles. The bulk of the emissions is unburned methane which does not contribute to photochemical smog formation. Based on test results from CNG vehicles that went through the Federal Test Procedure, emissions of reactive hydrocarbons declined 35 percent to 55 percent when compared to similar gasoline cars. Carbon monoxide emissions were very low and NOx emissions on average were slightly lower than for gasoline vehicles. These test results indicate that CNG vehicles could become an important part of any strategy to meet the air quality standards in the state.

Unfortunately, since many vehicles were converted with after market kits, the quality of the conversion varies. As a consequence the emissions may be worse than comparable gasoline cars. This will improve if factory built CNG vehicles become more common and the manufacturer maintains quality control.[33] Currently no major manufacturers have plans to produce

new CNG vehicles. Fleets desiring these vehicles must purchase conversion kits that with labor cost $1750 per vehicle.[34]

Most proponents of CNG target fleets as the most appropriate application, particularly large fleets with central fueling facilities. Indeed, several fleets have already placed CNG vehicles in service with satisfactory results. Utility companies own approximately half of the 30,000 CNG vehicles in the United States. Large fleets may find that they can cover the cost of conversion of their fleets in four to five years because of CNG's lower operating cost, excluding refueling station.[35]

Since CNG already has a cost advantage and has the potential for air quality benefits, greater use of CNG vehicles can aid efforts to diversify the fuels for transportation in an environmentally acceptable manner. The prospects for CNG vehicles will improve with additional technological development. Future research efforts will focus on improved storage systems such as the use of surface adsorbents like activated carbon. These systems reduce the weight, volume, and pressures necessary to store natural gas. Other research efforts include further evaluation of emissions, particularly from heavy duty applications of CNG and the use of small, relatively inexpensive compressors for individual vehicle refueling. The Gas Research Institute is funding the development of two-stroke and four-stroke natural gas engines to be used in heavy-duty applications.

IX. Other Alternative Fuels for Transportation

Propane vehicles have established the greatest market shares next to gasoline and diesel. As reported in the Energy Development Report, approximately 200,000 propane vehicles are in service in California. Propane is produced as a byproduct of petroleum and natural gas production and processing. Because 80 percent of propane production in California is derived from oil processing, the supply of propane is directly dependent upon oil use. Despite extensive marketing efforts by the propane industry, the future expansion of propane appears limited.

Prior CEC studies of neat ethanol fuel indicate that this fuel suffers from high production costs and will probably not be competitive with gasoline. However, ethanol in gasoline blends was used extensively when both federal and state tax credits provided incentives to distribute these blends. While the state tax credits have expired resulting in less gasoline blends sold, recent rulings passed by the EPA may improve the prospects for ethanol use. In the "DuPont Waiver", which was discussed earlier, the EPA will allow selling a gasoline blend which includes 2.5 percent ethanol.

Another alternative is an electric powered vehicle. Recent advances with new battery systems and improved drive systems have improved the prospects of electric vehicles. While the utility of the electric vehicles is less that of petroleum fueled vehicles, EV's may have their own market niche. The best application is in stop and go delivery vans within the urban

traffic environment. Additional technological development is still required to lower operating and front end capital costs.

FOOTNOTES - APPENDIX F

1. Acurex Corporation, "California's Methanol Program Evaluation Report", Volume II, Technical Analysis, prepared for California Energy Commission, July 1986. Pg. 32.

2. ibid, pg. 34.

3. ibid.

4. ibid.

5. ibid.

6. ibid.

7. Acurex Corporation, "California's Methanol Program, Evaluation Report", Volume I, Executive Summary, prepared for California Energy Commission, November 1986, pg. 12.

8. G.Z. Whitten and H. Hugo, "Impact of Methanol on Smog: A preliminary Estimate", Systems Applications, Inc., Publication No. 83044, February 1983.

9. op.cit., Acurex, Volume II, pg.74.

10. op.cit., Acurex, Volume I, pg. 13.

11. ibid.

12. W.P. Carter, et.al., "Effects of Methanol Fuel Substitution on Multi-day Air Pollution Episodes", Final Report to the California Air Resources Board under contract No. A3-125-32, September 1986.

13. op.cit., Acurex, Volume I, pg. 14.

14. ibid.

15. Environmental Protection Agency, "Evaluation of the Carcinogenicity of Unleaded Gasoline", Office of Health and Environmental Assessment, Office of Research and Development, EPA, Washington, D.C., report 600/6-87/001, April 1987.

16. ibid.

17. ibid.

18. op.cit. Acurex, Volume I, pg. 17.

19. ibid.

20. ibid.

21. ibid.

22. ibid.

23. K.H. MacRae, "Global Methanol Supply and Demand", presented at the 1986 World Methanol Conference, Frankfurt, West Germany, 1986.

24. Jack Faucett Associates, Methanol Prices During Transition, (California Energy Commission: Sacramento, CA 1987).

25. Testimony of Ronald H. Wolk, Electric Power Research Institute, for the 1987 Biennial Fuels Report Hearings, June 17, 1987.

26. M.D. Jackson and C.B. Moyer, "Marketing Methanol in California", presented at the New Fuels for Cleaner Air Inside EPA and Alcohol Week, June 16-17, 1987.

27. Communication from Crocco and Associates, Inc., June 11, 1987.

28. Letter Report from Energetics, Inc. "Preliminary Biennial Fuels Report Methanol Demand Forecasts 1987-2007", May 11, 1987.

29. ibid.

30. ibid.

31. Testimony of Jeffrey Seisler, American Gas Association, presented at the 1987 Biennial Fuels Report Hearings, June 17, 1987.

32. Personal communication with Rich Bechtold, Mueller Associes, August 10, 1987.

33. Richard L. Bechtold and Thomas J. Timbario, "The Status of Gaseous Fuels for Use in Highway Transportation: A 1983 Perspective", prepared for the U.S. Department of Energy, DOE/CS/56051-10, 198[illegible]

34. Testimony of Seisler, op cit.

35. Ibid.

APPENDIX G

PIIRA DATA

TABLE G-1

CALIFORNIA ANNUAL PETROLEUM SUMMARY
(Thousands of Barrels)

Activity	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Refinery Crude Oil Receipts											
Total Receipts	617,187	708,142	647,293	689,257	674,485	634,038	577,717	606,604	632,937	644,335	677,862
Domestic	349,147	394,513	494,258	565,100	576,100	573,783	544,164	558,613	579,675	608,927	640,985
Alaskan	39,346	80,783	203,580	269,361	267,478	245,005	196,462	189,538	210,450	210,647	237,508
California and Other	309,801	313,730	290,678	295,739	303,672	328,778	347,702	369,075	369,225	398,280	403,477
Foreign	268,040	313,629	153,035	124,157	98,335	60,255	33,553	47,991	53,262	35,408	36,877
Refinery Product Output											
Motor Gasoline	276,714	303,554	300,581	306,955	294,808	286,957	272,219	289,680	300,667	306,097	324,187
Aviation Fuels	71,057	76,624	71,300	75,955	73,394	71,472	69,368	73,443	81,705	82,443	86,855
Distillate Fuels	72,801	84,705	81,437	89,745	80,236	89,084	88,130	94,720	104,844	105,397	110,743
Residual Fuels	134,713	171,144	141,534	159,525	166,935	132,819	94,403	86,052	92,929	92,580	93,304
Other	99,082	115,844	127,752	146,913	137,513	118,863	108,584	111,461	118,226	120,210	128,711
Total Output	654,367	752,871	722,604	779,093	752,886	699,195	632,677	655,356	698,371	706,727	743,800
Product Import/Export											
Import											
Motor Gasoline	9,423	5,411	6,980	6,586	6,232	8,904	22,937	17,937	10,742	17,166	18,736
Aviation Fuels	1,354	883	7,828	3,945	1,583	1,639	3,978	1,314	826	832	2,535
Distillate Fuels	1,650	2,056	4,769	3,195	1,379	1,729	2,463	2,073	1,594	1,888	1,847
Residual Fuels	28,474	48,152	22,958	33,832	18,035	14,332	10,944	5,886	6,687	4,003	5,356
Export											
Motor Gasoline	36,162	43,274	50,681	38,911	38,403	42,133	40,788	39,064	40,147	36,897	40,624
Aviation Fuels	12,429	12,159	11,015	13,305	10,525	11,899	14,507	12,314	12,402	9,680	10,539
Distillate Fuels	20,551	20,656	19,030	21,271	16,568	17,594	19,901	17,578	22,778	16,434	17,838
Residual Fuels	27,960	27,860	21,798	19,407	24,984	22,616	24,843	28,981	23,868	12,754	15,112
Stocks at End of Year											
Motor Gasoline	18,587	19,019	18,096	16,921	18,145	19,993	19,021	17,843	20,301	18,372	19,171
Aviation Fuels	5,463	5,142	5,081	4,504	4,884	4,604	4,388	3,850	4,901	3,474	4,663
Distillate Fuels	7,863	8,737	5,560	7,836	6,674	7,929	7,981	7,584	7,736	7,470	6,798
Residual Fuels	41,634	51,035	31,074	34,005	46,260	42,304	40,482	29,336	25,421	22,469	23,038
Product Supplied											
Motor Gasoline	248,962	266,259	267,803	275,805	261,413	251,988	255,343	269,641	268,674	288,295	301,500
Aviation Fuels	59,303	65,669	68,174	67,172	64,072	61,492	59,025	62,970	69,031	75,022	77,662
Distillate Fuels	51,958	65,362	70,353	69,393	66,209	73,537	70,560	79,612	83,455	91,117	95,424
Residual Fuels	145,501	182,035	162,655	172,019	147,731	131,133	82,566	74,306	79,616	86,781	82,979

Source: OFER submittals for 1976 to 1982 and PIIRA submittals for 1981 to 1986.
PIIRA Forms: DOE/EIA-810 Monthly Refinery Report. CEC-M07/12 California Major Petroleum Product Marketer and Storer Reports.

TABLE G-2

ANNUAL PETROLEUM PRODUCT FUEL MARKET SUMMARY
(Thousands of Barrels)

	Refinery Output	Domestic Import	Foreign Import	Storage Change	Total Supply	Domestic Export	Foreign Export	Calif. Supplied
Aviation Fuels								
1976	71,057	595	759	679	71,732	12,163	266	59,303
1977	76,624	773	110	- 321	77,828	11,907	252	65,669
1978	71,300	2,897	4,931	- 61	79,189	10,720	295	68,174
1979	75,955	2,551	1,394	- 577	80,477	12,968	337	67,172
1980	73,394	1,426	157	380	74,597	10,254	271	64,072
1981	71,472	1,639	0	- 280	73,391	11,596	303	61.492
1982	69,368	3,005	973	- 186	73,532	13,594	913	59,025
1983	73,443	1,206	108	- 527	75,284	11,262	1,052	62,970
1984	81,705	681	145	1,098	81,433	11,599	803	69,031
1985	82,443	696	136	- 1,587	84,862	9,559	121	75,182
1986	86,855	1,299	1,236	1,189	88,201	10,436	103	77,662
Distillate Fuels								
1976	72,801	1,650	0	1,942	72,509	19,764	787	51,958
1977	84,705	2,056	0	743	86,018	19,717	939	65,362
1978	81,437	4,769	0	- 3,177	89,383	18,159	871	70,353
1979	89,745	2,841	354	2,276	90,664	20,416	855	69,393
1980	80,236	1,379	0	- 1,162	82,777	15,986	582	66,209
1981	89,084	1,729	0	- 318	91,131	16,901	693	73,537
1982	88,103	2,463	0	105	90,461	18,657	1,244	70,560
1983	94,720	1,995	78	- 397	97,190	16,930	648	79,612
1984	104,844	1,548	46	205	106,233	21,670	1,108	83,455
1985	105,397	1,776	112	- 243	107,528	15,852	582	91,094
1986	110,743	1,764	83	- 672	113,262	17,211	627	95,424
Motor Gasoline								
1976	276,714	9,423	0	1,013	285,124	36,160	2	248,962
1977	304,554	5,301	110	432	309,533	43,271	3	266,259
1978	300,581	6,692	288	- 923	308,484	40,680	1	267,803
1979	306,955	6,586	0	- 1,175	314,716	38,911	0	275,805
1980	294,808	6,081	151	1,224	299,816	38,398	5	261,413
1981	286,957	7,447	1,457	1,740	294,121	42,007	126	251,988
1982	280,973	8,395	5,389	- 376	295,133	39,863	575	254,695
1983	292,633	6,705	4,805	- 758	304,981	38,837	218	265,926
1984	304,347	4,682	3,279	2,256	310,052	39,513	564	269,975
1985	306,097	5,518	4,001	- 1,947	317,563	36,790	106	280,667
1986	324,187	8,014	1,232	556	332,877	38,212	963	293,202
Residual Fuel Oils								
1976	134,713	20,821	7,653	-10,274	173,461	13,303	14,657	145,501
1977	171,144	30,842	17,310	9,401	209,895	12,654	15,206	182,035
1978	141,534	18,101	4,857	-19,961	184,453	10,522	11,276	162,655
1979	159,525	23,032	11,800	2,931	191,426	9,515	9,892	172,019
1980	166,935	13,118	4,917	12,255	172,715	11,908	13,076	147,731
1981	132,819	9,490	4,842	- 6,598	153,749	6,885	15,731	131,133
1982	94,403	8,431	2,513	- 2,062	107,409	12,966	11,877	82,566
1983	86,052	4,492	1,394	-11,349	103,287	9,914	19,067	74,306
1984	92,929	5,738	949	- 3,868	103,484	11,761	12,107	79,616
1985	92,580	2,319	1,684	- 2,952	99,535	5,531	7,223	86,781
1986	93,304	1,718	3,628	566	98,094	4,107	11,005	82,982

SOURCE: QFER submittals for 1976 to 1981 and PIIRA submittals for 1981 to 1986.
PIIRA Forms: DOE/EIA-810 Monthly Refinery Report, CEC-M07-M12 California Major Petroleum Product Marketer and Storer Reports.

TABLE G-3

CRUDE OIL RECEIPTS AT CALIFORNIA REFINERIES
BY SOURCE OF SUPPLY
(Percent of Total)

	1981	1982	1983	1984	1985	1986
SOURCE OF SUPPLY						
Domestic						
California	50.97	58.44	59.20	54.78	58.01	55.77
Alaska North Slope	36.23	32.97	29.96	32.26	33.54	35.68
Alaska Other	2.42	1.91	1.76	1.68	1.30	1.38
Federal Offshore	0.56	0.76	1.11	2.38	1.52	1.63
Other States	0.32	0.27	0.22	0.00	0.14	0.00
Total Domestic	90.50	94.35	92.25	91.10	94.51	94.46
FOREIGN						
OPEC						
Mideast	0.12	0.00	0.00	0.00	0.00	0.04
Indonesia	8.58	5.06	6.93	7.67	4.49	4.55
Other	0.37	0.13	0.25	0.37	0.28	0.54
Total OPEC	9.07	5.19	7.18	8.04	4.77	5.13
NonOPEC						
Mexico	0.00	0.02	0.00	0.00	0.00	0.00
Other	0.43	0.44	0.57	0.86	0.72	0.41
Total NonOPEC	0.43	0.46	0.57	0.86	0.72	0.41
Total Foreign	9.50	5.65	7.75	8.90	5.49	5.54

Source: PIIRA Form: CEC-A04 California Refiners Report

Percentages in Table G-3 are based on percentages rounded to the nearest whole percent reported on CEC-A04 and will not equal volumes reported on Tables G-1, G-5 and G-6.

TABLE G-4

CALIFORNIA REFINERY ACTIVITY BY TYPE AND AREA
Year 1985

Activity	Refinery Type: Topping	Refinery Type: Hydro-Skimming	Refinery Type: Complex	State: Total	Refining Area: Northern	Refining Area: Central	Refining Area: Southern
Crude Receipts (mbbls)							
Domestic							
Alaska	515	471	209,661	210,647	108,535	0	102,112
California & Other	41,323	48,066	308,891	398,280	126,772	56,348	215,160
Total Domestic	41,838	48,537	518,552	608,927	235,307	56,348	317,272
Foreign	0	0	35,408	35,408	5,357	0	30,051
Total Receipts	41,838	48,537	553,960	644,335	240,664	56,348	350,023
Product Output (mbbls)							
Motor Gasoline, Leaded	0	5,519	95,103	100,532	43,040	4,458	53,034
Motor Gasoline, Unleaded	0	7,225	198,340	205,565	82,427	5,870	117,628
Motor Gasoline, Blendstocks	774	0	0	0	0	0	0
Motor Gasoline, Totals	774	12,744	293,443	306,097	125,467	10,328	170,302
Aviation Fuels	1,198	3,640	77,605	82,443	35,041	1,703	45,699
Distillate Fuels	8,326	10,938	86,133	105,397	33,781	9,086	62,530
Residual Fuels	8,295	8,488	75,797	92,580	36,803	11,710	44,067
Lubricating Oils	1,696	6	1,893	3,595	1,840	1,702	53
Asphalt and Road Oil	9,355	2,329	6,408	18,092	6,663	3,839	7,590
Wax	0	0	924	924	924	0	0
Petroleum Coke	0	0	37,776	37,776	12,219	0	25,557
Still Gas	47	1,197	38,058	39,302	14,906	787	23,609
Liquified Refinery Gases	0	9	13,585	13,594	6,189	9	7,396
Other Products	1,345	353	5,224	6,922	1,488	343	5,091
Unfinished Oils	818	10,094	0	0	0	9,759	0
Total Output	31,854	49,798	636,846	706,727	275,321	49,266	391,894
Feedstock Input (mbbls)							
Crude Oil	32,098	48,527	548,423	630,220	236,115	47,491	345,574
Natural Gas Plant Liquids	0	453	6,378	6,831	1,111	453	5,267
Other Hydrocarbons and Hydrogen	0	0	5,085	5,085	2,807	0	2,278
Unfinished Oils	0	0	22,175	11,259	9,541	0	11,477
Motor Gasoline, Blendstocks	0	1,564	11,259	12,085	4,731	1,590	5,764
Total Input	32.098	50.544	593,356	665,480	255,345	49,534	370,360
Distillation Capacity (mb/d)							
Shutdown	35.5	14.5	114.1	164.2	71.0	27.5	65.7
Operating	126.6	168.1	1,908.0	2,202.7	807.9	175.1	1,219.6
Operable	162.1	182.6	2,022.1	2,366.9	878.9	202.6	1,285.3
Distillation Unit Input (mb/d)	82.7	132.9	1,519.5	1,735.2	673.3	121.5	940.4
Utilization (Percent)							
Operating	65.34	79.08	79.64	78.77	83.33	69.38	77.11
Operable	51.03	72.80	75.14	73.31	76.60	59.97	73.17
Crude Quality							
Average API Gravity (°)	18.20	30.29	23.49	23.67	22.11	25.34	24.53
Average Sulfur Content (%)	1.46	0.71	1.15	1.14	1.19	0.92	1.13
Fuel Use							
Crude Oil (mbbls)	0	6	0	6	0	6	0
Fuel Oil, Distillate (mbbls)	0	26	322	349	310	11	27
Fuel Oil, Residual (mbbls)	160	85	1,314	1,560	944	246	370
LPG (mbbls)	0	23	3,379	3,402	1,459	0	1,942
Natural Gas (mmcf)	4,281	2,668	75,677	82,625	52,011	3,060	27,555
Still Gas (mbbls)	46	1,223	34,881	36,151	14,059	808	21,293
Petroleum Coke, Marketable (mbbls)	0	0	1,710	1,710	1,710	0	0
Petroleum Coke, Catalyst (mbbls)	0	0	8,884	8,884	4,139	0	4,745
Coal (mtons)	0	0	0	0	0	0	0
Electricity, Purchased (Gwh)	76	158	4,937	5,173	2,589	142	2,442
Steam, Purchased (mmlbs)	323	0	10,273	10,596	10,273	323	0

Source: PIIRA submittals - Form DOE/EIA-810 Monthly Refinery Report. CEC/M13 California Refinery Report.

TABLE G-5

CALIFORNIA REFINERY ACTIVITY BY TYPE AND AREA
Year 1986

Activity	Refinery Type: Topping	Refinery Type: Hydro-Skimming	Refinery Type: Complex	State: Total	Refining Area: Northern	Refining Area: Central	Refining Area: Southern
Crude Receipts (mbbls)							
Domestic							
Alaska	626	0	236,882	237,508	125,877	0	111,631
California & Other	38,208	45,138	320,131	403,477	133,642	49,285	220,550
Total Domestic	38,834	45,138	557,013	640,985	259,519	49,285	332,181
Foreign	0	0	36,877	36,877	8,867	0	28,010
Total Receipts	38,834	45,138	593,890	677,862	268,386	49,285	360,191
Product Output (mbbls)							
Motor Gasoline, Leaded	0	4,740	92,790	97,530	40,475	3,932	53,123
Motor Gasoline, Unleaded	0	8,009	218,648	226,657	91,816	5,615	129,226
Motor Gasoline, Blendstocks	687	0	0	0	0	0	0
Motor Gasoline, Totals	687	12,749	311,438	324,187	132,291	9,547	182,349
Aviation Fuels	966	3,488	82,431	86,855	38,060	1,290	47,505
Distillate Fuels	7,525	9,337	93,881	110,743	38,846	7,228	64,669
Residual Fuels	4,879	8,673	79,543	93,348	42,168	8,199	42,981
Lubricating Oils	1,803	3	4,713	6,519	4,747	1,806	-34
Asphalt and Road Oil	9,685	2,602	6,695	18,982	6,958	3,903	8,121
Wax	0	0	864	864	864	0	0
Petroleum Coke	0	502	39,149	39,651	12,518	502	26,631
Still Gas	46	1,502	39,374	40,922	16,391	949	23,582
Liquified Refinery Gases	0	133	13,691	13,824	6,490	133	7,201
Other Products	1,185	792	5,928	7,905	1,611	307	5,987
Unfinished Oils	760	6,115	0	0	0	6,292	0
Total Output	27,536	45,896	677,677	743,800	300,944	40,156	408,992
Feedstock Input (mbbls)							
Crude Oil	27,833	44,888	587,501	660,475	262,350	38,707	359,418
Natural Gas Plant Liquids	0	616	7,827	8,443	1,643	616	6,184
Other Hydrocarbons and Hydrogen	0	0	3,888	3,888	3,060	0	828
Unfinished Oils	0	0	19,224	12,351	8,795	0	9,848
Motor Gasoline, Blendstocks	0	1,037	13,987	14,337	3,931	851	9,555
Total Input	27,833	46,541	632,427	699,494	279,779	40,174	385,833
Refinery Gain/Loss	-297	-645	45,250	44,306	21,165	-18	23,159
Distillation Capacity (mb/d)							
Shutdown	125.1	7.2	41.9	174.2	71.0	44.3	58.8
Operating	1,917.6	163.6	112.0	2,193.0	825.7	141.8	1,225.5
Operable	2,042.4	170.8	153.9	2,367.2	898.7	186.1	1,284.3
Distillation Unit Input (mb/d)	1,635.7	117.3	63.3	1,816.4	748.4	90.1	977.9
Utilization (Percent)							
Operating	85.31	71.70	56.53	82.83	90.63	63.51	79.80
Operable	80.90	68.67	41.16	76.73	83.46	48.39	76.14
Crude Quality							
Average API Gravity (°)	17.86	29.71	23.50	23.56	22.66	23.73	24.22
Average Sulfur Content (%)	1.43	0.80	1.12	1.12	1.12	0.99	1.13
Fuel Use							
Crude Oil (mbbls)	0	1	0	1	0	1	0
Fuel Oil, Distillate (mbbls)	0	18	496	514	477	0	37
Fuel Oil, Residual (mbbls)	151	186	1,069	1,408	535	338	534
LPG (mbbls)	0	68	3,514	3,583	1,170	0	2,413
Natural Gas (mmcf)	4,195	2,546	68,100	74,841	45,081	3,102	26,657
Still Gas (mbbls)	46	1,174	37,844	39,065	15,813	627	22,623
Petroleum Coke, Marketable (mbbls)	0	0	1,131	1,131	1,131	0	0
Petroleum Coke, Catalyst (mbbls)	0	0	9,152	9,152	4,306	0	4,846
Coal (mtons)	0	0	0	0	0	0	0
Electricity, Purchased (Gwh)	76	154	5,086	5,316	2,643	125	2,547
Steam, Purchased (mmlbs)	519	0	3,936	4,456	3,936	519	0

Source: PIIRA submittals - Form DOE/EIA-810 Monthly Refinery Report. CEC/M13 California Refinery Report.

TABLE G-6

PROCESSING FACILITY CHANGES AT CALIFORNIA REFINERIES
FROM JANUARY 1, 1985 TO JANUARY 1, 1987

Operable Capacity (mbbls/stream day)

Type Refinery Facility	1985	Additions	Shut Downs	Net Change	1987	Percent Change
Complex						
Crude Distillation	2,170.0	95.1	120.4	-25.3	2,144.7	-7.17
Vacuum Distillation	1,183.3	49.6	96.9	-47.3	1,136.0	-4.00
Thermal Cracking	455.8	22.4	55.4	-33.0	422.8	-7.24
Catalytic Cracking	616.0	41.0	52.7	-11.7	604.3	-1.90
Catalytic Reforming	510.4	25.1	48.6	-23.5	486.9	-4.60
Catalytic Hydrocracking	367.2	18.0	24.8	- 6.8	360.4	-1.85
Catalytic Hydrotreating	1,211.7	108.5	38.2	70.3	1,282.0	5.80
Hydroskimming						
Crude Distillation	241.5	28.0	60.5	-32.5	209.0	13.46
Vacuum Distillation	74.0	21.0	15.0	6.0	80.0	8.10
Thermal Cracking	19.9	48.0	9.8	38.2	58.1	192.00
Catalytic Cracking	0.0	36.0	0.0	36.0	36.0	--
Catalytic Reforming	44.4	28.5	5.5	10.0	54.4	22.52
Catalytic Hydrocracking	0.0	20.0	0.0	20.0	20.0	--
Catalytic Hydrotreating	102.8	3.5	35.0	-31.5	71.3	-30.64
Topping						
Crude Distillation	185.1	1.4	17.5	-16.1	169.0	8.70
Vacuum Distillation	84.1	1.1	0.0	1.1	85.2	1.31
Thermal Cracking	16.8	0.0	0.0	0.0	16.8	0.00
Catalytic Hydrotreating	0.6	0.0	0.0	0.0	0.6	0.00
All Refineries						
Crude Distillation	2,596.7	124.5	198.4	-73.9	2,522.8	-2.85
Vacuum Distillation	1,314.4	71.7	111.9	-40.2	1,301.2	-3.00
Thermal Cracking	492.5	70.5	65.2	5.3	497.8	1.08
Catalytic Cracking	616.0	77.0	52.7	24.3	640.3	3.95
Catalytic Reforming	554.8	50.6	64.1	-13.5	541.3	-2.43
Catalytic Hydrocracking	367.2	38.0	24.8	13.2	360.4	3.60
Catalytic Hydrotreating	1,315.0	112.0	73.2	38.8	1,353.8	2.95

Source: PIIRA Submittals. Form DOE/EIA-820 Annual Refinery Report.

TABLE G-7

PROCESSING FACILITY CHANGES AT CALIFORNIA REFINERIES
FROM JANUARY 1, 1985 TO JANUARY 1, 1987

Operating Capacity (mbbls/stream day)

Type Refinery Facility	1985	Additions	Shut Downs	Net Change	1987	Percent Change
Complex						
Crude Distillation	1,939.0	164.0	90.4	73.6	2,012.6	3.80
Vacuum Distillation	1,089.8	68.6	22.4	46.2	1,136.0	4.24
Thermal Cracking	448.8	22.4	48.4	-26.0	422.8	-5.79
Catalytic Cracking	604.0	41.0	40.7	0.3	604.3	0.05
Catalytic Reforming	485.2	33.8	32.1	1.7	486.9	0.35
Catalytic Hydrocracking	353.2	18.0	10.8	7.2	360.4	2.04
Catalytic Hydrotreating	1,178.7	134.5	31.2	103.3	1,282.0	8.76
Hydroskimming						
Crude Distillation	180.5	41.0	27.5	13.5	194.0	7.48
Vacuum Distillation	46.5	33.5	0.0	33.5	80.0	72.04
Thermal Cracking	10.1	48.0	7.0	41.0	51.1	405.94
Catalytic Cracking	0.0	36.0	0.0	36.0	36.0	--
Catalytic Reforming	34.4	28.5	8.5	20.0	54.4	58.14
Catalytic Hydrocracking	0.0	20.0	0.0	20.0	20.0	--
Catalytic Hydrotreating	71.3	3.5	3.5	0.0	71.3	0.00
Topping						
Crude Distillation	161.4	1.4	52.3	-50.9	110.5	-31.54
Vacuum Distillation	74.0	1.6	13.4	-11.8	62.2	-15.95
Thermal Cracking	13.4	0.0	8.4	- 8.4	5.0	-62.69
Catalytic Hydrotreating	0.5	0.5	0.0	0.1	0.6	20.00
All Refineries						
Crude Distillation	2,280.9	206.4	170.2	36.2	2,317.1	1.59
Vacuum Distillation	1,210.3	103.7	35.8	67.9	1,278.2	5.61
Thermal Cracking	472.3	70.4	63.8	6.6	478.9	1.40
Catalytic Cracking	604.0	77.0	40.7	36.3	640.3	6.01
Catalytic Reforming	519.6	62.3	40.6	21.7	541.3	4.18
Catalytic Hydrocracking	353.2	38.0	10.8	7.2	360.4	2.04
Catalytic Hydrotreating	1,250.5	138.0	34.7	103.3	1,353.8	8.26

Source: PIIRA Submittals. Form DOE/EIA-820 Annual Refinery Report.

TABLE G-8

CALIFORNIA PETROLEUM PRODUCT SHIPMENTS OF MAJOR MARKETERS
BY TRANSPORTATION METHOD
(Percent)

	Pipeline	Tanker	Barge	Truck	Railroad
REFINER/MARKETER					
Motor Gasoline					
1984	56.54	0.80	7.55	34.88	0.00
1985	51.98	2.10	1.04	44.48	0.00
1986	53.54	2.63	0.79	43.03	0.00
Aviation Fuels					
1984	72.78	4.87	14.61	7.74	0.00
1985	75.61	6.57	1.09	16.73	0.00
1986	74.02	8.90	1.21	15.87	0.00
Distillate Fuels					
1984	54.88	4.50	11.32	29.09	0.22
1985	51.15	9.72	7.70	31.42	0.01
1986	50.39	10.34	6.69	32.40	0.19
Residual Fuels					
1984	27.59	17.79	29.21	25.41	0.00
1985	35.09	31.19	21.42	12.30	0.00
1986	34.83	34.97	18.22	11.99	0.00
OTHER MARKETERS					
Motor Gasoline					
1984	3.52	15.92	0.05	80.51	0.00
1985	47.13	2.00	0.62	50.25	0.00
1986	19.12	1.40	1.01	78.47	0.00
Aviation Fuels					
1984	56.19	15.62	0.00	28.19	0.00
1985	31.91	0.00	0.00	68.09	0.00
1986	50.59	2.87	1.28	45.25	0.00
Distillate Fuels					
1984	2.24	67.42	1.03	29.28	0.00
1985	41.33	1.94	2.66	54.07	0.00
1986	2.42	0.62	9.41	87.54	0.00
Residual Fuels					
1984	1.66	22.59	59.92	15.83	0.00
1985	4.88	12.70	47.23	35.19	0.00
1986	38.90	0.29	50.91	9.90	0.00
ALL MARKETERS					
Motor Gasoline					
1984	38.35	5.94	4.98	50.58	0.00
1985	51.69	2.09	1.01	45.21	0.00
1986	51.63	2.56	0.81	45.00	0.00
Aviation Fuels					
1984	72.29	4.86	14.05	8.80	0.00
1985	74.59	6.27	1.04	18.10	0.00
1986	73.56	8.49	1.18	16.77	0.00
Distillate Fuels					
1984	14.21	53.08	3.37	29.27	0.05
1985	50.53	9.23	7.38	32.84	0.01
1986	32.52	6.72	7.70	52.94	0.12
Residual Fuels					
1984	25.10	18.21	32.23	24.46	0.00
1985	33.44	30.18	22.83	13.55	0.00
1986	37.70	10.55	41.23	10.52	0.00

Note: Percentages are based on total shipments (some product shipments use more than one method of transportation before reaching final point of sale) rather than final sale.

Source: PIIRA FORM: CEC-A10 California Major Petroleum Product Marketer Annual Transportation Report.

TABLE G-9A

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
MOTOR GASOLINE, LEADED
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	9862	359	502	861	10196	1363	0	1363	8833	5841	527
FEBRUARY	8754	210	0	210	9495	1347	0	1347	8148	5310	-531
MARCH	9711	291	477	768	10459	1411	0	1411	9048	5330	20
APRIL	10074	169	114	283	10234	1791	0	1791	8443	5453	123
MAY	9776	397	336	733	10074	1522	0	1522	8552	5888	435
JUNE	9583	103	517	620	9586	1375	271	1646	7940	6505	617
JULY	9306	92	0	92	9963	1520	258	1778	8185	5873	-565
AUGUST	9131	96	160	256	9938	1924	0	1924	8014	5322	-551
SEPTEMBER	8657	83	425	508	9467	1716	2	1718	7749	5020	-302
OCTOBER	9633	279	0	279	10118	1509	0	1509	8609	4814	-206
NOVEMBER	8819	66	346	412	9062	1347	0	1347	7715	4983	169
DECEMBER	8965	138	182	320	8725	1274	31	1305	7420	5543	560
1985											
JANUARY	8623	226	181	407	8497	1206	0	1206	7291	6019	533
FEBRUARY	6408	150	652	802	8297	1064	0	1064	7233	4932	-1087
MARCH	7875	399	409	808	8560	1160	0	1160	7400	5055	123
APRIL	8533	-38	309	271	8356	1299	0	1299	7057	5503	448
MAY	9278	217	158	375	10643	1365	31	1396	9247	4513	-990
JUNE	9755	15	218	233	8639	1293	0	1293	7346	5862	1349
JULY	8463	91	174	265	9426	1352	0	1352	8074	5164	-698
AUGUST	8994	131	308	439	9369	1447	0	1447	7922	5228	64
SEPTEMBER	8038	108	156	264	9158	1224	62	1286	7872	4372	-856
OCTOBER	8090	101	125	226	8616	1339	13	1352	7264	4678	-300
NOVEMBER	8142	4	66	70	8161	1256	0	1256	6905	4729	51
DECEMBER	8333	174	66	240	7833	1205	0	1205	6628	5469	740
1986											
JANUARY	8024	124	0	124	7376	1154	5	1159	6217	6241	772
FEBRUARY	6923	117	0	117	7581	1071	0	1071	6510	5700	-541
MARCH	7780	60	0	60	9074	950	0	950	8124	4466	-1234
APRIL	7474	33	0	33	7411	1002	47	1049	6362	4562	96
MAY	8549	95	0	95	8127	1084	0	1084	7043	5079	517
JUNE	8160	78	114	192	7743	1245	119	1364	6379	5688	609
JULY	8499	5	141	146	8589	1357	150	1507	7082	5744	56
AUGUST	8285	160	92	252	9578	1324	0	1324	8254	4735	-1041
SEPTEMBER	8728	154	0	154	8411	1335	0	1335	7076	5206	471
OCTOBER	8524	139	0	139	8613	1548	210	1758	6855	5256	50
NOVEMBER	8120	190	0	190	8883	1326	0	1326	7557	4683	-573
DECEMBER	8464	88	9	97	8624	1249	0	1249	7375	4620	-63

TABLE G-9B

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
MOTOR GASOLINE, UNLEADED
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	15490	214	0	214	14146	1623	0	1623	12523	8449	1558
FEBRUARY	12833	337	0	337	14530	1449	0	1449	13081	7089	-1360
MARCH	15869	251	0	251	15515	1625	0	1625	13890	7694	605
APRIL	15869	369	0	369	16106	1713	0	1713	14393	7826	132
MAY	16874	162	109	271	15839	1945	0	1945	13894	9132	1306
JUNE	16368	101	111	212	16386	1695	0	1695	14691	9326	194
JULY	16116	87	0	87	16599	1747	0	1747	14852	8886	-396
AUGUST	16197	282	0	282	17429	1807	0	1807	15622	7936	-950
SEPTEMBER	16476	34	0	34	16210	2255	2	2257	13953	8236	300
OCTOBER	16085	229	0	229	16679	1938	0	1938	14741	7871	-365
NOVEMBER	16621	180	0	180	16457	1774	0	1774	14683	8215	344
DECEMBER	17278	153	0	153	16839	1843	0	1843	14996	8807	592
1985											
JANUARY	16584	512	0	512	16953	1762	0	1762	15191	8876	143
FEBRUARY	13493	413	0	413	14921	1431	0	1431	13490	7861	-1015
MARCH	16167	348	0	348	16623	1770	0	1770	14853	7753	-108
APRIL	18005	348	447	795	17809	1625	0	1625	16184	8744	991
MAY	18072	254	428	682	17203	2063	0	2063	15140	10295	1551
JUNE	17371	134	5	139	18646	2002	0	2002	16644	9159	-1136
JULY	18358	296	0	296	19009	2102	0	2102	16907	8804	-355
AUGUST	18109	431	75	506	19550	2006	0	2006	17544	7869	-935
SEPTEMBER	18052	291	74	365	17801	1785	0	1785	16016	8485	616
OCTOBER	17612	361	150	511	18561	1729	0	1729	16832	8048	-438
NOVEMBER	15799	250	0	250	16995	1532	0	1532	15463	7102	-946
DECEMBER	17943	302	0	302	17937	1773	0	1773	16164	7410	308
1986											
JANUARY	19402	478	272	750	17419	1885	0	1885	15534	10143	2733
FEBRUARY	15591	377	0	377	17134	1642	0	1642	15492	8977	-1166
MARCH	17239	382	0	382	19954	1695	0	1695	18259	6644	-2333
APRIL	17697	1161	0	1161	17872	1620	0	1620	16252	7630	986
MAY	18025	534	0	534	17373	1569	0	1569	15804	8816	1186
JUNE	18999	290	174	464	18848	1427	179	1606	17242	9431	615
JULY	20206	407	355	762	20777	2104	183	2287	18490	9622	191
AUGUST	20526	562	-12	550	22564	2072	0	2072	20492	8134	-1488
SEPTEMBER	19986	580	0	580	19163	2366	0	2366	16797	9537	1403
OCTOBER	19393	714	87	801	20762	2529	70	2599	18163	8969	-568
NOVEMBER	19913	458	0	458	19476	2330	0	2330	17146	9864	895
DECEMBER	19680	828	0	828	21525	2328	0	2328	19197	8847	-1017

TABLE G-9C

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
MOTOR GASOLINE, TOTAL
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	25352	573	502	1075	24342	2986	0	2986	21356	14290	2085
FEBRUARY	21587	547	0	547	24025	2796	0	2796	21229	12399	-1891
MARCH	25580	542	477	1019	25974	3036	0	3036	22938	13024	625
APRIL	25943	538	114	652	26340	3504	0	3504	22836	13279	255
MAY	26650	559	445	1004	25913	3467	0	3467	22446	15020	1741
JUNE	25951	204	628	832	25972	3070	271	3341	22631	15831	811
JULY	25422	179	0	179	26562	3267	258	3525	23037	14759	-961
AUGUST	25328	378	160	538	27367	3731	0	3731	23636	13258	-1501
SEPTEMBER	25133	117	425	542	25677	3971	4	3975	21702	13256	-2
OCTOBER	25718	508	0	508	26797	3447	0	3447	23350	12685	-571
NOVEMBER	25440	246	346	592	25519	3121	0	3121	22398	13198	513
DECEMBER	26243	291	182	473	25564	3117	31	3148	22416	14350	1152
1985											
JANUARY	25207	738	181	919	25450	2968	0	2968	22482	14895	676
FEBRUARY	19901	563	652	1215	23218	2495	0	2495	20723	12793	-2102
MARCH	24042	747	409	1156	25183	2930	0	2930	22253	12808	15
APRIL	26538	310	756	1066	26165	2924	0	2924	23241	14247	1439
MAY	27350	471	586	1057	27846	3428	31	3459	24387	14808	561
JUNE	27126	149	223	372	27285	3295	0	3295	23990	15021	213
JULY	26821	387	174	561	28435	3454	0	3454	24981	13968	-1053
AUGUST	27103	562	383	945	28919	3453	0	3453	25466	13097	-871
SEPTEMBER	26090	399	230	629	26959	3009	62	3071	23888	12857	-240
OCTOBER	25702	462	275	737	27177	3068	13	3081	24096	12726	-738
NOVEMBER	23941	254	66	320	25156	2788	0	2788	22368	11831	-895
DECEMBER	26276	476	66	542	25770	2978	0	2978	22792	12879	1048
1986											
JANUARY	27426	602	272	874	24795	3039	5	3044	21751	16384	3505
FEBRUARY	22514	494	0	494	24715	2713	0	2713	22002	14677	-1707
MARCH	25019	442	0	442	29028	2645	0	2645	26383	11110	-3567
APRIL	25171	1194	0	1194	25283	2622	47	2669	22614	12192	1082
MAY	26574	629	0	629	25500	2653	0	2653	22847	13895	1703
JUNE	27159	368	288	656	26591	2672	298	2970	23621	15119	1224
JULY	28705	412	496	908	29366	3461	333	3794	25572	15366	247
AUGUST	28811	722	80	802	32142	3396	0	3396	28746	12869	-2529
SEPTEMBER	28714	734	0	734	27574	3701	0	3701	23873	14743	1874
OCTOBER	27917	853	87	940	29375	4077	280	4357	25018	14225	-518
NOVEMBER	28033	648	0	648	28359	3656	0	3656	24703	14547	322
DECEMBER	28144	916	9	925	30149	3577	0	3577	26572	13467	-1080

TABLE G-9D

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
AVIATION FUELS
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	6328	2	0	2	6245	728	108	836	5409	3942	85
FEBRUARY	6298	0	0	0	5915	1069	95	1164	4751	4325	383
MARCH	6268	311	70	381	5956	646	104	750	5206	5018	693
APRIL	6794	0	0	0	6410	940	80	1020	5390	5402	384
MAY	6544	99	0	99	7070	989	61	1050	6020	4975	-427
JUNE	7094	0	0	0	7513	1369	56	1425	6088	4556	-419
JULY	7625	0	0	0	7517	1007	46	1053	6464	4610	108
AUGUST	7362	25	0	25	8045	1232	49	1281	6764	3952	-658
SEPTEMBER	7103	0	0	0	7094	1014	47	1061	5943	4051	99
OCTOBER	7091	0	0	0	6891	789	45	834	6057	4251	200
NOVEMBER	6788	0	75	75	6484	889	77	966	5518	4630	379
DECEMBER	6410	244	0	244	6383	927	35	962	5421	4901	271
1985											
JANUARY	7562	0	0	0	7384	1137	36	1173	6211	5079	178
FEBRUARY	5971	0	0	0	6243	667	18	685	5558	4807	-272
MARCH	6917	6	0	6	6761	1036	14	1050	5711	4969	162
APRIL	6726	305	0	305	7393	533	24	557	6836	4607	-362
MAY	6051	15	0	15	6634	725	11	736	5898	4039	-568
JUNE	7023	33	76	109	6662	890	1	891	5771	4509	470
JULY	7482	-20	0	-20	7366	657	17	674	6692	4605	96
AUGUST	6686	36	0	36	7547	635	0	635	6912	3780	-825
SEPTEMBER	7353	38	0	38	7175	1017	0	1017	6158	3996	216
OCTOBER	7193	144	0	144	7372	842	0	842	6530	4121	-35
NOVEMBER	6501	66	0	66	7266	788	0	788	6478	3422	-699
DECEMBER	6978	73	60	133	7059	632	0	632	6427	3474	52
1986											
JANUARY	7566	180	0	180	6864	659	0	659	6205	4356	882
FEBRUARY	6496	22	0	22	6497	1099	3	1102	5395	4377	21
MARCH	7044	98	80	178	7658	563	0	563	7095	3941	-436
APRIL	5822	178	0	178	6194	751	0	751	5443	3747	-194
MAY	6514	57	477	534	6648	613	0	613	6035	4147	400
JUNE	7752	164	194	358	8034	601	44	645	7389	4223	76
JULY	7919	29	106	135	7844	693	56	749	7095	4433	210
AUGUST	7905	132	229	361	8878	762	0	762	8116	3821	-612
SEPTEMBER	7264	75	0	75	6902	690	0	690	6212	4258	437
OCTOBER	7883	153	150	303	7905	1486	0	1486	6419	4539	281
NOVEMBER	7326	90	0	90	7072	995	0	995	6077	4883	344
DECEMBER	7364	121	0	121	7705	1524	0	1524	6181	4663	-220

TABLE G-9E

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
DISTILLATE FUELS
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	7698	39	0	39	8876	1750	38	1788	7088	6453	-1139
FEBRUARY	8367	369	0	369	8455	1828	22	1850	6605	6732	281
MARCH	9028	37	0	37	8530	1660	96	1756	6774	7267	535
APRIL	9194	69	44	113	9000	1943	120	2063	6937	7574	307
MAY	9775	17	0	17	9477	2042	348	2390	7087	7889	315
JUNE	9372	37	0	37	9809	1773	45	1818	7991	7489	-400
JULY	9188	125	0	125	9597	1712	36	1748	7849	7146	-284
AUGUST	9086	139	0	139	8946	1746	256	2002	6944	7425	279
SEPTEMBER	8640	381	0	381	9052	1714	41	1755	7297	7394	-31
OCTOBER	8603	103	0	103	8348	1744	52	1796	6552	7752	358
NOVEMBER	8079	42	0	42	8134	1805	23	1828	6306	7739	-13
DECEMBER	7814	190	2	192	8009	1953	31	1984	6025	7736	-3
1985											
JANUARY	7176	113	0	113	7888	1099	23	1122	6766	7114	-599
FEBRUARY	7454	120	0	120	7977	1338	29	1367	6610	6711	-403
MARCH	8148	169	75	244	7274	1400	26	1426	5848	7829	1118
APRIL	7521	163	0	163	8921	948	103	1051	7870	6592	-1237
MAY	8849	64	0	64	7335	1408	141	1549	5786	8170	1578
JUNE	9109	178	37	215	9364	1985	31	2016	7348	8130	-40
JULY	9233	323	0	323	10105	1633	32	1665	8440	7581	-549
AUGUST	8715	207	0	207	9403	1090	39	1129	8274	7100	-481
SEPTEMBER	9567	86	0	86	10598	1044	32	1076	9522	6155	-945
OCTOBER	10592	56	0	56	10471	1484	56	1540	8931	6332	177
NOVEMBER	10020	145	0	145	9357	1436	34	1470	7887	7140	808
DECEMBER	9013	152	0	152	8835	987	36	1023	7812	7470	330
1986											
JANUARY	8953	122	0	122	8612	1387	117	1504	7108	7933	463
FEBRUARY	7580	86	0	86	7785	1103	31	1134	6651	7814	-119
MARCH	8557	91	0	91	9820	1205	36	1241	8579	6642	-1172
APRIL	10373	142	0	142	10369	1450	145	1595	8774	6788	146
MAY	11025	133	0	133	10845	1194	50	1244	9601	7101	313
JUNE	10186	103	52	155	9853	1602	46	1648	8205	7589	488
JULY	9705	149	45	194	10981	1377	73	1450	9531	6507	-1082
AUGUST	9453	288	0	288	10181	1108	29	1137	9044	6067	-440
SEPTEMBER	9339	56	0	56	9349	1566	15	1581	7768	6113	46
OCTOBER	9242	191	0	191	8974	1846	27	1873	7101	6572	459
NOVEMBER	7871	110	0	110	7768	1454	23	1477	6291	6785	213
DECEMBER	8459	293	-14	279	8725	1919	35	1954	6771	6798	13

TABLE G-9F

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
RESIDUALS, LOW SULFUR
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	980	650	0	650	1664	833	0	833	831	24239	24239
FEBRUARY	1063	364	0	364	1905	1033	0	1033	872	23761	23761
MARCH	1266	97	0	97	1661	825	0	825	836	23463	23463
APRIL	1115	629	0	629	2007	1017	0	1017	990	23200	23200
MAY	999	218	0	218	1411	1251	0	1251	160	23006	23006
JUNE	934	211	0	211	1487	1049	0	1049	438	22664	22664
JULY	1098	213	0	213	1584	626	0	626	958	22391	22391
AUGUST	1120	219	0	219	1554	429	0	429	1125	22176	22176
SEPTEMBER	1005	214	0	214	1533	743	0	743	790	21862	21862
OCTOBER	1151	13	0	13	859	0	0	0	859	22167	22167
NOVEMBER	1027	138	0	138	1579	1024	0	1024	555	21753	21753
DECEMBER	939	96	327	423	2040	514	0	514	1526	21075	21075
1985											
JANUARY	666	0	0	0	827	134	0	134	693	20914	20914
FEBRUARY	696	430	0	430	2155	1362	0	1362	793	19885	19885
MARCH	449	282	0	282	872	591	0	591	281	19744	19744
APRIL	951	210	0	210	1097	210	0	210	887	19808	19808
MAY	501	0	0	0	1328	187	0	187	1141	18981	18981
JUNE	580	210	0	210	1229	210	0	210	1019	18542	18542
JULY	709	0	363	363	655	363	0	363	292	18959	18959
AUGUST	736	0	0	0	992	0	0	0	992	18703	18703
SEPTEMBER	634	0	968	968	1624	439	0	439	1185	18681	18681
OCTOBER	668	0	283	283	1235	309	283	592	643	18397	18114
NOVEMBER	490	0	0	0	496	0	0	0	496	18391	18391
DECEMBER	1441	0	70	70	3111	0	70	70	3041	16791	16721
1986											
JANUARY	978	0	363	363	804	0	120	120	684	17328	17208
FEBRUARY	610	0	293	293	924	0	293	293	631	17307	17014
MARCH	1117	203	484	687	1556	506	217	723	833	17555	17338
APRIL	1329	0	210	210	1726	0	210	210	1516	17370	17160
MAY	902	301	217	518	1189	153	217	370	819	17601	17384
JUNE	650	0	210	210	1161	0	210	210	951	17300	17090
JULY	353	0	217	217	951	0	216	216	735	16919	16703
AUGUST	632	284	714	998	1799	94	219	313	1486	16750	16531
SEPTEMBER	1042	0	60	60	601	0	60	60	541	17251	17191
OCTOBER	811	153	367	520	1379	0	367	367	1012	17203	16836
NOVEMBER	809	126	210	336	918	241	216	457	461	17430	17214
DECEMBER	767	0	217	217	1150	253	217	470	680	17264	17047

TABLE G-9G

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
RESIDUALS, HIGH SULFUR
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	6852	258	0	258	7010	619	1402	2021	4989	5131	3729
FEBRUARY	6242	486	0	486	5461	628	1051	1679	3782	6398	5347
MARCH	6343	666	0	666	6942	67	1061	1128	5814	6465	5404
APRIL	6384	718	0	718	6860	112	516	628	6232	6707	6191
MAY	6237	162	0	162	7912	34	1301	1335	6577	5239	3938
JUNE	6904	14	267	281	6295	28	992	1020	5275	6129	5137
JULY	6896	1	318	319	5760	33	760	793	4967	7524	6764
AUGUST	6397	12	0	12	7009	443	631	1074	5935	6924	6293
SEPTEMBER	6096	113	0	113	7506	66	670	736	6770	5627	4957
OCTOBER	6942	11	37	48	6501	69	1138	1207	5294	6116	4978
NOVEMBER	6611	232	0	232	8286	80	1691	1771	6515	4673	2982
DECEMBER	8451	3	0	3	8781	238	894	1132	7649	4346	3452
1985											
JANUARY	7392	174	0	174	6267	100	845	945	5322	5645	4800
FEBRUARY	8145	62	0	62	7343	397	881	1278	6065	6509	5628
MARCH	9097	45	0	45	8971	310	606	916	8055	6680	6074
APRIL	8370	71	0	71	8271	223	449	672	7599	6850	6401
MAY	6378	52	0	52	7024	137	827	964	6060	6256	5429
JUNE	5637	6	0	6	7656	127	555	682	6974	4243	3688
JULY	5804	146	0	146	4203	-29	483	454	3749	5990	5507
AUGUST	5950	61	0	61	6639	50	455	505	6134	5362	4907
SEPTEMBER	6386	235	0	235	6788	109	381	490	6298	5195	4814
OCTOBER	6910	104	0	104	6635	132	502	634	6001	5574	5072
NOVEMBER	6583	87	0	87	7160	8	432	440	6720	5084	4652
DECEMBER	7558	144	0	144	7108	162	454	616	6492	5678	5224
1986											
JANUARY	7509	48	0	48	6444	238	485	723	5721	6791	6306
FEBRUARY	6255	389	0	389	6883	29	358	387	6496	6552	6194
MARCH	6980	-143	0	-143	6430	649	567	1216	5214	6959	6392
APRIL	7507	1	0	1	9955	354	1317	1671	8284	4513	3196
MAY	7719	60	0	60	6181	196	349	545	5636	6111	5762
JUNE	6118	49	0	49	6370	217	953	1170	5200	5908	4955
JULY	6928	274	0	274	7170	202	486	688	6482	5940	5454
AUGUST	6966	0	66	66	8608	235	940	1175	7433	4364	3424
SEPTEMBER	5974	0	0	0	4638	66	402	468	4170	5700	5298
OCTOBER	6294	-66	0	-66	6729	118	710	828	5901	5199	4489
NOVEMBER	8127	0	0	0	6087	534	1023	1557	4530	7239	6216
DECEMBER	6713	49	0	49	8227	22	853	875	7352	5774	4921

TABLE G-9H

CALIFORNIA PETROLEUM FUEL MARKET SUMMARY
RESIDUAL FUEL OILS
(THOUSANDS OF BARRELS)

	REFINERY OUTPUT	DOMESTIC IMPORTS	FOREIGN IMPORTS	TOTAL IMPORTS	TOTAL SUPPLIED	DOMESTIC EXPORTS	FOREIGN EXPORTS	TOTAL EXPORTS	PRODUCT SUPPLIED	ENDING STOCKS	STORAGE CHANGE
1984											
JANUARY	7832	908	0	908	8674	1452	1402	2854	5820	29370	66
FEBRUARY	7305	850	0	850	7366	1661	1051	2712	4654	30159	789
MARCH	7609	763	0	763	8603	892	1061	1953	6650	29928	-231
APRIL	7459	1347	0	1347	8827	1129	516	1645	7182	29907	-21
MAY	7236	380	0	380	9323	1285	1301	2586	6737	28245	-1707
JUNE	7838	225	267	492	7782	1077	992	2069	5713	28793	548
JULY	7994	214	318	532	7344	659	760	1419	5925	29915	1182
AUGUST	7483	231	0	231	8529	872	631	1503	7026	29100	-815
SEPTEMBER	7101	327	0	327	9039	809	670	1479	7560	27489	-1611
OCTOBER	8093	24	37	61	7360	69	1138	1207	6153	28283	794
NOVEMBER	7639	370	0	370	9866	1104	1691	2795	7071	26426	-1857
DECEMBER	9340	99	327	426	10771	752	894	1646	9125	25421	-1005
1985											
JANUARY	8058	174	0	174	7094	234	845	1079	6015	26559	1138
FEBRUARY	8841	492	0	492	9498	1759	881	2640	6858	26394	-165
MARCH	9546	327	0	327	9843	901	606	1507	8336	26424	30
APRIL	9321	281	0	281	9368	433	449	882	8486	26658	234
MAY	6879	52	0	52	8352	324	827	1151	7201	25237	-1421
JUNE	6217	216	0	216	8885	337	555	892	7993	22785	-2452
JULY	6513	146	363	509	4858	334	483	817	4041	24949	2164
AUGUST	6686	61	0	61	7631	50	455	505	7126	24065	-884
SEPTEMBER	7020	235	968	1203	8412	548	381	929	7483	23876	-189
OCTOBER	7578	104	283	387	7870	441	785	1226	6644	23971	95
NOVEMBER	6922	87	0	87	7505	8	432	440	7065	23475	-496
DECEMBER	8999	144	70	214	10219	162	524	686	9533	22469	-1006
1986											
JANUARY	8701	48	363	411	7462	238	605	843	6619	24119	1650
FEBRUARY	6865	389	293	682	7807	29	651	680	7127	23859	-260
MARCH	8097	60	484	544	7986	1155	784	1939	6047	24514	655
APRIL	8836	1	210	211	11681	354	1527	1881	9800	21883	-2634
MAY	8621	361	217	578	7370	349	566	915	6455	23712	1829
JUNE	6768	49	210	259	7531	217	1163	1380	6151	23208	-504
JULY	7281	274	217	491	8121	202	702	904	7217	22859	-349
AUGUST	7598	284	780	1064	10407	329	1159	1488	8919	21114	-1745
SEPTEMBER	7016	0	60	60	5239	66	462	528	4711	22951	1837
OCTOBER	7105	87	367	454	8108	118	1077	1195	6913	22402	-549
NOVEMBER	8936	126	210	336	7005	775	1239	2014	4991	24669	2267
DECEMBER	7480	49	217	266	9377	275	1070	1345	8032	23038	-1631

TABLE G-10

PETROLEUM PRODUCT STORAGE TANK CAPACITIES
AT MAJOR MARKETER AND MAJOR STORER FACILITIES
BY REGION AND BY TYPE FACILITY AT END OF YEAR

PRODUCT	NORTHERN CALIFORNIA	CENTRAL CALIFORNIA	SOUTHERN CALIFORNIA	STATE TOTAL	REFINING FACILITY	BULK TERMINAL	OTHER FACILITY
84							
MOTOR GASOLINES	12762	1284	15589	29635	21627	7384	624
AVIATION FUELS	2936	77	3845	6858	5524	1143	191
DISTILLATE FUELS	3958	649	8255	12862	7510	2285	3067
RESIDUALS, LOW SULFUR	5107	3359	32233	40699	1616	305	38778
RESIDUALS, HIGH SULFUR	3929	1081	7777	12787	11324	1042	421
TOTAL STORAGE	46706	11520	81337	139563	70361	15141	54060
85							
MOTOR GASOLINES	11816	977	15429	28222	20381	6722	1119
AVIATION FUELS	3296	82	3980	7358	5675	1454	229
DISTILLATE FUELS	3802	661	9329	13792	7648	2292	3852
RESIDUALS, LOW SULFUR	4117	3233	32765	40115	2015	173	37927
RESIDUALS, HIGH SULFUR	4278	622	8877	13777	12339	1012	426
TOTAL STORAGE	47509	11161	82925	141595	71347	14227	56021
86							
MOTOR GASOLINES	10417	698	14009	25124	17999	6081	3494
AVIATION FUELS	3153	58	3536	6747	5766	964	876
DISTILLATE FUELS	4183	596	9968	14747	8585	2276	12387
RESIDUALS, LOW SULFUR	4158	2604	29919	36681	1400	174	35110
RESIDUALS, HIGH SULFUR	3566	807	8967	13340	11800	1227	313
TOTAL STORAGE	42788	9868	64351	117007	72781	11212	33021

TABLE G-11A

ANNUAL CRUDE OIL PRODUCTION
AND TEOR FUEL USE BY MAJOR CRUDE OIL PRODUCERS
IN DESIGNATED OIL FIELDS
FOR YEAR 1984

	20 GRAVITY AND LESS (BARRELS)	TOTAL PRODUCTION (BARRELS)	NET PRODUCTION (BARRELS)	CRUDE OIL BURNED (BARRELS)	NATURAL GAS BURNED (MCF)	EQIVALENT CRUDE (BARRELS)
SAN JOAQUIN, EASTSIDE						
KERN BLUFF	195051	195051	170897	24154	0	24154
KERN FRONT	2624353	2624353	2288948	335405	340402	397026
KERN RIVER	48985506	49038554	38413451	10625103	6576621	11815686
POSO CREEK	1702633	1702633	1634936	67697	0	67697
OTHER EASTSIDE	7956969	8171627	6524769	1646858	144653	1673035
*TOTAL SAN JOAQUIN, EASTSIDE	61464512	61732218	49033001	12699217	7061676	13977598
SAN JOAQUIN, WESTSIDE						
BELRIDGE N. & S.	36119014	46215382	44288567	1926815	38953935	8978796
COALINGA	9353477	9999306	7819499	2179807	1604444	2470262
CYMRIC	5516029	5581941	5557749	24192	1915363	370934
LOST HILLS	2377301	5185376	5185376	0	1372222	248402
MCKITTRICK	3912276	4142091	3767641	374450	1580008	660475
MIDWAY-SUNSET	47128178	47919152	43710173	4208979	6376740	5363337
*TOTAL SAN JOAQUIN, WESTSIDE	104406275	119043248	110329005	8714243	51802712	18092206
LOS ANGELES BASIN						
NEWPORT, WEST	5244	5244	5244	0	0	0
WILMINGTON	33236456	39336581	39336581	0	722296	130740
YORBA LINDA	1990137	1997248	1997248	0	2235308	404655
OTHER L.A. BASIN	3549188	8281123	8273694	7429	517837	101164
*TOTAL LOS ANGELES BASIN	38781025	49620196	49612767	7429	3475441	636559
CENTRAL COAST						
CAT CANYON	4612551	4621921	4621921	0	149602	27072
OTHER CENTRAL COAST	12133308	12272909	10094626	2178283	3746038	2856417
*TOTAL CENTRAL COAST	16745859	16894830	14716547	2178283	3895640	2883489
UNDESIGNATED FIELDS						
ALL OTHER FIELDS	11680438	58544796	58544796	0	619071	112044
*TOTAL UNDESIGNATED FIELDS	11680438	58544796	58544796	0	619071	112044
*TOTAL YEAR 1984	233078109	305835288	282236116	23599172	66854540	35701896

TABLE G-11B

ANNUAL CRUDE OIL PRODUCTION
AND TEOR FUEL USE BY MAJOR CRUDE OIL PRODUCERS
IN DESIGNATED OIL FIELDS
FOR YEAR 1985

	20 GRAVITY AND LESS (BARRELS)	TOTAL PRODUCTION (BARRELS)	NET PRODUCTION (BARRELS)	CRUDE OIL BURNED (BARRELS)	NATURAL GAS BURNED (MCF)	EQIVALENT CRUDE (BARRELS)
SAN JOAQUIN, EASTSIDE						
KERN BLUFF	189961	189961	147298	42663	0	42663
KERN FRONT	2628774	2628774	2258456	370318	293980	423533
KERN RIVER	51304532	51429334	43549176	7880158	27308195	12823865
POSO CREEK	1328179	1328179	1308316	19863	20082	23495
OTHER EASTSIDE	7879549	8052532	7048332	1004200	4837231	1879897
*TOTAL SAN JOAQUIN, EASTSIDE	63330995	63628780	54311578	9317202	32459488	15193453
SAN JOAQUIN, WESTSIDE						
BELRIDGE N. & S.	40845789	53996648	51707786	2288862	45102074	10453870
COALINGA	10693231	11312505	9542537	1769968	5860148	2830845
CYMRIC	6206162	6266983	6205657	61326	2779076	564419
LOST HILLS	2407982	4920836	4920836	0	1909024	345582
MCKITTRICK	3893538	4108413	3727938	380475	3248494	968543
MIDWAY-SUNSET	52328242	53138904	48362633	4776271	8393743	6295783
*TOTAL SAN JOAQUIN, WESTSIDE	116374944	133744289	124467387	9276902	67292559	21459042
LOS ANGELES BASIN						
NEWPORT, WEST	3814	3814	3814	0	0	0
WILMINGTON	33421889	39891854	39891854	0	560052	101370
YORBA LINDA	1846726	1855108	1855108	0	2496216	451891
OTHER L.A. BASIN	3417283	7836491	7836491	0	124886	22600
*TOTAL LOS ANGELES BASIN	38689712	49587267	49587267	0	3181154	575861
CENTRAL COAST						
CAT CANYON	4347829	4355867	4355867	0	980827	177546
OTHER CENTRAL COAST	12268161	12451977	10415156	2036821	4390391	2831598
*TOTAL CENTRAL COAST	16615990	16807844	14771023	2036821	5371218	3009144
UNDESIGNATED FIELDS						
ALL OTHER FIELDS	11740184	59423132	59423132	0	5232289	947202
*TOTAL UNDESIGNATED FIELDS	11740184	59423132	59423132	0	5232289	947202
*TOTAL YEAR 1985	246751825	323191312	302560387	20630925	113536708	41184702

TABLE G-11C

ANNUAL CRUDE OIL PRODUCTION
AND TEOR FUEL USE BY MAJOR CRUDE OIL PRODUCERS
IN DESIGNATED OIL FIELDS
FOR YEAR 1986

	20 GRAVITY AND LESS (BARRELS)	TOTAL PRODUCTION (BARRELS)	NET PRODUCTION (BARRELS)	CRUDE OIL BURNED (BARRELS)	NATURAL GAS BURNED (MCF)	EQIVALENT CRUDE (BARRELS)
SAN JOAQUIN, EASTSIDE						
KERN BLUFF	129811	129811	95118	34693	0	34693
KERN FRONT	1470176	1470176	1184634	285542	167689	315886
KERN RIVER	47495426	47600561	43003706	4596855	23084673	8775959
POSO CREEK	998667	998667	971016	27651	133711	51850
OTHER EASTSIDE	8722120	8817506	7886247	931259	4963507	1829806
*TOTAL SAN JOAQUIN, EASTSIDE	58816200	59016721	53140721	5876000	28349580	11008194
SAN JOAQUIN, WESTSIDE						
BELRIDGE N. & S.	45620275	58338335	57001021	1337314	51246018	10614587
COALINGA	10896648	11416784	9628432	1788352	4470743	2597706
CYMRIC	6883099	6978283	6869470	108813	1537586	387146
LOST HILLS	2281074	4720790	4720790	0	2003691	362715
MCKITTRICK	3283927	3571306	3348781	222525	469635	307527
MIDWAY-SUNSET	54146580	54824711	50331385	4493326	8359963	6006717
*TOTAL SAN JOAQUIN, WESTSIDE	123111603	139850209	131899879	7950330	68087636	20276398
LOS ANGELES BASIN						
WILMINGTON	29881184	35462308	35462308	0	405108	73324
YORBA LINDA	1648105	1648105	1648105	0	2373803	429730
OTHER L.A. BASIN	3175880	6865803	6865803	0	366172	66283
*TOTAL LOS ANGELES BASIN	34705169	43976216	43976216	0	3145083	569337
CENTRAL COAST						
CAT CANYON	3247642	3250633	3250633	0	807609	146193
OTHER CENTRAL COAST	10545005	10655388	9342224	1313164	2108346	1694806
*TOTAL CENTRAL COAST	13792647	13906021	12592857	1313164	2915955	1840999
UNDESIGNATED FIELDS						
ALL OTHER FIELDS	9651035	56902702	56902702	0	4872688	882110
*TOTAL UNDESIGNATED FIELDS	9651035	56902702	56902702	0	4872688	882110
*TOTAL YEAR 1986	240076654	313651869	298512375	15139494	107370942	34577038

TABLE G-12A

ANNUAL CRUDE OIL PRODUCTION BY ALL PRODUCERS
AND TEOR FUEL USE BY MAJOR CRUDE OIL PRODUCERS
IN DESIGNATED OIL FIELDS
FOR YEAR 1984

	20 GRAVITY AND LESS (BARRELS)	TOTAL PRODUCTION (BARRELS)	NET PRODUCTION (BARRELS)	CRUDE OIL BURNED (BARRELS)	NATURAL GAS BURNED (MCF)	EQIVALENT CRUDE (BARRELS)
SAN JOAQUIN, EASTSIDE						
KERN BLUFF	259879	259879	235725	24154	0	24154
KERN FRONT	2823705	2823705	2488300	335405	340402	397026
KERN RIVER	49305591	49358639	38697499	10661140	6576621	11851723
POSO CREEK	2059660	2059660	1911384	148276	0	148276
OTHER EASTSIDE	8871664	9299594	7652736	1646858	144653	1673035
*TOTAL SAN JOAQUIN, EASTSIDE	63320499	63801477	50985644	12815833	7061676	14094214
SAN JOAQUIN, WESTSIDE						
BELRIDGE N. & S.	36242156	47804722	45877907	1926815	38953935	8978796
COALINGA	9427113	10075101	7895294	2179807	1604444	2470262
CYMRIC	5567828	5658797	5634605	24192	1915363	370934
LOST HILLS	2429727	5237802	5237802	0	1372222	248402
MCKITTRICK	3937372	4178923	3804473	374450	1623208	668287
MIDWAY-SUNSET	49897804	50841540	46627089	4214451	6376740	5368809
*TOTAL SAN JOAQUIN, WESTSIDE	107502000	123796885	115077170	8719715	51845912	18105490
LOS ANGELES BASIN						
NEWPORT, WEST	1159986	1175283	1175283	0	0	0
WILMINGTON	34422226	40634629	40634629	0	722296	130740
YORBA LINDA	2007665	2014776	2014776	0	2235308	404655
OTHER L.A. BASIN	4151395	9179562	9172133	7429	517837	101164
*TOTAL LOS ANGELES BASIN	41741272	53004250	52996821	7429	3475441	636559
CENTRAL COAST						
CAT CANYON	4985244	4994614	4994614	0	149602	27072
OTHER CENTRAL COAST	12693181	12844200	10665917	2178283	3746038	2856417
*TOTAL CENTRAL COAST	17678425	17838814	15660531	2178283	3895640	2883489
UNDESIGNATED FIELDS						
ALL OTHER FIELDS	16472080	123434492	123431177	3315	619071	115359
*TOTAL UNDESIGNATED FIELDS	16472080	123434492	123431177	3315	619071	115359
*TOTAL YEAR 1984	246714276	381875918	358151343	23724575	66897740	35835111

TABLE G-12B

ANNUAL CRUDE OIL PRODUCTION BY ALL PRODUCERS
AND TEOR FUEL USE BY MAJOR CRUDE OIL PRODUCERS
IN DESIGNATED OIL FIELDS
FOR YEAR 1985

	20 GRAVITY AND LESS (BARRELS)	TOTAL PRODUCTION (BARRELS)	NET PRODUCTION (BARRELS)	CRUDE OIL BURNED (BARRELS)	NATURAL GAS BURNED (MCF)	EQIVALENT CRUDE (BARRELS)
SAN JOAQUIN, EASTSIDE						
KERN BLUFF	252013	252013	209350	42663	0	42663
KERN FRONT	2818439	2818439	2448121	370318	293980	423533
KERN RIVER	51537281	51662083	43781925	7880158	27308195	12823865
POSO CREEK	1770967	1770967	1751104	19863	20082	23495
OTHER EASTSIDE	8806721	9206200	8202000	1004200	4837231	1879897
*TOTAL SAN JOAQUIN, EASTSIDE	65185421	65709702	56392500	9317202	32459488	15193453
SAN JOAQUIN, WESTSIDE						
BELRIDGE N. & S.	40905117	56409035	54120173	2288862	45102074	10453870
COALINGA	10763980	11385258	9615290	1769968	5860148	2830845
CYMRIC	6263787	6340803	6279477	61326	2779076	564419
LOST HILLS	2471410	4984264	4984264	0	1909024	345582
MCKITTRICK	3915514	4142100	3761625	380475	3248494	968543
MIDWAY-SUNSET	54066509	55046411	50270140	4776271	8393743	6295783
*TOTAL SAN JOAQUIN, WESTSIDE	118386317	138307871	129030969	9276902	67292559	21459042
LOS ANGELES BASIN						
NEWPORT, WEST	1024187	1039034	1039034	0	0	0
WILMINGTON	34651965	41192335	41192335	0	560052	101370
YORBA LINDA	1881887	1890269	1890269	0	2496216	451891
OTHER L.A. BASIN	3864505	8568629	8568629	0	124886	22600
*TOTAL LOS ANGELES BASIN	41422544	52690267	52690267	0	3181154	575861
CENTRAL COAST						
CAT CANYON	4732051	4744587	4744587	0	980827	177546
OTHER CENTRAL COAST	12826675	13014860	10978039	2036821	4390391	2831598
*TOTAL CENTRAL COAST	17558726	17759447	15722626	2036821	5371218	3009144
UNDESIGNATED FIELDS						
ALL OTHER FIELDS	18326649	120157097	120157097	0	5232289	947202
*TOTAL UNDESIGNATED FIELDS	18326649	120157097	120157097	0	5232289	947202
*TOTAL YEAR 1985	260879657	394624384	373993459	20630925	113536708	41184702

TABLE G-12C

ANNUAL CRUDE OIL PRODUCTION BY ALL PRODUCERS
AND TEOR FUEL USE BY MAJOR CRUDE OIL PRODUCERS
IN DESIGNATED OIL FIELDS
FOR YEAR 1986

	20 GRAVITY AND LESS (BARRELS)	TOTAL PRODUCTION (BARRELS)	NET PRODUCTION (BARRELS)	CRUDE OIL BURNED (BARRELS)	NATURAL GAS BURNED (MCF)	EQIVALENT CRUDE (BARRELS)
SAN JOAQUIN, EASTSIDE						
KERN BLUFF	167174	167174	132481	34693	0	34693
KERN FRONT	2195017	2195017	1909475	285542	167689	315886
KERN RIVER	47669218	47774353	43177498	4596855	23084673	8775959
POSO CREEK	1220586	1220586	1192935	27651	133711	51850
OTHER EASTSIDE	9506990	9801901	8870642	931259	4963507	1829806
*TOTAL SAN JOAQUIN, EASTSIDE	60758985	61159031	55283031	5876000	28349580	11008194
SAN JOAQUIN, WESTSIDE						
BELRIDGE N. & S.	46283760	63048119	61710805	1337314	51246018	10614587
COALINGA	10922810	11445007	9656655	1788352	4470743	2597706
CYMRIC	6929727	7035004	6926191	108813	1537586	387146
LOST HILLS	2322453	4762169	4762169	0	2003691	362715
MCKITTRICK	3309106	3612035	3389510	222525	469635	307527
MIDWAY-SUNSET	55898802	56759421	52266095	4493326	8359963	6006717
*TOTAL SAN JOAQUIN, WESTSIDE	125666658	146661755	138711425	7950330	68087636	20276398
LOS ANGELES BASIN						
NEWPORT, WEST	881645	895528	895528	0	0	0
WILMINGTON	30909170	36567643	36567643	0	405108	73324
YORBA LINDA	1674660	1674660	1674660	0	2373803	429730
OTHER L.A. BASIN	3601190	7540877	7540877	0	366172	66283
*TOTAL LOS ANGELES BASIN	37066665	46678708	46678708	0	3145083	569337
CENTRAL COAST						
CAT CANYON	3530067	3533058	3533058	0	807609	146193
OTHER CENTRAL COAST	11135660	11250498	9937334	1313164	2108346	1694806
*TOTAL CENTRAL COAST	14665727	14783556	13470392	1313164	2915955	1840999
UNDESIGNATED FIELDS						
ALL OTHER FIELDS	14952424	109214447	109214447	0	4872688	882110
*TOTAL UNDESIGNATED FIELDS	14952424	109214447	109214447	0	4872688	882110
*TOTAL YEAR 1986	253110459	378497497	363358003	15139494	107370942	34577038

TABLE G-13

WORKING STORAGE TANK CAPACITY AT CALIFORNIA REFINERIES
ON JANUARY FIRST EACH YEAR
(THOUSANDS OF BARRELS)

	NORTH	CENTRAL	SOUTH	STATEWIDE	COMPLEX	HYDRO SKIMMING	TOPPING
1986							
CRUDE OIL	13051	2180	13652	28883	25133	1411	2059
MOTOR GASOLINES	4851	540	5645	11036	9864	765	212
GASOLINE, BLENDING COMPONENTS	4425	517	6991	11933	10434	577	189
MIDDLE DISTILLATES	2490	950	4574	8014	6393	649	677
RESIDUAL FUEL OILS	5207	531	6271	12009	10685	833	491
ASHPALT AND ROAD OILS	734	1133	772	2639	634	492	1513
LUBRICATING OILS	1817	363	69	2249	1886	0	363
LIQUIFIED REFINERY GASES	812	6	700	1518	1509	7	0
AVIATION FUELS	2007	81	2855	4943	4730	174	39
OTHER STORAGE	2866	636	15117	18619	17664	811	137
1987							
CRUDE OIL	11906	2134	12950	26990	23284	1241	2185
MOTOR GASOLINES	4567	644	5162	10373	9099	867	212
GASOLINE, BLENDING COMPONENTS	4364	617	7821	12802	11206	674	189
MIDDLE DISTILLATES	2530	879	4587	7996	6423	546	732
RESIDUAL FUEL OILS	4653	489	5826	10968	9759	697	512
ASHPALT AND ROAD OILS	428	1158	846	2432	328	566	1538
LUBRICATING OILS	1519	373	69	1961	1588	0	373
LIQUIFIED REFINERY GASES	791	71	667	1529	1456	72	0
AVIATION FUELS	1852	96	2785	4733	4492	202	39
OTHER STORAGE	4763	2782	14451	21996	18895	2957	137

SOURCE: PIIRA SUBMITTALS.
PIIRA FORM: DOE/EIA-820 ANNUAL REFINERY REPORT