CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET, MS-20
SACRAMENTO, CA 95815-5512

October 1996

Dear Interested Party:

We are pleased to provide you with a copy of the report ***Modeling Competitive Energy Markets In California An Analysis of Restructuring*** prepared by LCG Consulting for the California Energy Commission. LCG has spent much of the last year and a half following the restructuring debate and creating a computer model which attempts to accurately emulate the bidding protocols of the proposed Western Energy Power Exchange and the dispatch and commitment procedures of the Independent System Operator.

We welcome your comments on the report. Written comments may be sent by mail or via the Internet to the following email address: erao@energy.ca.gov. The comments we receive will be incorporated into a follow-up document to the report. We are planning to schedule several meetings for reviewers of the report with LCG and Commission staff. These meetings will provide an informal setting for reviewers to ask questions of and provide feedback to LCG on the report. We are planning to hold these meetings during the last week of October. The meetings will occur at either the Energy Commission in Sacramento or at LCG's Office in Los Altos. If you are interested in participating in such a meeting, please let me know by October 24th which day or days you would be available and a preference for location.

Should you have any questions on the report, or on scheduling a meeting with LCG and Commission staff to go over the report, please call me at (916) 654-4859.

Sincerely,

Richard Grix
Electricity Resource Assessment Office
California Energy Commission

MODELING COMPETITIVE ENERGY MARKETS

IN CALIFORNIA:

ANALYSIS OF RESTRUCTURING

October 11, 1996

(Revision 1)

Prepared for

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§1. MODELING THE COMPETITIVE POWER MARKETS

1.1 Utility Restructuring

The electric utility industry is undergoing a profound change due to deregulation. Competition is reshaping the nature of electricity generation, transmission and distribution. Anticipating these changes, the California Energy Commission (CEC) wants to examine the impact of restructuring on a wide variety of issues related to the electricity industry. CEC is also concerned about the implications to the industry's structure from potential reforms in the California regulatory environment.

In recognition of the need for new power market modeling capabilities to analyze the impacts of deregulation, CEC contracted with LCG Consulting (LCG) to address a list of policy issues related to economic efficiency, market power, environmental concerns, and other potential impacts of the proposed restructuring of California utilities.

In response to utility restructuring in the US and abroad, LCG has developed the Network Power Model (NPM) which is capable of analyzing competition in the electricity market. The NPM program provides a new approach to multi-area analysis with simultaneous optimization of both the generation and delivery of electric power.

Since 1992, the California Public Utilities Commission (CPUC) has been developing a policy to restructure the electric utility industry. Under its preferred policy, the CPUC would end the practice of a single utility providing all electric services within its service area, and introduce choice and competition to provide consumers with more economical electricity services. Implementation of this policy will require creation of new organizations to operate the physical electric system and the financial market for electricity.

The CPUC restructuring policy applies primarily to the regulated utilities in California, although a similar policy to open the access to the wholesale transmission system is being advanced nationwide by the Federal Energy Regulatory Commission (FERC). Both federal and state policies were triggered by provisions of the federal Energy Policy Act of 1992, intended to introduce greater market competition to the energy industry as a means of improving efficiency and reducing rates charged to the customers.

On December 20, 1995, the California Public Utility Commission issued its decision that encourages competition among the suppliers of electricity, offers the retail customers choice and flexibility in energy suppliers, and reforms the manner in which the investor-owned utilities (IOU) will be regulated. To develop this new market structure, the Commission will require the establishment of a statewide Independent System Operator (ISO) and a power pool called Western Electric Power Exchange (WEPEX or simply PX).

On September 24, 1996, Pete Wilson, the Governor of California, signed Assembly Bill 1890, a broad legislation that will open the state's electricity market to competition. The California law provides that all generators of electricity, the three investor-owned utilities and any others such as independent power producers (IPP), sell their electricity into WEPEX. The state's IOUs, municipal utilities (muni) and cooperatives will continue to distribute power to customers and continue to be regulated. During the transition period, the bill will include a "competitive transition charge" (CTC) to enable utilities to pay down investments made under state regulation.

Independent System Operator (ISO)

The ISO will provide non-discriminatory open access to the transmission grid while preserving reliability and achieving the lowest total cost for all users of the transmission system. It will manage the current transmission system but it will not own the system or be responsible for maintenance. Ownership and maintenance will stay with the investor-owned utilities. The ISO will have the final authority to correct transmission congestion that may affect the choice of which generators will actually be dispatched.

Some of the functions of the ISO are listed below:

- Operate transmission system,
- Maintain reliability,
- Provide open and nondiscriminatory services and access to transmission,
- Procure ancillary services,
- Coordinate day-ahead and hour-ahead scheduling and balancing,
- Administer congestion contracts,
- Administer billing and settlement system.

Power Exchange (PX)

The Power Exchange is intended to establish a competitive, wholesale power pool for electric generation. The power exchange will act to match supply bids with bids from utilities, power marketers, and others. The power exchange will rank the bids on a least-cost basis and determine a preferred schedule for delivery of power to the ISO. The PX will be separate and independent from the ISO, and will have no financial interest in any source of generation.

The PX is to develop a visible spot market that will determine electricity prices and will be open to all suppliers, including Out-of-State suppliers and municipal utilities. It is expected to enhance efficiency by introducing competitive pressures into the generation sectors. It will determine on a forecast basis the needs of those California customers with electric loads that are not represented by brokers or marketers. As a market institution, it will function as a clearinghouse by providing an auction for generation with hourly or half-hourly price signals aimed at immediate users as well as long-term investors.

During a five-year transition period, the California IOUs are required to purchase all their energy requirements to serve their customers from the power exchange. They are also required to sell all their generation into the power exchange until a market value has been established for each of their generation assets. Municipalities, independent power producers, Out-of-State producers and other public utilities may participate in the power exchange, although purchasing from and selling through the exchange are voluntary for them.

The functions of the Power Exchange include the following:

- Establish preferred schedule of generation offers and demand bids,
- Administer transparent and nondiscriminatory bidding protocols,
- Establish necessary information links to ISO and market participants.

Although the PX and the ISO will be independent entities, the ISO will coordinate the day-ahead scheduling and balancing for all users of the grid, making use of tentative PX bids for generation and loads and the bilateral participant's bids for increments and decrements of generation and demand in order to redispatch the system. The ISO also determines the locational marginal costs that define the locational market clearing price for the PX and the price of transmission use for bilateral transactions.

1.2 Summary of the UPLAN Study and Report Organization

The objective of this study is to investigate the environmental and economic consequences of electric utility long-term supply plans. The Commission recognizes the important role of utility simulation models in examining how well the new competitive market is operating and whether consumers are receiving the benefits of greater efficiency, or if there is excessive market power being exerted by certain players in the market. Since the framework of the restructuring of the utilities in California is still under discussion, the major effort in this study was directed to develop an appropriate methodology for analyzing different restructuring scenarios of the California utilities. At this stage, the results of the study are tentative because of the many unknown factors affecting the future electricity market.

The remainder of this report is organized into three major sections. Section 2 describes the Western System Coordinating Council (WSCC) database, the three California IOUs, the California municipal utilities and the transmission network. It also includes documentation of data requirements and the source of the data used in the model's restructured scenarios.

Section 3 describes the methodology used in analyzing the data and contains the results of the main study. It includes modeling of ISO/PX operation of the three IOUs and comparison of the operating costs of SDG&E, SCE and PG&E within the proposed regional power market configuration. We provide the forecasted sellers' and buyers' market clearing prices for each of the proposed four zones under ISO/PX control and determine the revenue and the generation costs of PG&E, SCE and SDG&E . We also analyze the impact of the municipal utilities joining the ISO/PX. This involves a comparison of market clearing prices for IOUs and nodal spot prices for municipal utilities, and assessment of the impact of municipal participation on market clearing price.

Also contained in section 3 is an analysis of the potential for new market entrants and the ability of the large IOUs to exert market power, as well as a comparison of power plant emissions occurring in the competitive restructured future.

The Network Power Model (NPM) of UPLAN-E, an Optimal Power Flow (OPF) model with a built-in multi-area production cost, AC load flow and a power market model for bidding was used for this study. Appendix A describes the UPLAN methodology for simulating the operation of the PX and the ISO, the market bidding mechanics and the process for determining the market clearing price. Also described is the UPLAN process for emulating the transmission network, the accounting of transmission congestion costs, and the model's dispatch procedure.

§ 2. MULTI-AREA REGIONAL DATABASE

The California utilities are members of the Western System Coordinating Council (WSCC) and are electrically linked to the regional resources that make up the WSCC through an extensive network of transmission lines. Analysis of the competitive power market in California requires simulation of the entire WSCC region.

LCG Consulting has developed a relational database (PLATO) of plants, loads, assets and transmission lines for the existing electric utility resources of all the North American Electric Reliability Council (NERC) regions of the United States for regional analysis and power market studies. The major source of data for this study has been the PLATO database and the references cited in this section.

2.1 Western System Coordinating Council (WSCC) Database

The WSCC represents a complex regional system with a large number of investor-owned and municipal utilities. The region encompasses an area of nearly 1.8 million square miles of highly interconnected transmission network spanning across western United States. The strength of the transmission network has already fostered a significant interaction of operations and interchange of energy between many of the members of the WSCC, and will continue to support the on-going operations that will take place when competition comes to the marketing of energy in California.

The US service territory extends from the Canadian border in the north, south to the Mexican border, and includes all or portions of the fourteen western states. Transmission lines span long distances from the Pacific Northwest with abundant hydroelectric resources to the Southwest with large coal-fired and nuclear facilities.

In this study, the region outside California is divided into four major demand areas, which reflect distinct geographic and climatic conditions. Southern Nevada, the

Pacific Northwest, the Rocky Mountain Power Area and Arizona/New Mexico are represented as separate areas. The regions associated with Western Canada and Mexico are represented only in terms of their net surplus resources available for sale and import to the United States. Sufficient detail of the northwest transmission network has been developed to capture the impact of transfer interface limits between the states of Washington, Oregon, Montana, Idaho, Southern Nevada, Arizona/New Mexico and California.

To meet the needs of this study, the major emphasis has been placed on detailed representation of the California utilities. In California, Pacific Gas and Electric Company, Southern California Edison and San Diego Gas and Electric have been modeled as a single ISO control area.

Utilities, such as Sacramento Municipal Utility District, LADWP, Northern California (all municipal and small utilities in northern California) and Southern California (all remaining loads in southern California) are represented either as non-participant utilities or as independent power generators. We have also studied a case where all California utilities participate in the pool. To do this, the status of all utilities were redefined from a utility not participating in the pool to one participating using UPLAN's participation option.

2.2 Transmission Network

As of 1995, the WSCC region had more than one hundred thousand miles of transmission lines. These lines have been designed and constructed to provide a network of connections enabling the delivery and interchange of electricity between the major demand areas. We have specified the major transmission that interconnect the demand areas represented in this study.

Over forty percent of the WSCC transmission lines are rated at 161 kV or less. These lower voltage lines are not generally used to transfer large amounts of energy between the interconnected areas of the WSCC, and as such are only indirectly represented in the network configuration as equivalent transfer paths. The remaining lines, 230 kV and above, were analyzed to identify the major transmission paths linking the demand areas modeled for the WSCC regions. To reduce the computational burden, some of these transmission paths were modeled as composite lines connecting major transmission junctions (nodes) and equivalent electrical characteristics for the resistance and reactance parameters which control the physical flow were developed for these paths.

An equivalent WSCC transmission system was developed representing all major transmission lines and major interfaces that have been identified as having flow constraints. These constraints on flow have been externally developed, from WSCC detailed load flow studies under extreme conditions and from operating practices. The load flow in the equivalent system has been analyzed and compared to validate the equivalency.

For this study, the following interface capacities were used for the California area. These include the newly added transmission lines from Westwing to Marketplace and Marketplace to Adelanto.

	Max. Flow in MW to	
Interface	West/South	East/North
West of Colorado River (WOR)	9406	10000
East of Colorado River (EOR)	7365	10000
Southern California Import Transmission (SCIT)	17720	20000
South of Los Banos (Path 15)	3545	5000
California Oregon Interface (COI)	4880	3705

The UPLAN database includes a transmission table that includes the starting and ending nodes, transfer capabilities, electrical characteristics, ownership and location. This table also includes regional interface, nomogram, and composite path critical flow limits.

WSCC describes the path in terms of the transmission lines comprising the path and the area that are interconnected by the path. In this study, the above 5 interfaces are modeled and the ratings are expressed as a linear combination of the lines that makes up the path.

The interfaces designated in the ISO filing for trading include Palo Verde, El Dorado, Moenkopi, Four Corners, COB, the Nevada-Oregon Boarder, Mead, Sylmar, Donner Summit, Mirage, Silver Peak, Inyo, North Gila, Miguel, Control, and Imperial Valley. In this study eighty nodes including all the above interfaces are provided for trading . In Figure 2.1 we present a map of the major interconnections used in this study.

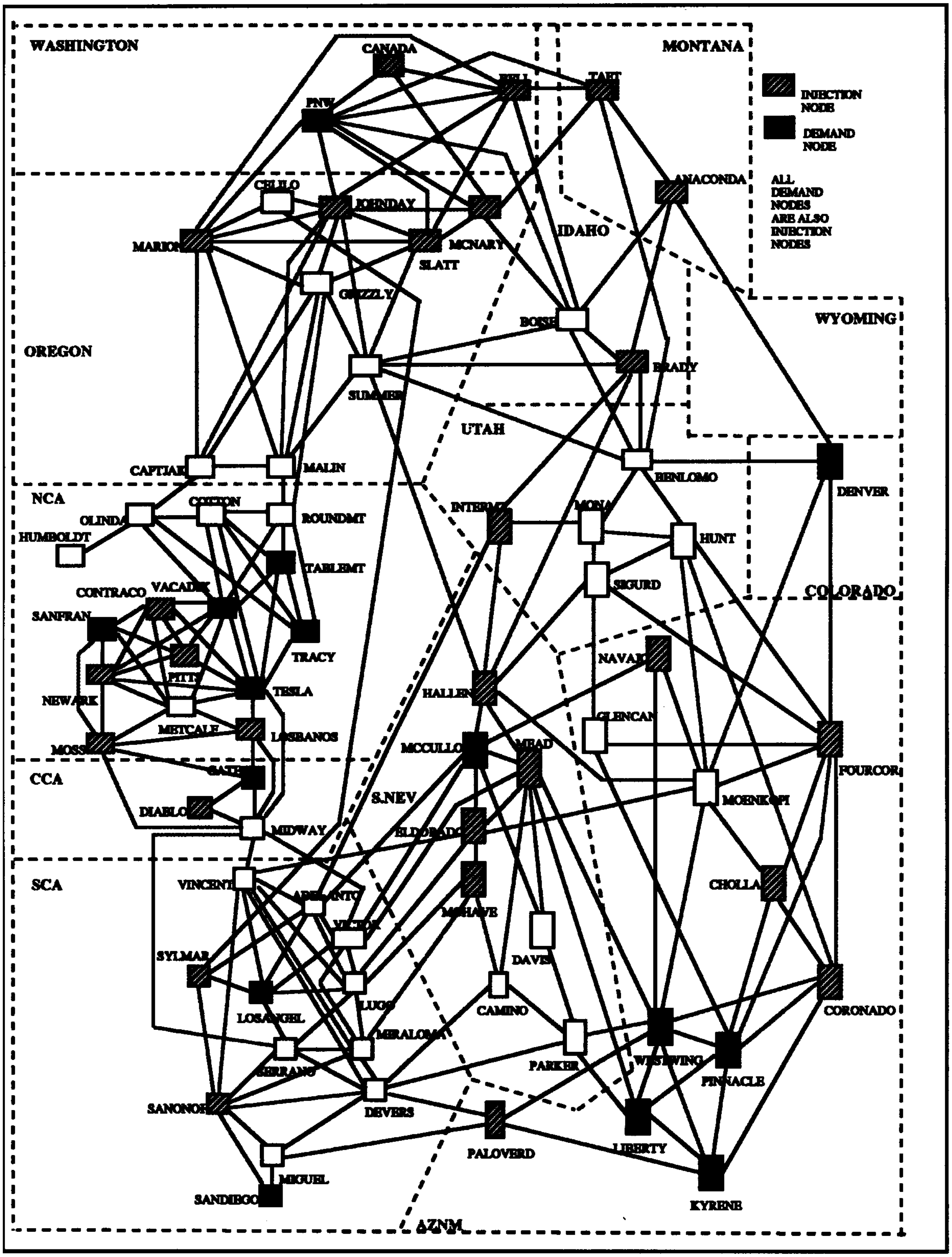
Figure 2.1 WSCC Equivalent Transmission Network and Interfaces

(See next page)

References:
1. Federal Energy Regulatory Commission Forms 1 and 2
2. Western System Coordinating Council (1995) Loads and Resources Report, OE-411.
3. Western System Coordinating Council (1995) Path Rating Catalogue.
4. Energy Information Administration (1995) Form EIA 412.

5. PLATO Database.

WSCC EQUIVALENT TRANSMISSION NETWORK



2.3 Peak and Energy Requirements

WSCC region has been divided into 14 demand areas (regions), four of these regions are outside California. California is divided into 10 demand areas, four of which are in the ISO control area and are hereinafter called zones. These demand areas generally correspond to the service territories of individual utilities. Within a demand area, a node (junction, bus) refers to a location where electricity is injected (by a generator) or withdrawn (by a customer) or a transmission junction (bus) such as a major sub-station. For each demand area sufficient detailed electricity demand, generation resources and transmission constraints data were developed.

Within California, Northern and Central California are divided into five demand areas; three for the PG&E service territory, one for the SMUD service territory, and the remaining Northern California entities. The ISO zones for Northern California are the City of San Francisco (Zone 1), Humboldt Bay (Zone 2) and the rest of the PG&E service area north of the Gates node. The Southern California (Zone 4) includes the rest of the PG&E area south of Gates and the service territories of SCE and SDG&E. Other California demand areas are Los Angeles Department of Water and Power, and the remaining Southern California entities. The Northwest Power Pool, the Rocky Mountain Power Area Southern Nevada and Arizona/New Mexico are identified as separate demand areas.

For each demand area, a load forecast is made, a chronological load shape is developed and a node is assigned for withdrawal of electricity. The chronological demand of electricity for each of the major WSCC areas was developed using regional peak and energy forecasts available from 1996 to 2007. Hourly profiles are required to determine the flows in the transmission network, generation and hourly market clearing prices. The following regions are represented in our study.

- *Pacific North West (UPLAN Region 5, Demand Area 9):* US Northwest Power Pool Area. Source of data is 1996 forecast of US Area I of WSCC.

- *PG&E Northern California (UPLAN Region 3, ISO Zone 3):* Includes Lassen MUD, PG&E, Port of Oakland, Shasta PUD, Shelter Cove, Tuolumne CPPA, Truckee Donner PUD, CVP.

- *San Francisco (UPLAN Region 1, Demand Area 1, ISO Zone 1):* San Francisco loads and resources. Source of data is CEC.

- *Humboldt (UPLAN Region 2, Demand Area 2, ISO Zone 2):* Humboldt county loads and resources.

- *Northern California (UPLAN Region 6, Demand Area 4):* Includes loads and resource for Redding, MID, TID, NCPA, Santa Clara and adjustments for loads served by others. Peaks were adjusted 97% for non-coincidence demand.

- *SMUD (UPLAN Region 10, Demand Area 4):* Sacramento Municipal Utility District loads and resources.

- *SCE, SDG&E, and PG&E Southern California Loads (UPLAN Region 4, ISO Zone 4, Demand Areas 6, 8 and 4 respectively):* Service Territory Loads for Southern California Edison, San Diego Gas and Electric and part of Pacific Gas and Electric Loads assigned to ISO Zone 4**.**

- *Southern California (UPLAN Region 12, Demand Area 7):* Includes loads and resource for Burbank, Glendale, Pasadena, Imperial Irrigation District and credits for miscellaneous loads. The data for this area were obtained from California Energy Commission.

- *LADWP & CDWR (UPLAN Region 12, Demand Region 5):* Loads for Los Angeles Department of Water and Power and California Department of Water.

- *Southern Nevada (UPLAN Region 8, Demand Area 12):* Loads and resources for Southern Nevada as represented in 1996 forecast of Area IV of WSCC. This load was adjusted for CEC California Service Territory Loads.

- *Arizona and New Mexico (UPLAN Region 7, Demand Area 10):* Loads and resources for Arizona and New Mexico Power area as represented in 1996 forecast of Area III of WSCC.

- *Rocky Mountain Power Pool (UPLAN Region 8, Demand Area 12):* Loads and resources for Rocky Mountain Power Pool as represented in 1996 forecast of Area II of WSCC.

- *Western Canada and Mexico:* These two areas have been represented only in terms of their net surplus resources available for sale and import to the United States.

Although UPLAN-E has the capability to model multi-level demand bidding, the demand bid in this study is assumed to be at 160$/MWh in 1996 dollars. Demand-side management programs beyond what had already been incorporated in the load forecast were not considered.

We have used the California Energy Commission Load Forecasts contained in Tables 6-2 and 6-3 (November 1995, p. 82-83) of the 1994 Electricity Report for developing loads for each zone modeled within California. For areas outside California, the WSCC forecast was used. These load forecasts were aggregated and hourly load shapes were developed for the adjusted loads.

The peak and energy forecast for each of the areas modeled in UPLAN for this study is presented in Table 2.3. This forecast includes only distribution losses. The transmission losses are calculated by the UPLAN load flow program and added automatically to the total demand at the distribution buses.

References:

1. “Coordinated Bulk Power Supply Program 1994-2004”. Replies to the United States Department of Energy Form OE-411 which requests information from the Regional Reliability Councils on Coordinated Regional Bulk Power Supply Programs. April 1, 1995.

2. The 1994 Electricity Report (ER94). California Energy Commission P300-95-002. Nov. 1995, Tables 6-2, 6-3.

3. Federal Energy Regulatory Commission Forms 1 and 2 (Annual Report of Major Electric Utilities, licensees and Others).

4. Western System Coordinating Council (1995)   Loads and Resources Report, OE- 411.

5. Common Forecasting Methodology 10 Reports (Electric Supply Forms) for California utilities.

6. California Energy Commission Staff and reports for specific California utilities, specially for various years and California Energy Commission.

7. PLATO and UPLAN Databases.

Table 2.3 Area Demand and Energy for WSCC Region

Northern California

Area	San Francisco		Humboldt		PG&E Zone 3		SMUD		No Cal Others		Total	
Year	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
1996	1138	5983	80	399	10396	56100	2411	9613	1842	8951	**15867**	**81046**
1997	1148	6035	81	404	10597	57185	2461	9813	1883	9150	**16170**	**82587**
1998	1171	6156	82	409	10762	58076	2508	10000	1922	9341	**16445**	**83982**
1999	1182	6214	84	419	10969	59192	2555	10187	1911	9289	**16701**	**85301**
2000	1191	6261	85	424	11196	60417	2596	10351	1993	9687	**17061**	**87140**
2001	1197	6293	86	429	11356	61283	2656	10590	2058	10003	**17353**	**88597**
2002	1200	6308	88	439	11538	62262	2715	10825	2102	10215	**17643**	**90050**
2003	1204	6329	89	444	11742	63365	2774	11061	2147	10433	**17956**	**91632**
2004	1207	6345	90	449	11909	64266	2832	11292	2193	10660	**18231**	**93012**
2005	1210	6361	92	459	12100	65297	2863	11415	2238	10877	**18503**	**94410**
2006	1214	6382	93	464	12305	66401	2922	11651	2288	11122	**18822**	**96020**

Southern California

Area	PG&E Zone 4		So Cal Edison		LADWP & CDWR		San Diego G&E		So Cal Others		Total	
Year	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
1996	4975	27047	18661	95014	6519	35189	3308	17414	1453	6262	**34916**	**180927**
1997	5066	27542	19069	97092	6616	35710	3366	17722	1489	6415	**35606**	**184481**
1998	5146	27979	19547	99528	6771	36547	3427	18041	1525	6569	**36416**	**188665**
1999	5103	27744	19137	97438	6875	37110	3351	17642	1562	6731	**36029**	**186665**
2000	5294	28781	19594	99766	6999	37780	3425	18031	1596	6876	**36908**	**191233**
2001	5414	29436	19986	101761	7093	38287	3513	18495	1628	7013	**37634**	**194991**
2002	5494	29871	21353	108723	7192	38821	3776	19881	1659	7149	**39476**	**204446**
2003	5585	30361	21736	110670	7287	39330	3854	20293	1691	7286	**40152**	**207941**
2004	5658	30760	22153	112793	7394	39907	3944	20763	1719	7405	**40867**	**211629**
2005	5742	31216	22578	114957	7496	40458	4037	21253	1753	7555	**41605**	**215439**
2006	5831	31702	22956	116884	7592	40977	4131	21749	1753	7555	**42264**	**218868**

Out-of-State

	Northwest PP		Rocky Mountain		Arizona/N. Mexico		So Nevada		Total	
Year	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
1996	38479	221426	7282	43130	14088	72836	3132	14028	**62981**	**351420**
1997	39210	225631	7420	43947	14342	74149	3186	14270	**64158**	**357997**
1998	39955	229922	7561	44782	14600	75483	3240	14512	**65356**	**364699**
1999	40714	234289	7705	45635	14863	76843	3295	14758	**66577**	**371525**
2000	41487	238737	7851	46500	15130	78223	3351	15009	**67819**	**378469**
2001	42277	243279	8000	47382	15403	79635	3408	15264	**69088**	**385560**
2002	43079	247896	8152	48282	15680	81067	3466	15524	**70377**	**392769**
2003	43897	252606	8307	49200	15962	82525	3525	15789	**71691**	**400119**
2004	44732	257406	8465	50136	16249	84008	3585	16057	**73031**	**407608**
2005	45582	262298	8626	51090	16542	85523	3646	16330	**74396**	**415242**
2006	46448	267283	8790	52061	16840	87064	3708	16608	**75786**	**423016**

2.4 Supply System Overview

The WSCC region includes a wide variety of generating plants such as coal, gas, nuclear, geothermal, solar, wind turbines, hydroelectric, and other non-traditional resources. Hydroelectric facilities constitute a significant part of the resources available to serve the demand, especially in the Pacific Northwest and Northern California. The energy available from these resources depends greatly on the availability of water. Since a chronological dispatch simulation has no long-term foresight regarding the appropriate times for the operation of hydro units, it is necessary to schedule the hourly operation. UPLAN's hydro scheduler is used to preschedule the hydro units to minimize the total operating costs for each year of the study based on average hydro conditions.

A number of thermal resources in the WSCC, nuclear stations, geothermal plants, and qualified facilities (QFs), are dispatched on a must-run basis. A variety of reasons require plants to operate at certain levels to meet contractual requirements, operating constraints or loading conditions.

The remaining thermal plants are operated on an economic basis. These units are assumed to form the core of the supply offers to the Power Exchange. The thermal plants are generally identified by fuel usage and other operating costs. Coal fired units constitute very large generating stations operating at relatively low costs and are generally operated as base load facilities. Efficient gas and oil fired stations are generally operated as load following or cycling facilities, and have higher costs. The highest cost units, using gas and oil, are used for peaking service and are generally run only for a short period of time to meet the highest loads during the day and are designated as ”quick start units”.

The supply-side data representing the Western Systems Coordinating Council US Systems includes resources in the following four WSCC areas:

· *Area 1* - Northeast Power Pool,

· *Area II* - Rocky Mountain Power Area,

· *Area III* - Arizona/New Mexico Power Area, and

· *Area IV* - California/Southern Nevada Power Area.

The data of California includes resources owned or controlled by the five major individual California utilities, i.e., Southern California Edison Co. (SCE), Pacific Gas and Electric Co. (PG&E), San Diego Gas and Electric Co. (SDG&E), Los Angeles Department of Water and Power (LADWP), and Sacramento Municipal Utility District (SMUD). Each generator in the UPLAN database is assigned an injection node and a demand node.

For some cases, where the loads of smaller utilities could not be separated from the loads of major utilities' service territory loads, the resources of these utilities have been included in the primary utility's supply database. In particular, SCE's generator base includes units for Burbank, Glendale and Pasadena; PG&E's supply file includes units for Modesto Irrigation District (MID), Turlock Irrigation District (TID), Santa Clara (SCL), Northern California Power Agency (NCPA), and the city of Redding. The LADWP supply file includes resources for the California Department of Water Resources (CDWR).

The resource assumptions have been developed employing a range of public and proprietary data sources including the references cited below.

References:

1. "Coordinated Bulk Power Supply Program 1994-2004". Replies to the United States Department of Energy Form OE-411 which requests information from the Regional Reliability Councils on Coordinated Regional Bulk Power Supply Programs. April 1, 1995.

2. The 1994 Electricity Report (ER94). California Energy Commission. P300-95-002. November 1995.

3. Federal Energy Regulatory Commission Forms 1 and 2 (Annual Report of Major Electric Utilities, licensees and Others)

4. Common Forecasting Methodology 10 Reports (Electric Supply Forms) for California utilities

5. California Energy Commission Staff and reports for specific California utilities, specially for various years and California Energy Commission.

Table 2.4 WSCC Resources by Fuel Type (1996)

	MW	% of Total
COAL	37005	25.7%
GAS/OIL	30281	21.0%
CT	3027	2.1%
GEO	684	0.5%
NUC	9220	6.4%
QF	9677	6.7%
OTHER	1628	1.1%
HYDRO	47648	33.0%
PS	2628	1.8%
DSM	2439	1.7%
TOTAL	144237	100.0%

Table 2.4 summarizes the initial WSCC resources that have been included in the UPLAN database for 1996 by fuel type.

2.5 Fuel Prices

Two fuel price scenarios, a base fuel (BF) cost case and a low fuel (LF) cost case were analyzed in this study. The natural gas and other fuel prices employed in the BF case are based on the information supplied by the California Energy Commission and correspond to the ER96/FR95 (Fuel Report) Base Case.

Coal prices have been taken from ER94 Appendix A, Part III, Table III. For those plants for which specific fuel prices were not available from this table, approximations have been used based on the prices for similar plants, taking into account the fuel type, plant type, method of delivery and location.

Nuclear prices are based on ELFIN and ESPAR data. Diablo Canyon fuel price has been assumed to approximate Palo Verde fuel prices for the competitive simulation.

Table 2.5.1 Natural Gas Prices (1996 $/mmBtu)
Base Fuel Cost Case (BF)

Company	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual		$/
													Avg.	Esc (%)	Wh
PG&E	1.97	1.88	1.78	1.76	1.80	1.72	1.79	1.77	1.71	1.70	1.94	2.11	1.83	4.69	0.60
SCE	2.15	2.04	2.00	1.87	1.85	1.83	2.01	2.11	2.15	2.18	2.34	2.54	2.09	4.12	0.35
Cool Water	1.73	1.60	1.55	1.44	1.41	1.46	1.43	1.51	1.54	1.59	1.73	1.92	1.58	6.03	0.26
SDG&E	2.26	2.14	1.96	1.93	2.06	1.97	1.88	2.04	2.05	2.02	2.26	2.49	2.09	3.87	0.77
LADWP	2.15	2.04	2.00	1.87	1.85	1.83	2.01	2.11	2.15	2.18	2.34	2.54	2.09	4.12	0.35
SMUD	1.97	1.88	1.78	1.76	1.80	1.72	1.79	1.77	1.71	1.70	1.94	2.11	1.83	4.69	0.60
AZ/NM	1.88	1.84	1.73	1.72	1.72	1.70	1.73	1.76	1.80	1.83	1.86	1.96	1.79	3.50	0.54
Nevada	1.68	1.65	1.56	1.54	1.54	1.52	1.55	1.58	1.62	1.64	1.66	1.76	1.61	3.50	0.46
North West	1.69	1.61	1.51	1.50	1.50	1.48	1.51	1.53	1.57	1.60	1.62	1.71	1.57	4.30	0.47
Canada	1.42	1.39	1.31	1.30	1.30	1.28	1.31	1.33	1.36	1.39	1.40	1.48	1.36	4.30	0.41
Rocky Mtn.	1.64	1.60	1.51	1.50	1.50	1.48	1.51	1.53	1.57	1.60	1.62	1.71	1.56	3.50	0.47

Table 2.5.2 Natural Gas Prices (1996 $/mmBtu)
Low Fuel Cost Case (LF)

Company	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual		Trans.
													Avg.	Esc (%)	Cost
PG&E	1.44	1.37	1.30	1.28	1.31	1.26	1.31	1.29	1.25	1.24	1.42	1.54	1.33	3.69	0.44
SCE	1.57	1.49	1.46	1.37	1.35	1.34	1.47	1.54	1.57	1.59	1.71	1.85	1.53	3.12	0.26
Cool Water	1.26	1.17	1.13	1.05	1.03	1.07	1.04	1.10	1.12	1.16	1.26	1.40	1.15	5.03	0.19
SDG&E	1.65	1.56	1.43	1.41	1.50	1.44	1.37	1.49	1.50	1.47	1.65	1.82	1.52	2.87	0.56
LADWP	1.57	1.49	1.46	1.37	1.35	1.34	1.47	1.54	1.57	1.59	1.71	1.85	1.53	3.12	0.26
SMUD	1.44	1.37	1.30	1.28	1.31	1.26	1.31	1.29	1.25	1.24	1.42	1.54	1.33	3.69	0.44
AZ/NM	1.37	1.34	1.27	1.25	1.25	1.24	1.26	1.28	1.32	1.34	1.35	1.43	1.31	2.50	0.39
Nevada	1.23	1.20	1.14	1.13	1.13	1.11	1.13	1.15	1.18	1.20	1.21	1.28	1.17	2.50	0.34
North West	1.24	1.17	1.10	1.10	1.10	1.08	1.10	1.12	1.15	1.17	1.18	1.25	1.15	3.30	0.34
Canada	1.04	1.02	0.96	0.95	0.95	0.94	0.95	0.97	0.99	1.01	1.02	1.08	0.99	3.30	0.30
Rocky Mtn.	1.20	1.17	1.10	1.09	1.09	1.08	1.10	1.12	1.15	1.17	1.18	1.25	1.14	2.50	0.34

Table 2.5.3 Other Fuel Prices (1996 $/mmBtu)
Base and Low Fuel Cost Cases - Annual

Company	Coal		Nuclear		Oil	
	Avg. Cost	Esc Rate (%)	Avg. Cost	Esc (%)	Avg. Cost	Esc (%)
PG&E			0.52	3.59	3.50-5.79	4.69-5.56
SCE			0.58	3.52	4.50-5.36	1.26-5.00
SDG&E					4.50	3.87
Arizona/New Mexico	0.9-1.86	0.48-5.01	0.52	3.59		
Nevada	1.10	4.20			3.2	3.5
North West	0.7-1.37	0.50-3.58	0.62	3.6	4.87	4.3
Canada	1.21	3.50				
Rocky Mountain	1.07	5.26				

Tables 2.5.1, 2.5.2, and 2.5.3 display the fuel prices for each individual utility and area. These tables show natural gas prices for both the base fuel cost case (BF) and the low fuel cost case (LF). The monthly distribution, escalation and transportation costs are also included in the tables.

In the LF case (table 2.5.2), both the commodity and transportation costs are approximately 27% lower than the base case but slightly higher than the Competitive America scenario[2] described in CEC's Natural Gas Market Outlook Report. We also assumed a lower escalation rate in the LF case. Costs for nuclear and oil were assumed to remain the same under the base case and the LF case.

References:

1. The 1994 Electricity Report (ER94). California Energy Commission. P300-95-002. November 1995. Appendix A, Part III, Table III.

2. Natural Gas Market Outlook. California Energy Commission. P300-95-017A. October 1995.

3. Common Forecasting Methodology 10 Reports (Electric Supply Forms) for California utilities.

4. California Energy Commission Staff and reports for specific California utilities, specially for various years and California Energy Commission Fuel Reports ER96/FR95 Base Case.

5. California Energy Commission, ELFIN data base, ESPAR Coal Prices, ESPAR ER94 Nuclear Prices.

6. LCG Consulting, PLATO database.

§ 3. MULTI-AREA NETWORK POWER MODEL

LCG Consulting has developed a comprehensive multi-area model to analyze the economic and environmental impacts of implementing the CPUC's Preferred Policy. The UPLAN-E Network Power Model (NPM) is used in this study to analyze the impact on generation costs, total utility net revenue, system average costs, and emissions resulting from the CPUC electricity market restructuring proposal. The model is also used to address market power issues by providing a market share analysis of suppliers.

3.1 Multi-Area Modeling and Network Power Model

The multi-area modeling involves partitioning the WSCC region into demand areas as described in Section 2.1 through Section 2.4. The service areas of electric utilities, power pools, and independent power producers (IPP) are all included in the study. The loads, resources, transmission constraints and operating rules of each of the control areas are modeled in the UPLAN-E NPM using the dispatch protocol of each individual demand area.

The NPM model combines multi-area production costing and AC load flow with a Linear Programming Optimum Power Flow (LPOPF) algorithm to emulate operation of the transmission network and the ISO. The load flow is used for the multi-area dispatch and for determining marginal and congestion costs. Wheeling rates or access charges are not specified for this study. Simultaneous transfer limits on the amount of electricity that can flow across interfaces designated in the WSCC rating catalogue are imposed by using a linear combination of the line limits.

3.2 Modeling of ISO Control Area

UPLAN's unit commitment, dispatch and optimal load flow algorithms use a large scale linear program with integer capabilities to maximize producers' and consumers' surpluses. This is equivalent to minimizing the total costs to customers of meeting the bid-in demand, taking into account known transmission constraints. The combined unit commitment and the multi-area production cost and optimal load flow programs generate a production schedule for each generator for each hour, which is sufficient to meet the demand bids, clear the market and minimize the sum of the start-up, no-load and the incremental energy bids.

In developing the unit commitment (*preferred schedule*) for the ISO control area using energy and demand bids, provisions are made for slow start units, nuclear plants, pre-scheduled hydro, bilateral contracts, regulatory units and transmission losses. The scheduling of hydro and other limited energy is optimized by UPLAN's Multi Stage Hydro and Transaction Scheduling Model. The UPLAN model also considers known transmission limitations and system constraints, including loop flow and estimates of congestion which might occur due to the schedules of non-members.

The NPM model develops hourly schedules of resources to meet the loads at each control area using each areas' protocol and simulates the PX's *day-ahead* forward market. The OPF model of UPLAN determines the real and reactive flows and manages congestion by redispatching the system and schedules DC lines.

To model bilateral contracts between parties which are settled at an agreed upon price, UPLAN provides system level or generating unit level sales between areas. The *day-ahead* schedule is modified every hour for any unforeseen outages, deratings, loop-flow, and congestion to simulate the *hour-ahead* forward market.

3.3 Generation Offers and Demand Bids

Hourly supply offers from generators in the ISO control area are specified in UPLAN's bidding model. The supply bid may consist of several components such as price, amount, injection point and the location for which the generation bid is made. The operating characteristics of each unit are also considered. These characteristics include ramp rates, maximum and minimum run-time, minimum startup-time, minimum down-time, minimum and maximum output level, and hours the unit is available. The following bid components are included in the UPLAN model:

A. Supply Bidding

- *Energy bid* (\$/MWh). This bid is the price at or above which the generator is prepared to produce the next increment of energy and assumes the generator can be operated within its minimum/maximum output range each hour.

- *No-load bid* (\$/hour). This bid represents the minimum fixed hourly payment, which is independent of the unit's output level.

- *Start-up bid* (\$). This bid represents the minimum fixed price which the generator is prepared to accept in order to start and be available for energy dispatch for the scheduling day.

- *Reserve bid* (\$/MW). This bid represents the payment for keeping units in reserve for reliability purpose. In this study, we have used the deficit in the net operating income of the reserve units as an estimate of reserve payments instead of explicit reserve bids.

B. Demand Bidding

- *Demand Bid* (MW). Demand bids are modeled up to a maximum of 5 blocks at a different price preference for each demand quantity in each location. The bid is the maximum price in each hour at which the buyer is prepared to take a specified amount of energy. If demand is bid without a price, it is assumed that the bidder is prepared to pay the market-clearing price. A demand bid may be specified for each day of the week for designated hours.

In this study we have used the hourly short-run average heat rate (SRAH) and start-up costs as the proxy for the generation bids. In the absence of information regarding bidding strategies by the generators, this is the only reasonable indicator of the likely offers. The use of the SRAH minimizes the total operating cost of the system. In UPLAN, users may also use the long-run average heat rate (LRAH) as a proxy for energy, no-load and start-up bids. The LRAH is the average cost of unit's generation over a period of one year and needs to be adjusted for the expected start-up and no-load costs.

Figure 3.1 presents the relationship between bids and MCP on a hourly basis.

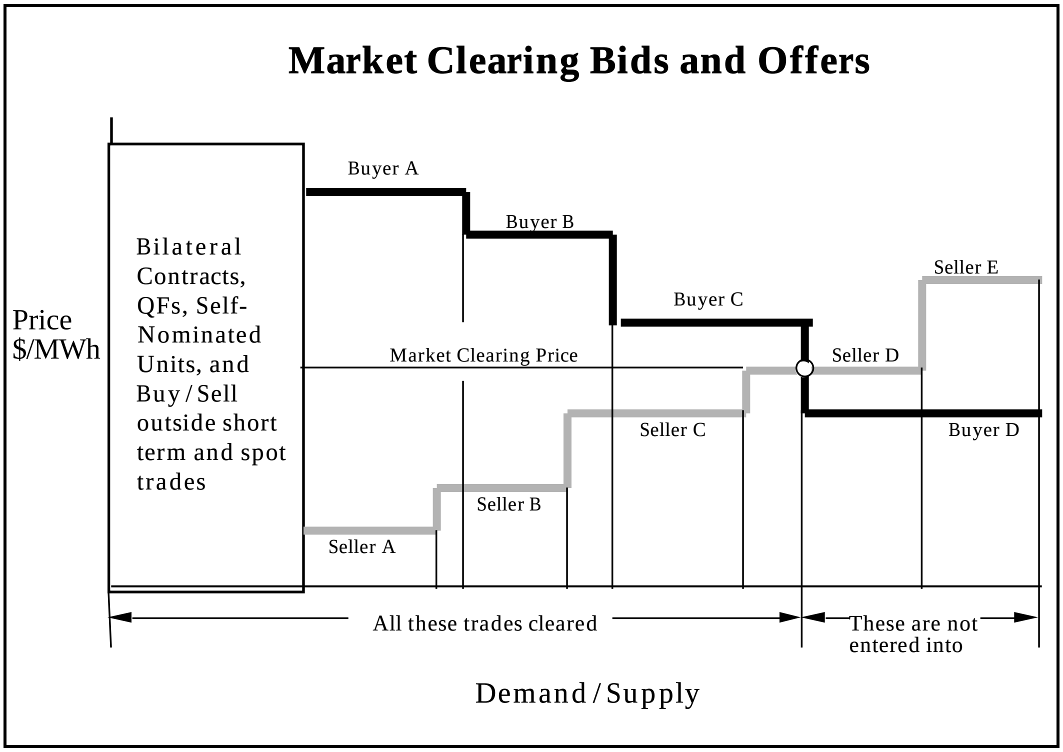

Market Clearing Bids and Offers
Price
$/MWh
Bilateral
Contracts,
QFs, Self-
Nominated
Units, and
Buy / Sell
outside short
term and spot
trades
Buyer A
Buyer B
Buyer C
Buyer D
Seller A
Seller B
Seller C
Seller D
Seller E
Market Clearing Price
All these trades cleared
These are not
entered into
Demand / Supply

Figure 3-1

3.4 Determination of Zonal Market-Clearing Prices (MCP)

In the WEPEX filing to FERC on May 29, 1996, the ISO control region is divided into four zones between which congestion is expected to occur. WEPEX has proposed a uniform MCP for PX buyers in each zone, to be determined based on the cost of the marginal generator in that zone for each hour.

UPLAN calculates the MCP at each zone according to the following principles:

- If supply is sufficient to meet demand at or below the demand price bid, the MCP is set by the marginal generating unit. In the absence of adequate supply offers, demand is curtailed to match supply, and the market-clearing price is set equal to a pre-determined value of lost demand.

- If demand at a price exceeds supply, the market-clearing price is set by the lowest winning demand price bid.

- The market-clearing price is adjusted to include all or a portion of the start-up and no-load cost of the marginal unit, such that each generator scheduled to operate during the day will be paid no less than its full bid price for its scheduled operation.

All bilateral contracts such as QFs, must-run units, must-take contracts and other regulatory resources are dispatched without any consideration of their costs and cannot set the market clearing price. UPLAN also reports revenue generated by each supply unit from energy, spinning, and non-spinning reserve payments.

It is assumed in the UPLAN model that a spinning reserve payment is made for the portion of the generation with price below the MCP which is committed but not used, and paid at the rate of the difference between the market clearing prices and the generator bids.

The MCP is adjusted on a 24-hour basis so that all accepted generation units are paid at their bid prices, including the start-up and no-load costs. Payments for the non-spinning reserve are based on the actual costs incurred by the quick-start units (i.e. combustion turbines) providing the non-spinning reserve. These units are not allowed to set or adjust the market clearing prices. This assumption is consistent with the market power filing of the IOUs.

Nuclear, Hydro, and QFs will be dispatched directly by the ISO. Their cost recovery process will be through the CTC, PBR and other means and therefore, they do not compete with the existing and new thermal units. As a result, the market clearing price will be set by the thermal units.

3.5 Nodal Spot Prices (NSP)

UPLAN has the capability to determine nodal spot prices (NSP) as well as the zonal MCP. The NSP is the locational marginal cost and it represents the incremental cost of an additional MW of load at a specific node on the transmission grid. The NSP depends on all the units throughout the WSCC and how their generation might change in order to meet an increment of load change at a particular node. The MCP is the operating cost (or bid) of the marginal unit in a zone or a region (a set of nodes) adjusted for any applicable start-up and no-load cost.

3.6 Transmission Costs

Transmission cost includes costs related to the revenue requirement of the transmission owner which would be recovered through grid access fees, reservation charges and congestion costs. The presence of congestion results in over collection of revenues by the ISO. For the purpose of modeling, any excess revenue collected due to the difference in MCP between two zones is applied to reduce the bills for the customers of the zone paying the higher charges. UPLAN also reports the congestion charge which is the marginal value of increasing the flow through an interface or a line and is useful in analyzing the cost benefit of transmission upgrades.

3.7 Multi-Area Analysis

Using UPLAN's Network Power Model (NPM) and the data base described in Section 2, a number of scenarios were studied for the years 1998, 2001 and 2006. 1998 is the first year of operation of the competitive market in California. In 2001, the bulk of deregulation is expected to be completed and in 2006, the transition period is expected to be completed and the full impact of competition can be modeled.

A number of cases were run and studied using UPLAN to analyze the effects of restructuring in California. However, only the following cases are presented in this report.

- *Base Fuel Costs Case (BF):* This is the primary case which is used for comparison with other scenarios. The fuel cost assumptions can be found in Tables 2.5.2 and 2.5.3. Natural gas prices are adopted from the ER96/ER95 fuel report, coal, nuclear, geothermal are based on ER94.

- *Low Fuel Costs Case (LF):* This is the fuel cost alternative case, with the assumption that the gas fuel costs will be lower than the BF, as exhibited in Table 2.5.1.

- *Municipal Participation Case (MP):* This is a modified version of the primary BF case, where we assume all municipal utilities participate in the pool. An Independent System Operator (ISO) controls dispatch and preserves system reliability for all of California. Base fuel costs are used for this case.

- *Regulated Case (RG):* This is the regulatory status quo case. In this case each individual utility dispatches its units and maintains its own reliability according to WSCC requirements. Due to open transmission access, utilities will be buying and selling energy on an economic basis as in the deregulated cases. In 1998 and 2001 the electricity production in BF and RG cases are identical. However, in year 2006, new CT units are added in both Northern to maintain higher reliability.

In addition to the above cases analyzed in this report, we have also studied several alternative scenarios to evaluate the impact of various modeling assumptions regarding bidding strategies, refurbishment, reserve capacities and market power. Some of the results from these additional sensitivity cases are referenced in this report for completeness.

3.8 California Energy Market

Supply curves for energy and capacity have been developed from the NPM multi-area OPF runs for the WSCC and State of California. These curves group the simulation results for the units that make up each of these areas, based on the ranked cumulative generation average operating cost. Figures 3.2 through 3.3 show the curves for the various areas for 1998, 2001 and 2006, respectively. There is a large amount of capacity and energy ranked at or near zero, corresponding to hydro, renewable and other alternative technologies. The curves display a very gradual build-up of average cost over a large range of capacity and energy.

Tables 3.8.1 and 3.8.2 below summarize the electricity demand and the results are also graphically presented in the supply curves in Figures 3.2 and 3.3.

Table 3.8.1 Peak Load and Energy Demand

	WSCC		California	
Year	Peak Load (MW)	Energy Demand (GWh)	Peak Load (MW)	Energy Demand (GWh)
1998	118,217	637,346	52,861	272,647
2001	124,075	669,148	54,987	283,588
2006	136,872	737,904	61,086	314,888

These tables also provide valuable insights into available energy in WSCC and its impact on the energy market in California in 1998, 2001, and 2006. For example, as shown in Table 3.8.1 in the column of Energy Demand, the California area demand for electricity is approximately 273, 284, and 315 thousands of GWh in 1998, 2001 and 2006 respectively. To meet these demands, as shown in Table 3.8.2 in the column of California Energy, California's own generation can supply approximately 271, 275, and 297 thousands of GWh in each of the three years at the MCP level displayed in the column of Average Variable Cost. The remaining California demand could be met from the higher cost range, and even then there is a need for additional generation or import. The WSCC column shows that there is surplus energy which would be available for import into California at the same cost range. This is sufficient to provide a cap on the market prices within California.

Table 3.8.2 Western Energy Market:
Distribution of Available Energy vs. Price Range

	Energy Available at MCP Level				
		WSCC		California	
Year	**Average Var. Cost ($/MWh)**	Total Capacity (GW)	Energy (GWh) (in 000s)	Total Capacity (GW)	Energy (GWh) (in 000s)
1998	**$25-$30**	119-141	602-654	41-56	233-271
2001	**$30-$35**	131-148	652-688	45-58	246-275
2006	**$35-$40**	136-156	708-752	46-60	262-297

	Energy Available at High Cost Range				
		WSCC		California	
Year	**Average Var. Cost ($/MWh)**	Total Capacity (GW)	Energy (GWh) (in 000s)	Total Capacity (GW)	Energy (GWh) (in 000s)
1998	**$30-$35**	141-149	654-658	56-61	271-275
2001	**$35-$40**	148-154	688-691	58-61	275-278
2006	**$40-$45**	156-162	752-758	60-65	297-303

These supply curves also imply that under normal hydro condition and in the absence of any transmission constraints, there are approximately 17,000, 19,000, and 14,000 GWh surplus energy available in WSCC at prices below $30, $35 and $40/MWh in the years 1998, 2001 and 2006 respectively. This surplus energy may disappear in a dry hydro year.

Figure 3.2 WSCC Capacity and Energy

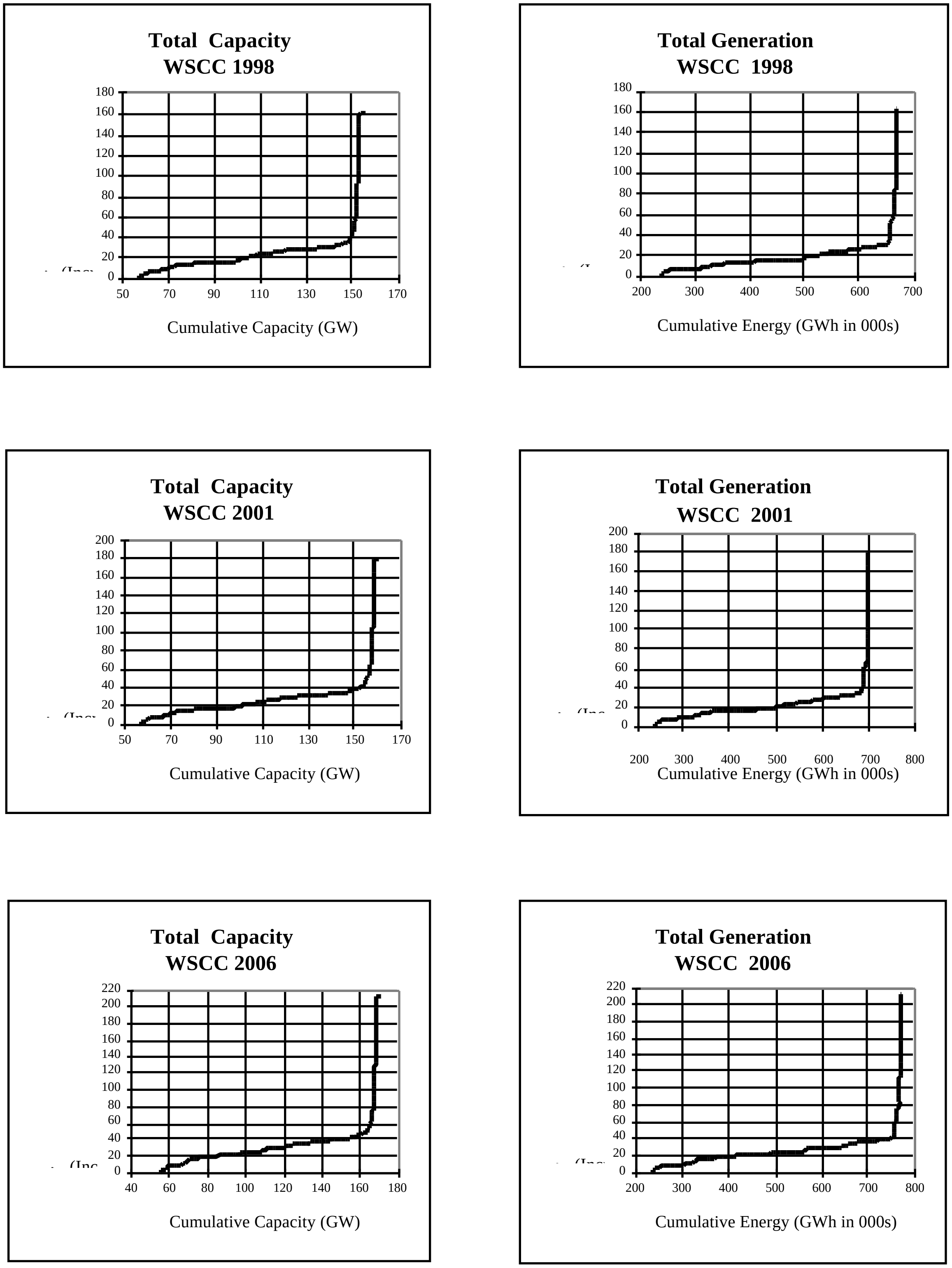
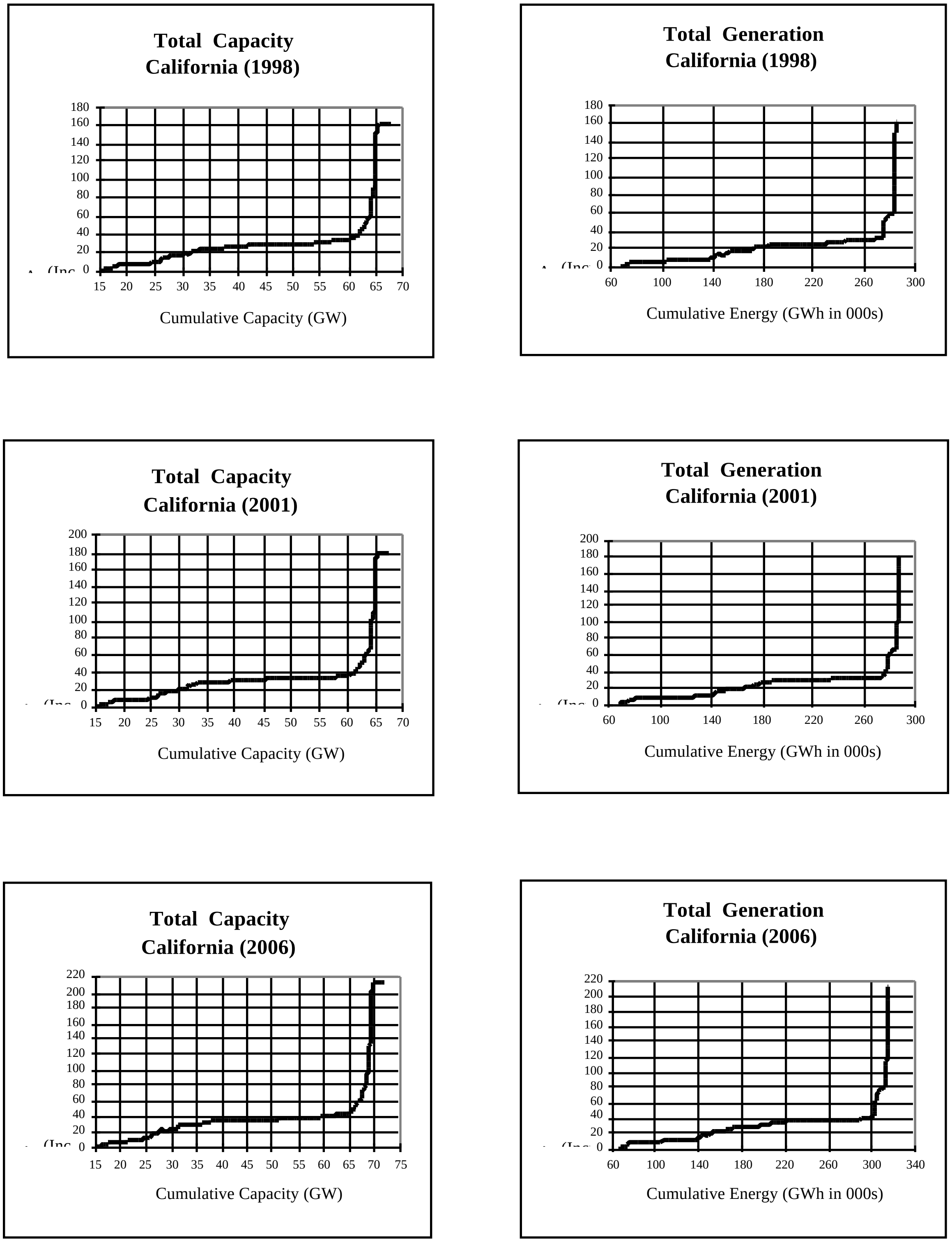


Figure 3.3 California Capacity and Energy



3.9 Import and Export of Electricity

The flow of electricity between the fourteen demand areas represented in the UPLAN database are monitored to determine the extent of import and export. The flow between the demand areas is limited by rating of individual transmission lines connecting theses demand areas. In addition there are interface limits on electricity transfer between areas depending on external condition and contingencies. WSCC has determined these limits and listed them in the WSCC report of the Path Rating Catalog. The UPLAN AC load flow program maintains the physical flow of electricity at or below the assigned interface or line limits. The program automatically redispatches the system when line or interface limits are reached.

Table 3.9.1 presents the annual loads, generation, imports and exports for each of the major areas and zones for the three study years in the base case.

Total imports into California from all Out-of-State sources are 82,300, 92,855 and 96,727 GWh respectively in 1998, 2001 and 2006. Total exports from California remain at the 270 to 683 GWh range during these years. The flow from NOCAL to SOCAL is 15,893 GWh, 13,631 GWh, and 10,168 GWh in 1998, 2001, and 2006, showing a gradual decrease whereas the flow from SOCAL to NOCAL is 1,052 GWh, 1,349 GWh, and 2,313 GWh respectively, indicating a gradual increase of imports from the Southwest.

Table 3.9.2 shows the distribution of the imports and exports between the areas represented in this study. The table also indicates that there is a shortage of generation in Southern Nevada area. However, additional capacities installed in Southern Nevada may not be able to supply any significant amount of energy to California due to increasing congestion in WOR interface in 2006 (Table 3.13.1).

Table 3.9.1 Regional (Zonal) Generation and Loads
Base Fuel Costs Case

YEAR 1998

Region	in GWh			
	Generation	Load	Import	Export
NOCAL	76925	84617	25348	15966
SOCAL	139984	189521	73899	1269
PNW	265385	229922	13714	46218
AZ/NM	95882	75483	10338	29657
RMPP	68151	44782	1167	24093
SNV	22263	14512	23005	30267
TOTAL	668590	638838	147470	147470

YEAR 2001

Region	in GWh			
	Generation	Load	Import	Export
NOCAL	77065	89233	27677	13709
SOCAL	141778	195853	80158	1541
PNW	281978	243279	13925	49544
AZ/NM	109153	79635	8657	37253
RMPP	69622	47382	1352	23172
SNV	22426	15265	28247	34798
TOTAL	702022	670646	160017	160017

YEAR 2006

Region	in GWh			
	Generation	Load	Import	Export
NOCAL	80738	96650	27837	10250
SOCAL	164385	219664	81372	2914
PNW	303402	267283	14722	47244
AZ/NM	126127	87064	6515	44826
RMPP	72167	52061	1866	21562

SNV	22817	16609	32547	38063
TOTAL	769635	739330	164859	164859

Table 3.9.2 Annual Energy Flows between Regions
Base Fuel Costs Case

YEAR 1998

REGION	NOCAL	SOCAL	PNW	AZ/NM	RMPP	SNV	EXPORT
NOCAL	0	15893	72	0	0	0	15966
SOCAL	1052	0	80	58	0	79	1269
PNW	24295	21012	0	0	911	0	46218
AZ/NM	0	8834	0	0	255	20567	29657
RMPP	0	0	13562	8172	0	2358	24093
SNV	0	28159	0	2108	0	0	30267
IMPORT	25347	73899	13714	10338	1167	23005	147470

YEAR 2001

REGION	NOCAL	SOCAL	PNW	AZ/NM	RMPP	SNV	EXPORT
NOCAL	0	13631	78	0	0	0	13709
SOCAL	1349	0	88	53	0	52	1541
PNW	26328	22255	0	0	961	0	49544
AZ/NM	0	11025	0	0	391	25837	37253
RMPP	0	0	13760	7054	0	2358	23172
SNV	0	33247	0	1551	0	0	34798
IMPORT	27677	80158	13925	8657	1352	28247	160017

YEAR 2006

REGION	NOCAL	SOCAL	PNW	AZ/NM	RMPP	SNV	EXPORT
NOCAL	0	10168	82	0	0	0	10250
SOCAL	2313	0	442	29	0	129	2914
PNW	25523	20665	0	0	1055	0	47244
AZ/NM	0	13746	0	0	810	30270	44826
RMPP	0	0	14198	5216	0	2148	21562
SNV	0	36792	0	1270	1	0	38063
IMPORT	27836	81372	14722	6515	1866	32547	164859

3.10 New Market Entrants

The UPLAN resource database was developed using information available for existing units as of 1995. The 1994 WSCC report “Coordinated Bulk Power Supply 1994-2004”, (dated April 1995) contains a forecast of capacity additions in the WSCC control area and was used as a guideline for this study. Installation of additional new generation was deemed necessary in 1998, 2001 and 2006 for reliability and to satisfy increase in demand. We have examined the needs for new generation capacity and the opportunities for new market entrants during the years 1998 -2006.

The capacity expansion analysis was performed using a competitive analysis technique developed as an alternative to the cost-based methodology used in the traditional regulated planning process designed to minimize the revenue requirements. In a competitive environment, it is more appropriate to focus on the economic viability of existing and new units as indicated by the net income which they can earn within the new market structure in California. The net income which a unit earns depends on the zonal Market Clearing Price and the fixed and variable cost of the generator. In the absence of congestion, the MCP monotonically decreases as new generation is added, resulting in lower income for both existing and new generation. However, this trend is somewhat offset by increased demand due to lower costs (price elasticity of demand).

We used a sequential search process with a small initial amount of generation installed at each potential nodes to determine the direction of the optimal resource mix. A multi-dimensional method of bi-section was used to determine the size and location of the California units which earned sufficient revenues to recover both capital and operating costs.

For units located outside of California, a set of minimum operating criteria were established that, if met, would indicate that the installation of these units would be economically viable for their area's ratepayers. These criteria included meeting native demand, contributing to reliability, and having the potential to sell into the California market. The new technique has been incorporated into the UPLAN Economic Dynamic System Optimizer (EDSO) model for future use.

Table 3.10.1 Minimum Cost Recovery Required for New Generating Plants

Cost Element	UNIT COST (expressed in 1996$)			
	Combined Cycle Plants [1]		**Combustion Turbine Plants** [2]	
	Costs	**$/MWh**	**Costs**	**$/MWh**
Capital	$400/kW	8.8	$250/kW	110
Fixed O&M	$5/kW-yr.	0.6	$7.2/kW-yr.	20
Var. O&M	2 mills/kWh	2	7 mills/kWh	7
Fuel	$1.80-2.50/mmBtu @7250 Btu/kWh	13 - 18	$1.80/mmBtu @9000 Btu/kWh	16-22
TOTAL		**24.4 - 29.4**		**153 - 160**

[1] 15% levelized capital recovery @ 80% Capacity Factor

[2] CT units are assumed to compete with demand bids @ 4% capacity factor.

We assume that a new combined cycle unit in California must generate a net operating income to pay the minimum annual carrying charge necessary for the recovery of its 400$/KW in 1996$ construction cost. In addition, the unit must earn sufficient revenue to recover its fixed and variable O&M costs plus fuel costs, which are estimated to be 16-21$/MWh. The new combustion turbines which could be added in the WSCC region for maintaining reliability should compete with demand bids at $160/MWh. This cost corresponds to a CT operating at a capacity factor greater than 4%, having an operating cost less than 45 $/MWh and a construction cost of 250 $/KW. Combined cycle units added outside California are required to have an annual capacity factor greater than 67.5% and maintain an average total cost of less than 25 $/MWh in 1996$. These cost assumptions have been summarized in Table 3.10.1. The proposed capacity expansion plan is presented in Table 3.10.2.

For California, a number of potential resources options were evaluated, including new combined cycle units, combustion turbines, coal plants and repowering of existing units. Prior to 1998 no new California-based resources were forecasted in the WSCC report and none were added in the UPLAN database. Based on the analysis for the combined cycle units, no new resources are economically viable within California for the study years 1998 and 2001. In 2001, combined cycle units in Northern California and Southern California could earn, respectively, 317 $/KW and 364 $/KW in excess of their operating costs based on 10 MW of incremental capacity addition. This capital return decreases at the rate of 0.0369$/KW for each megawatt added thereafter.

Table 3.10.2 Cumulative Capacity Added For Base Case

Region/Year	1998	2001	2006
Northern Cal	-	-	500
Southern Cal	-	-	4000
RkyMtn	500	1100	2000
Northwest	2850	4800	6850
Southwest	1750	4250	7050
Total	5100	10,150	20,400

For 2006 the analysis for new market entrants in California for the BF case indicates that up to 4000 MW of new combined cycle units are economically viable in Southern California and up to 500 MW of new combined cycle units are economically viable in Northern California. Assuming this level of installed capacity, the Southern California units earn an annual net income exceeding operating costs equal to the annual carrying charge for an assumed construction cost of 421 $/KW (1996$) for new units. The Northern California unit earns an annual net revenue equal to the annual carrying charge for a construction cost of 407 $/KW (1996$) for the new unit

An alternative scenario was evaluated for 2006 with the same overall level of new capacity additions as in the BF case, but which assumed 2000 MW of new combined cycle units installed in Southern California, plus a new 2000 MW coal plant installed in the Southwest for dedicated sales to California. With this level of installed capacity, and 500 MW of combined cycle units installed in Northern California, the Southern California units earn an annual net income over operating costs equivalent to the annual carrying charge for a construction cost of 508 $/KW (1996$) for the new units. The Northern California units earn a annual net revenue equivalent to the annual carrying charge for a construction cost of 448 $/KW (1996$) for the new units. However, the coal plant earns an annual net income over operating costs equivalent to the annual carrying charge for a construction cost of only 873 $/KW (1996$) for the new unit. This amount is considered to be insufficient to justify the development of a coal facility for the sole purpose of sales to California.

We also evaluated a capacity additions case for 2006 with 800 MW of repowering, 400 MW in Northern California associated with Pittsburgh Unit 6, and 400 MW in Southern California associated with Encina Units 1, 2 and 3. In addition, 3600 MW of new combined cycle units installed in Southern California, 100 MW of new combined cycle units installed in Northern California. The overall capacity added was at the same level as the BF case additions. With this level of installed capacity, the new Southern California and Northern California units earn an annual net income over operating costs equal to the annual carrying charge for a construction cost of 454 $/KW (1996$) and 452 $/KW respectively for the new units. The repowered Pittsburgh unit in Northern California earns an annual net revenue equal to a construction cost of 116 $/KW (1996$) and the repowered Encina units in Southern California earn an annual net revenue equal to a construction cost of 84 $/KW (1996$). Although repowering costs are typically lower than construction costs for new units, both of the repowering revenues appear to be lower than are economically justified.

An examination of combined cycle unit additions under a low gas fuel costs scenario reveals that no new resources are economically viable within California for the study years 1998 and 2001. For 2006 the study shows that up to 3500 MW of new combined cycle units are economically viable in Southern California but no new combined cycle units are economically viable in Northern California. Assuming this level of installed capacity, the Southern California units earn an annual net income over operating costs equal to the annual carrying charge for a construction cost of 413 $/KW (1996$) for the new units. A small Northern California addition earns an annual net revenue equal to the annual carrying charge for a construction cost of only 379 $/KW (1996$) for the new units and therefore is not economically viable. The results of the evaluation of the capacity expansion plan is presented in Table 3.10.3.

Table 3.10.3 Performance of New Additions in California in 2006

Region/Year	Capacity (MW)	Energy (GWh)	Net Income Million $	Cap. Cost Recovery 1996$/KW-yr.
Northern Cal- BF Case	500	3821	43.06	407
Southern Cal- BF case	4000	25292	355.94	421
Northern Cal- LF Case	-	-	-	379
Southern Cal- LF case	3500	27074	305.66	413

The WSCC report also identified a number of generating plant additions in the Rocky Mountain, Pacific Northwest, and Southwest regions through 1998, that were consistent with their forecasted loads. These have been added to the UPLAN database as either new combined cycle (CC) or new combustion turbines (CT). These amounted to 500 MW of CT in the Rocky Mountain Power Pool, 2850 MW of CC in the Pacific Northwest, and 350 MW of CT and 1400 MW of CC in the Southwest.

For the year 2001, 600 megawatts of CT were added in the Rocky Mountain Power Pool, 1950 megawatts of CC were added in the Pacific Northwest, and 500 megawatts of CT plus 2000 megawatts of CC were added in the Southwest. For 2006, an additional 900 megawatts of CC were added in the Rocky Mountain Power Pool, 2050 megawatts of CC were added in the Pacific Northwest, and 500 megawatts of CT plus 2300 megawatts of CC were added in the Southwest.

Table 3.10.4 Cumulative Capacity Expansion Analysis and Total Operating Costs

		1998			2001			2006		
Location	Type	Capacity MW	Capacity Factor (%)	Total Cost $/MWh	Capacity MW	Capacity Factor (%)	Total Cost $/MWh	Capacity MW	Capacity Factor (%)	Total Cost $/MWh
Northern Cal	CC	-	-	-	-	-	-	500	87.2	30
Southern Cal	CC	-	-	-	-	-	-	4,000	72.2	29
Rky Mtn	CT	500	5.5	42	1,100	7.4	41	1,100	7.9	47
Rky Mtn	CC	-	-	-	-	-	-	900	92.9	25
Northwest	CC	2,850	77.5	21	4,800	85.5	22	6,850	91.4	25
Southwest	CT	350	6.5	43	850	5.3	51	1,350	7.3	54
Southwest	CC	1,400	67.6	23	3,400	72.7	25	5,700	80.1	29

Note: Total costs does not include capital cost recovery. Northwest and Southwest units may earn revenues for bid sales to Power Exchange.

These capacity additions are found to be sufficient to maintain a level of unserved energy level of 47.29, 54.25 and 95.08 GWh in the WSCC region during the years 1998, 2001 and 2006 respectively. This represents less than 0.01% of the total generation and could be satisfied by interruptible loads and demand bids. The cumulative capacity additions in California and other areas within WSCC can be found in Table 3.10.4.

3.11 Market Clearing and Nodal Spot Prices

This section contains UPLAN's forecasts of annual average sellers, buyers, and ratepayers market clearing prices for several of the proposed zones under ISO/PX control, and nodal spot prices for a selected demand node. The sellers' MCP is the price paid to the generators for all their generation injected into the transmission grid for meeting the energy requirements of the PX. The buyers' MCP is the price paid by the demand bidders for the energy received at their respective zones and differs from the sellers' MCP by transmission losses. The ratepayers' MCP is the price paid by the distribution customers, and includes distribution losses. The ratepayers' MCP is similar to the energy component of the utilities' regulated rates which are currently filed by the utilities and approved by the CPUC in the utilities' Energy Cost Adjustment Clause (ECAC) proceeding. The ratepayers' MCP plus the non-generation and CTC components are compared to the forecast rates of PG&E and SCE under a regulated environment for the coming years.

The zonal MCPs are presented for Zone 3, Northern California, and Zone 4, Southern California, and are calculated for sellers at the generator level and buyers at the zonal level. The MCPs calculation uses the shortfall method of adjustment for start-up, no-load and spinning cost.

The MCP results for the three restructured cases are summarized in Tables 3.11.1 through 3.11.3. Average NSPs for the regulated and restructured cases are summarized in Table 3.11.4.

Table 3.11.1 Annual Average Sellers' Market Clearing Prices

($/MWh)

Case Name	Northern California (Zone 3)			Southern California (Zone 4)		
	1998	2001	2006	1998	2001	2006
Base Fuel Cost (BF)	28.55	32.25	39.86	29.81	33.73	40.86
Low Fuel Cost (LF)	23.02	26.26	32.61	24.07	27.37	33.38
BF Case With Municipals (MP)	28.55	32.41	39.79	30.10	34.57	41.29

From Table 3.11.1, we can see that the average sellers' market clearing prices decrease from the Base Fuel Cost Case (BF) to the Low Fuel Cost Case (CF) by approximately 18% to 19% due to the decrease in fuel cost. When the municipal units participate in the pool, referred to as (MP), there in no impact in the sellers' MCP in Northern California.

The MCPs are generally higher for Southern California compared to Northern California. Although the incremental generating costs are comparable in Southern and Northern California, the average generation costs in Southern California generators seem to be slightly higher than the Northern California generators.

The annual average buyers' market clearing prices shown in Table 3.11.2 are the average sellers' market clearing prices adjusted for transmission losses determined by UPLAN's load flow program. The prices in Southern California are higher than Northern California due to the difference in underlying sellers' MCP. The trend shown here is also similar to the sellers' market clearing prices.

Table 3.11.2 Annual Average Buyers' Market Clearing Prices

($/MWh)

Case Name	Northern California (Zone 3)			Southern California (Zone 4)		
	1998	2001	2006	1998	2001	2006
Base Fuel Cost (BF)	29.12	32.92	40.59	30.15	34.13	41.34
Low Fuel Cost (CF)	23.40	26.71	33.15	24.29	27.64	33.74
BF Case With Municipals (MP)	29.12	33.08	40.52	30.44	34.99	41.78

Table 3.11.3 shows the annual average ratepayers' market clearing prices. These MCPs are calculated from the buyers' market clearing prices by adjusting for the distribution losses. A trend similar to the sellers' market clearing prices is also shown here. For comparison, the initial estimated MCPs used by the utilities for their energy component calculations from the CTC filings of PG&E for Northern California and from the CTC filings of SCE for Southern California are also shown.

Table 3.11.3 Annual Average Ratepayers' Market Clearing Prices

($/MWh)

	Northern California (Zone 3)			Southern California (Zone 4)		
Case Name	**1998**	**2001**	**2006**	**1998**	**2001**	**2006**
Base Fuel Cost (BF)	31.19	35.24	43.57	32.38	36.64	44.39
Low Fuel Cost (CF)	24.91	28.31	35.31	26.65	30.27	36.89
BF Case With Municipals (MP)	28.55	32.41	39.79	30.10	34.57	41.29
Utility Estimate	29.00	32.00	37.00	34.00	38.00	46.00

Table 3.11.4 shows the annual average nodal spot prices for PG&E and SCE demand nodes in Northern and Southern California, respectively. These are the incremental costs of an extra megawatt hour of consumption of electricity at each of the respective demand nodes. The values in the table reflect the average variable costs associated with the change in generation on all units in the entire WSCC region necessary to meet the addition increment of demand at these nodes.

Table 3.11.4 Annual Average Nodal Spot Prices

($/MWh)

	Northern California (Zone 3)			Southern California (Zone 4)		
Case Name	**1998**	**2001**	**2006**	**1998**	**2001**	**2006**
Base Fuel Cost (BF)	20.07	23.33	28.43	19.95	22.78	27.48
Low Fuel Cost (CF)	16.64	19.59	24.48	16.65	19.19	23.47
BF Case With Municipals (MP)	20.07	23.54	28.43	19.95	22.79	27.48
Regulated Case (RG)	20.07	23.33	28.01	19.95	22.78	27.19

As shown in the Table 3.11.4, the nodal spot prices for Southern California are equivalent to or are slightly lower than those in Northern California. Since the cost of natural gas is lower in Northern California, this indicates that the efficiency from the incremental operation of the Southern California units is greater than the comparable units in Northern California. The trend between the cases is however, similar to that of sellers', buyers', and ratepayers' MCPs. The RG case has only slightly lower nodal prices than for the restructured plan because of the additional CTs in Northern California.

Table 3.11. 5 Adjustment to Sellers' MCP and Nodal Spot Price

	Northern California (Zone 3)			Southern California (Zone 4)		
Category	1998	2001	2006	1998	2001	2006
Transmission Losses	2.00%	2.08%	1.83%	1.14%	1.19%	1.17%
T&D Losses	9.24%	9.27%	9.31%	8.61%	8.62%	8.64%
Nodal Spot Price Uplift	30%	28%	29%	33%	32%	33%

In Table 3.11.5 we show the transmission losses derived from UPLAN simulation and the distribution losses calculated from ER95. The last row of Table 3.11.5 displays the adjustment to the nodal spot prices required to bring the nodal spot price to the same level as the sellers'.MCP for the Base Fuel Cost case.

The MCP trends are shown graphically in Figure 3.4. Tables for sellers', buyers', and ratepayers' MCPs, and nodal spot prices, for 1998, 2001, and 2006 on a monthly basis for off-peak, on-peak and average are presented in Tables 3.11.6 through 3.11.11 in Appendix B.

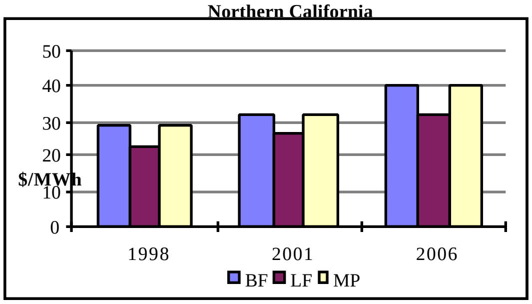
Figures 3.5 through 3.10 show the hourly market clearing prices and price duration and moving average cost curves for the BF case. The plot for the hourly MCPs show the hourly variations in the market clearing prices. By and large the hourly variations range from 10 to 20$/MWh around the annual average, with occasional summer spikes to very high values for hours with prices set by demand bids in the face of extreme supply deficiency. These variations basically follow the diurnal cycle of the hourly loads from off-peak to on-peak.

The price duration curves and the moving average costs indicate the level of operations and the average payment that can be expected to occur for various bids. For example, in Northern California, if a unit bids 40 $/MWh, it is likely that it will run for approximately 400 hours and earn an average revenue rate of 48 $/MWh. This graph can be used in analyzing the opportunities for a new market entrant. The operating costs of the new entrants and the corresponding duration of operation and average revenue must be sufficient to support the revenue requirement of the new entrants. These graphs along with the method described in the determination of U-MCPI and U-MRI indices in Section 3.17 can be used to design successful bidding strategies.

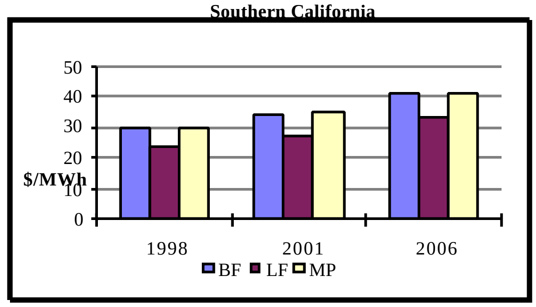
Tables 3.11.6 through 3.11.11 in Appendix B contain sellers' MCP, buyers' MCP and the nodal spot prices for the BF, LF, muni participation and the regulated cases. The weighed averages of hourly MCPs and nodal spot prices for peak and off-peak periods are summarized for each month in these tables. The cases with the use of LRAH and markets bids for reserves are also presented in Appendix B.

Figure 3.4: Comparison of Market Clearing Prices

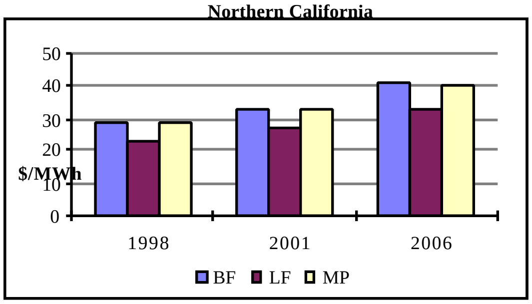
Annual Average Seller's Market Clearing Prices
Northern California



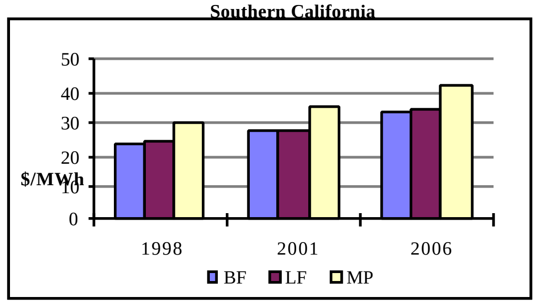
Annual Average Seller's Market Clearing Prices
Southern California



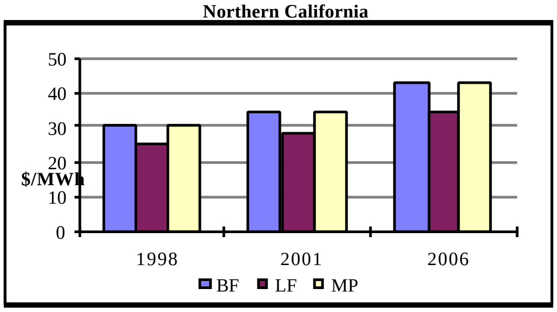
Annual Average Buyer's Market Clearing Prices
Northern California



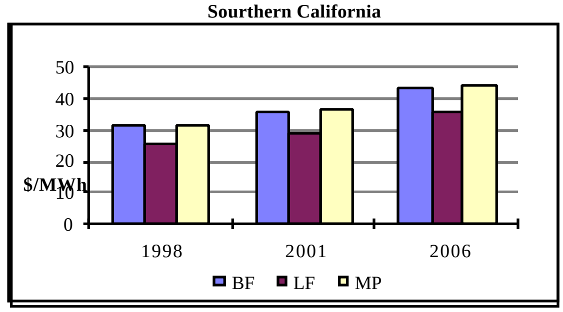
Annual Average Buyer's Market Clearing Prices
Southern California



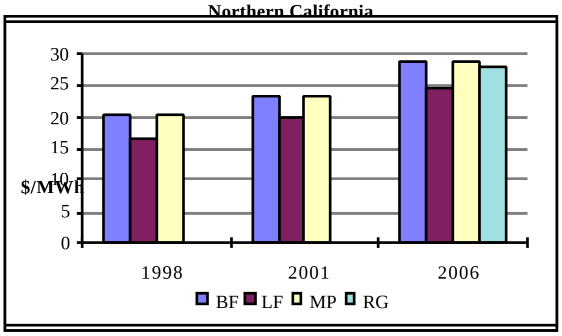
Average Ratepayer's Market Clearing Prices
Northern California



Average Ratepayer's Market Clearing Prices
Sourthern California



Annual Average Nodal Spot Prices
Northern California



Annual Average Nodal Spot Prices
Southern California

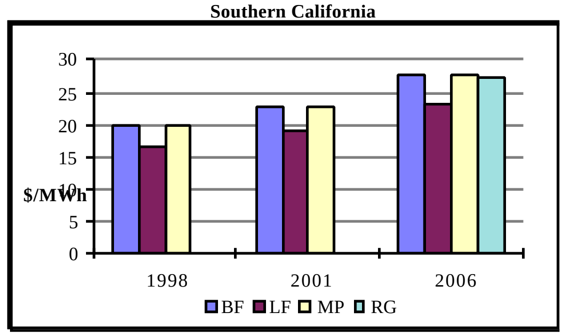
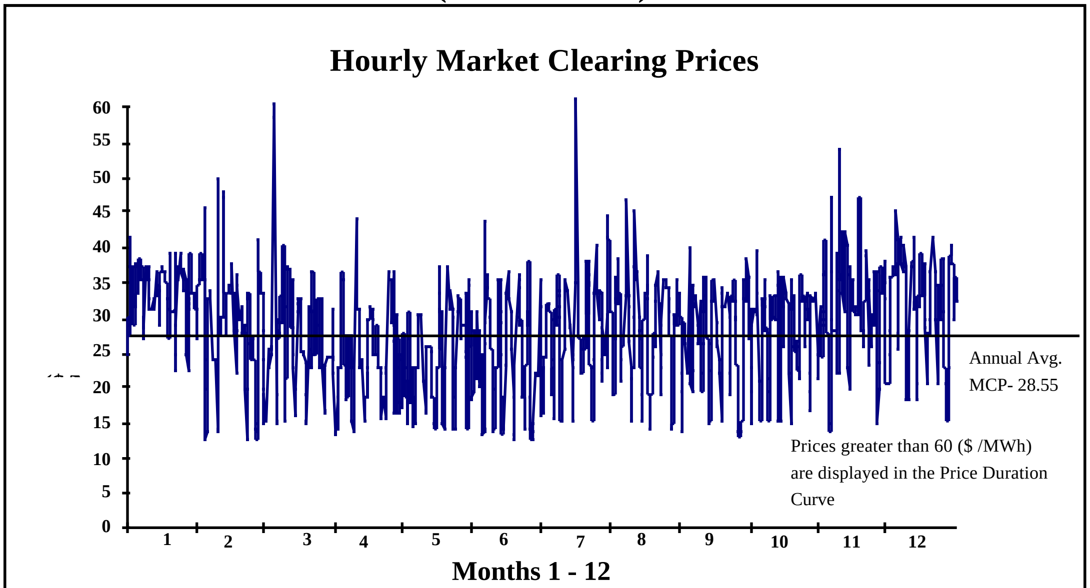


Figure 3.5: Base Fuel Cost Case
(PG&E Zone 3) -1998



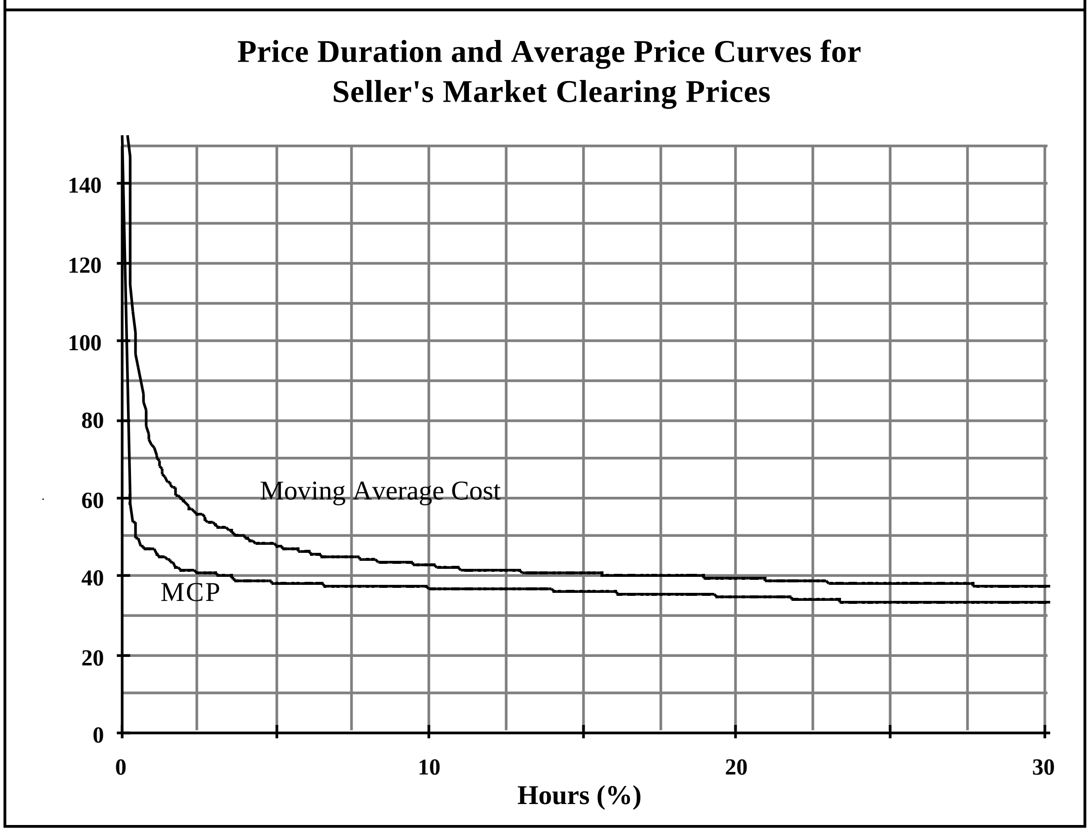


Figure 3.6: Base Fuel Cost Case
(PG&E Zone 3) - 2001

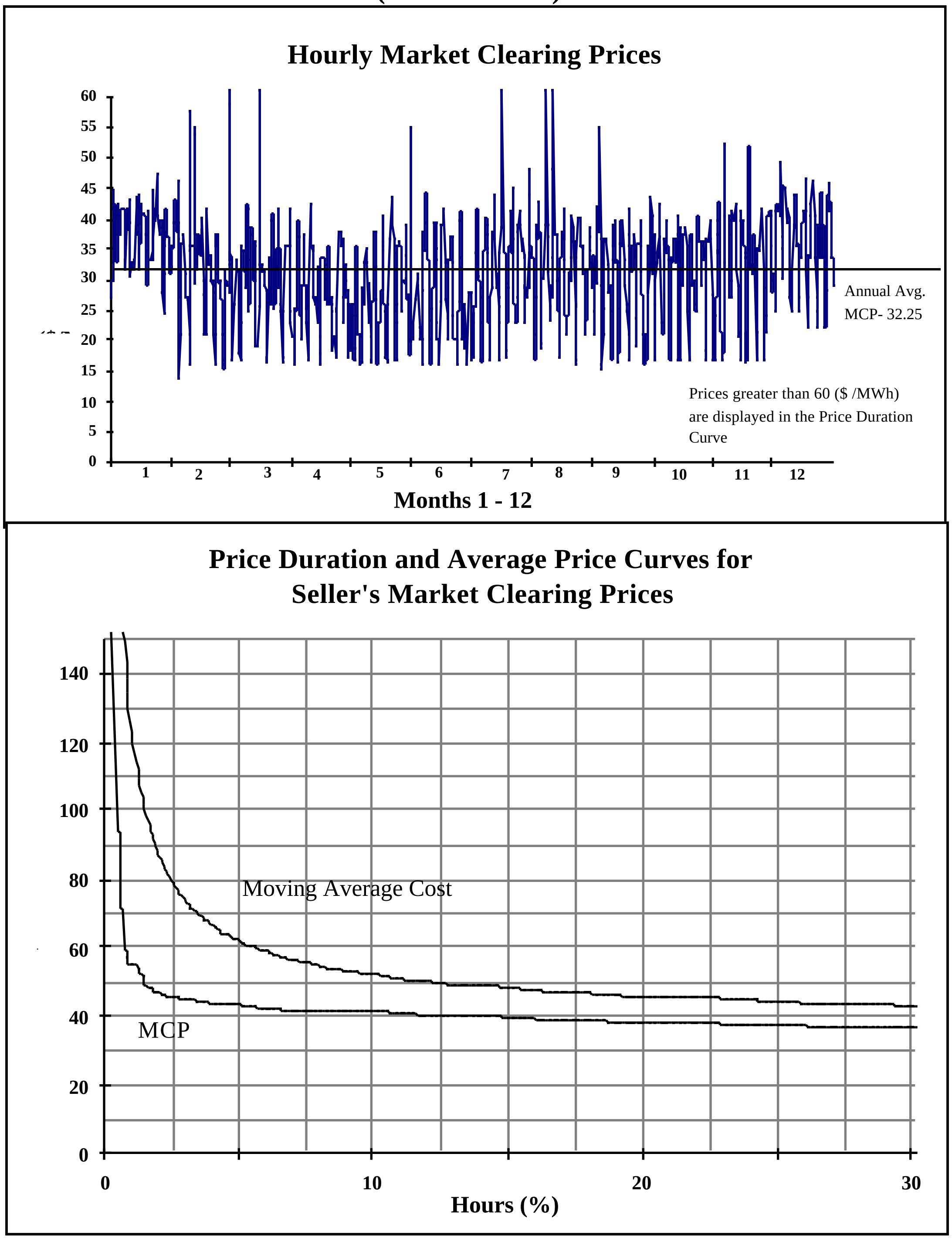
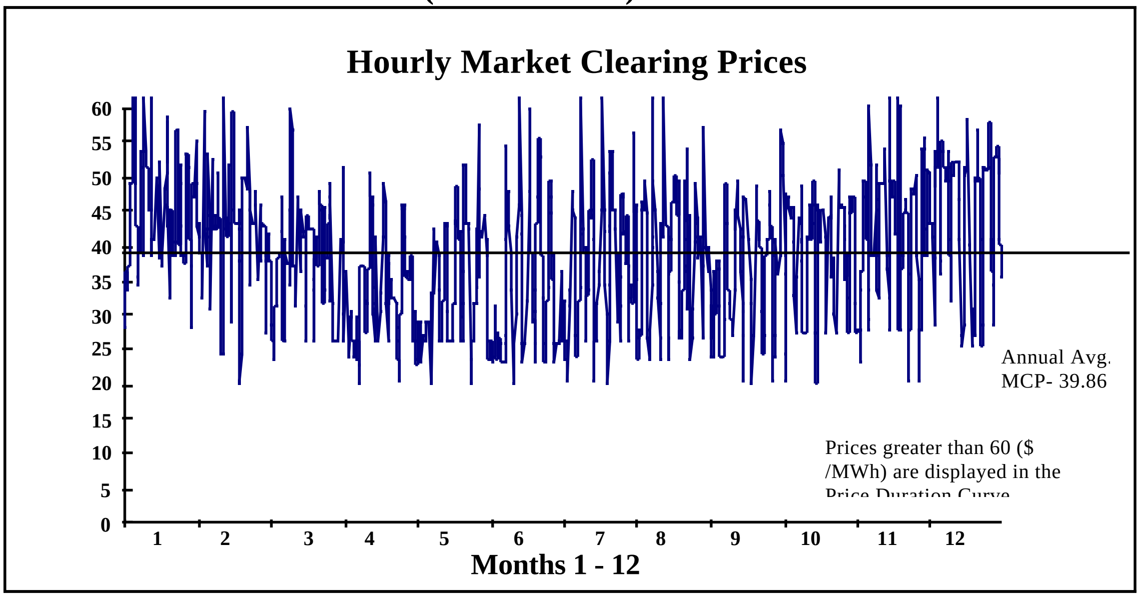


Figure 3.7: Base Fuel Cost Case
(PG&E Zone 3) - 2006



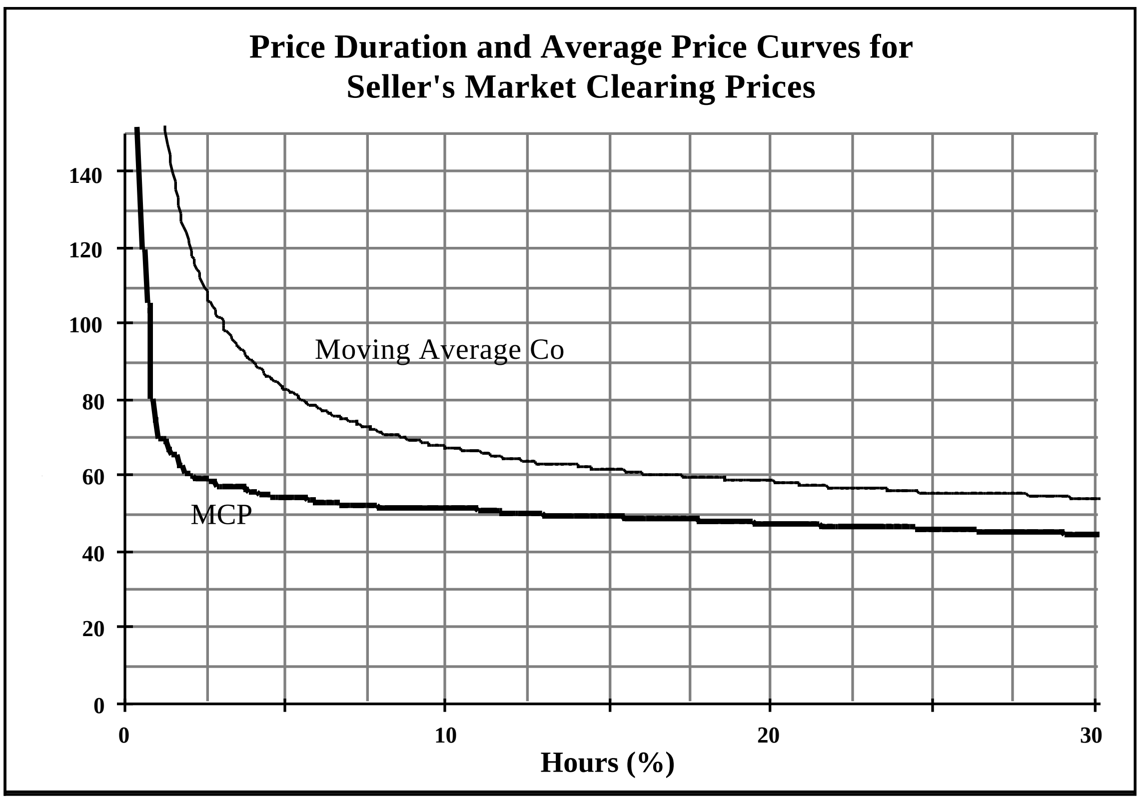


Figure 3.8: Base Fuel Cost Case
(Southern California Zone 4) - 1998

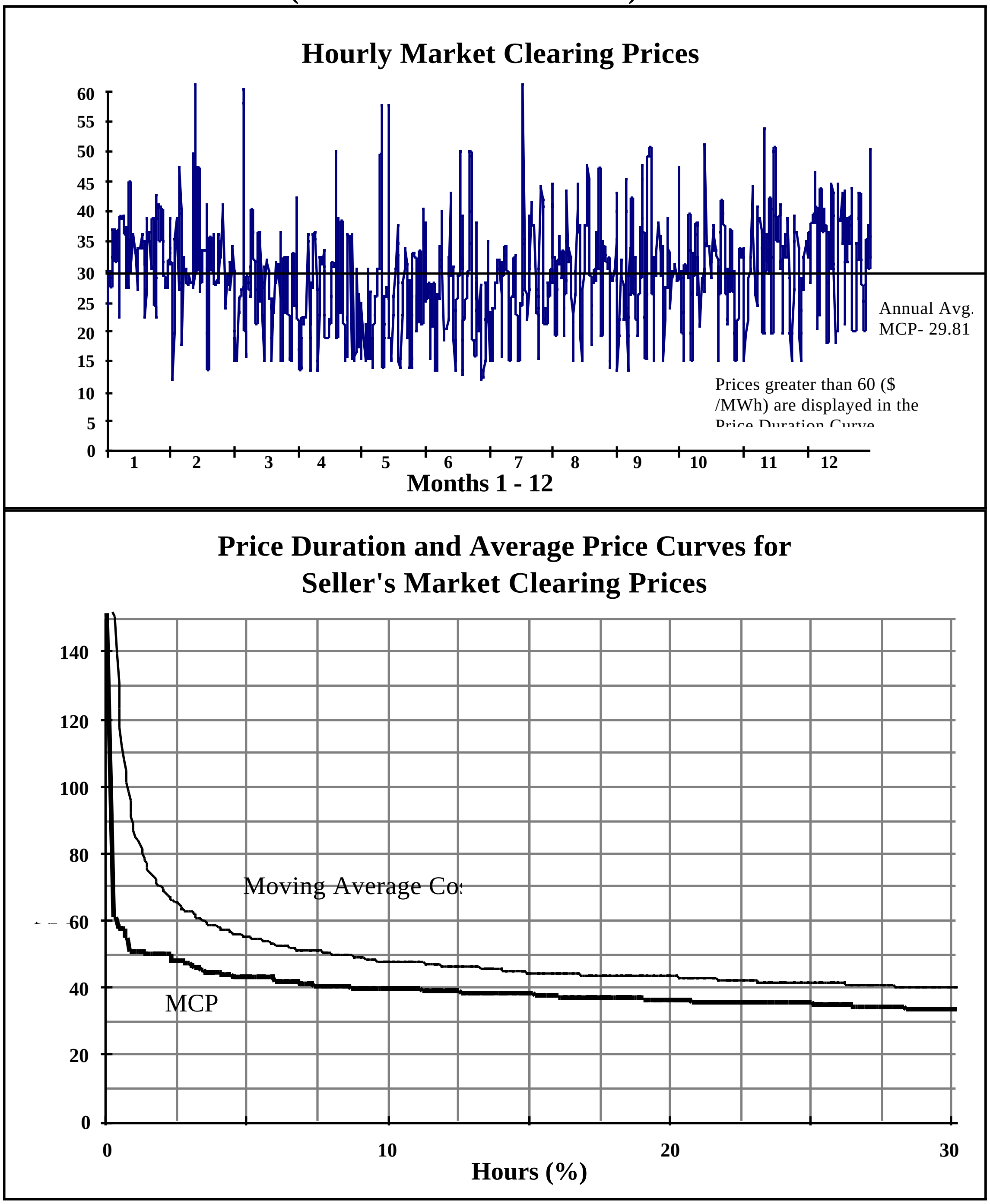


Figure 3.9: Base Fuel Cost Case (Southern California Zone 4) - 2001

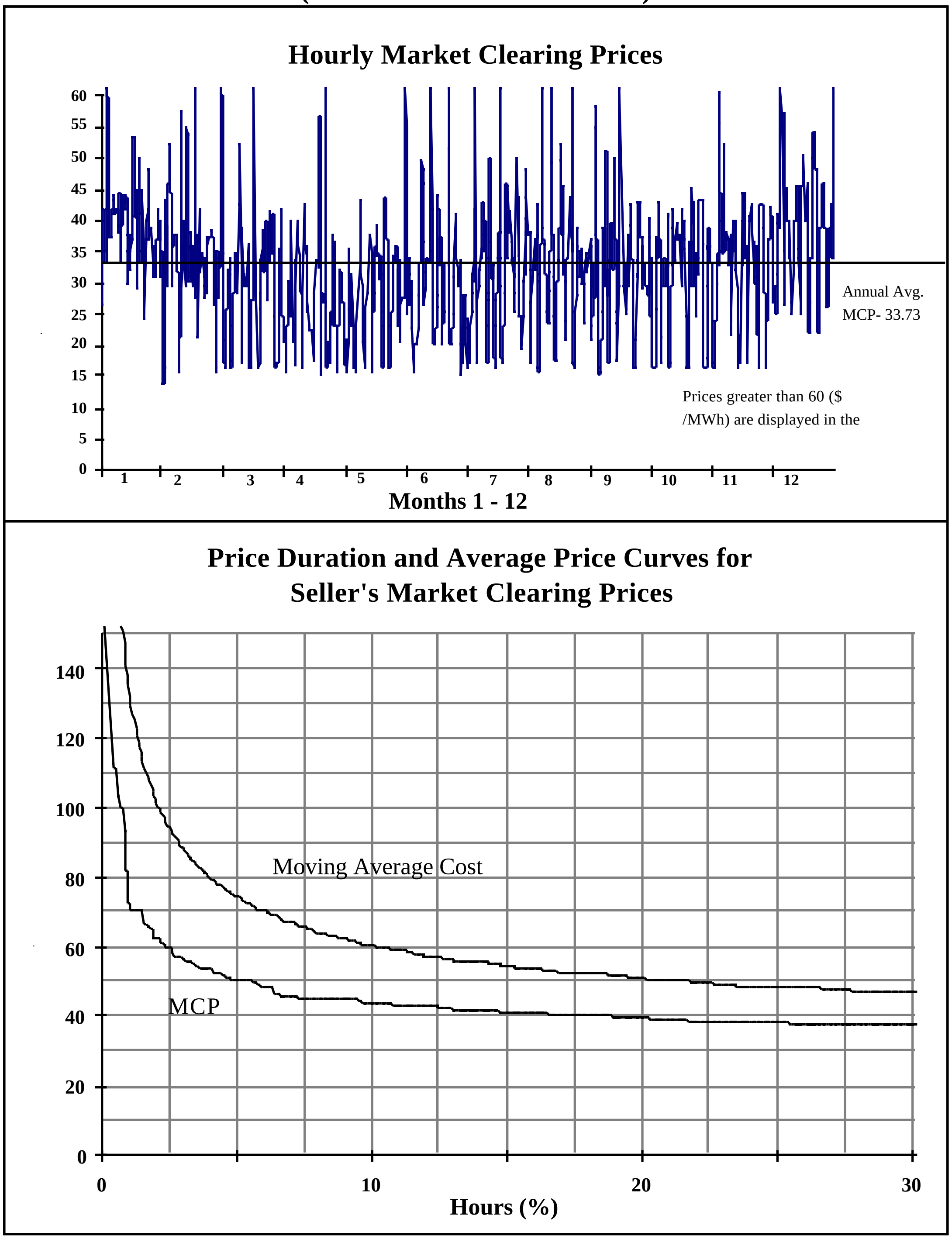
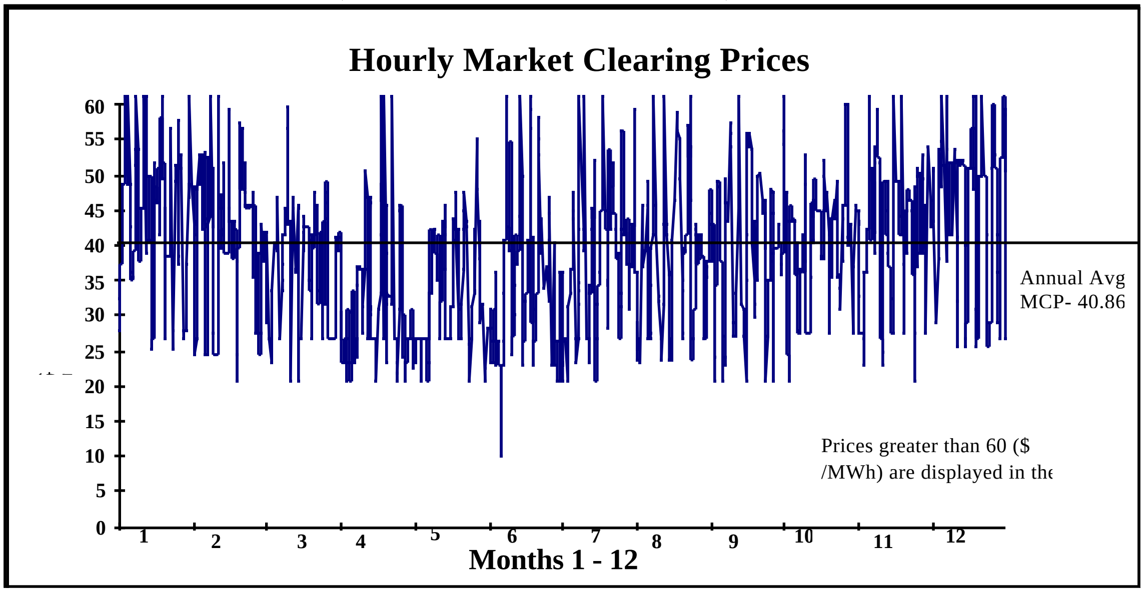
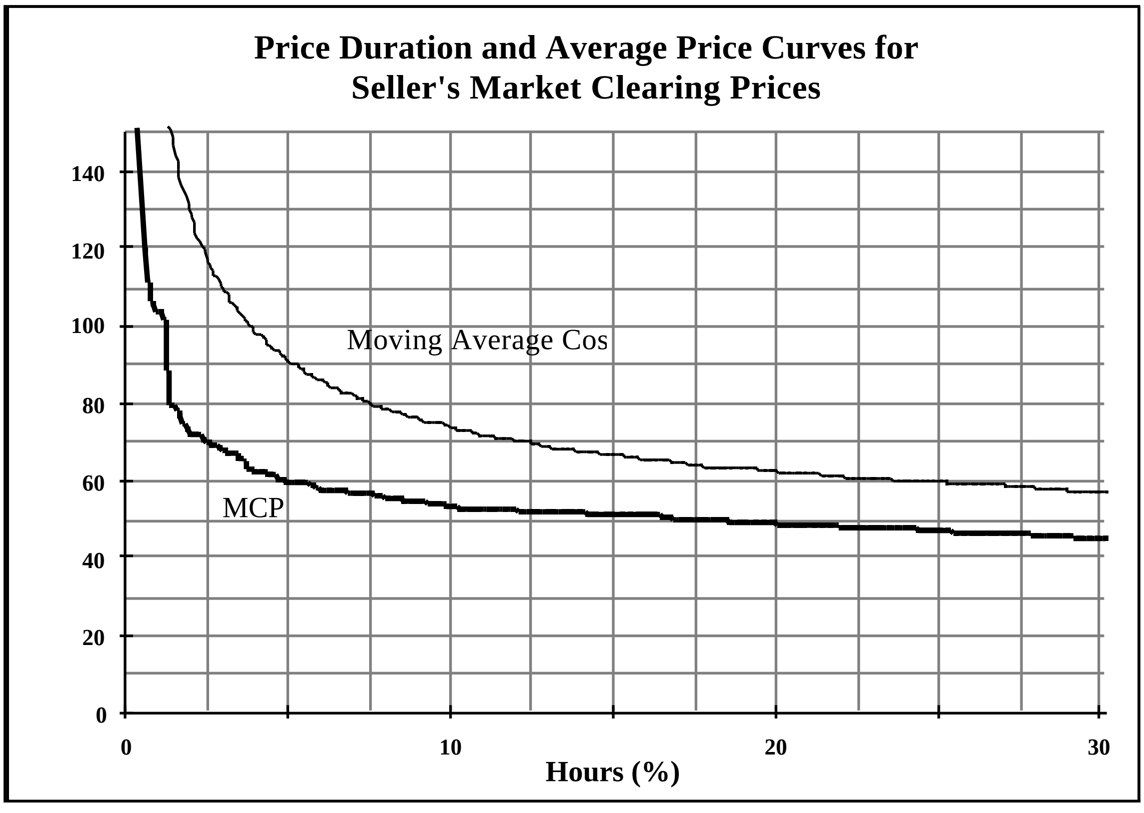


Figure 3.10: Base Fuel Cost Case (Southern California Zone 4) - 2006





3.12 Revenues and Generation Costs

In this section, we describe the results of the study from the perspective of the IOUs and other energy suppliers. The simulation runs use the UPLAN Network Power Model and the WSCC database developed for the study. Throughout this study, we have used the short-run average heat rate with explicit start-up costs as proxy for energy bids. Instead of using reserve bid, we have assumed that the deficit in the net operating income of the reserve (quick start) units is a reliable estimate for reserve payments. We have also assumed that the MCP is not adjusted for the operating cost of the reserve units.

As an alternative case, we have also run the base fuel cost case using an estimate of the most likely long run average heat rate and start-up cost for megawatt hour of energy generated. A comparison of the market clearing prices using the SRAH and the LRAH method of bidding for the base case is presented in Table 3.12.1. The results show that, in this particular case, the differences in the MCPs of the LRAH and the SRAH cases are insignificant. However, there are significant differences in the dispatch of a particular generating unit, its operating cost, and revenue earned between these two bidding methods. The result of using LRAH for bidding is presented in Tables 3.11.10 and 3.12.13 in Appendix B.

In addition to payment for energy and spinning, we have also calculated the reserve payment required to recover the deficit in the net operating income of reserve units. Due to low utilization none of these units can be expected to recover their fixed expenses without special arrangement such as PBR or call options as proposed in the market power filing of May 29 and July 19, 1996 by SCE, SDG&E and PG&E. Table 3.12.1 shows that the impact of adjusting MCP for energy bids of reserve units is relatively minor.

Table 3.12.1 Comparison of Annual Average Sellers' MCP

Case Name / Year	Northern California (Zone 3)			Southern California (Zone 4)		
	1998	2001	2006	1998	2001	2006
BF with SRAH Bids	28.55	32.25	39.86	29.81	33.73	40.86
BF with reserve CT payment	28.56	32.39	39.88	29.89	33.87	40.91
BF with LRAH Bids	28.72	32.77	40.48	29.41	33.36	40.77

The unit operations, costs and revenues for each utility are presented in Tables 3.12.2 through 3.12.8. The generation costs are based on the fixed and variable O&M, start-up costs, and fuel costs. The revenues are based on hourly market clearing prices. In the following sections we describe the results for each individual utility.

3.12.2 Energy with QF Units (in GWh)

Case	PG&E			SCE			SDG&E		
	1998	2001	2006	1998	2001	2006	1998	2001	2006
Base Fuel Cost (BF)	90,371	90,599	90,315	91,981	92,257	90,609	7,262	7,519	7,921
Low Fuel Cost (LF)	98,615	96,740	96,120	95,093	94,888	94,918	8,418	8,651	9,340
With Muni (MP)	90,371	90,653	90,315	91,981	92,300	90,609	7,262	7,518	7,921
Regulated Case (RG)	90,371	90,599	94,814	91,981	92,257	115,740	7,262	7,519	7,871
New Units (BF)	-	-	3,821	-	-	25,292	-	-	-
New Units (LF)	-	-	-	-	-	27,074	-	-	-

Based on our assumptions, there is no difference in the net generation between BF, RG and MP cases for years 1998 and 2001. In 2006, the generation for RG is somewhat higher due to the addition of a 500 MW CT in Northern and Southern California. In the deregulated cases, we assume that the demand bids will set the MCP when there is unserved energy. For the regulated case, in the absence of demand bids CTs are added in to reduce to unserved energy to the level prevailing in 2001.

For the BF case, when the generation of new units is taken into consideration, the overall generation of PG&E, SCE and SDG&E areas increases overtime. The total supply from outside California are 82,011, 92,585, and 96,044 GWh in years 1996, 2001 and 2006, respectively.

In the LF case, there is no new unit added in Northern California. In Southern California in 2006, the new generation is 27,074GWh. Compared to the BF case, there is also an overall decrease of imports to California by 17,591, 15283, and 15,275 GWh in 1998, 2001, and 2006. This decrease in energy import is compensated by an increase in the California energy generation of 12,512, 9,904, and 9,494 GWh respectively in 1998, 2001 and 2006..

Pacific Gas & Electric Company (PG&E):

No PG&E units are retired during the study period because replacement units are not viable as explained in section 3.11. Net income from Contra Costa 6 & 7 is negative in 1998 and 2001, net income from Pittsburgh 5 is negative in 1998 and net income from Pittsburgh 6 is negative in all the three study years. These units can become more efficient by reducing their fixed O&M costs during the transition year when these deficits will be covered by the CTC. In 2006, only Pittsburgh 6 can not cover its fixed O&M costs by 8%, which we assume to be insignificant.

We have found that refurbishing Pittsburgh 6 is not economical because it can only produce a return of investment at the rate of 164 $/KW. Hunters Point 1, 2, 3, 4, Humboltd 1 & 2, Pittsburgh 1, 2, 3, 4 and Portrero 3, 4, 5 & 6 are required for reliability purposes and, according to the PG&E July 19, 1996 market power filing (Tables B.3 and B.4) are "must run" units and their cost is recovered through a reserve payment.

In the LF case, PG&E's generation increases in every year of the study over the BF case. In the Base Case (BF) with all QF units, PG&E's generation is less than the generation in the regulated case (RG) in 2006 due to the addition of 500MW CT.

The average variable cost of generation for the base case decreases by 0.96$/MWh in the year 2006 from the regulated case because of the inclusion of the CT. In the alternative low fuel cost case LF, the cost of generation decreases by 2.76 $/MWh over the regulated case. These results are summarized in Table 3.12.3.

The revenues during these same years for the base fuel costs case(BF) are higher than the low fuel cost case (CF) by 6.88, 7.39, and 8.80 $/MWh which is mainly due to the higher cost of fuel. The payments to PG&E by ISO during these study years for the reserve units are 1.27%, 1.08%, and 0.88% and spinning payments are 0.10%, 0.09%, and 0.10% of total revenue.

Table 3.12.3 Average Generation Costs and Revenue
Pacific Gas & Electric Company

Case	1998			2001			2006		
	Total Energy Gen. (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh	Total Energy Gen (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh	Total Energy Gen. (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh
BF	62,884	11.02	30.99	63,113	12.52	35.33	62,829	15.29	43.72
LF	71,129	10.00	24.11	69,253	11.05	27.94	68,633	13.49	34.92
MP	62,884	11.02	31.08	63,167	12.53	35.63	62,829	15.29	43.74
RG	62,884	11.02	30.99	63,113	12.52	35.33	67,327	16.25	42.98

In Case MP the generation and the average cost of generation remain the same as Case BF. The increase in revenue and net income with muni participation is insignificant.

Table 3.12.4 Net Income - Pacific Gas & Electric

	Net Income (in $000s)			Increase over Base Case		
Case	1998	2001	2006	1998	2001	2006
Base Fuel Cost (BF)	859,372	996,278	1,254,858	-	-	-
Low Fuel Cost (LF)	602,876	720,765	934,326	-30%	-28%	-26%
With Muni (MP)	864,528	1,015,929	1,257,685	0.6%	2%	0.2%

The net income for all the cases for PG&E is summarized in Table 3.12.4. These results indicate that participation by SMUD and other municipal utilities slightly increases the net income of PG&E due to higher demand for energy in Northern California.

Southern California Edison Company (SCE):

In our analysis, we have found that all the SCE plants except Redondo and El Segundo 1,2,3,4 have positive net income in 1998. Only El Segundo has negative income of 14% and 10% of fixed O&M costs in 2001 and 2006. This does not justify retiring the units.

Table 3.12.2 indicates that, for the BF case, in 2001 the total generation increases 276 GWh. In 2006, after adjusting for 25,292 GWh of generation from the new units, SCE's generation is 161 GWh more than the generation in the regulated case (RG).

Table 3.12.5 Average Generation Costs and Revenue
Southern California Edison

Case	1998			2001			2006		
	Total Energy Gen. (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh	Total Energy Gen. (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh	Total Energy Gen (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh
BF	65,334	12.69	31.72	65,610	14.27	36.14	63,962	16.93	44.19
LF	68,446	11.42	25.18	68,241	12.80	29.17	68,271	15.58	36.17
MP	65,334	12.69	32.06	65,652	14.27	36.98	63,962	16.93	44.68
RG	65,334	12.69	31.72	65,610	14.27	36.14	89,093	19.99	43.90

In 2006, the average cost of generation for the base case (BF) is 3.06$/MWh (15%) lower than the regulated case (RG), indicating gradual improvements in generation efficiency over the years. In the low fuel cost case LF, the cost of generation decreases by 4.41$/MWh (22%) from the regulated case.

The revenues during the study years for the base case are higher than the low fuel cost case by 6.54, 6.97, and 8.02 $/MWh which is due to the higher cost of fuel.. Comparison of SCE's generation for different scenarios are displayed in table 3.12.5.

In the MP case, the total generation and the average cost of generation remain the same as that of the base case. The average revenue increases slightly due to increased demand placed by municipal loads on the total available generation in the State of California.

Table 3.12.6 Net Income - Southern California Edison

	Net Income (in $000s)			Increase over Base Case		
Case	1998	2001	2006	1998	2001	2006
Base Fuel Cost (BF)	839,031	986,087	1,210,496	-	-	-
Low Fuel Cost (LF)	536,566	667,913	872,685	-36%	-32%	-28%
With Muni (MP)	860,723	1,042,593	1,242,312	3%	6%	3%

The net income for all the cases for SCE is summarized in Table 3.12.6. The payments to SCE by ISO for reserve units are 0.13% across the study years, and payments for spinning are 0.22%, 0.19%, and 0.19% respectively of total revenue. For the base cases, the net income shows an increase of 302, 318, and 338 million dollars over the low fuel cost case LF. The difference between MP and BF case is 22, 56 and 32 million dollars respectively in the years 1998, 2001 and 2006.

San Diego Gas & Electric Company (SDG&E):

No units were shut down for economic considerations in the SDG&E area. The net income for SDG&E from the operation of the thermal plants is negative. Nine units are unable to meet their operating costs during every year of the study. Because of the low utilization, these units are not viable on an economic basis alone. We have investigated the possibility of repowering Encina 1,2&3 and have found that the repowered unit can generate only a 118$/KW-yr return on investment, which we believe is insufficient to cover refurbishment costs. As a result these units may have to recover their through some form of PBR as proposed by SDG&E.

SDG&E's generation remains the same in the BF, MP and RG cases. The LF case produces approximately 20% more generation than the other cases due to the low fuel cost.

The average costs of generation are basically the same in all cases except in the LF case, when it is slightly lower (4-8%) due to higher generation.

Table 3.12.7 Average Generation Costs and Revenue
San Diego Gas and Electric Company

Case	**1998**			**2001**			**2006**		
	Total Energy Gen. (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh	Total Energy Gen. (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh	Total Energy Gen. (GWh)	Avg. Var. Cost in $/MWh	Avg. Revenue in $/MWh
BF	5,414	14.03	32.79	5,670	16.42	37.60	6,073	20.99	45.95
LF	6,570	13.44	26.27	6,802	15.25	30.45	7,492	19.33	37.57
MP	5,415	14.03	33.04	5,670	16.45	38.38	6,073	20.99	46.43
RG	5,414	14.03	32.79	5,670	16.42	37.60	6,023	20.81	45.83

The net income for all the cases for SDG&E is summarized in Table 3.12.8. For the base fuel cost case, the net income shows an increase of approximately 15 million dollars over the low fuel cost case in these same years. The payments to SDG&E by ISO for reserve are 1.45%, 1.34%, and 1.21%, and payments for spinning payment are 0.43%, 0.34%, and 0.54% of total revenue in 1998, 2001, and 2006 respectively. Although the generation is higher in the Low fuel cost case, the MCP is significantly lower, resulting in a revenue stream that does not completely recover the SDG&E unit's fixed costs. The higher MCP in the base case earns more average revenues and results in a higher net income.

Table 3.12.8 Net Income - San Diego Gas & Electric

	Net Income (in $000s)			Increase over Base Case		
Case	1998	2001	2006	1998	2001	2006
Base Fuel Cost (BF)	28,318	38,949	55,164	-	-	-
Low Fuel Cost (LF)	11,054	22,214	40,289	-61%	-43%	-27%
With Muni (MP)	29,699	43,196	58,080	5%	11%	5%

The detailed results for all the cases for each individual utility are shown in Tables 3.12.9 through 3.12.16 in Appendix B. These include costs and revenues for each utility for the years 1998, 2001 and 2006 for the four cases described in Section 3.7. Also included in the appendix are the costs and revenues for the case with the use of LRAH for bidding strategies, the cases with the use of bidding of reserves, repowering of units, and the case of installing a new coal in the Southwest.

3.13 Transmission and Congestion

Using the UPLAN load flow program, we have monitored the flow across several interfaces described in Section 2. Figure 3.11 through 3.13 present the chronological flows through Path 15, EOR, WOR and COI interfaces. In Table 3.13.1, we display the average savings and the transmission Congestion Costs (CC) for these interfaces. CC indicates the total savings to the customers if all the congestion is relieved across that interface. The average saving or marginal saving is the savings over the year for each additional increase in the capacity of the flow across the interface. The congestion cost reported in Table 3.13.1 is the sum of the hourly saving (dual of interface variable) for relieving the congestion across the interface by one megawatt. In the absence of congestion, these costs, both average savings and CC, are zero. The holders of the Transmission Congestion Contracts (TCC) will receive a payment equal to the transmission Congestion Costs (CC) displayed in Table 3.13.1. Since an interface is composed of several lines and has a complex structure, it is not possible to estimate the cost of a required transmission upgrade.

Table 3.13.1 Summary of Congestion Costs for the Interfaces

	1998		2001			
	COI		EOR		COI	
Case	Avg Saving $1000/MW	CC $1,000	Avg Saving $1000/MW	CC $1,000	Avg Saving $1000/MW	CC $1,000
BF	11.65	56,839	0.21	1,516	23.16	113,052
LF	8.43	41,097	-	14	16.21	79,104
MP	11.65	56,836	0.19	1,409	22.61	110,351
RG	11.65	56,839	0.21	1,516	23.16	113,052

	2006					
	EOR		WOR		COI	
Case	Avg Saving $1000/MW	CC $1,000	Avg Saving $1000/MW	CC $1,000	Avg Saving $1000/MW	CC $1,000
BF	1.78	13,145	0.07	364	30.26	147,667
LF	0.21	1,563	0.15	754	23.00	112,241
MP	1.78	13,145	0.07	364	30.26	147,667

RG	1.88	13,879	0.18	895	26.90	131,279

The COI interface shows 1000-1500 hours of congestion in every year of the study. The CC at COI ranges from 41 to 147.7 million dollars per year. In the year 2001 and 2006, there is congestion on the East of the River (EOR) interface, constraining imports from the Pacific Southwest to California. The congestion costs savings range from $14,000 to 13.9 million dollars between 2001 and 2006 depending on the case. For the WOR interface, there is no significant congestion in 1998 and 2001 but some congestion ranging from $364,000 to $895,000 in 2006 depending on the cases.

The annual savings from congestion relief range from 8,430 to 30,260$/MW for COI and 0 to 1,880$/MW for the EOR interface. The congestion cost of the LF case is the lowest when California generation replaces some of the imports.

The flow duration curves for these paths are show in Figures 3.14 through 3.16. Only the COI interface from Oregon to NOCAL shows congestion for all years; 1998 through 2006. The flow duration curves are particularly helpful in analyzing the impact of an interface capacity on the number of hours the flow across the interface is constrained and the additional cost incurred for meeting the demand from higher cost generation. For example consider the flow duration in Figure 3.14, if the interface capacity in Path15 north to south in 1998 is 3,000 MW, the interface will be congested for 2370 hours. Also note that to reduce the congestion to 740 hours will require an increase in the interface limit to 4000 MW an increase of 1000 MW.

Figure 3.11.a: Hourly Flow Through Path 15

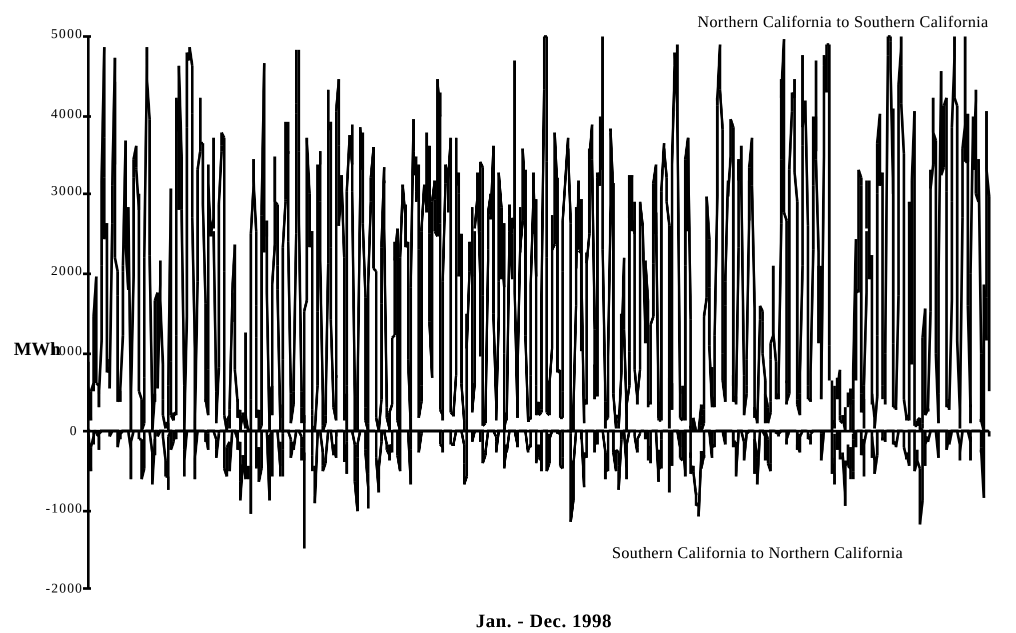
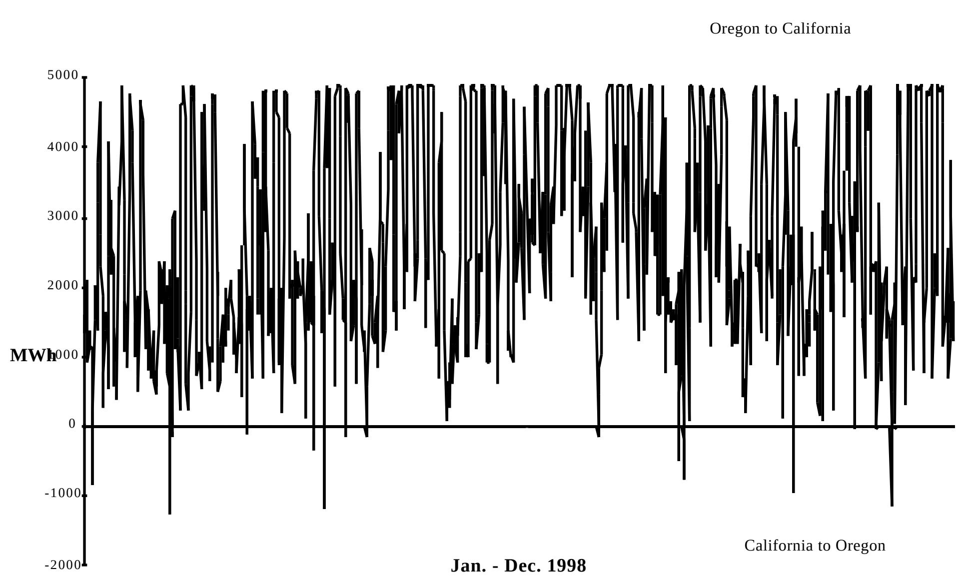


Figure 3.11.b: Hourly Flow Through California-Oregon Transmission



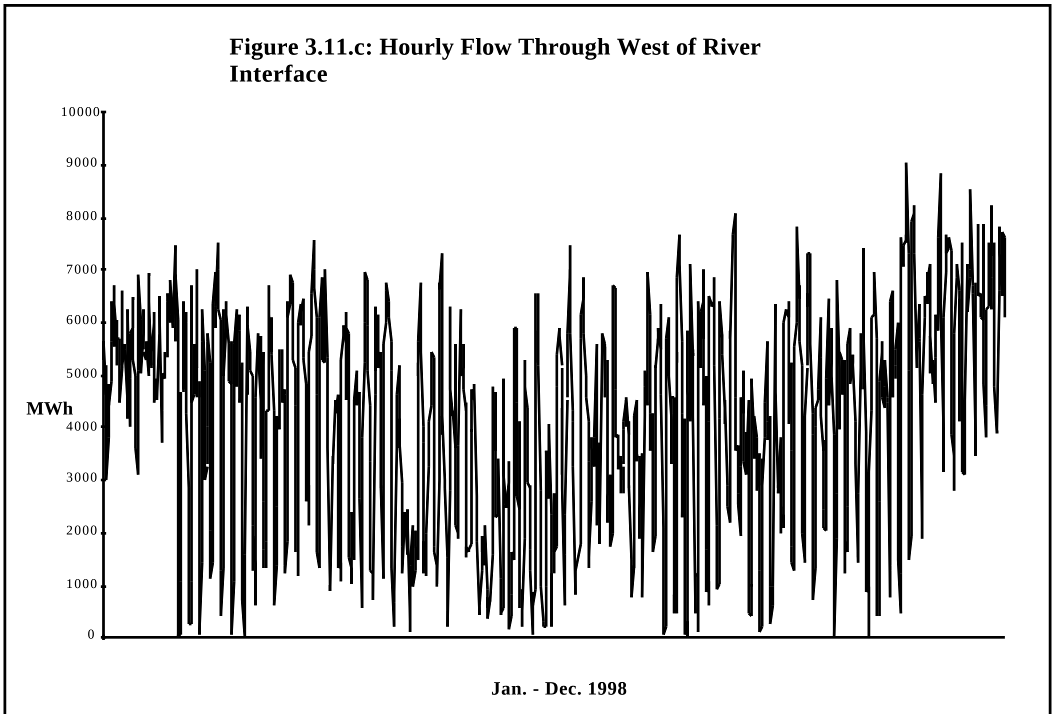


Figure 3.11.c: Hourly Flow Through West of River Interface
MWh
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
Jan. - Dec. 1998

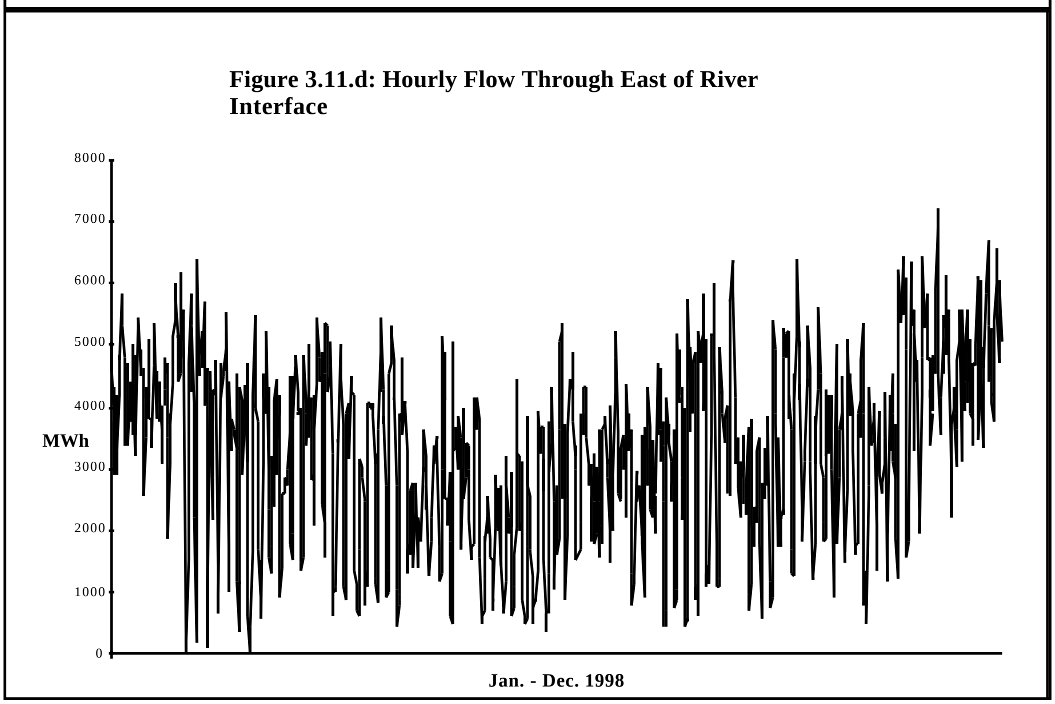


Figure 3.11.d: Hourly Flow Through East of River Interface
MWh
8000
7000
6000
5000
4000
3000
2000
1000
0
Jan. - Dec. 1998

Figure 3.12.a: Hourly Flow Through Path 15

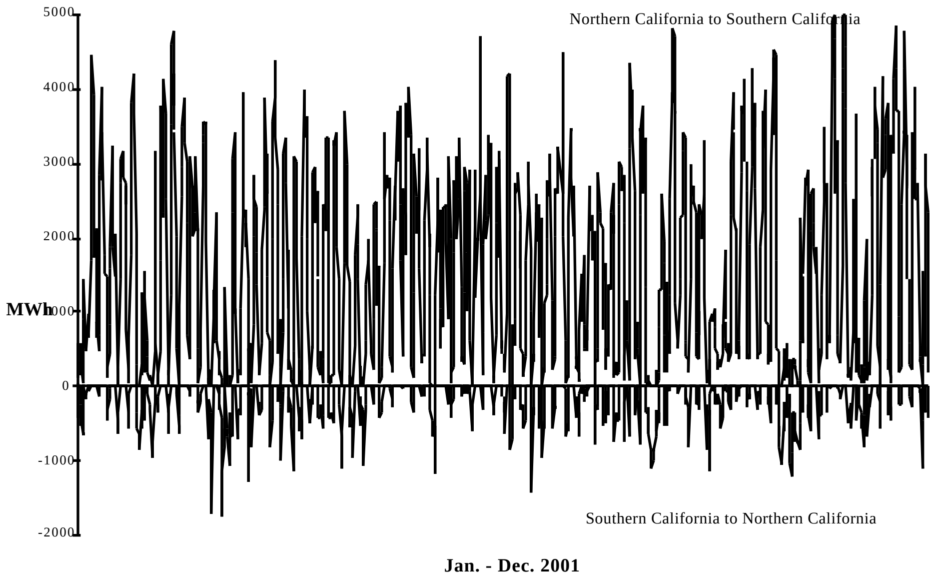


Figure 3.12.b: Hourly Flow Through California-Oregon Transmission

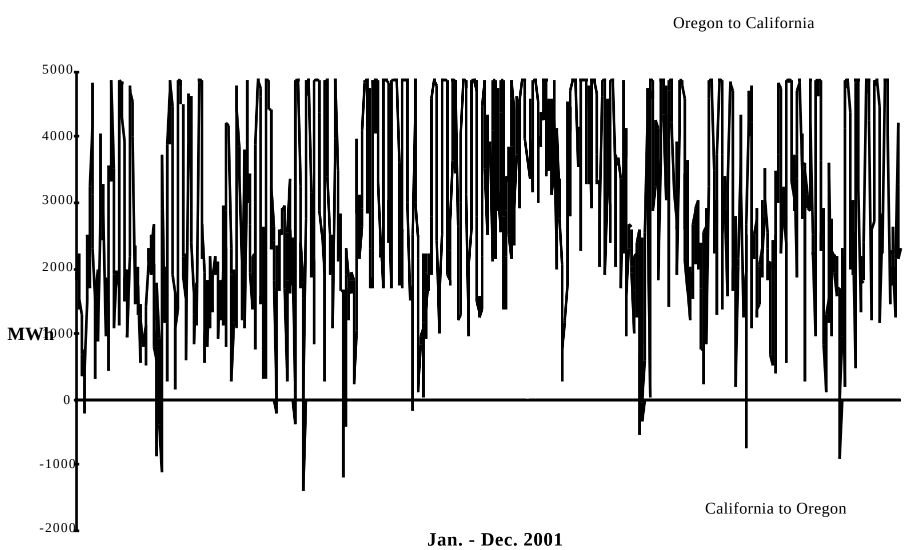


Figure 3.12.c: Hourly Flow Through West of River Interface

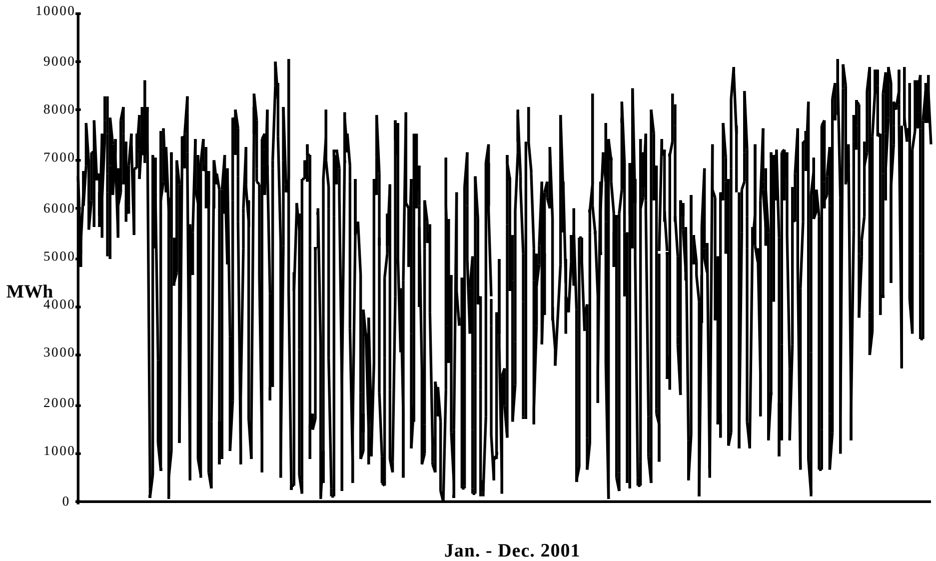


Figure 3.12.d: Hourly Flow Through East of River Interface

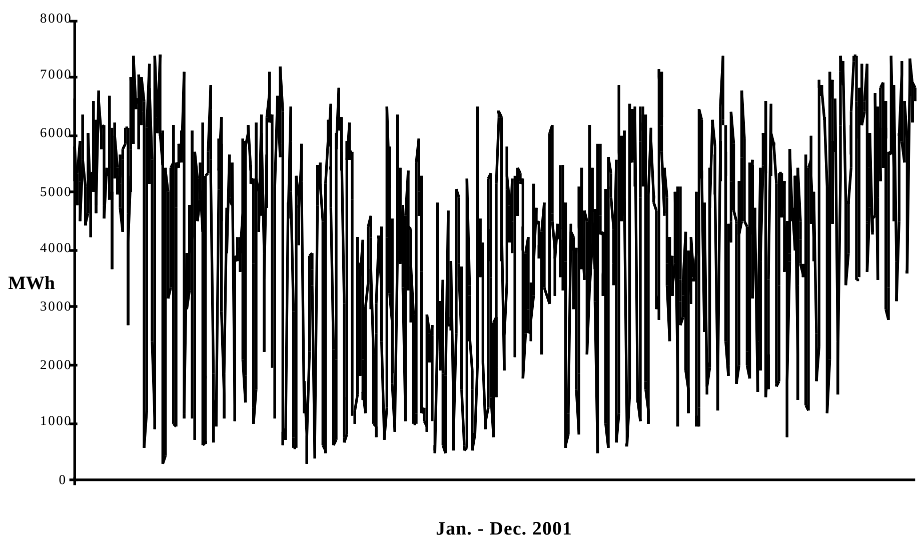


Figure 3.13.a: Hourly Flow Through Path 15

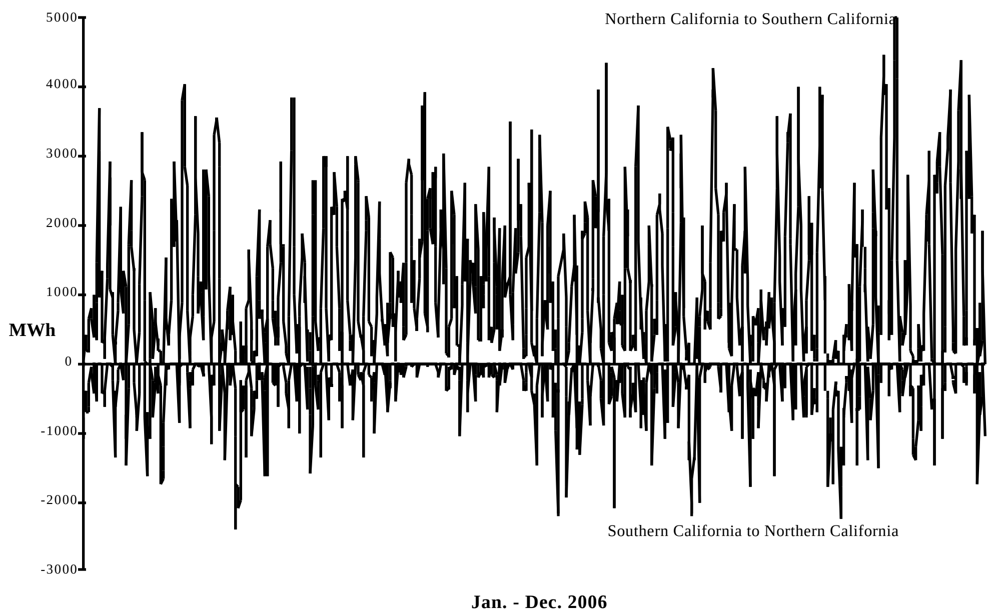


Figure 3.13.b: Hourly Flow Through California-Oregon Transmission

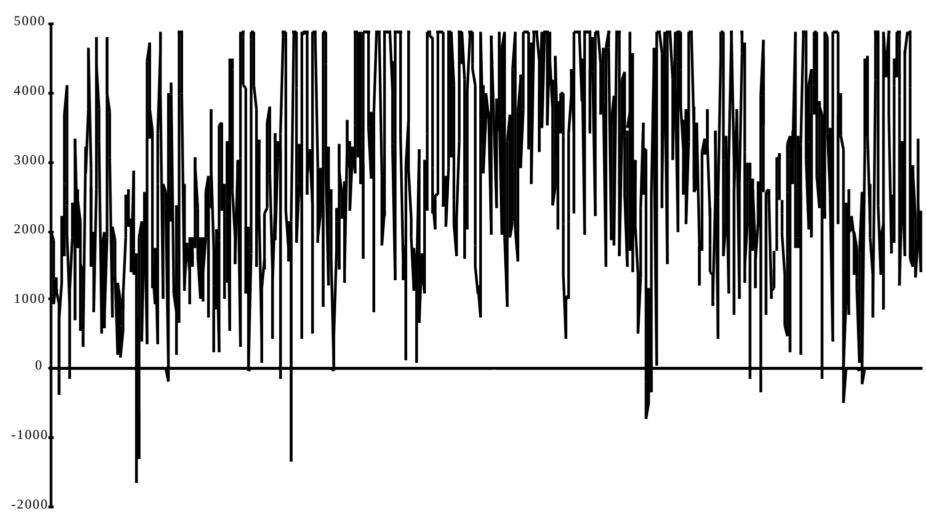


Figure 3.13.c: Hourly Flow Through West of River Interface

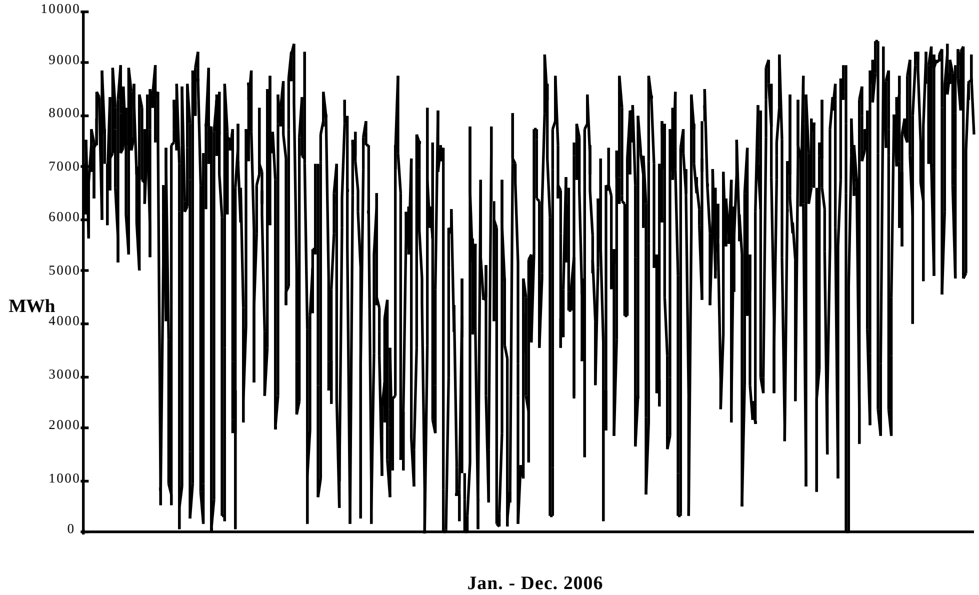


Figure 3.13.d: Hourly Flow Through East of River Interface

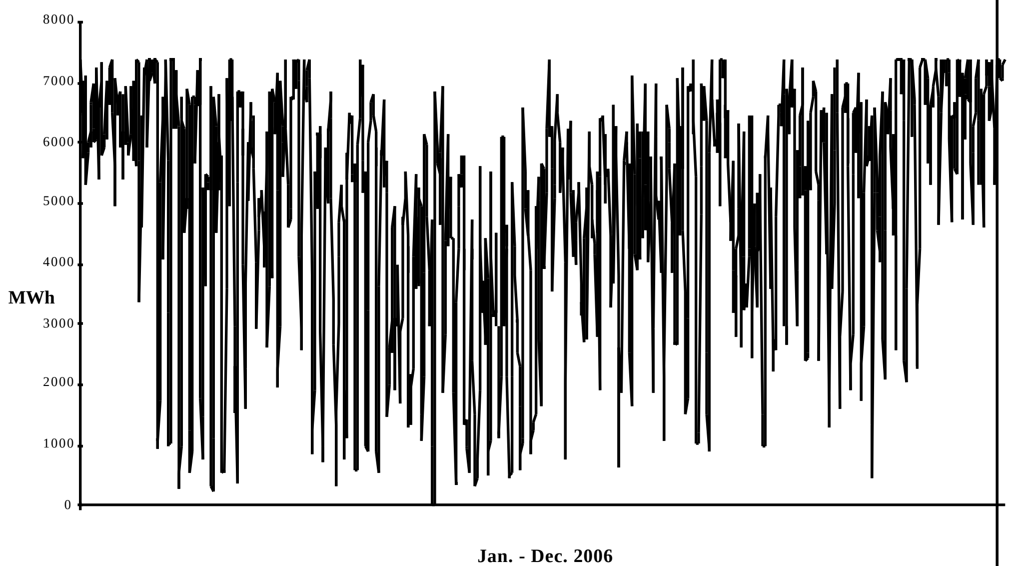


Figure 3.14: Hourly Flow Duration Curves
1998

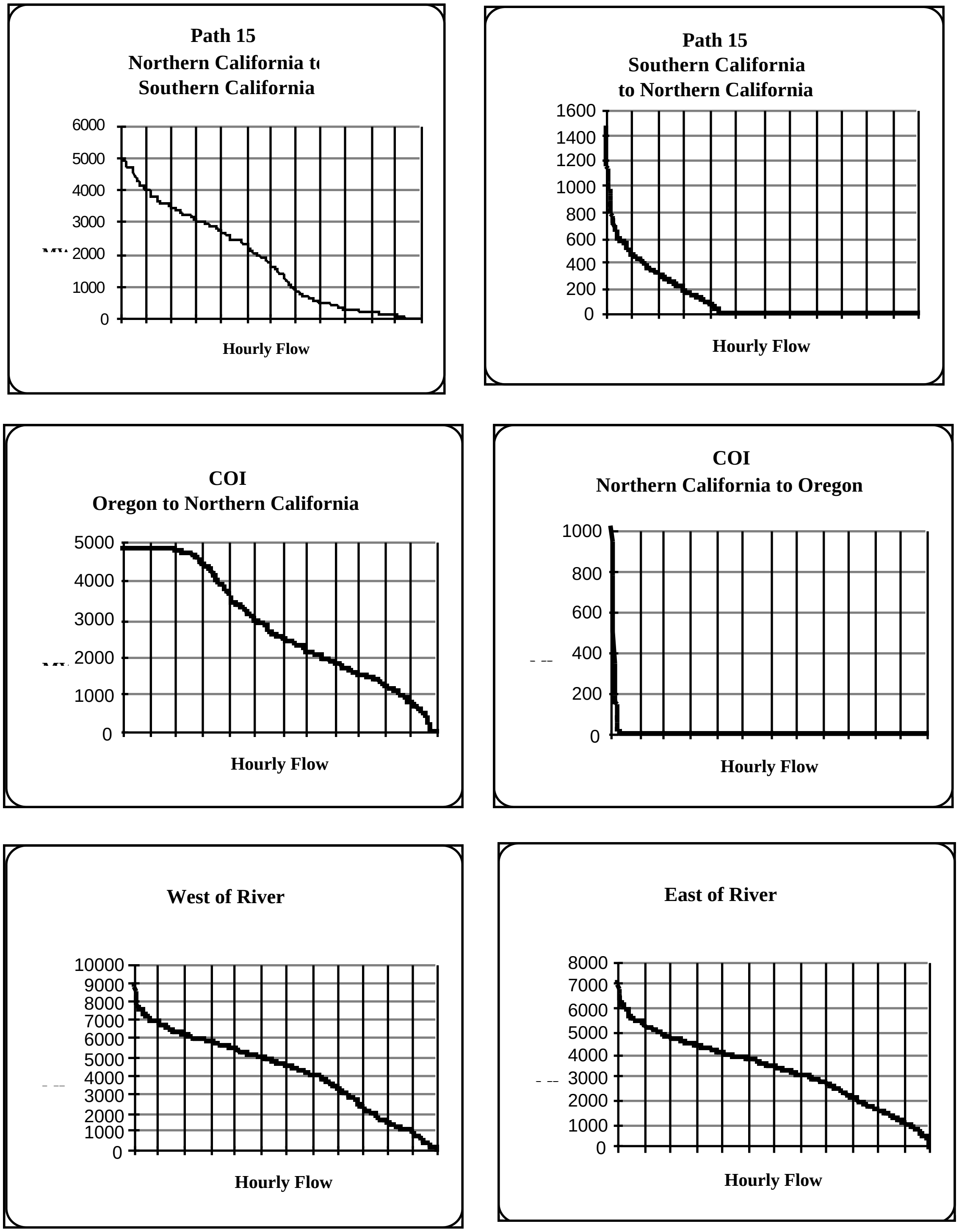


Figure 3.15: Hourly Flow Duration Curves
2001

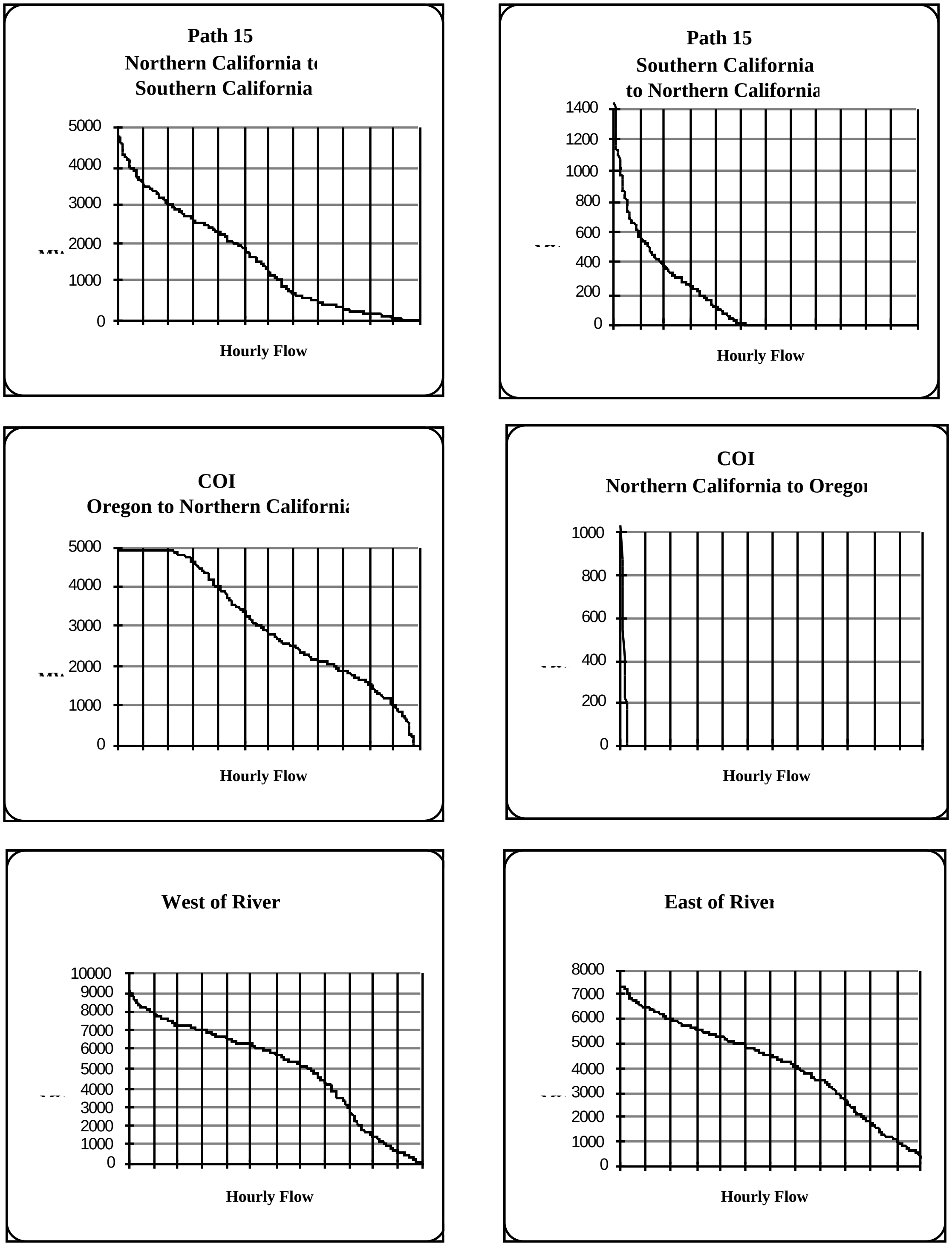
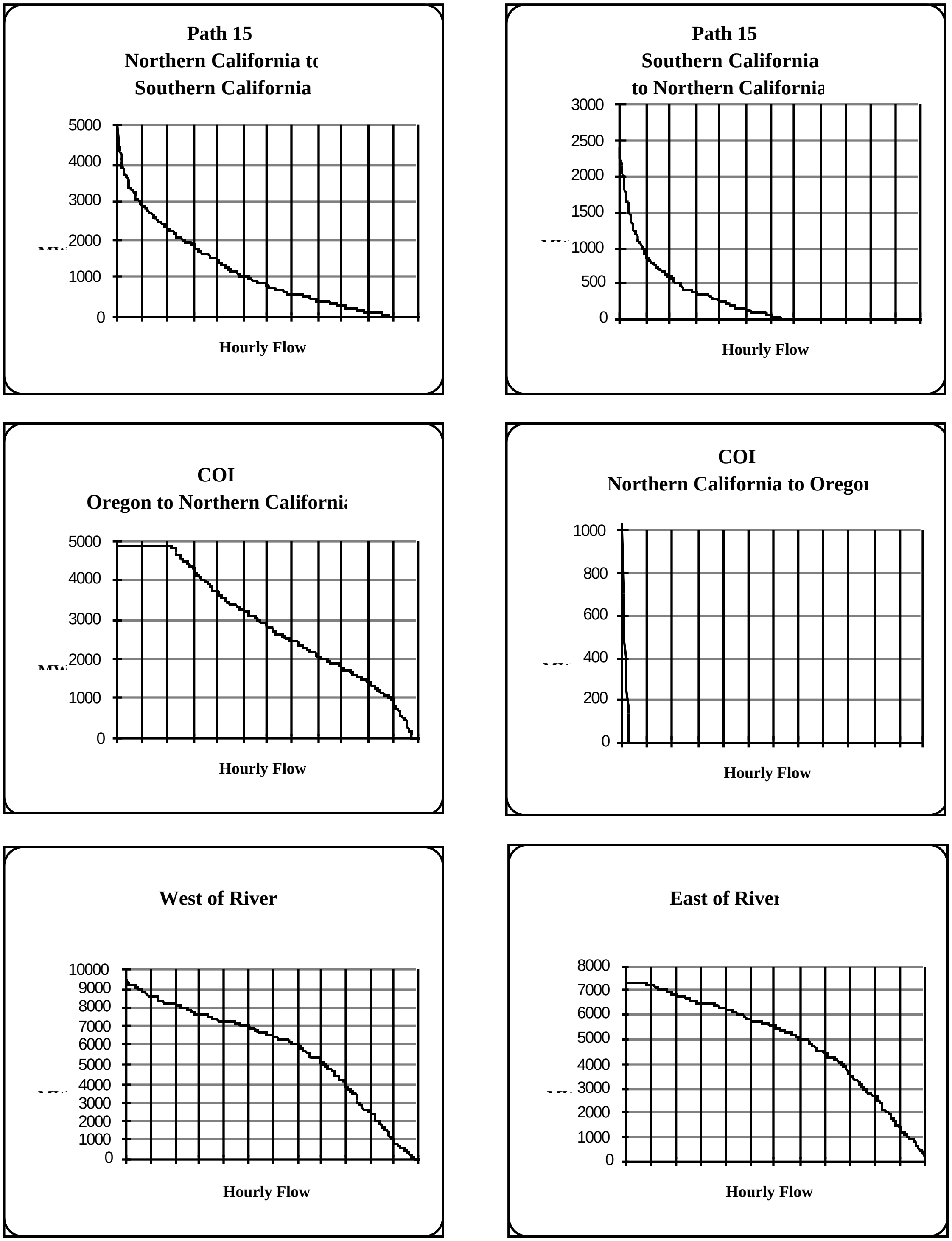


Figure 3.16: Hourly Flow Duration Curves
2006



3.13.1 Congestion Rebates

In addition to the congestion costs described in Section 3.13, the ISO will accumulate revenue due to difference in MCPs between the four ISO control zones. These differences could be due to congestion, unavailability of import from low cost zones or due to the method of computing MCP in different zones. As a result the customers in the higher MCP zone may over pay the ISO for the lower cost import from other zones. In this study we have calculated the over payment as rebate to the customer at higher cost zones.

Table 3.13.2 Buyers' Rebate
Congestion Payment For MCP Differential ($000)

Custome r Zone*	Year		
	1998	2001	2006
1	$10,684	$12,181	$15,241
2	$182	$236	$350
3	$3,759	$5,520	$10,176
4	$61,009	$50,917	$42,879

* Zone 1 = San Francisco   Zone 2 = Humboldt
Zone 3 = PG&E (Northern California)   Zone 4 = SCE, SDG&E, and 30% of PG&E

In Table 3.13.2, we provide estimates ISO over-collection which can be used to reduce the bills for the customer in each of the four zones. The rebate to the customers in zone 4 ranges form 42 to 61 million dollars and is mainly due to import from zone 3. There is a slight decrease in rebates in the zone 4 in 2006 due to decrease in import to zone 4 from zone 3 from 15,893GWh in 1998 to 10,168 GWh in 2006. The total rebated for the PG&E service territory ranges from 14.6 million in 1998 to 25,8 million in 2006. In 2006 the low cost import from Southern California increases by 120% from 1998.

More than 50% of the rebate in PG&E territory is applied to customers in San Francisco for imports from PG&E zone 3.

3.14 Emissions

The impact of restructuring and competition on emissions has been analyzed using the production data and emission calculations in UPLAN. Table 3.14 in Appendix B shows the emissions produced by the IOUs as well as in the WSCC region for the three study years. The emissions analyzed were Sulfur Dioxide (SO_2), Oxides of Nitrogen (NO_X), Reactive Organic Gases (ROG), Carbon Monoxide (CO), Elemental Carbon (C), and Particulate Matter -10 microns or less in size (PM10).

It is difficult to compare the emission of the California utilities from year to year due to changes in imports and exports between demand areas. There is also a shift of generation between different regions within WSCC. A better indicator of changes in the emission is to compare the overall emission rates from year to year in the entire WSCC region. Our results indicate that although there is a gradual increase in total emission in the region in all categories, there is an overall decreases of emission rates in WSCC control area for every category of emission type.

This decrease probably results from the introduction of new generating units using technologies with greater emission controls for limiting emission. The California emission rate does not indicate any substantial improvements over time. This may be partly due to the fact that few new generating units with better emission rate are added in California. Moreover, in Table 3.14, the emissions for new California generating units is added to the emission in WSCC and not to the emission of the California IOUs. The IOUs will not necessarily be the owners of new California generating units.

Table 3.15: Annual Emission Report

Year	Company	Emission (1000 lbs)					
		SO2	NOx	ROG	CO	C	PM10
1998	PG&E	7,794	77,578	9,245	77,745	15,868,286	4,618
	SCE	131,344	329,765	68,428	52,669	26,762,964	16,289
	SDG&E	42	4,967	267	1,544	1,282,898	123
	WSCC	**1,026,431**	**1,310,032**	**88,980**	**201,848**	**160,506,960**	**60,815**
2001	PG&E	7,800	77,461	9,251	77,799	15,925,138	4,629
	SCE	131,712	330,354	68,371	52,662	26,870,359	16,277
	SDG&E	43	5,252	270	1,642	1,364,092	131
	WSCC	**1,028,516**	**1,316,382**	**90,714**	**204,634**	**168,603,984**	**64,133**
2006	PG&E	7,834	77,381	9,465	77,958	16,712,874	4,971
	SCE	130,501	329,072	69,433	53,354	32,337,410	18,457
	SDG&E	51	5,735	275	1,801	1,502,426	144
	WSCC	**1,055,943**	**1,313,121**	**94,375**	**207,873**	**183,672,992**	**72,031**

Year	Company	Emission (lbs/GWh)					
		SO2	NOx	ROG	CO	C	PM10
1998	PG&E	86	858	102	860	175,591	51
	SCE	1,428	3,585	744	573	290,962	177
	SDG&E	6	684	37	213	176,649	17
	WSCC	**1,535**	**1,959**	**133**	**302**	**240,068**	**91**
2001	PG&E	86	855	102	859	175,776	51
	SCE	1,428	3,581	741	571	291,256	176
	SDG&E	6	698	36	218	181,429	17
	WSCC	**1,465**	**1,875**	**129**	**291**	**240,169**	**91**
2006	PG&E	87	857	105	863	185,051	55
	SCE	1,440	3,632	766	589	356,890	204
	SDG&E	6	724	35	227	189,676	18
	WSCC	**1,372**	**1,706**	**123**	**270**	**238,649**	**94**

Note:

SO2	Sulfur Dioxide	CO	Carbon Monoxide
NOx	Oxides of Nitrogen	C	Elemental Carbon
ROG	Reactive Organic Gases	PM10	Particulate Matter (10 microns or less in

Note 2: The emissions of SCE include the following numbers

Coal (SCE)	= 13%	QF	= 47%
Coal (Others)	= 13%	Self Generation	= 22%
Thermal	= 5%		

3.16 Municipal Utilities Participation

An analysis of the impact of the municipal utilities joining the ISO/PX is done in MP case. In this case, the municipal loads and resources follow the PX rules, and the transmission operation is under the control of the ISO. In the municipal participation case, the dispatch of the generating plants is not expected to be different from the other cases without municipal participation, since the SRAH is used for the dispatch of the units in both cases. However, in the presence of bidding, this may change if the bid prices are substantially different from SRAH costs.

A comparison of nodal MCs shows that there is very little difference in marginal cost of generation between the municipals and the adjacent zones. A comparison of the nodal spot prices for SMUD and LADWP can be found in Table 3.16.

Table 3.16 Comparison of Muni and IOU Nodal MC (Current $/MWh)

Year	PG&E	SMUD	SCE	LADWP
1998	20.07	20.11	19.95	19.9
2001	23.33	23.39	22.78	22.63
2006	28.43	28.47	27.48	27.29

We cannot conclude at this time from the UPLAN results whether it will be economically advantageous for the municipal customers to participate in the power pool. Other factors, such as the preferential treatment munis receive in the allocation of energy from federal hydro facilities and their access to lower cost capital through tax-exempt bonds may also influence the munis' decision to participate in the in a competitive energy market.

3.17 Rate Impact

In their CTC filings to the California State Senate, the IOUs have responded to a data request for the components of the average annual system cost for electricity under the CPUC's restructuring plan and continuation of the regulatory status quo. These data have been used to estimate the elements of the total rate that needs to be added to the Ratepayers' MCP to determine the total average rate in the restructured case. For PG&E, the data for restructuring rate settlement was used. For SCE, assumption associated with the scenario for the fossil market value equal to the book value were used. Insufficient data was available for San Diego Gas and Electric Company in their CTC filing to calculate rate impact.

Table 3.17 Annual Average Rates for Base Case

($/MWh)

	Pacific Gas and Electric			Southern California Edison		
Price Components	**1998**	**2001**	**2006**	**1998**	**2001**	**2006**
BF Rate	31	35	44	32	37	44
T&D	29	30	33	30	33	36
PSP	3	3	3	2	2	1
CTC	38	34		35	21	
Total Rate	101	102	80	99	93	81
Utility Regulatory Rates	99	109	79	101	98	88

Since data to recalculate the CTC based on the MCP is not available, the IOUs' initial CTC estimates were modified and used in Table 3.16 to determine the total rate impact of the restructured industry. We have also assumed that the CTC will not be applicable in 2006 and thereafter. For comparison, the IOU estimates of the rates under regulatory status quo are also shown. The comparison shows an overall decrease in rates to be paid by PG&E's and SCE's consumers as a result of the restructuring plan during the transition period in 2001 and 2006.

The results in Table 3.17 is approximate. An accurate determination of the rate impact requires a detailed assessment of the Competitive Transition Charge and T&D costs . However, such an assessment is beyond the scope of this study.

3.18 Market Power

Whether or not a firm can exercise market power depends on its relationship to other firms in the market. One of the simplest measures of dominance is the share of the market which the largest firm controls in an oligopolistic structure. Although there are no hard or fast cut-off points for market share, a degree of market power may be indicated when the market share of any individual utility rises above 35 percent.

A more elaborate measure of market power is the Herfindahl-Hirschman Index (HHI). The UPLAN analysis applied the market shares/HHI test to the annual energy generation of the California utilities for the study year 2006. The HH indices were developed for Northern California, Southern California and for the composite California energy market taking into consideration the inter and intra- regional flows. Table 3.17.1 presents the market shares and the associated HHIs of all electricity supplied by the California utilities, non-utility generators (NUG) and Out-of-State power sources (OSP) in 2006, the last year of the study.

Table 3.18.1 HERFINDAHL - HERSCHMAN INDEX

		Year 2006 (%)	
	Company	California Regional Market Share	California Composite
NORTH	PG&E	43.3	14.6
	PG&E QF	22.3	7.5
	PG&E div	7.6	2.6
	SMUD	3.5	1.2
	Others	0.8	0.3
	N.Import	20.7	7.0
	S.Import	1.9	-
	Index-North	**2872.3**	-
SOUTH	LADWP	25.6	17.1
	SCE	23.0	15.4
	SCE QF	10.9	7.3
	SCE div	3.3	2.2
	SDG&E	3.3	2.2
	BGPIID	0.6	0.4
	N.Import	12.7	8.5
	S.Import	20.7	13.9
	Index-South	**1914.8**	-
	Index-California	-	**1182.8**

In this analysis, it has been assumed that the utilities will divest half of their fossil fuel generation capacity and new firms will supply approximately 50 percent of the energy that the IOUs would have generated from these plants. Furthermore, a significant portion of the PG&E and SCE generation are from their hydro and nuclear facilities. The treatment of these plants has not been resolved and it is possible that these indices will change depending on the operational control of these units.

For the overall California market, PG&E and SCE hold 43.3% and 23.0% respectively of the market share after divestiture and excluding QFs. The corresponding HH index in year 2006 ranges between 2872 for Northern California to 1915 for Southern California. For California as a whole, the HH index is 1183.

The impact of bidding strategies and the proposed Bidding trust by PG&E has not been studied in this report. We recommend that further UPLAN analysis to simulate the impact of alternative bidding strategies in order to understand the potential for market power in a restructured industry.

A more accurate insight of market power can be gained by examining various utility bidding strategies, evaluating how often particular plants set the market clearing price, and determining how many total dollars the MCP setting supplier is receiving from the PX. To evaluate the impact of bidding on the MCP, LCG has developed two dynamic indices, namely the UPLAN Market Clearing Price Duration Index (U-MCPI) and the Market Revenue Index (U-MRI). U-MCPI determines the percent of time a unit or a group of units set the MCP and U-MRI reflects the percent of the market (in terms of total revenues) controlled by a group of units. These results are presented in the Tables 3.17.2 and 3.17.3 and are useful in designing strategies for successful bids. These zonal indices are presented as the sum of the squares of the market share for each zone. These tables do not incorporate the divestiture of the PG&E and SCE units as proposed.

Table 3.18.2 UPLAN Market Clearing Price Duration Index (U-MCPI)
for the year 2006

Owner \ Zone	Average MCP of the Units ($/MWh)				Percent of Hours MCP Set by Units (%)			
	1	2	3	4	1	2	3	4
PG&E	41.4	41.2	44.0	43.8	58.0	57.9	70.3	37.0
Arizona/New Mexico	27.2	26.8	26.8	26.9	22.0	21.6	14.3	16.4
SDG&E	57.5	57.9	59.7	57.1	2.5	2.3	2.4	18.4
Pacific Northwest	27.8	27.2	27.9	28.2	8.8	8.6	4.6	5.9
Northern California	28.3	28.3	28.3	28.3	0.8	0.8	3.2	0.7
Nevada	37.5	35.6	35.3	35.0	1.7	2.4	1.4	2.7
Rocky Mountain	23.3	23.5	23.3	24.1	4.8	5.1	2.8	2.7
SCE	41.4	37.4	41.0	39.6	0.8	0.7	0.9	15.8
Southern California	23.9	23.9	20.5	23.9	0.6	0.6	0.2	0.6
UPLAN Index					3964	3937	5198	2272
UPLAN Index-50% Divestiture of PG&E and SCE					2280	2258	2724	1463

Table 3.18.3 UPLAN
Market Revenue Index (U-MRI)
for the year 2006

Owner \ Zone	Total Market Revenue Set by the Units ($000)				Percent of Market Revenue Set by the Units (%)			
	1	2	3	4	1	2	3	4
PG&E	173423	12201	2231918	2667299	70.8	71.1	80.7	44.1
Arizona/New Mexico	32668	2207	203432	434687	13.3	12.9	7.4	7.2
SDG&E	11649	793	122829	1753513	4.8	4.6	4.4	29.0
Pacific Northwest	13503	875	66100	181144	5.5	5.1	2.4	3.0
Northern California	1114	81	46955	18268	0.5	0.5	1.7	0.3
Nevada	4376	427	34409	144866	1.8	2.5	1.2	2.4
Rocky Mountain	5278	420	33044	52887	2.2	2.4	1.2	0.9
SCE	2334	118	26822	786836	1.0	0.7	1.0	13.0
Southern California	655	47	1706	12017	0.3	0.3	0.1	0.2

UPLAN Index		5250	5277	6592	3019
UPLAN Index - 50% Divestiture of PG&E and SCE		2745	2751	3338	1963

If we assume that PG&E and SCE divest half of their units which are setting the MCP, we can recalculate the indices. The correspondingly revised values are reported in the last row of each of the Tables 3.18.2 and 3.18.3. Note that divesting 50% of the thermal units does not necessarily imply divestiture of half of the units which set market clearing prices.

It is interesting to note that a small number of units can dominate the market in terms of the U-MCPI and U-MRI indices. In the above example, the San Diego Gas and Electric units Encina 1,2,3,4&5 and South Bay 1,2,3&4 set the market clearing price for 18% of the hours whereas the same units control 29% of the revenues for entire Southern California zone. The U-MCP and U-MRI indices are useful in determining the market power which can be exercised through bidding strategies by a group of units.

APPENDIX A

A.1 Simulation of Supply Resources

In UPLAN, a generating plant is identified as a resource which can be dispatched to meet the load for an individual utility or a pool. The utilization of generating plants is optimized by the Dispatch Model, the Hydro Scheduler, the Maintenance Model, and the Network Power Model.

All constrained units like hydro can be optimally scheduled by using the powerful multi-stage Hydro and Transaction Scheduling Model which determines the optimal hourly schedules to minimize the marginal operating cost.

Pump storage and hydroelectric generation can be scheduled to achieve maximum economy consistent with the reservoir limitation and any maximum/minimum generation constraints arising from physical or operating considerations. Hydraulically coupled units with multiple reservoirs in series and the effect of variable head can be modeled. The pumped storage operation can be scheduled on the basis of daily, weekly, or monthly cycling. In this study, we have used single stage hydro modeling.

UPLAN can be used to plan scheduled maintenance outages or to accept prescheduled maintenance cycles from an external database, or a combination of the two. The UPLAN automatic maintenance scheduler can preschedule the planned outages to either minimize the total operating cost over the planning period or to levelize the reliability or reserves of the system on a daily basis. The model uses maintenance cycles to schedule major and minor overhauls over the planning period, while respecting user defined forbidden time zones. The schedule of all units can be graphically displayed.

Wholesale contracts can be represented as bilateral buy/sales contracts to be traded at a designated interface point. A purchases and sales model allows users to create unit-specific buy and sales contracts. Unit specific contracts are assigned to the appropriate areas according to the parties of the contract. The sellers' unit is credited to the buyers' control area and assigned an injection node at the nearest interface point (designated bus). In this way, the unit participates in the buyers' unit commitment requirements. The seller is paid the MCP at the assigned interface point determined by UPLAN.

Contracts may also be based on system-wide sales, which increases the sellers' commitment and reduces buyers' commitment. The sellers bid their blocks to the PX, referenced to their interface point. UPLAN determines the control area commitment requirements, and determines if purchases can be made to meet the commitment level. When a bid is accepted, the unit is committed and all sales are paid at the interface MCP.

A.2 Fuel Model

UPLAN contains a multiple fuel contract model which is used for inventory control, fuel switching and emission control. The inventory level can be controlled on an annual and monthly basis. The model allocates the type and amount of fuel to each unit on a day-by-day basis with hourly constraints for all fuel limited resources. Individual units can use multiple fuels and multiple units can use the same fuel. The fuel utilization is optimized using linear programming within the multi-area chronological dispatch model. For more detailed modeling, users may use the UPLAN-G (natural gas model) system in conjunction with UPLAN-E (electricity model), which includes models for analysis of:

- detailed fuel and pipe line contracts
- optimized gas and oil pipeline flow
- optimization of storage and inventory management
- optimization of future contracts
- hedging and risk management

A.3 Portfolio Optimization Model (POM)

UPLAN POM Model selects the optimal portfolio of generation and transmission using Bender's decomposition method for area expansion respecting reliability as a criterion. It can use, at the users' choice, either the market clearing price or the marginal cost as the driver for determining the optimal portfolio. Under deregulation, or in a competitive market, an individual generator who wants to enter the market, the market clearing price is the appropriate driver. However, under traditional regulation where a cost benefit analysis is done for a specific utility system, the marginal cost is the appropriate criterion for selecting new generating and transmission resources. For multi-area expansion in a competitive environment, UPLAN uses an multi-dimensional search for timing and sizing at various injection points. Bidding strategy plays a key role.

POM was not used in this study because of the extra time required to run the model.

A.4 Risk & Uncertainty Analysis/Automatic Scenario Generation

UPLAN can systematically evaluate uncertainty and risk associated with critical variables by using the automatic Monte Carlo analysis. This eliminates the need for further user intervention. The uncertainty associated with up to seven exogenous variables may be studied simultaneously. Endogenous uncertainties, such as the outages and stochastic transition between states, are modeled through the probabilistic dispatch.

A.5 Financial Planning and Economic Analysis

Our financial modeling capabilities complement the integrated planning process and provide several levels of detail for financial planning. The Strategic Financial Model can be used for integrated planning and determines the annual revenue requirements in support of the Strategic Planning functions. This model can provide financial projections for both investor-owned and municipal utilities. The Strategic Financial Model's major functions include:

- Sources and uses of funds analysis
- O&M expenses analysis
- Plant and Project-level accounting
- Income statement/balance sheet
- Project construction analysis
- Tax modeling
- External finance analysis
- Key financial statistics

A.6 Demand-Side Modeling

UPLAN includes sophisticated demand-side models for representation of load data, for managing load shapes, for graphical display and aggregation of load shapes. Models for benefit/cost analysis, market penetration and demand side management are included. A list of some of the demand-side management capabilities of UPLAN are listed below.

- Automatic setup of strategic DSM objectives related to peak clipping, valley filling, load shifting, and conservation.
- Comprehensive treatment of load shape impacts due to Multi-fuel competition, DSM market penetration and DSM program participation.
- Models for dynamic simulation of dispatchable programs such as appliance cycling or interruptible loads or any other price induced or user-specified demand changes.
- Capability of evaluating multiple DSM packages against each other and as alternative expansion options in the resource selection and optimization model in DSO.
- Benefit/cost analysis of DSM programs based on industry standard B/C ratios and customer playback.

A.7 Emission and Environmental Modeling

UPLAN production simulation can be operated for minimization of emissions and cost to meet specified targets or constraints. Up to ten (10) emissions can be monitored per generating unit. UPLAN calculates emissions during the dispatch and accumulates the results over the period of operation. UPLAN can recognize user defined limits and dispatch the system to meet these limits or report any violation. Associated with each emission variable the user may enter an emission cost. The unit dispatch can be based on variable operating costs, unit emission costs, or a combination of both variable and emission costs.

The model automatically takes into account the banking, trading of emission, and the interaction between DSM programs with emission. Output reports provide unit-by-unit emissions on a monthly and an annual basis.

APPENDIX B

Table 3.11.6a Average Monthly Sellers' Market Clearing Prices

Base Fuel Cost Case

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	31.96	34.14	33.33	36.18	37.72	37.14	42.89	48.78	46.57	30.97	35.41	33.74	36.90	39.79	38.71	40.52	52.03	47.72
Feb	23.93	31.93	28.93	28.29	35.42	32.74	36.77	44.15	41.38	28.12	36.03	33.06	31.41	36.27	34.45	35.37	44.98	41.38
Mar	23.11	29.31	26.99	25.39	33.71	30.59	33.17	40.60	37.81	22.61	29.25	26.76	24.59	34.17	30.58	30.57	40.83	36.99
Apr	21.19	25.99	24.19	25.45	28.78	27.53	30.86	33.43	32.46	20.54	27.37	24.81	23.56	31.12	28.29	28.10	34.80	32.29
May	20.97	26.83	24.63	23.86	30.62	28.09	28.89	36.40	33.58	23.78	27.53	26.13	23.41	31.40	28.40	29.48	35.47	33.22
Jun	18.39	27.91	24.34	21.21	31.11	27.40	26.22	39.06	34.25	20.95	28.87	25.90	28.40	33.27	31.44	31.69	38.84	36.16
Jul	23.16	35.90	31.13	25.55	40.74	35.05	31.54	49.75	42.92	23.68	36.24	31.53	27.10	40.95	35.75	33.92	49.00	43.35
Aug	23.60	32.32	29.05	25.93	43.80	37.10	30.38	57.01	47.02	24.88	32.88	29.88	28.65	43.86	38.16	33.34	55.73	47.33
Sep	22.83	31.17	28.04	24.15	35.28	31.11	28.59	41.41	36.61	26.18	33.31	30.63	26.19	39.46	34.48	33.59	46.79	41.84
Oct	23.44	31.18	28.27	25.07	34.95	31.25	33.33	42.81	39.26	25.25	32.31	29.66	25.49	36.03	32.07	35.04	43.17	40.12
Nov	27.99	33.86	31.66	24.93	36.75	32.32	34.27	45.21	41.10	25.86	34.55	31.29	27.14	37.26	33.46	37.30	46.11	42.81
Dec	25.08	36.22	32.04	29.87	40.87	36.74	36.71	50.55	45.36	27.29	38.58	34.34	33.36	42.32	38.96	37.57	52.80	47.09
Annual	**23.80**	**31.40**	**28.55**	**26.32**	**35.81**	**32.25**	**32.80**	**44.10**	**39.86**	**25.01**	**32.69**	**29.81**	**28.02**	**37.16**	**33.73**	**33.87**	**45.05**	**40.86**

Table 3.11.6b Average Monthly Buyers' Market Clearing Price

Base Fuel Cost Case

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	32.26	34.79	33.84	36.55	38.42	37.72	43.32	49.47	47.16	31.31	35.82	34.13	37.38	40.29	39.20	41.04	52.65	48.29
Feb	24.13	32.56	29.40	28.54	36.11	33.27	37.15	44.86	41.97	28.33	36.51	33.44	31.66	36.79	34.86	35.66	45.59	41.86
Mar	23.34	29.86	27.42	25.68	34.37	31.11	33.55	41.20	38.33	22.78	29.65	27.08	24.80	34.70	30.99	30.88	41.41	37.46
Apr	21.41	26.64	24.68	25.76	29.48	28.09	31.30	34.14	33.08	20.68	27.73	25.09	23.74	31.55	28.62	28.32	35.23	32.64
May	21.22	27.61	25.21	24.17	31.47	28.73	29.33	37.30	34.31	23.94	27.88	26.40	23.58	31.82	28.73	29.71	35.93	33.60
Jun	18.56	28.60	24.84	21.44	31.96	28.02	26.59	40.00	34.97	21.08	29.18	26.14	28.58	33.59	31.71	31.91	39.23	36.48
Jul	23.59	36.90	31.91	26.12	41.81	35.93	32.23	50.78	43.83	23.88	36.60	31.83	27.38	41.38	36.13	34.30	49.54	43.82
Aug	24.00	33.15	29.72	26.49	44.96	38.03	31.04	58.30	48.08	25.07	33.22	30.16	28.89	44.34	38.55	33.68	56.36	47.85
Sep	23.16	31.83	28.58	24.58	36.02	31.73	29.14	42.23	37.32	26.37	33.66	30.92	26.40	39.91	34.85	33.91	47.31	42.29
Oct	23.72	31.88	28.82	25.41	35.73	31.86	33.81	43.60	39.93	25.44	32.76	30.01	25.70	36.54	32.48	35.37	43.73	40.59
Nov	28.33	34.64	32.27	25.29	37.60	32.99	34.82	46.12	41.88	26.07	35.06	31.69	27.39	37.83	33.92	37.69	46.80	43.38
Dec	25.34	37.27	32.80	30.24	42.03	37.61	37.13	51.73	46.26	27.60	39.20	34.85	33.77	43.04	39.56	38.08	53.61	47.79
Annual	**24.09**	**32.14**	**29.12**	**26.69**	**36.66**	**32.92**	**33.28**	**44.98**	**40.59**	**25.21**	**33.11**	**30.15**	**28.27**	**37.65**	**34.13**	**34.21**	**45.62**	**41.34**

Table 3.11.6c Average Monthly Nodal Spot Prices

Base Fuel Cost Case

	Northern California									Southern California								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	20.66	23.46	22.41	23.14	26.54	25.27	27.67	32.01	30.38	20.30	23.57	22.34	22.44	26.33	24.87	26.45	31.93	29.87

Feb	15.22	21.21	18.96	17.23	23.99	21.46	20.88	29.67	26.37	14.92	21.49	19.02	17.03	24.11	21.45	20.68	29.37	26.11
Mar	15.80	19.44	18.07	18.01	22.09	20.56	21.69	27.03	25.03	15.65	19.36	17.97	17.79	21.96	20.39	21.36	26.39	24.50
Apr	14.75	17.28	16.33	16.67	20.02	18.77	20.52	23.72	22.52	14.69	17.27	16.31	16.56	19.66	18.50	20.35	23.13	22.09
May	14.27	19.23	17.37	16.15	22.62	20.19	19.29	27.67	24.53	14.34	18.89	17.19	16.28	21.72	19.68	19.59	26.18	23.71
Jun	13.69	19.28	17.18	15.34	22.16	19.60	18.64	27.09	23.92	13.76	19.17	17.14	15.48	21.47	19.23	18.81	26.01	23.31
Jul	16.87	28.29	24.01	18.65	32.64	27.39	22.13	40.06	33.34	16.62	27.77	23.59	18.46	31.51	26.61	21.81	36.97	31.28
Aug	15.95	25.74	22.07	18.05	39.71	31.59	21.81	50.16	39.53	15.77	24.93	21.49	17.73	34.89	28.45	21.44	43.97	35.52
Sep	15.75	22.18	19.77	17.84	25.02	22.33	21.42	30.55	27.12	15.65	22.22	19.75	17.54	24.69	22.01	21.12	29.36	26.27
Oct	16.52	22.09	20.00	18.38	24.99	22.51	22.74	30.21	27.41	16.42	22.24	20.06	18.21	24.80	22.33	22.18	29.79	26.94
Nov	16.89	23.49	21.02	18.72	26.36	23.50	23.60	32.02	28.86	16.60	23.76	21.07	18.49	26.62	23.57	22.86	31.97	28.55
Dec	18.88	26.41	23.59	21.45	30.06	26.83	26.76	35.35	32.13	18.87	26.15	23.42	21.22	29.29	26.26	26.03	35.03	31.65
Annual	**16.27**	**22.34**	**20.07**	**18.30**	**26.35**	**23.33**	**22.26**	**32.13**	**28.43**	**16.13**	**22.24**	**19.95**	**18.10**	**25.59**	**22.78**	**21.89**	**30.84**	**27.48**

Table 3.11.7a Average Monthly Sellers' Market Clearing Prices

Low Fuel Cost Case

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	23.27	25.76	24.82	27.27	29.60	28.73	32.02	38.34	35.97	23.39	27.64	26.05	26.47	31.35	29.52	40.34	40.65	40.53
Feb	19.09	24.35	22.38	24.26	27.19	26.09	28.20	33.91	31.77	22.50	25.44	24.34	24.75	28.01	26.79	27.77	34.74	32.13
Mar	20.79	22.98	22.16	22.07	25.06	23.94	25.62	30.76	28.83	21.47	23.71	22.87	22.62	25.90	24.67	26.45	30.16	28.77
Apr	20.76	21.24	21.06	21.12	23.87	22.84	25.33	28.28	27.17	21.25	22.05	21.75	20.76	25.00	23.41	26.30	28.49	27.67
May	18.79	21.16	20.27	20.68	23.82	22.64	23.95	30.10	27.79	19.65	22.06	21.16	22.05	23.98	23.26	25.86	28.97	27.80
Jun	18.74	22.45	21.06	19.65	25.04	23.02	22.76	33.19	29.28	19.00	24.87	22.67	20.50	29.23	25.95	25.02	35.97	31.87
Jul	20.56	29.96	26.43	21.96	34.81	29.99	26.19	41.47	35.74	21.45	29.46	26.45	23.27	32.73	29.18	27.34	38.96	34.60
Aug	20.15	25.23	23.32	22.25	38.83	32.61	25.21	56.08	44.51	21.97	26.27	24.65	23.48	39.65	33.58	28.62	53.94	44.44
Sep	19.63	24.50	22.67	21.11	26.96	24.77	25.21	33.08	30.13	20.24	26.67	24.26	22.71	30.37	27.50	24.92	34.55	30.94
Oct	20.74	23.97	22.76	23.32	26.94	25.58	27.22	32.20	30.34	21.17	23.85	22.84	24.15	27.41	26.19	27.05	31.93	30.10
Nov	20.88	25.22	23.59	23.78	28.00	26.42	27.02	33.76	31.23	23.31	26.06	25.03	25.52	29.63	28.09	32.66	36.57	35.10
Dec	22.73	27.58	25.76	24.40	30.99	28.52	28.83	37.65	34.34	23.76	28.52	26.74	27.04	32.23	30.28	33.62	40.87	38.15
Annual	**20.51**	**24.53**	**23.02**	**22.65**	**28.43**	**26.26**	**26.46**	**35.74**	**32.26**	**21.60**	**25.55**	**24.07**	**23.61**	**29.62**	**27.37**	**28.83**	**36.32**	**33.51**

Table 3.11.7b Average Monthly Buyers' Market Clearing Prices

Low Fuel Cost Case

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	23.46	26.16	25.15	27.50	30.07	29.10	32.32	38.85	36.40	23.59	27.90	26.29	26.73	31.68	29.83	40.78	41.08	40.97
Feb	19.25	24.77	22.70	24.49	27.65	26.46	28.53	34.42	32.21	22.65	25.72	24.57	24.94	28.32	27.05	28.04	35.12	32.46
Mar	20.95	23.32	22.43	22.24	25.43	24.23	25.91	31.18	29.21	21.60	23.95	23.07	22.79	26.16	24.90	26.73	30.47	29.07
Apr	20.94	21.65	21.39	21.33	24.30	23.19	25.73	28.71	27.59	21.38	22.29	21.95	20.93	25.24	23.62	26.65	28.75	27.96
May	18.94	21.68	20.66	20.87	24.44	23.10	24.26	30.76	28.32	19.78	22.31	21.36	22.21	24.26	23.49	26.13	29.28	28.10
Jun	18.89	22.93	21.42	19.83	25.62	23.45	23.03	33.88	29.81	19.12	25.10	22.86	20.63	29.48	26.16	25.26	36.29	32.16
Jul	20.78	30.64	26.94	22.24	35.58	30.58	26.60	42.43	36.49	21.61	29.70	26.67	23.45	33.02	29.43	27.62	39.34	34.95
Aug	20.34	25.78	23.74	22.51	39.80	33.32	25.59	57.14	45.31	22.12	26.50	24.85	23.66	40.03	33.89	28.94	54.46	44.89
Sep	19.84	24.98	23.05	21.36	27.48	25.18	25.54	33.71	30.65	20.38	26.90	24.46	22.88	30.66	27.74	25.15	34.89	31.23
Oct	20.92	24.45	23.12	23.51	27.45	25.97	27.52	32.76	30.79	21.31	24.11	23.06	24.33	27.72	26.45	27.31	32.27	30.41
Nov	21.07	25.71	23.97	24.01	28.56	26.85	27.38	34.38	31.75	23.48	26.41	25.31	25.75	30.05	28.44	33.06	37.06	35.56
Dec	22.92	28.30	26.28	24.62	31.78	29.09	29.13	38.48	34.97	23.98	28.91	27.06	27.34	32.69	30.69	34.03	41.42	38.65
Annual	**20.69**	**25.03**	**23.40**	**22.88**	**29.01**	**26.71**	**26.80**	**36.39**	**32.79**	**21.75**	**25.82**	**24.29**	**23.80**	**29.94**	**27.64**	**29.14**	**36.70**	**33.87**

Table 3.11.7c Average Monthly Nodal Spot Prices

Low Fuel Cost Case

	Northern California									Southern California								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	16.70	18.08	17.56	18.56	20.52	19.78	23.23	25.44	24.61	16.55	18.17	17.56	18.37	20.30	19.58	22.58	24.83	23.99

Feb	13.41	16.39	15.27	14.91	18.54	17.18	17.81	23.22	21.19	13.32	16.72	15.45	14.89	18.73	17.29	17.63	23.01	20.99
Mar	14.29	15.59	15.10	16.14	17.81	17.19	19.19	22.21	21.07	14.26	15.73	15.18	15.93	17.94	17.19	18.66	21.87	20.66
Apr	13.57	14.96	14.44	15.14	17.03	16.32	17.86	20.73	19.66	13.51	15.22	14.58	15.01	17.04	16.28	17.51	20.62	19.46
May	13.23	15.82	14.85	14.38	18.38	16.88	16.75	23.37	20.88	13.32	15.92	14.95	14.46	18.11	16.74	16.49	22.47	20.23
Jun	12.35	15.96	14.61	13.51	18.07	16.36	15.96	21.94	19.70	12.44	16.02	14.67	13.57	17.87	16.25	15.91	21.47	19.38
Jul	14.86	25.17	21.31	16.39	28.46	23.94	19.71	38.99	31.76	14.92	24.92	21.17	16.41	27.82	23.54	19.54	36.28	30.00
Aug	14.21	21.13	18.53	15.73	39.40	30.52	18.83	51.01	38.94	14.21	20.50	18.14	15.59	34.33	27.31	18.54	41.56	32.93
Sep	13.80	17.79	16.29	15.38	19.88	18.19	18.30	25.18	22.60	13.88	17.66	16.25	15.41	19.65	18.06	18.13	24.39	22.04
Oct	14.48	17.51	16.38	16.14	19.75	18.39	19.14	24.20	22.30	14.45	17.40	16.30	15.99	19.47	18.17	18.65	23.62	21.76
Nov	14.88	17.97	16.81	16.83	20.54	19.15	19.93	25.88	23.64	14.78	18.27	16.96	16.53	20.57	19.05	19.37	25.17	22.99
Dec	16.47	19.81	18.56	18.52	22.68	21.12	22.85	27.80	25.94	16.38	20.03	18.66	18.36	22.32	20.83	22.25	26.93	25.17
Annual	**14.35**	**18.01**	**16.64**	**15.97**	**21.75**	**19.59**	**19.13**	**27.50**	**24.36**	**14.33**	**18.05**	**16.65**	**15.88**	**21.18**	**19.19**	**18.77**	**26.02**	**23.30**

Table 3.11.8a Average Monthly Sellers' Market Clearing Prices

Municipal Utilities Participating in the Pool

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	32.05	34.24	33.42	36.12	37.68	37.10	42.88	49.10	46.77	31.53	35.63	34.09	37.39	40.09	39.08	41.30	52.49	48.30
Feb	23.93	31.93	28.93	28.28	35.44	32.75	36.75	44.15	41.37	28.12	36.15	33.14	31.39	36.39	34.52	35.36	45.27	41.55
Mar	23.11	29.31	26.99	25.39	33.71	30.59	33.13	40.50	37.73	22.65	29.27	26.79	25.01	35.20	31.37	30.58	40.87	37.01
Apr	21.19	25.99	24.19	25.45	28.79	27.54	30.90	33.43	32.48	20.61	27.69	25.04	24.58	32.26	29.38	28.07	35.40	32.65
May	20.97	26.83	24.63	23.80	30.91	28.24	28.85	36.53	33.65	23.83	28.16	26.53	23.16	32.77	29.17	29.46	36.24	33.70
Jun	18.37	27.82	24.28	21.94	32.06	28.26	26.26	37.57	33.33	20.98	29.55	26.34	28.32	35.43	32.76	32.01	39.11	36.45
Jul	23.16	35.90	31.13	26.12	40.70	35.23	31.51	49.80	42.94	23.68	36.98	31.99	27.84	41.87	36.61	33.95	49.94	43.94
Aug	23.60	32.26	29.01	25.58	43.75	36.94	30.38	57.07	47.06	24.88	33.61	30.34	28.53	46.23	39.59	33.34	57.44	48.40
Sep	22.83	31.17	28.04	24.18	35.28	31.12	28.60	41.41	36.61	26.13	33.93	31.00	26.18	40.71	35.26	33.59	47.31	42.17
Oct	23.37	31.17	28.24	25.19	35.03	31.34	33.33	42.86	39.29	25.29	32.99	30.10	25.77	36.58	32.53	34.99	44.28	40.80
Nov	27.85	33.92	31.65	26.58	37.12	33.16	34.27	45.24	41.13	25.50	35.13	31.52	30.12	38.89	35.60	37.28	46.75	43.20
Dec	25.08	36.22	32.04	29.75	40.87	36.70	36.83	50.17	45.17	27.18	38.63	34.34	32.17	43.10	39.00	37.66	53.07	47.29
Annual	**23.79**	**31.40**	**28.55**	**26.53**	**35.94**	**32.41**	**32.81**	**43.98**	**39.79**	**25.03**	**33.14**	**30.10**	**28.37**	**38.29**	**34.57**	**33.97**	**45.68**	**41.29**

Table 3.11.8b Average Monthly Buyers' Market Clearing Prices

Municipal Utilities Participating in the Pool

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	32.35	34.88	33.93	36.50	38.38	37.67	43.31	49.79	47.36	31.87	36.04	34.48	37.87	40.59	39.57	41.83	53.11	48.88
Feb	24.13	32.56	29.40	28.53	36.13	33.28	37.13	44.86	41.96	28.33	36.63	33.52	31.65	36.90	34.93	35.65	45.87	42.04
Mar	23.34	29.86	27.42	25.68	34.37	31.11	33.51	41.10	38.25	22.82	29.67	27.10	25.22	35.74	31.79	30.89	41.44	37.49
Apr	21.41	26.64	24.68	25.76	29.49	28.09	31.34	34.14	33.09	20.75	28.06	25.32	24.77	32.71	29.73	28.30	35.84	33.01
May	21.22	27.61	25.21	24.12	31.76	28.90	29.28	37.44	34.38	23.99	28.51	26.81	23.33	33.21	29.50	29.69	36.71	34.07
Jun	18.55	28.51	24.77	22.17	32.86	28.85	26.63	38.46	34.03	21.10	29.86	26.58	28.50	35.77	33.04	32.23	39.50	36.77
Jul	23.59	36.90	31.91	26.68	41.76	36.10	32.19	50.83	43.84	23.88	37.36	32.30	28.12	42.32	36.99	34.33	50.49	44.43
Aug	24.00	33.08	29.68	26.13	44.91	37.87	31.04	58.37	48.12	25.07	33.96	30.62	28.77	46.74	40.00	33.68	58.09	48.93
Sep	23.16	31.83	28.58	24.61	36.02	31.74	29.15	42.22	37.32	26.32	34.28	31.30	26.40	41.17	35.63	33.91	47.84	42.62
Oct	23.65	31.87	28.79	25.52	35.82	31.96	33.81	43.65	39.96	25.48	33.44	30.46	25.99	37.11	32.94	35.31	44.86	41.28
Nov	28.18	34.70	32.26	26.97	37.97	33.85	34.82	46.16	41.91	25.71	35.65	31.92	30.40	39.51	36.09	37.67	47.45	43.78
Dec	25.34	37.27	32.80	30.11	42.03	37.56	37.24	51.35	46.06	27.49	39.26	34.85	32.57	43.84	39.61	38.17	53.89	47.99
Annual	**24.08**	**32.14**	**29.12**	**26.90**	**36.79**	**33.08**	**33.29**	**44.86**	**40.52**	**25.23**	**33.56**	**30.44**	**28.63**	**38.80**	**34.99**	**34.31**	**46.26**	**41.78**

Table 3.11.8c Average Monthly Nodal Spot Prices

Municipal Utilities Participating in the Pool

	Northern California									Southern California								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	20.66	23.46	22.41	23.14	26.54	25.27	27.67	32.01	30.38	20.30	23.57	22.34	22.45	26.33	24.87	26.45	31.93	29.87

Feb	15.22	21.21	18.96	17.21	23.95	21.43	20.88	29.67	26.37	14.92	21.49	19.02	17.02	24.09	21.44	20.68	29.37	26.11
Mar	15.80	19.44	18.07	18.01	22.09	20.56	21.69	27.03	25.03	15.65	19.36	17.97	17.79	21.96	20.40	21.36	26.39	24.50
Apr	14.75	17.28	16.33	16.67	20.03	18.77	20.52	23.72	22.52	14.69	17.27	16.31	16.56	19.68	18.51	20.35	23.13	22.09
May	14.27	19.23	17.37	16.10	22.61	20.17	19.29	27.67	24.53	14.34	18.89	17.19	16.22	21.64	19.61	19.59	26.18	23.71
Jun	13.69	19.28	17.18	15.49	22.13	19.64	18.64	27.09	23.92	13.76	19.17	17.14	15.56	21.59	19.33	18.81	26.01	23.31
Jul	16.87	28.29	24.01	18.68	32.62	27.39	22.13	40.06	33.34	16.62	27.77	23.59	18.48	31.69	26.73	21.81	36.97	31.28
Aug	15.95	25.74	22.07	18.04	39.72	31.59	21.81	50.16	39.53	15.77	24.93	21.49	17.70	34.87	28.43	21.44	43.97	35.52
Sep	15.75	22.18	19.77	17.85	25.01	22.32	21.42	30.55	27.12	15.65	22.22	19.75	17.54	24.69	22.01	21.12	29.36	26.27
Oct	16.52	22.09	20.00	18.38	24.97	22.50	22.74	30.21	27.41	16.42	22.24	20.06	18.21	24.79	22.32	22.18	29.79	26.94
Nov	16.89	23.49	21.02	18.78	26.57	23.65	23.60	32.02	28.86	16.60	23.76	21.07	18.54	26.60	23.57	22.86	31.97	28.55
Dec	18.88	26.41	23.59	21.55	30.04	26.85	26.76	35.35	32.13	18.87	26.15	23.42	21.25	29.30	26.29	26.03	35.03	31.65
Annual	**16.27**	**22.34**	**20.07**	**18.32**	**26.36**	**23.34**	**22.26**	**32.13**	**28.43**	**16.13**	**22.24**	**19.95**	**18.11**	**25.60**	**22.79**	**21.89**	**30.84**	**27.48**

Table 3.11.9a Average Monthly Sellers' Market Clearing Prices

Regulated Case

	Zone 3 (Northern California)			Zone 4 (Southern California)		
	2006			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	42.18	47.35	45.41	41.61	52.16	48.20
Feb	36.80	43.72	41.13	35.58	45.01	41.47
Mar	32.89	40.62	37.72	31.04	40.64	37.04
Apr	30.83	33.50	32.50	27.94	34.66	32.14
May	28.67	36.11	33.32	29.45	34.74	32.76
Jun	26.04	38.70	33.95	32.39	38.42	36.16
Jul	31.53	48.19	41.94	34.11	49.23	43.56
Aug	30.57	52.97	44.57	33.71	52.88	45.69
Sep	28.59	41.36	36.57	33.73	47.17	42.13
Oct	33.88	42.97	39.56	35.62	43.63	40.62
Nov	35.95	44.96	41.58	38.48	46.52	43.50
Dec	36.18	50.36	45.04	38.08	53.63	47.80
Annual	**32.84**	**43.40**	**39.44**	**34.31**	**44.89**	**40.92**

Table 3.11.9b Average Monthly Buyers' Market Clearing Prices

Regulated Case

	Zone 3 (Northern California)			Zone 4 (Southern California)		
	2006			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	42.59	48.00	45.97	42.15	52.77	48.79
Feb	37.18	44.43	41.71	35.87	45.61	41.96
Mar	33.27	41.21	38.23	31.35	41.21	37.51
Apr	31.26	34.22	33.11	28.17	35.09	32.49
May	29.12	37.01	34.05	29.69	35.19	33.13
Jun	26.41	39.62	34.67	32.62	38.80	36.48
Jul	32.22	49.29	42.89	34.49	49.76	44.04
Aug	31.23	54.22	45.60	34.06	53.47	46.19
Sep	29.14	42.17	37.28	34.05	47.70	42.58
Oct	34.36	43.76	40.23	35.95	44.20	41.10
Nov	36.54	45.85	42.36	38.87	47.21	44.09
Dec	36.59	51.52	45.92	38.60	54.48	48.52
Annual	**33.33**	**44.27**	**40.17**	**34.65**	**45.46**	**41.41**

Table 3.11.9c Average Monthly Nodal Spot Prices

Regulated Case

	Zone 3 (Northern California)			Zone 4 (Southern California)		
	2006			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	27.57	32.00	30.34	26.38	31.82	29.78
Feb	20.84	29.54	26.28	20.60	29.29	26.03
Mar	21.61	27.05	25.01	21.33	26.32	24.45
Apr	20.49	23.59	22.43	20.33	23.04	22.03
May	19.28	27.20	24.23	19.57	25.91	23.53
Jun	18.63	26.64	23.64	18.78	25.70	23.10
Jul	22.10	38.99	32.65	21.77	36.41	30.92
Aug	21.85	46.25	37.10	21.48	40.58	33.42
Sep	21.34	29.96	26.73	21.09	29.05	26.07
Oct	22.96	30.16	27.46	22.31	29.73	26.95
Nov	23.48	31.60	28.56	22.83	31.87	28.48
Dec	26.72	34.72	31.72	26.02	34.77	31.49
Annual	**22.24**	**31.48**	**28.01**	**21.87**	**30.37**	**27.19**

Table 3.11.10a Average Monthly Sellers' Market Clearing Prices

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

	Zone 3 (Northern California)									**Zone 4 (Southern California)**								
	1998			**2001**			**2006**			**1998**			**2001**			**2006**		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	32.00	35.48	34.18	35.78	39.61	38.17	45.57	48.96	47.69	31.47	34.13	33.13	35.56	39.83	38.23	52.55	53.03	52.85
Feb	21.40	30.70	27.21	25.32	34.89	31.30	32.43	44.20	39.79	24.01	31.31	28.57	27.23	35.47	32.38	30.99	43.03	38.51
Mar	21.69	28.53	25.97	24.53	31.85	29.10	31.34	39.95	36.72	23.60	31.06	28.26	26.56	33.28	30.76	30.66	39.11	35.94
Apr	21.97	24.73	23.70	23.17	29.05	26.84	30.59	35.03	33.36	19.47	28.48	25.10	22.12	32.01	28.30	26.71	33.84	31.17
May	20.08	26.90	24.34	23.31	31.13	28.20	28.49	36.81	33.69	20.61	27.31	24.79	22.85	30.99	27.94	28.62	35.74	33.07
Jun	20.32	28.24	25.27	24.03	32.74	29.47	26.60	38.49	34.03	20.44	29.41	26.04	24.46	32.50	29.48	32.81	38.89	36.61
Jul	22.55	36.07	31.00	26.21	40.58	35.19	30.47	48.84	41.95	23.80	37.36	32.27	26.75	41.77	36.14	31.80	50.54	43.52
Aug	23.89	33.14	29.67	25.40	45.24	37.80	32.73	58.01	48.53	24.40	33.97	30.38	25.38	45.66	38.06	31.50	56.81	47.32
Sep	22.19	31.85	28.23	26.34	35.92	32.33	30.47	42.45	37.96	22.94	34.74	30.31	25.06	38.60	33.52	30.61	46.26	40.39
Oct	24.01	32.10	29.07	27.31	35.82	32.63	35.33	43.46	40.41	24.53	31.83	29.09	26.93	35.77	32.45	34.75	42.90	39.84
Nov	28.04	33.75	31.61	28.33	37.21	33.88	38.18	46.99	43.69	25.90	33.60	30.71	28.33	38.11	34.44	38.42	46.12	43.23
Dec	29.26	37.47	34.39	32.15	42.09	38.36	42.63	51.22	48.00	28.47	37.67	34.22	33.47	41.78	38.66	39.89	51.01	46.84
Annual	**23.95**	**31.58**	**28.72**	**26.82**	**36.34**	**32.77**	**33.74**	**44.53**	**40.48**	**24.14**	**32.57**	**29.41**	**27.06**	**37.15**	**33.36**	**34.11**	**44.77**	**40.77**

Table 3.11.10b Average Monthly Buyers' Market Clearing Prices

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

	Zone 3 (Northern California)									**Zone 4 (Southern California)**								
	1998			**2001**			**2006**			**1998**			**2001**			**2006**		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	32.29	36.17	34.72	36.14	40.38	38.79	46.02	49.67	48.30	31.82	34.55	33.53	36.03	40.36	38.74	53.24	53.71	53.54
Feb	21.56	31.34	27.67	25.54	35.61	31.83	32.74	44.92	40.35	24.21	31.74	28.91	27.46	35.98	32.78	31.25	43.64	38.99
Mar	21.91	29.07	26.38	24.77	32.46	29.58	31.68	40.54	37.22	23.78	31.44	28.57	26.79	33.74	31.14	30.99	39.64	36.40
Apr	22.20	25.34	24.16	23.43	29.77	27.39	30.99	35.77	33.98	19.60	28.86	25.39	22.30	32.48	28.66	26.95	34.26	31.52
May	20.30	27.71	24.93	23.64	32.02	28.88	28.93	37.70	34.41	20.75	27.66	25.07	23.02	31.41	28.27	28.86	36.19	33.44
Jun	20.51	29.02	25.83	24.27	33.64	30.13	26.97	39.41	34.74	20.56	29.75	26.30	24.61	32.83	29.75	33.05	39.29	36.95
Jul	22.97	37.09	31.80	26.76	41.70	36.10	31.11	49.89	42.84	24.02	37.74	32.59	27.02	42.23	36.53	32.17	51.10	44.01
Aug	24.30	34.00	30.36	25.91	46.45	38.75	33.41	59.30	49.60	24.60	34.34	30.68	25.62	46.18	38.47	31.84	57.45	47.85
Sep	22.49	32.55	28.78	26.77	36.69	32.97	31.00	43.30	38.69	23.12	35.11	30.62	25.27	39.04	33.88	30.91	46.78	40.83
Oct	24.28	32.83	29.62	27.65	36.61	33.25	35.80	44.24	41.07	24.72	32.28	29.44	27.16	36.29	32.87	35.11	43.47	40.34
Nov	28.36	34.53	32.22	28.72	38.09	34.58	38.77	47.91	44.48	26.12	34.11	31.12	28.61	38.71	34.92	38.83	46.79	43.81
Dec	29.56	38.56	35.18	32.53	43.29	39.25	43.12	52.41	48.93	28.79	38.30	34.73	33.89	42.50	39.27	40.44	51.81	47.55
Annual	**24.23**	**32.35**	**29.30**	**27.18**	**37.23**	**33.46**	**34.21**	**45.42**	**41.22**	**24.34**	**32.99**	**29.75**	**27.32**	**37.65**	**33.77**	**34.47**	**45.35**	**41.27**

Table 3.11.10c Average Monthly Nodal Spot Prices

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

	Northern California									**Southern California**								
	1998			**2001**			**2006**			**1998**			**2001**			**2006**		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	20.81	24.42	23.06	23.51	27.37	25.93	27.98	32.69	30.92	20.45	24.37	22.90	22.97	27.12	25.57	27.01	32.49	30.44

Feb	15.31	21.88	19.42	17.35	24.80	22.00	21.06	30.43	26.92	15.02	22.08	19.43	16.96	24.67	21.78	20.69	29.93	26.47
Mar	15.82	19.61	18.19	17.92	22.30	20.66	21.78	27.62	25.43	15.63	19.60	18.11	17.74	22.20	20.53	21.44	26.70	24.73
Apr	14.80	17.48	16.47	16.67	19.97	18.73	20.44	23.76	22.52	14.60	17.67	16.52	16.48	19.97	18.66	20.32	23.23	22.14
May	14.28	19.63	17.62	15.95	22.88	20.28	19.49	27.54	24.52	14.36	19.26	17.43	16.10	21.96	19.76	19.59	26.21	23.72
Jun	13.63	19.51	17.31	15.39	22.41	19.78	18.46	27.33	24.01	13.66	19.38	17.24	15.47	21.81	19.43	18.58	26.10	23.28
Jul	16.79	28.46	24.09	19.06	33.01	27.78	22.11	40.29	33.47	16.71	28.22	23.90	18.66	31.91	26.94	21.76	37.42	31.54
Aug	15.88	26.31	22.40	18.13	40.15	31.89	21.90	50.67	39.88	15.72	25.52	21.85	17.86	35.26	28.73	21.60	44.40	35.85
Sep	15.77	22.82	20.17	17.94	25.32	22.55	21.46	31.07	27.47	15.66	22.62	20.01	17.72	24.78	22.13	21.26	29.88	26.64
Oct	16.55	22.75	20.43	18.59	25.78	23.09	22.86	31.63	28.34	16.38	22.70	20.33	18.43	25.32	22.74	22.34	30.60	27.51
Nov	17.12	24.24	21.57	19.06	27.42	24.29	23.55	33.17	29.56	16.68	24.35	21.48	18.68	26.98	23.87	23.03	32.45	28.92
Dec	19.21	26.82	23.97	21.62	30.53	27.19	26.77	36.41	32.80	19.03	26.74	23.85	21.42	29.93	26.74	26.21	35.49	32.01
Annual	**16.33**	**22.83**	**20.39**	**18.43**	**26.83**	**23.68**	**22.32**	**32.72**	**28.82**	**16.16**	**22.71**	**20.25**	**18.21**	**25.99**	**23.07**	**21.99**	**31.24**	**27.77**

Table 3.11.11a Average Monthly Sellers' Market Clearing Prices

Base Fuel Cost Case with PX Bids for Reserve Units

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	31.96	34.14	33.33	36.18	37.72	37.14	42.89	48.78	46.57	30.97	35.41	33.74	36.90	39.79	38.71	40.52	52.03	47.72
Feb	23.93	31.93	28.93	28.29	35.42	32.74	36.77	44.15	41.38	28.12	36.03	33.06	31.41	36.27	34.45	35.37	44.98	41.38
Mar	23.11	29.31	26.99	25.39	33.71	30.59	33.17	40.60	37.81	22.61	29.25	26.76	24.59	34.17	30.58	30.57	40.83	36.99
Apr	21.19	25.99	24.19	25.45	28.78	27.53	30.86	33.43	32.46	20.54	27.37	24.81	23.56	31.12	28.29	28.10	34.80	32.29
May	20.97	26.83	24.63	23.86	30.62	28.09	28.89	36.40	33.58	23.78	27.53	26.13	23.41	31.40	28.40	29.48	35.47	33.22
Jun	18.39	27.91	24.34	21.21	31.11	27.40	26.22	39.16	34.31	20.95	29.07	26.02	28.40	33.27	31.44	31.69	38.94	36.22
Jul	23.16	35.92	31.14	25.55	40.76	35.06	31.54	49.80	42.95	23.68	36.22	31.52	27.10	41.00	35.79	33.92	49.27	43.51
Aug	23.60	32.51	29.17	25.93	46.43	38.74	30.39	57.24	47.17	24.88	34.04	30.61	28.61	46.60	39.85	33.38	56.29	47.70
Sep	22.83	31.17	28.04	24.15	35.28	31.11	28.59	41.41	36.61	26.18	33.31	30.63	26.19	39.46	34.48	33.59	46.79	41.84
Oct	23.44	31.18	28.27	25.07	34.95	31.25	33.33	42.81	39.26	25.25	32.38	29.71	25.49	36.03	32.07	35.04	43.17	40.12
Nov	27.99	33.86	31.66	24.93	36.75	32.32	34.27	45.21	41.10	25.86	34.55	31.29	27.14	37.26	33.46	37.30	46.11	42.81
Dec	25.08	36.22	32.04	29.87	40.87	36.74	36.71	50.55	45.36	27.29	38.58	34.34	33.36	42.32	38.96	37.57	52.80	47.09
Annual	**23.80**	**31.41**	**28.56**	**26.32**	**36.03**	**32.39**	**32.80**	**44.13**	**39.88**	**25.01**	**32.81**	**29.89**	**28.01**	**37.39**	**33.87**	**33.88**	**45.12**	**40.91**

Table 3.11.11b Average Monthly Buyers' Market Clearing Prices

Base Fuel Cost Case with PX Bids for Reserve Units

	Zone 3 (Northern California)									Zone 4 (Southern California)								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.			
Jan	32.26	34.79	33.84	36.55	38.42	37.72	43.32	49.47	47.16	31.31	35.82	34.13	37.38	40.29	39.20	41.04	52.65	48.29
Feb	24.13	32.56	29.40	28.54	36.11	33.27	37.15	44.86	41.97	28.33	36.51	33.44	31.66	36.79	34.86	35.66	45.59	41.86
Mar	23.34	29.86	27.42	25.68	34.37	31.11	33.55	41.20	38.33	22.78	29.65	27.08	24.80	34.70	30.99	30.88	41.41	37.46
Apr	21.41	26.64	24.68	25.76	29.48	28.09	31.30	34.14	33.08	20.68	27.73	25.09	23.74	31.55	28.62	28.32	35.23	32.64
May	21.22	27.61	25.21	24.17	31.47	28.73	29.33	37.30	34.31	23.94	27.88	26.40	23.58	31.82	28.73	29.71	35.93	33.60
Jun	18.56	28.60	24.84	21.44	31.96	28.02	26.59	40.10	35.03	21.08	29.38	26.26	28.58	33.59	31.71	31.91	39.33	36.55
Jul	23.59	36.92	31.92	26.12	41.82	35.94	32.23	50.83	43.86	23.88	36.59	31.82	27.38	41.43	36.16	34.30	49.81	43.99
Aug	24.00	33.34	29.84	26.49	47.68	39.73	31.05	58.54	48.23	25.07	34.39	30.90	28.86	47.11	40.26	33.72	56.93	48.23
Sep	23.16	31.83	28.58	24.58	36.02	31.73	29.14	42.23	37.32	26.37	33.66	30.92	26.40	39.91	34.85	33.91	47.31	42.29
Oct	23.72	31.88	28.82	25.41	35.73	31.86	33.81	43.60	39.93	25.44	32.82	30.06	25.70	36.54	32.48	35.37	43.73	40.59
Nov	28.33	34.64	32.27	25.29	37.60	32.99	34.82	46.12	41.88	26.07	35.06	31.69	27.39	37.83	33.92	37.69	46.80	43.38
Dec	25.34	37.27	32.80	30.24	42.03	37.61	37.13	51.73	46.26	27.60	39.20	34.85	33.77	43.04	39.56	38.08	53.61	47.79
Annual	**24.09**	**32.16**	**29.13**	**26.69**	**36.89**	**33.07**	**33.28**	**45.01**	**40.61**	**25.21**	**33.22**	**30.22**	**28.27**	**37.88**	**34.28**	**34.22**	**45.69**	**41.39**

Table 3.11.11c Average Monthly Nodal Spot Prices

Base Fuel Cost Case with PX Bids for Reserve Units

	Northern California									Southern California								
	1998			2001			2006			1998			2001			2006		
Months	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.	Off-Peak	On-Peak	Avg.
Jan	20.66	23.46	22.41	23.14	26.54	25.27	27.67	32.01	30.38	20.30	23.57	22.34	22.44	26.33	24.87	26.45	31.93	29.87

Feb	15.22	21.21	18.96	17.23	23.99	21.46	20.88	29.67	26.37	14.92	21.49	19.02	17.03	24.11	21.45	20.68	29.37	26.11
Mar	15.80	19.44	18.07	18.01	22.09	20.56	21.69	27.03	25.03	15.65	19.36	17.97	17.79	21.96	20.39	21.36	26.39	24.50
Apr	14.75	17.28	16.33	16.67	20.02	18.77	20.52	23.72	22.52	14.69	17.27	16.31	16.56	19.66	18.50	20.35	23.13	22.09
May	14.27	19.23	17.37	16.15	22.62	20.19	19.29	27.67	24.53	14.34	18.89	17.19	16.28	21.72	19.68	19.59	26.18	23.71
Jun	13.69	19.28	17.18	15.34	22.16	19.60	18.64	27.09	23.92	13.76	19.17	17.14	15.48	21.47	19.23	18.81	26.01	23.31
Jul	16.87	28.29	24.01	18.65	32.64	27.39	22.13	40.06	33.34	16.62	27.77	23.59	18.46	31.51	26.61	21.81	36.97	31.28
Aug	15.95	25.74	22.07	18.05	39.71	31.59	21.81	50.16	39.53	15.77	24.93	21.49	17.73	34.89	28.45	21.44	43.97	35.52
Sep	15.75	22.18	19.77	17.84	25.02	22.33	21.42	30.55	27.12	15.65	22.22	19.75	17.54	24.69	22.01	21.12	29.36	26.27
Oct	16.52	22.09	20.00	18.38	24.99	22.51	22.74	30.21	27.41	16.42	22.24	20.06	18.21	24.80	22.33	22.18	29.79	26.94
Nov	16.89	23.49	21.02	18.72	26.36	23.50	23.60	32.02	28.86	16.60	23.76	21.07	18.49	26.62	23.57	22.86	31.97	28.55
Dec	18.88	26.41	23.59	21.45	30.06	26.83	26.76	35.35	32.13	18.87	26.15	23.42	21.22	29.29	26.26	26.03	35.03	31.65
Annual	**16.27**	**22.34**	**20.07**	**18.30**	**26.35**	**23.33**	**22.26**	**32.13**	**28.43**	**16.13**	**22.24**	**19.95**	**18.10**	**25.59**	**22.78**	**21.89**	**30.84**	**27.48**

Table 3.12.9a Generation Cost and Revenues

Base Fuel Cost Case

Pacific Gas and Electric Units - 1998

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	**(MW)**	**(%)**	**(GWh)**	**Var**	**Fuel**	**Fixed**	**Total**	**Energy**	**Reserve**	**Spin**	**Total**	**Income**	**Cost**	**Rev.**
CCosta6	340	25.2	751.5	6,384	14,830	6,687	27,901	26,130	0	255	26,384	-1,517	28.23	35.11
CCosta7	340	21.8	649.7	5,519	12,826	6,687	25,032	22,708	0	89	22,797	-2,235	28.24	35.09
HntrsPt1	56	0.3	1.3	13	65	220	298	78	220	0	298	0	61.32	60.94
HntrsPt2	107	4.6	42.8	276	1,061	3,549	4,886	1,551	3,328	7	4,886	0	31.25	36.43
HntrsPt3	107	4.1	38.2	246	966	3,549	4,761	1,388	3,368	6	4,761	0	31.78	36.54
HntrsPt4	163	60.7	866.0	5,415	17,540	6,181	29,136	24,785	4,298	53	29,136	0	26.51	28.68
Humbld12	105	34.9	320.7	2,055	8,604	4,778	15,437	8,886	6,432	119	15,437	0	33.23	28.08
Mobil123	45	0.2	0.8	8	73	289	370	81	289	0	370	0	104.09	103.85
Morro12	326	22.5	642.0	4,595	13,589	4,647	22,831	24,054	0	59	24,112	1,281	28.33	37.56
Morro3	338	36.1	1,068.4	6,920	21,201	6,648	34,769	37,620	0	4	37,623	2,854	26.32	35.21
Morro4	338	40.4	1,197.3	7,755	23,387	6,648	37,790	42,263	0	86	42,350	4,560	26.01	35.37
Moss6	739	49.2	3,182.5	19,900	58,912	11,020	89,832	102,311	0	360	102,671	12,839	24.76	32.26
Moss7	739	61.9	4,008.5	25,064	72,244	11,020	108,328	124,728	0	562	125,291	16,963	24.28	31.26
Oakln123	192	0.2	2.7	28	220	318	566	248	318	0	566	0	93.03	92.88
Pitsbg5	325	28.9	823.0	5,331	16,397	6,396	28,124	27,665	0	32	27,697	-427	26.40	33.65
Pitsbg6	325	35.5	1,011.3	6,550	23,258	6,396	36,204	33,925	0	0	33,925	-2,279	29.47	33.55
Pitsbrg7	720	33.5	2,113.7	13,216	42,403	10,718	66,337	70,541	0	161	70,702	4,365	26.31	33.45
Pitsbu12	326	10.1	287.7	2,059	5,746	4,647	12,452	10,097	2,323	32	12,452	0	27.13	35.21
Pitsbu34	326	25.0	712.9	5,103	17,946	4,647	27,696	25,696	2,000	0	27,696	0	32.33	36.04
Potr456	168	0.2	2.6	27	208	875	1,110	235	875	0	1,110	0	91.80	91.80
Potrero3	207	61.3	1,111.5	7,199	22,226	4,071	33,496	31,908	1,530	58	33,496	0	26.47	28.76
Thermal	**6,332**	**34.0**	**18,834.8**	**123,663**	**373,702**	**109,991**	**607,356**	**616,898**	**24,981**	**1,883**	**643,760**	**36,404**	**26.41**	**32.85**
Nuclear	**2,160**	**89.5**	**16,939.4**	**36,291**	**101,299**	**198,708**	**336,298**	**504,429**	**0**	**0**	**504,429**	**168,131**	**8.12**	**29.78**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**75,256**	**75,256**	**731,871**	**0**	**0**	**731,871**	**656,615**	**0.00**	**30.64**
Geo	**635**	**49.0**	**2,725.7**	**3,837**	**54,171**	**17,958**	**75,966**	**77,818**	**0**	**0**	**77,818**	**1,852**	**21.28**	**28.55**
PumpStorage	**1,174**	**4.7**	**488.1**	**0**	**0**	**19,619**	**19,619**	**15,793**	**0**	**0**	**15,793**	**-3,826**	**0.00**	**32.35**
DSM & Solar	**518**	**0.3**	**12.6**	**19**	**0**	**141**	**160**	**356**	**0**	**0**	**356**	**196**	**1.51**	**28.28**
QF	**4,209**	**74.5**	**27,486.3**	**100,357**	**506,369**	**94,229**	**700,955**	**780,440**	**0**	**0**	**780,440**	**79,485**	**22.07**	**28.39**
Total less QFs	**15,322**	**46.8**	**62,884.2**	**163,810**	**529,172**	**421,673**	**1,114,655**	**1,947,165**	**24,981**	**1,883**	**1,974,027**	**859,372**	**11.02**	**30.99**
Total	**19,531**	**52.8**	**90,370.5**	**264,167**	**1,035,541**	**515,902**	**1,815,610**	**2,727,605**	**24,981**	**1,883**	**2,754,467**	**938,857**	**14.38**	**30.20**

Table 3.12.9b Generation Cost and Revenues

Base Fuel Cost Case

Southern California Edison Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
ALA7HNT5	276	0.4	9.3	74	341	1,774	2,189	415	1,774	0	2,189	0	44.50	44.48
ALAMIT34	640	12.3	687.4	3,268	15,472	4,114	22,854	26,918	0	104	27,022	4,168	27.26	39.31
ALAMIT56	960	27.4	2,307.9	10,972	51,809	6,170	68,951	80,348	0	617	80,964	12,013	27.20	35.08
ANAHMCT	46	0.7	2.8	23	82	92	197	105	92	0	197	0	37.29	37.23
CWAT12	146	54.9	702.2	2,681	12,969	2,552	18,202	23,367	0	15	23,382	5,180	22.29	33.30
CWTRCC	512	59.1	2,650.3	10,119	43,817	4,311	58,247	87,121	0	56	87,177	28,930	20.35	32.89
ELSG1234	1,020	10.6	949.1	4,512	21,976	10,371	36,859	33,337	0	400	33,737	-3,122	27.91	35.55
ELWOOD1	53	0.7	3.3	26	92	185	303	119	184	0	303	0	35.99	36.06
ETWAND34	670	17.2	1,011.5	4,809	23,067	5,392	33,268	36,416	0	287	36,703	3,435	27.56	36.29
ETWANDA5	138	0.3	3.4	27	124	334	485	151	334	0	485	0	44.69	44.54
HN12MA12	860	30.3	2,282.7	2,445	51,702	19,015	73,162	80,099	0	888	80,987	7,825	23.72	35.48
LNBCHCC	560	15.1	741.7	3,526	17,045	5,478	26,049	27,441	0	282	27,723	1,674	27.74	37.38
MNDALY3	140	0.4	4.9	39	178	299	516	217	299	0	516	0	44.50	44.56
ORMND1	750	23.5	1,544.1	7,341	34,359	5,418	47,118	54,058	0	182	54,240	7,122	27.01	35.13
ORMND2	750	24.3	1,598.8	7,601	35,568	5,418	48,587	55,593	0	209	55,801	7,214	27.00	34.90
REDNDO56	350	4.2	129.5	615	3,059	2,744	6,418	5,355	0	39	5,394	-1,024	28.38	41.67
REDNDO78	960	30.0	2,523.7	11,998	56,096	7,528	75,622	88,721	0	682	89,403	13,781	26.98	35.43
VERNDSL	20	0.3	0.6	2	33	77	112	35	77	0	112	0	60.95	60.34
Thermal	**8,852**	**22.1**	**17,153.2**	**70,078**	**367,789**	**81,272**	**519,139**	**599,816**	**2,760**	**3,761**	**606,335**	**87,196**	**25.53**	**35.19**
Nuclear	**2,326**	**88.9**	**18,109.4**	**1,939**	**113,761**	**228,145**	**343,845**	**537,683**	**0**	**0**	**537,683**	**193,838**	**6.39**	**29.69**
Coal	**3,060**	**70.8**	**18,980.3**	**51,561**	**223,676**	**65,654**	**340,891**	**589,864**	**0**	**822**	**590,685**	**249,794**	**14.50**	**31.12**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**25,085**	**25,085**	**217,401**	**0**	**0**	**217,401**	**192,316**	**0.00**	**31.36**
PumpStorage	**207**	**7.0**	**127.0**	**0**	**0**	**3,459**	**3,459**	**4,315**	**0**	**0**	**4,315**	**856**	**0.00**	**33.97**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**19**	**0**	**3,959**	**3,978**	**119,009**	**0**	**0**	**119,009**	**115,031**	**0.00**	**29.52**
QF	**4,622**	**65.8**	**26,647.4**	**462,489**	**499,721**	**326,518**	**1,288,728**	**792,009**	**0**	**0**	**792,009**	**-496,719**	**36.11**	**29.72**
Total less QFs	**18,060**	**41.3**	**65,333.5**	**123,597**	**705,226**	**407,574**	**1,236,397**	**2,068,089**	**2,760**	**4,583**	**2,075,429**	**839,031**	**12.69**	**31.72**
Total	**22,682**	**46.3**	**91,980.9**	**586,086**	**1,204,947**	**734,092**	**2,525,125**	**2,860,098**	**2,760**	**4,583**	**2,867,438**	**342,312**	**19.47**	**31.14**

Table 3.12.9c Generation Cost and Revenues

Base Fuel Cost Case

San Diego Gas & Electric Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.2	0.3	2	22	125	149	24	125	0	149	0	85.78	85.71
ENCIN123	321	4.5	125.6	1,021	2,978	6,190	10,189	5,583	0	19	5,602	-4,587	31.84	44.61
ENCINA45	615	10.0	538.7	4,378	13,085	10,277	27,740	22,519	0	387	22,906	-4,834	32.42	42.52
KRNYGT23	132	0.6	7.0	56	261	1,035	1,352	317	1,035	0	1,352	0	45.33	45.42
MRMARGT	39	0.5	1.7	14	57	306	377	71	306	0	377	0	41.80	42.01
NRISLGT1	19	0.3	0.5	4	36	149	189	40	149	0	189	0	80.56	80.00
NTCKRNGT	33	0.7	2.0	16	71	259	346	87	259	0	346	0	43.23	43.28
NVLNRIGT	42	0.7	2.4	19	78	329	426	97	329	0	426	0	40.02	39.92
STHBAY4	222	1.6	30.2	245	780	4,195	5,220	1,670	0	6	1,676	-3,544	33.98	55.57
STHBAYGT	19	1.8	2.9	23	85	149	257	108	149	0	257	0	36.90	36.73
STHBY123	468	22.4	918.5	7,465	21,144	10,528	39,137	33,758	0	359	34,117	-5,020	31.15	37.14
TWOGTS	32	0.4	1.1	9	41	251	301	49	252	0	301	0	44.46	44.14
Thermal	**1,958**	**9.5**	**1,630.9**	**13,252**	**38,638**	**33,793**	**85,683**	**64,323**	**2,604**	**771**	**67,698**	**-17,985**	**31.82**	**39.91**
Nuclear	**430**	**89.1**	**3,357.8**	**360**	**21,914**	**41,456**	**63,730**	**99,739**	**0**	**0**	**99,739**	**36,009**	**6.63**	**29.70**
DSM/SelfGen	**126**	**38.7**	**425.5**	**1,824**	**0**	**566**	**2,390**	**12,684**	**0**	**0**	**12,684**	**10,294**	**4.29**	**29.81**
QF	**237**	**88.9**	**1,848.2**	**7,656**	**37,402**	**3,339**	**48,397**	**55,263**	**0**	**0**	**55,263**	**6,866**	**24.38**	**29.90**
Total less QFs	**2,514**	**24.6**	**5,414.2**	**15,436**	**60,552**	**75,815**	**151,803**	**176,746**	**2,604**	**771**	**180,121**	**28,318**	**14.03**	**32.79**
Total	**2,751**	**30.1**	**7,262.4**	**23,092**	**97,954**	**79,154**	**200,200**	**232,009**	**2,604**	**771**	**235,384**	**35,184**	**16.67**	**32.05**

Table 3.12.9d Generation Cost and Revenues

Base Fuel Cost Case

Pacific Gas and Electric Units - 2001

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
CCosta6	340	27.6	821.9	7,497	18,560	7,414	33,471	32,265	0	319	32,583	-888	31.70	39.64
CCosta7	340	23.6	701.8	6,402	15,885	7,414	29,701	28,217	0	94	28,311	-1,390	31.75	40.34
HntrsPt1	56	0.6	3.0	34	178	244	456	212	244	0	456	0	71.11	71.14
HntrsPt2	107	4.7	43.6	298	1,254	3,934	5,486	2,166	3,304	16	5,486	0	35.61	50.06
HntrsPt3	107	4.2	39.5	270	1,142	3,934	5,346	1,881	3,462	3	5,346	0	35.77	47.72
HntrsPt4	163	60.4	862.8	5,725	20,061	6,853	32,639	28,101	4,506	32	32,639	0	29.89	32.61
Humbld12	105	35.8	329.0	2,239	10,109	5,298	17,646	10,753	6,798	95	17,646	0	37.54	32.98
Mobil123	45	0.5	2.0	23	224	321	568	247	321	0	568	0	121.42	121.08
Morro12	326	26.7	762.5	5,825	18,493	5,153	29,471	32,294	0	230	32,524	3,053	31.89	42.65
Morro3	338	36.7	1,087.7	7,488	24,741	7,370	39,599	43,879	0	57	43,936	4,337	29.63	40.39
Morro4	338	41.3	1,221.6	8,410	27,307	7,370	43,087	48,836	0	70	48,906	5,819	29.24	40.03
Moss6	739	49.4	3,196.3	21,209	67,871	12,218	101,298	116,598	0	263	116,862	15,564	27.87	36.56
Moss7	739	59.7	3,864.8	25,645	80,094	12,218	117,957	137,036	0	514	137,551	19,594	27.36	35.59
Oakln123	192	0.3	4.4	50	413	353	816	463	353	0	816	0	106.04	106.19
Pitsbg5	325	32.5	924.1	6,361	21,086	7,092	34,539	34,963	0	39	35,002	463	29.70	37.88
Pitsbg6	325	33.9	964.4	6,639	25,411	7,092	39,142	37,548	0	0	37,548	-1,594	33.23	38.93
Pitsbrg7	720	32.7	2,064.9	13,702	47,521	11,883	73,106	78,962	0	183	79,145	6,039	29.65	38.33
Pitsbu12	326	10.3	294.0	2,246	6,721	5,153	14,120	12,326	1,758	36	14,120	0	30.50	42.05
Pitsbu34	326	26.4	752.6	5,749	21,679	5,153	32,581	31,401	1,180	0	32,581	0	36.44	41.72
Potr456	168	0.5	7.7	87	715	970	1,772	802	970	0	1,772	0	104.62	104.56
Potrero3	207	61.3	1,112.4	7,658	25,521	4,514	37,693	36,080	1,554	59	37,693	0	29.83	32.49
Thermal	**6,332**	**34.4**	**19,061.0**	**133,557**	**434,986**	**121,951**	**690,494**	**715,030**	**24,450**	**2,010**	**741,491**	**50,997**	**29.83**	**37.62**
Nuclear	**2,160**	**89.5**	**16,939.4**	**40,237**	**112,606**	**220,312**	**373,155**	**569,706**	**0**	**0**	**569,706**	**196,551**	**9.02**	**33.63**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**83,437**	**83,437**	**835,648**	**0**	**0**	**835,648**	**752,211**	**0.00**	**34.99**
Geo	**635**	**49.0**	**2,725.7**	**4,254**	**64,518**	**19,910**	**88,682**	**87,916**	**0**	**0**	**87,916**	**-766**	**25.23**	**32.25**
PumpStorage	**1,174**	**4.8**	**490.3**	**0**	**0**	**21,752**	**21,752**	**18,811**	**0**	**0**	**18,811**	**-2,941**	**0.00**	**38.37**
DSM & Solar	**518**	**0.3**	**12.6**	**28**	**0**	**157**	**185**	**411**	**0**	**0**	**411**	**226**	**2.22**	**32.54**
QF	**4,209**	**74.5**	**27,486.3**	**111,268**	**577,212**	**104,473**	**792,953**	**881,397**	**0**	**0**	**881,397**	**88,444**	**25.05**	**32.07**
Total less QFs	**15,322**	**47.0**	**63,112.5**	**178,076**	**612,110**	**467,519**	**1,257,705**	**2,227,522**	**24,450**	**2,010**	**2,253,983**	**996,278**	**12.52**	**35.33**
Total	**19,531**	**53.0**	**90,598.8**	**289,344**	**1,189,322**	**571,992**	**2,050,658**	**3,108,919**	**24,450**	**2,010**	**3,135,380**	**1,084,722**	**16.32**	**34.34**

Table 3.12.9e Generation Cost and Revenues

Base Fuel Cost Case

Southern California Edison Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
ALA7HNT5	276	0.5	11.6	100	483	1,967	2,550	583	1,967	0	2,550	0	50.45	50.48
ALAMIT34	640	13.3	747.8	3,811	19,044	4,561	27,416	32,922	0	124	33,046	5,630	30.56	44.19
ALAMIT56	960	27.6	2,319.4	11,820	59,102	6,841	77,763	91,336	0	763	92,099	14,336	30.58	39.71
ANAHMCT	46	0.9	3.6	32	120	103	255	152	103	0	255	0	41.84	41.87
CWAT12	146	51.1	654.0	2,683	14,404	2,830	19,917	24,868	0	50	24,918	5,001	26.13	38.10
CWTRCC	512	55.5	2,490.2	10,216	49,283	4,780	64,279	93,971	0	86	94,058	29,779	23.89	37.77
ELSG1234	1,020	10.4	925.3	4,716	24,309	11,499	40,524	38,343	0	537	38,880	-1,644	31.37	42.02
ELWOOD1	53	0.8	3.8	32	119	205	356	152	204	0	356	0	40.42	40.53
ETWAND34	670	20.4	1,197.6	6,103	30,546	5,978	42,627	48,786	0	442	49,228	6,601	30.60	41.10
ETWANDA5	138	0.5	6.6	57	278	370	705	334	371	0	705	0	50.93	50.84
HN12MA12	860	28.8	2,167.6	2,574	55,401	21,082	79,057	87,386	0	728	88,113	9,056	26.75	40.65
LNBCHCC	560	16.5	807.2	4,114	20,671	6,074	30,859	34,652	0	194	34,846	3,987	30.70	43.17
MNDALY3	140	0.6	7.3	63	306	331	700	369	331	0	700	0	50.59	50.55
ORMND1	750	24.6	1,617.2	8,242	40,324	6,007	54,573	65,676	0	170	65,846	11,273	30.03	40.72
ORMND2	750	24.9	1,638.9	8,352	41,373	6,007	55,732	65,881	0	187	66,068	10,336	30.34	40.31
REDNDO56	350	4.2	129.3	659	3,496	3,043	7,198	7,252	0	13	7,265	67	32.13	56.17
REDNDO78	960	30.4	2,552.0	13,005	63,986	8,346	85,337	100,860	0	540	101,400	16,063	30.17	39.73
VERNDSL	20	0.7	1.2	5	72	86	163	77	86	0	163	0	63.55	63.11
Thermal	**8,852**	**22.3**	**17,280.5**	**76,584**	**423,317**	**90,110**	**590,011**	**693,600**	**3,062**	**3,834**	**700,496**	**110,485**	**28.93**	**40.36**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,151**	**126,261**	**252,949**	**381,360**	**608,436**	**0**	**0**	**608,436**	**227,076**	**7.09**	**33.60**
Coal	**3,060**	**71.4**	**19,128.9**	**57,258**	**250,563**	**72,792**	**380,613**	**675,304**	**0**	**744**	**676,049**	**295,436**	**16.09**	**35.34**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**27,812**	**27,812**	**248,634**	**0**	**0**	**248,634**	**220,822**	**0.00**	**35.86**
PumpStorage	**207**	**7.0**	**127.3**	**0**	**0**	**3,835**	**3,835**	**5,047**	**0**	**0**	**5,047**	**1,212**	**0.00**	**39.64**
DSM/SelfGen	**2,114**	**21.8**	**4,031.0**	**14**	**0**	**4,390**	**4,404**	**135,460**	**0**	**0**	**135,460**	**131,056**	**0.00**	**33.60**
QF	**4,622**	**65.8**	**26,647.4**	**512,770**	**563,965**	**362,017**	**1,438,752**	**896,720**	**0**	**0**	**896,720**	**-542,032**	**40.41**	**33.65**
Total less QFs	**18,060**	**41.5**	**65,609.6**	**136,007**	**800,141**	**451,888**	**1,388,035**	**2,366,481**	**3,062**	**4,578**	**2,374,122**	**986,087**	**14.27**	**36.14**
Total	**22,682**	**46.4**	**92,257.0**	**648,777**	**1,364,106**	**813,905**	**2,826,787**	**3,263,201**	**3,062**	**4,578**	**3,270,842**	**444,055**	**21.82**	**35.42**

Table 3.12.9f Generation Cost and Revenues

Base Fuel Cost Case

San Diego Gas & Electric Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.5	0.7	6	61	139	206	67	139	0	206	0	95.65	95.71
ENCIN123	321	6.1	171.4	1,479	4,679	6,862	13,020	9,254	0	13	9,267	-3,753	35.93	54.06
ENCINA45	615	11.5	618.3	5,337	16,816	11,395	33,548	28,465	0	349	28,814	-4,734	35.83	46.60
KRNYGT23	132	0.7	8.0	68	334	1,148	1,550	402	1,148	0	1,550	0	50.12	50.06
MRMARGT	39	0.8	2.6	22	99	339	460	121	339	0	460	0	46.40	46.36
NRISLGT1	19	0.6	1.0	8	81	165	254	89	165	0	254	0	89.80	89.90
NTCKRNGT	33	0.8	2.3	19	89	287	395	109	286	0	395	0	47.41	47.60
NVLNRIGT	42	0.9	3.3	28	119	365	512	146	366	0	512	0	44.56	44.38
STHBAY4	222	1.6	30.5	263	893	4,651	5,807	2,357	0	41	2,398	-3,409	37.94	78.65
STHBAYGT	19	1.5	2.5	21	79	165	265	100	165	0	265	0	40.42	40.32
STHBY123	468	25.5	1,045.1	9,020	26,796	11,673	47,489	44,250	0	332	44,582	-2,907	34.27	42.66
TWOGTS	32	0.5	1.4	12	56	278	346	67	279	0	346	0	48.51	48.20
Thermal	**1,958**	**11.0**	**1,887.1**	**16,283**	**50,102**	**37,467**	**103,852**	**85,427**	**2,887**	**735**	**89,049**	**-14,803**	**35.18**	**45.66**
Nuclear	**430**	**89.1**	**3,357.8**	**399**	**24,311**	**45,963**	**70,673**	**112,791**	**0**	**0**	**112,791**	**42,118**	**7.36**	**33.59**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,022**	**0**	**627**	**2,649**	**14,283**	**0**	**0**	**14,283**	**11,634**	**4.75**	**33.57**
QF	**237**	**88.9**	**1,848.2**	**8,486**	**41,915**	**3,701**	**54,102**	**62,625**	**0**	**0**	**62,625**	**8,523**	**27.27**	**33.88**
Total less QFs	**2,514**	**25.8**	**5,670.4**	**18,704**	**74,413**	**84,057**	**177,174**	**212,501**	**2,887**	**735**	**216,123**	**38,949**	**16.42**	**37.60**
Total	**2,751**	**31.2**	**7,518.6**	**27,190**	**116,328**	**87,758**	**231,276**	**275,126**	**2,887**	**735**	**278,748**	**47,472**	**19.09**	**36.69**

Table 3.12.9g Generation Cost and Revenues

Base Fuel Cost Case

Pacific Gas and Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	27.9	830.9	8,540	23,601	8,806	40,947	41,370	0	519	41,888	941	38.68	50.41
CCosta7	340	23.7	706.6	7,263	20,117	8,806	36,186	36,259	0	230	36,489	303	38.75	51.64
HntrsPt1	56	0.6	3.0	39	233	290	562	272	290	0	562	0	91.25	91.28
HntrsPt2	107	4.7	44.3	336	1,638	4,673	6,647	2,852	3,780	15	6,647	0	44.54	64.70
HntrsPt3	107	5.3	49.2	373	1,827	4,673	6,873	2,693	4,173	7	6,873	0	44.72	54.90
HntrsPt4	163	58.4	833.3	6,105	24,437	8,139	38,681	34,120	4,521	40	38,681	0	36.65	40.99
Humbld12	105	33.4	306.8	2,310	11,965	6,292	20,567	12,525	7,994	48	20,567	0	46.53	40.99
Mobil123	45	0.6	2.4	30	338	381	749	369	380	0	749	0	157.19	157.02
Morro12	326	23.8	679.3	5,786	20,851	6,120	32,757	36,769	0	434	37,203	4,446	39.21	54.77
Morro3	338	35.3	1,044.2	7,958	29,841	8,754	46,553	52,840	0	56	52,896	6,343	36.20	50.66
Morro4	338	39.7	1,174.1	8,949	33,023	8,754	50,726	57,741	0	102	57,843	7,117	35.75	49.26
Moss6	739	45.7	2,957.1	21,664	79,122	14,511	115,297	135,993	0	336	136,329	21,032	34.08	46.10
Moss7	739	56.7	3,673.4	26,912	95,827	14,511	137,250	163,504	0	424	163,928	26,678	33.41	44.63
Oakln123	192	0.2	4.1	53	485	419	957	537	420	0	957	0	132.00	131.94
Pitsbg5	325	32.5	924.2	7,044	26,512	8,423	41,979	44,018	0	41	44,059	2,080	36.31	47.67
Pitsbg6	325	35.3	1,006.0	7,667	33,435	8,423	49,525	48,848	0	0	48,848	-677	40.86	48.56
Pitsbrg7	720	36.9	2,327.5	17,052	67,564	14,113	98,729	111,430	0	277	111,706	12,977	36.35	47.99
Pitsbu12	326	11.2	318.6	2,714	9,185	6,120	18,019	17,052	925	42	18,019	0	37.34	53.65
Pitsbu34	326	28.8	821.4	6,996	29,834	6,120	42,950	42,922	28	0	42,950	0	44.84	52.26
Potr456	168	0.5	7.2	94	847	1,152	2,093	940	1,153	0	2,093	0	130.22	130.19
Potrero3	207	58.6	1,062.8	8,100	30,713	5,361	44,174	43,252	765	157	44,174	0	36.52	40.84
Thermal	**6,332**	**33.9**	**18,776.3**	**145,985**	**541,395**	**144,841**	**832,221**	**886,306**	**24,429**	**2,728**	**913,461**	**81,240**	**36.61**	**47.35**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**690,278**	**0**	**0**	**690,278**	**246,504**	**10.75**	**40.75**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**1,033,860**	**0**	**0**	**1,033,860**	**934,762**	**0.00**	**43.29**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**108,649**	**0**	**0**	**108,649**	**-6,390**	**33.53**	**39.86**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**24,287**	**0**	**0**	**24,287**	**-1,547**	**0.00**	**49.46**
DSM & Solar	**518**	**0.3**	**12.6**	**36**	**0**	**186**	**222**	**511**	**0**	**0**	**511**	**289**	**2.85**	**40.43**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**718,272**	**124,082**	**974,506**	**1,089,088**	**0**	**0**	**1,089,088**	**114,582**	**30.94**	**39.62**
Total less QFs	**15,322**	**46.8**	**62,828.6**	**198,862**	**762,058**	**555,268**	**1,516,188**	**2,743,891**	**24,429**	**2,728**	**2,771,046**	**1,254,858**	**15.29**	**43.72**
Total	**19,531**	**52.8**	**90,314.9**	**331,014**	**1,480,330**	**679,350**	**2,490,694**	**3,832,979**	**24,429**	**2,728**	**3,860,134**	**1,369,440**	**20.06**	**42.47**

Table 3.12.9h Generation Cost and Revenues

Base Fuel Cost Case

Southern California Edison Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
ALA7HNT5	276	0.5	11.6	115	591	2,336	3,042	706	2,336	0	3,042	0	61.10	61.13
ALAMIT34	640	12.6	704.5	4,034	22,103	5,417	31,554	40,470	0	196	40,666	9,112	37.10	57.73
ALAMIT56	960	26.2	2,200.0	12,597	68,693	8,125	89,415	108,291	0	565	108,856	19,441	36.95	49.48
ANAHMCT	46	1.2	4.8	49	194	122	365	243	122	0	365	0	50.23	50.21
CWAT12	146	36.7	469.4	2,173	13,880	3,361	19,414	22,363	0	31	22,394	2,980	34.20	47.71
CWTRCC	512	36.9	1,654.7	7,659	43,525	5,677	56,861	79,930	0	78	80,008	23,147	30.93	48.35
ELSG1234	1,020	10.1	904.6	5,180	29,283	13,657	48,120	46,206	0	572	46,778	-1,342	38.10	51.71
ELWOOD1	53	1.1	4.9	48	186	243	477	235	242	0	477	0	48.36	48.45
ETWAND34	670	20.3	1,192.4	6,827	37,566	7,100	51,493	59,958	0	269	60,227	8,734	37.23	50.51
ETWANDA5	138	0.5	6.6	65	340	439	844	405	439	0	844	0	61.68	61.64
HN12MA12	860	27.6	2,079.5	2,933	64,876	25,039	92,848	104,133	0	1,002	105,135	12,287	32.61	50.56
LNBCHCC	560	16.6	815.0	4,666	25,748	7,214	37,628	43,642	0	240	43,882	6,254	37.32	53.84
MNDALY3	140	0.6	7.8	78	399	393	870	476	394	0	870	0	61.16	61.18
ORMND1	750	24.7	1,620.6	9,279	50,426	7,135	66,840	83,072	0	226	83,298	16,458	36.84	51.40
ORMND2	750	24.0	1,576.1	9,024	49,149	7,135	65,308	79,593	0	507	80,100	14,792	36.91	50.82
REDNDO56	350	8.8	269.4	1,543	9,165	3,614	14,322	16,324	0	35	16,359	2,037	39.74	60.72
REDNDO78	960	27.9	2,346.0	13,433	72,009	9,913	95,355	116,555	0	696	117,251	21,896	36.42	49.98
VERNDSL	20	0.7	1.2	6	77	102	185	83	102	0	185	0	68.17	68.03
Thermal	**8,852**	**20.5**	**15,868.9**	**79,709**	**488,210**	**107,022**	**674,941**	**802,685**	**3,635**	**4,417**	**810,737**	**135,796**	**35.79**	**50.86**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**735,502**	**0**	**0**	**735,502**	**282,304**	**8.44**	**40.61**
Coal	**3,060**	**70.5**	**18,891.9**	**66,724**	**295,278**	**86,454**	**448,456**	**808,275**	**0**	**888**	**809,163**	**360,707**	**19.16**	**42.83**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**304,329**	**0**	**0**	**304,329**	**271,298**	**0.00**	**43.90**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**6,416**	**0**	**0**	**6,416**	**1,861**	**0.00**	**50.15**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**26**	**0**	**5,214**	**5,240**	**163,771**	**0**	**0**	**163,771**	**158,531**	**0.01**	**40.63**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**689,913**	**429,961**	**1,728,882**	**1,085,022**	**0**	**0**	**1,085,022**	**-643,860**	**48.74**	**40.72**
Total less QFs	**18,060**	**40.4**	**63,961.6**	**149,014**	**933,707**	**536,700**	**1,619,421**	**2,820,978**	**3,635**	**5,305**	**2,829,918**	**1,210,496**	**16.93**	**44.19**
Total	**22,682**	**45.6**	**90,609.0**	**758,022**	**1,623,620**	**966,661**	**3,348,303**	**3,906,000**	**3,635**	**5,305**	**3,914,940**	**566,636**	**26.28**	**43.17**

Table 3.12.9i Generation Cost and Revenues

Base Fuel Cost Case

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.5	0.7	7	73	165	245	80	165	0	245	0	114.76	114.29
ENCIN123	321	8.2	230.7	2,201	7,839	8,150	18,190	13,946	0	150	14,097	-4,093	43.52	61.11
ENCINA45	615	14.2	762.7	7,278	25,180	13,533	45,991	41,947	0	838	42,784	-3,207	42.56	56.09
KRNYGT23	132	0.9	10.3	97	513	1,363	1,973	610	1,363	0	1,973	0	59.07	59.11
MRMARGT	39	0.9	3.1	29	138	403	570	167	403	0	570	0	54.59	54.75
NRISLGT1	19	0.6	1.0	9	97	196	302	107	195	0	302	0	107.69	108.08
NTCKRNGT	33	0.9	2.6	24	121	341	486	145	341	0	486	0	56.16	56.20
NVLNRIGT	42	0.9	3.4	32	147	434	613	179	434	0	613	0	52.54	52.65
STHBAY4	222	2.1	39.9	381	1,444	5,524	7,349	3,682	0	3	3,685	-3,664	45.72	92.33
STHBAYGT	19	1.4	2.3	22	89	196	307	110	197	0	307	0	47.65	47.62
STHBY123	468	30.0	1,231.4	11,750	38,132	13,863	63,745	62,770	0	544	63,313	-432	40.51	51.42
TWOGTS	32	0.5	1.4	13	67	330	410	80	330	0	410	0	57.76	57.55
Thermal	**1,958**	**13.3**	**2,289.5**	**21,843**	**73,840**	**44,498**	**140,181**	**123,823**	**3,428**	**1,535**	**128,785**	**-11,396**	**41.79**	**54.75**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**136,311**	**0**	**0**	**136,311**	**52,346**	**8.75**	**40.59**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**17,361**	**0**	**0**	**17,361**	**14,214**	**5.65**	**40.80**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**50,678**	**4,396**	**65,153**	**75,928**	**0**	**0**	**75,928**	**10,775**	**32.87**	**41.08**
Total less QFs	**2,514**	**27.6**	**6,072.8**	**24,719**	**102,741**	**99,833**	**227,293**	**277,495**	**3,428**	**1,535**	**282,457**	**55,164**	**20.99**	**45.95**
Total	**2,751**	**32.9**	**7,921.0**	**34,798**	**153,419**	**104,229**	**292,446**	**353,423**	**3,428**	**1,535**	**358,385**	**65,939**	**23.76**	**44.81**

Table 3.12.10a Generation Cost and Revenues

Low Fuel Cost Case

Pacific Gas and Electric Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	29.5	878.7	5,981	12,606	6,687	25,274	23,158	0	132	23,290	-1,984	21.15	26.50
CCosta7	340	25.6	762.9	5,193	10,994	6,687	22,874	20,297	0	64	20,361	-2,513	21.22	26.69
HntrsPt1	56	0.3	1.3	11	65	220	296	76	220	0	296	0	59.63	59.38
HntrsPt2	107	5.5	51.2	243	951	3,549	4,743	1,481	3,257	5	4,743	0	23.33	29.04
HntrsPt3	107	7.0	65.5	311	1,206	3,549	5,066	1,754	3,302	10	5,066	0	23.17	26.93
HntrsPt4	163	80.1	1,144.0	5,222	16,531	6,181	27,934	24,794	3,136	4	27,934	0	19.02	21.68
Humbld12	105	42.8	393.6	1,857	7,459	4,778	14,094	8,697	5,337	60	14,094	0	23.67	22.25
Mobil123	45	0.2	0.8	7	73	289	369	80	289	0	369	0	102.40	102.56
Morro12	326	38.7	1,104.0	6,038	16,818	4,647	27,503	30,440	0	79	30,519	3,016	20.70	27.64
Morro3	338	53.3	1,579.4	7,563	22,449	6,648	36,660	41,040	0	17	41,057	4,397	19.00	26.00
Morro4	338	62.8	1,857.9	8,897	26,001	6,648	41,546	47,355	0	38	47,392	5,846	18.78	25.51
Moss6	739	72.2	4,674.1	21,335	62,099	11,020	94,454	109,538	0	64	109,601	15,147	17.85	23.45
Moss7	739	83.8	5,424.3	24,760	70,451	11,020	106,231	123,989	0	21	124,010	17,779	17.55	22.86
Oakln123	192	0.2	3.8	34	313	318	665	347	318	0	665	0	91.35	91.32
Pitsbg5	325	49.6	1,411.3	6,758	20,083	6,396	33,237	34,191	0	32	34,222	985	19.02	24.25
Pitsbg6	325	40.9	1,164.6	5,577	19,524	6,396	31,497	30,025	0	0	30,025	-1,472	21.55	25.78
Pitsbrg7	720	63.3	3,989.8	18,211	56,884	10,718	85,813	95,447	0	82	95,529	9,716	18.82	23.94
Pitsbu12	326	12.3	352.5	1,928	5,097	4,647	11,672	9,522	2,121	29	11,672	0	19.93	27.10
Pitsbu34	326	26.3	751.8	4,112	13,806	4,647	22,565	20,797	1,768	0	22,565	0	23.83	27.66
Potr456	168	0.2	2.6	23	208	875	1,106	230	876	0	1,106	0	90.11	89.84
Potrero3	207	80.8	1,465.7	7,019	21,005	4,071	32,095	31,924	153	18	32,095	0	19.12	21.79
Thermal	**6,332**	**48.8**	**27,079.6**	**131,080**	**384,623**	**109,991**	**625,694**	**655,182**	**20,777**	**655**	**676,611**	**50,917**	**19.04**	**24.22**
Nuclear	**2,160**	**89.5**	**16,939.4**	**36,291**	**101,299**	**198,708**	**336,298**	**406,407**	**0**	**0**	**406,407**	**70,109**	**8.12**	**23.99**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**75,256**	**75,256**	**577,462**	**0**	**0**	**577,462**	**502,206**	**0.00**	**24.18**
Geo	**635**	**49.0**	**2,725.7**	**3,837**	**54,171**	**17,958**	**75,966**	**62,758**	**0**	**0**	**62,758**	**-13,208**	**21.28**	**23.02**
PumpStorage	**1,174**	**4.7**	**488.1**	**0**	**0**	**19,619**	**19,619**	**12,340**	**0**	**0**	**12,340**	**-7,279**	**0.00**	**25.28**
DSM & Solar	**518**	**0.3**	**12.6**	**19**	**0**	**141**	**160**	**291**	**0**	**0**	**291**	**131**	**1.51**	**23.11**
QF	**4,209**	**74.5**	**27,486.3**	**100,357**	**369,627**	**94,229**	**564,213**	**630,198**	**0**	**0**	**630,198**	**65,985**	**17.10**	**22.93**
Total less QFs	**15,322**	**53.0**	**71,128.9**	**171,227**	**540,093**	**421,673**	**1,132,993**	**1,714,440**	**20,777**	**655**	**1,735,869**	**602,876**	**10.00**	**24.11**
Total	**19,531**	**57.6**	**98,615.2**	**271,584**	**909,720**	**515,902**	**1,697,206**	**2,344,638**	**20,777**	**655**	**2,366,067**	**668,861**	**11.98**	**23.78**

Table 3.12.10b Generation Cost and Revenues

Low Fuel Cost Case

Southern California Edison Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
ALA7HNT5	276	0.3	6.9	48	185	1,774	2,007	233	1,774	0	2,007	0	33.65	33.62
ALAMIT34	640	19.5	1,091.5	4,104	17,730	4,114	25,948	31,610	0	57	31,667	5,719	20.00	29.01
ALAMIT56	960	36.4	3,062.2	11,513	49,535	6,170	67,218	79,753	0	320	80,073	12,855	19.94	26.15
ANAHMCT	46	0.7	2.6	19	56	92	167	75	92	0	167	0	28.41	28.52
CWAT12	146	74.5	952.7	2,931	12,604	2,552	18,087	23,657	0	2	23,659	5,572	16.31	24.83
CWTRCC	512	76.9	3,450.7	10,615	41,484	4,311	56,410	84,672	0	5	84,677	28,267	15.10	24.54
ELSG1234	1,020	13.3	1,191.0	4,478	19,870	10,371	34,719	31,691	0	297	31,988	-2,731	20.44	26.86
ELWOOD1	53	0.9	4.0	28	80	185	293	108	185	0	293	0	27.23	27.27
ETWAND34	670	28.2	1,656.8	6,229	27,311	5,392	38,932	44,847	0	27	44,874	5,942	20.24	27.09
ETWANDA5	138	0.4	4.4	31	119	334	484	150	334	0	484	0	34.19	34.25
HN12MA12	860	42.5	3,199.2	3,427	51,926	19,015	74,368	83,326	0	794	84,120	9,752	17.30	26.29
LNBCHCC	560	21.4	1,047.6	3,939	17,242	5,478	26,659	29,785	0	263	30,048	3,389	20.22	28.68
MNDALY3	140	0.4	5.2	36	140	299	475	177	298	0	475	0	33.91	33.97
ORMND1	750	37.2	2,443.1	9,186	38,586	5,418	53,190	64,328	0	89	64,418	11,228	19.55	26.37
ORMND2	750	40.7	2,671.0	10,043	42,270	5,418	57,731	68,901	0	259	69,160	11,429	19.59	25.89
REDNDO56	350	10.1	308.1	1,158	5,355	2,744	9,257	9,451	0	51	9,502	245	21.14	30.84
REDNDO78	960	39.0	3,279.2	12,329	52,296	7,528	72,153	85,677	0	212	85,889	13,736	19.71	26.19
VERNDSL	20	0.3	0.5	2	30	77	109	32	77	0	109	0	60.95	61.54
Thermal	**8,852**	**31.4**	**24,376.6**	**80,116**	**376,819**	**81,272**	**538,207**	**638,473**	**2,760**	**2,376**	**643,610**	**105,403**	**18.74**	**26.29**
Nuclear	**2,326**	**88.9**	**18,109.4**	**1,939**	**113,761**	**228,145**	**343,845**	**432,656**	**0**	**0**	**432,656**	**88,810**	**6.39**	**23.89**
Coal	**3,060**	**55.5**	**14,868.9**	**36,128**	**173,116**	**65,654**	**274,898**	**377,139**	**0**	**1,116**	**378,254**	**103,356**	**14.07**	**25.44**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**25,085**	**25,085**	**171,900**	**0**	**0**	**171,900**	**146,815**	**0.00**	**24.80**
PumpStorage	**207**	**7.0**	**127.0**	**0**	**0**	**3,459**	**3,459**	**3,368**	**0**	**0**	**3,368**	**-91**	**0.00**	**26.51**
DSM/SelfGen	**2,114**	**21.8**	**4,031.0**	**13**	**0**	**3,959**	**3,972**	**96,245**	**0**	**0**	**96,245**	**92,273**	**0.00**	**23.88**
QF	**4,622**	**65.8**	**26,647.4**	**462,489**	**367,618**	**326,518**	**1,156,625**	**640,452**	**0**	**0**	**640,452**	**-516,173**	**31.15**	**24.03**
Total less QFs	**18,060**	**43.3**	**68,445.5**	**118,196**	**663,696**	**407,574**	**1,189,466**	**1,719,780**	**2,760**	**3,492**	**1,726,032**	**536,566**	**11.42**	**25.18**
Total	**22,682**	**47.9**	**95,092.9**	**580,685**	**1,031,314**	**734,092**	**2,346,091**	**2,360,232**	**2,760**	**3,492**	**2,366,484**	**20,393**	**16.95**	**24.86**

Table 3.12.10c Generation Cost and Revenues

Low Fuel Cost Case

San Diego Gas & Electric Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.2	0.3	2	22	125	149	23	126	0	149	0	83.62	82.14
ENCIN123	321	7.8	218.5	1,304	3,904	6,190	11,398	7,544	0	20	7,564	-3,834	23.83	34.61
ENCINA45	615	18.0	970.4	5,793	16,981	10,277	33,051	29,401	0	323	29,724	-3,327	23.47	30.63
KRNYGT23	132	0.6	6.9	40	186	1,035	1,261	226	1,035	0	1,261	0	32.85	32.85
MRMARGT	39	0.7	2.4	14	58	306	378	71	307	0	378	0	30.44	30.21
NRISLGT1	19	0.3	0.5	3	36	149	188	39	149	0	188	0	78.40	78.00
NTCKRNGT	33	0.7	2.0	12	51	259	322	62	260	0	322	0	31.08	30.85
NVLNRIGT	42	1.4	5.1	30	117	329	476	147	329	0	476	0	28.89	28.88
STHBAY4	222	2.3	43.7	261	835	4,195	5,291	1,898	0	26	1,924	-3,367	25.07	43.99
STHBAYGT	19	2.1	3.5	20	72	149	241	92	149	0	241	0	26.64	26.51
STHBY123	468	37.4	1,532.7	9,150	25,317	10,528	44,995	42,227	0	198	42,426	-2,569	22.49	27.68
TWOGTS	32	0.3	0.8	5	22	251	278	26	252	0	278	0	31.76	31.33
Thermal	**1,958**	**16.2**	**2,786.8**	**16,634**	**47,601**	**33,793**	**98,028**	**81,756**	**2,607**	**567**	**84,931**	**-13,097**	**23.05**	**29.54**
Nuclear	**430**	**89.1**	**3,357.8**	**360**	**21,914**	**41,456**	**63,730**	**80,137**	**0**	**0**	**80,137**	**16,407**	**6.63**	**23.87**
DSM/SelfGen	**126**	**38.7**	**425.5**	**1,823**	**0**	**566**	**2,389**	**10,133**	**0**	**0**	**10,133**	**7,744**	**4.28**	**23.81**
QF	**237**	**88.9**	**1,848.2**	**7,656**	**27,306**	**3,339**	**38,301**	**44,584**	**0**	**0**	**44,584**	**6,283**	**18.92**	**24.12**
Total less QFs	**2,514**	**29.8**	**6,570.1**	**18,817**	**69,515**	**75,815**	**164,147**	**172,026**	**2,607**	**567**	**175,201**	**11,054**	**13.44**	**26.27**
Total	**2,751**	**34.9**	**8,418.3**	**26,473**	**96,821**	**79,154**	**202,448**	**216,610**	**2,607**	**567**	**219,785**	**17,337**	**14.65**	**25.80**

Table 3.12.10d Generation Cost and Revenues

Low Fuel Cost Case

Pacific Gas and Electric Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	30.2	899.3	6,591	14,792	7,414	28,797	27,797	0	142	27,939	-858	23.78	31.07
CCosta7	340	24.9	742.6	5,443	12,275	7,414	25,132	23,724	0	152	23,875	-1,257	23.86	32.15
HntrsPt1	56	0.6	3.0	29	178	244	451	207	244	0	451	0	69.32	69.46
HntrsPt2	107	6.0	55.9	283	1,154	3,934	5,371	2,253	3,110	7	5,371	0	25.69	40.42
HntrsPt3	107	7.3	68.6	347	1,454	3,934	5,735	2,317	3,403	14	5,735	0	26.24	33.96
HntrsPt4	163	76.9	1,097.8	5,318	18,255	6,853	30,426	27,596	2,801	29	30,426	0	21.47	25.16
Humbld12	105	41.7	383.7	1,924	8,385	5,298	15,607	10,064	5,447	97	15,607	0	26.87	26.49
Mobil123	45	0.7	2.7	26	298	321	645	324	321	0	645	0	119.63	119.56
Morro12	326	34.0	970.5	5,675	17,057	5,153	27,885	32,305	0	55	32,360	4,475	23.42	33.34
Morro3	338	50.1	1,484.5	7,560	24,254	7,370	39,184	45,261	0	8	45,269	6,085	21.43	30.49
Morro4	338	59.3	1,756.0	8,943	28,259	7,370	44,572	51,738	0	8	51,747	7,175	21.18	29.47
Moss6	739	68.0	4,405.0	21,337	67,235	12,218	100,790	118,968	0	141	119,109	18,319	20.11	27.04
Moss7	739	79.8	5,165.7	25,022	77,086	12,218	114,326	136,531	0	118	136,649	22,323	19.77	26.45
Oakln123	192	0.3	5.5	53	518	353	924	571	353	0	924	0	104.25	104.39
Pitsbg5	325	46.7	1,328.0	6,763	21,714	7,092	35,569	37,220	0	22	37,242	1,673	21.44	28.04
Pitsbg6	325	39.2	1,117.1	5,689	21,418	7,092	34,199	33,712	0	0	33,712	-487	24.27	30.18
Pitsbrg7	720	50.3	3,172.0	15,365	52,337	11,883	79,585	90,531	0	95	90,626	11,041	21.34	28.57
Pitsbu12	326	10.1	289.4	1,692	4,821	5,153	11,666	10,256	1,398	12	11,666	0	22.51	35.49
Pitsbu34	326	29.7	847.1	4,953	17,796	5,153	27,902	27,743	159	0	27,902	0	26.86	32.75
Potr456	168	0.5	7.7	74	715	970	1,759	788	971	0	1,759	0	102.83	102.74
Potrero3	207	77.2	1,400.0	7,129	23,074	4,514	34,717	35,010	0	39	35,050	333	21.57	25.04
Thermal	**6,332**	**45.4**	**25,201.9**	**130,216**	**413,075**	**121,951**	**665,242**	**714,916**	**18,207**	**939**	**734,064**	**68,822**	**21.56**	**28.40**
Nuclear	**2,160**	**89.5**	**16,939.4**	**40,237**	**112,606**	**220,312**	**373,155**	**460,941**	**0**	**0**	**460,941**	**87,786**	**9.02**	**27.21**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**83,437**	**83,437**	**671,094**	**0**	**0**	**671,094**	**587,657**	**0.00**	**28.10**
Geo	**635**	**49.0**	**2,725.7**	**4,254**	**64,518**	**19,910**	**88,682**	**71,581**	**0**	**0**	**71,581**	**-17,101**	**25.23**	**26.26**
PumpStorage	**1,174**	**4.8**	**490.3**	**0**	**0**	**21,752**	**21,752**	**15,196**	**0**	**0**	**15,196**	**-6,556**	**0.00**	**31.00**
DSM & Solar	**518**	**0.3**	**12.6**	**30**	**0**	**157**	**187**	**344**	**0**	**0**	**344**	**157**	**2.37**	**27.22**
QF	**4,209**	**74.5**	**27,486.3**	**111,268**	**421,344**	**104,473**	**637,085**	**716,199**	**0**	**0**	**716,199**	**79,114**	**19.38**	**26.06**
Total less QFs	**15,322**	**51.6**	**69,253.4**	**174,737**	**590,199**	**467,519**	**1,232,455**	**1,934,072**	**18,207**	**939**	**1,953,220**	**720,765**	**11.05**	**27.94**
Total	**19,531**	**56.5**	**96,739.7**	**286,005**	**1,011,543**	**571,992**	**1,869,540**	**2,650,271**	**18,207**	**939**	**2,669,419**	**799,879**	**13.41**	**27.41**

Table 3.12.10e Generation Cost and Revenues

Low Fuel Cost Case

Southern California Edison Units - 2001

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
ALA7HNT5	276	0.5	11.6	88	352	1,967	2,407	440	1,967	0	2,407	0	38.11	38.10
ALAMIT34	640	21.6	1,208.6	4,884	22,045	4,561	31,490	40,724	0	50	40,774	9,284	22.28	33.74
ALAMIT56	960	37.9	3,188.8	12,886	57,966	6,841	77,693	96,411	0	336	96,747	19,054	22.22	30.34
ANAHMCT	46	0.9	3.6	28	88	103	219	116	103	0	219	0	31.86	31.96
CWAT12	146	67.2	859.4	2,849	13,578	2,830	19,257	24,540	0	0	24,540	5,283	19.12	28.56
CWTRCC	512	71.2	3,195.3	10,594	45,736	4,780	61,110	90,539	0	11	90,550	29,440	17.63	28.34
ELSG1234	1,020	16.7	1,494.2	6,038	27,880	11,499	45,417	46,040	0	368	46,408	991	22.70	31.06
ELWOOD1	53	0.8	3.8	29	87	205	321	116	205	0	321	0	30.79	30.93
ETWAND34	670	33.0	1,936.2	7,824	35,929	5,978	49,731	59,327	0	88	59,414	9,683	22.60	30.69
ETWANDA5	138	0.5	6.6	50	203	370	623	253	370	0	623	0	38.45	38.51
HN12MA12	860	42.8	3,226.0	3,831	58,787	21,082	83,700	98,910	0	769	99,679	15,979	19.41	30.90
LNBCHCC	560	23.1	1,133.2	4,579	20,896	6,074	31,549	38,359	0	307	38,665	7,116	22.48	34.12
MNDALY3	140	0.6	7.3	56	223	331	610	279	331	0	610	0	38.21	38.22
ORMND1	750	33.6	2,205.9	8,914	39,705	6,007	54,626	69,197	0	163	69,360	14,734	22.04	31.44
ORMND2	750	35.6	2,340.7	9,459	42,228	6,007	57,694	72,798	0	76	72,874	15,180	22.08	31.13
REDNDO56	350	10.9	334.2	1,351	6,521	3,043	10,915	13,061	0	59	13,120	2,205	23.55	39.25
REDNDO78	960	37.9	3,190.6	12,893	57,320	8,346	78,559	97,145	0	221	97,367	18,808	22.01	30.52
VERNDSL	20	0.7	1.2	5	72	86	163	77	86	0	163	0	63.55	63.11
Thermal	**8,852**	**31.4**	**24,347.1**	**86,358**	**429,616**	**90,110**	**606,084**	**748,332**	**3,062**	**2,448**	**753,841**	**147,757**	**21.19**	**30.84**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,151**	**126,261**	**252,949**	**381,360**	**491,993**	**0**	**0**	**491,993**	**110,633**	**7.09**	**27.17**
Coal	**3,060**	**54.8**	**14,693.6**	**39,570**	**189,760**	**72,792**	**302,122**	**432,769**	**0**	**854**	**433,621**	**131,499**	**15.61**	**29.51**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**27,812**	**27,812**	**200,256**	**0**	**0**	**200,256**	**172,443**	**0.00**	**28.89**
PumpStorage	**207**	**7.0**	**127.3**	**0**	**0**	**3,835**	**3,835**	**4,081**	**0**	**0**	**4,081**	**246**	**0.00**	**32.05**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**29**	**0**	**4,390**	**4,419**	**109,753**	**0**	**0**	**109,753**	**105,334**	**0.01**	**27.23**
QF	**4,622**	**65.8**	**26,647.4**	**512,770**	**414,850**	**362,017**	**1,289,637**	**726,017**	**0**	**0**	**726,017**	**-563,620**	**34.81**	**27.25**
Total less QFs	**18,060**	**43.1**	**68,241.1**	**128,108**	**745,637**	**451,888**	**1,325,632**	**1,987,184**	**3,062**	**3,302**	**1,993,545**	**667,913**	**12.80**	**29.17**
Total	**22,682**	**47.8**	**94,888.4**	**640,878**	**1,160,487**	**813,905**	**2,615,269**	**2,713,201**	**3,062**	**3,302**	**2,719,562**	**104,293**	**18.98**	**28.63**

Table 3.12.10f Generation Cost and Revenues

Low Fuel Cost Case

San Diego Gas & Electric Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.5	0.7	4	61	139	204	65	139	0	204	0	93.36	92.86
ENCIN123	321	11.6	326.9	2,073	6,648	6,862	15,583	12,842	0	160	13,002	-2,581	26.68	39.77
ENCINA45	615	18.7	1,009.4	6,401	19,769	11,395	37,565	35,340	0	343	35,683	-1,882	25.93	35.35
KRNYGT23	132	0.8	9.2	57	277	1,148	1,482	334	1,148	0	1,482	0	36.37	36.38
MRMARGT	39	0.8	2.7	17	75	339	431	92	339	0	431	0	33.90	33.95
NRISLGT1	19	0.6	1.0	6	81	165	252	87	165	0	252	0	87.51	87.88
NTCKRNGT	33	0.9	2.6	16	74	287	377	90	287	0	377	0	34.70	34.88
NVLNRIGT	42	1.2	4.4	27	115	365	507	142	365	0	507	0	32.16	32.13
STHBAY4	222	2.6	50.3	319	1,088	4,651	6,058	3,099	0	38	3,138	-2,920	27.97	62.35
STHBAYGT	19	1.9	3.1	19	73	165	257	93	164	0	257	0	29.55	29.62
STHBY123	468	39.2	1,607.0	10,191	29,587	11,673	51,451	51,344	0	261	51,605	154	24.75	32.11
TWOGTS	32	0.6	1.7	10	49	278	337	59	278	0	337	0	35.64	35.33
Thermal	**1,958**	**17.6**	**3,019.0**	**19,140**	**57,897**	**37,467**	**114,504**	**103,587**	**2,885**	**802**	**107,275**	**-7,229**	**25.52**	**34.58**
Nuclear	**430**	**89.1**	**3,357.8**	**399**	**24,311**	**45,963**	**70,673**	**91,124**	**0**	**0**	**91,124**	**20,451**	**7.36**	**27.14**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,022**	**0**	**627**	**2,649**	**11,641**	**0**	**0**	**11,641**	**8,992**	**4.75**	**27.36**
QF	**237**	**88.9**	**1,848.2**	**8,486**	**30,600**	**3,701**	**42,787**	**50,770**	**0**	**0**	**50,770**	**7,983**	**21.15**	**27.47**
Total less QFs	**2,514**	**30.9**	**6,802.3**	**21,561**	**82,208**	**84,057**	**187,826**	**206,352**	**2,885**	**802**	**210,040**	**22,214**	**15.25**	**30.45**
Total	**2,751**	**35.9**	**8,650.5**	**30,047**	**112,808**	**87,758**	**230,613**	**257,122**	**2,885**	**802**	**260,810**	**30,197**	**16.51**	**29.82**

Table 3.12.10g Generation Cost and Revenues

Low Fuel Cost Case

Pacific Gas and Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000				Revenue in $000				in $000	Energy $/MWh	
				Var	Fuel	Fixed	Total	Energy	Others Reserve	Others Spin	Total	Net Income	Avg. Var Cost	Avg. Rev.
CCosta6	340	34.3	1,022.7	8,489	21,101	8,806	38,396	39,927	0	133	40,060	1,664	28.93	39.17
CCosta7	340	26.6	792.9	6,581	16,550	8,806	31,937	32,778	0	45	32,823	886	29.17	41.40
HntrsPt1	56	0.7	3.4	37	267	290	594	304	290	0	594	0	89.27	89.15
HntrsPt2	107	8.4	78.5	439	2,142	4,673	7,254	3,841	3,393	21	7,254	0	32.90	49.23
HntrsPt3	107	9.0	84.6	473	2,287	4,673	7,433	3,630	3,785	18	7,433	0	32.64	43.13
HntrsPt4	163	72.4	1,033.5	5,527	21,715	8,139	35,381	32,285	3,080	16	35,381	0	26.36	31.25
Humbld12	105	42.0	386.0	2,143	10,582	6,292	19,017	12,820	6,134	62	19,017	0	32.96	33.37
Mobil123	45	0.7	2.7	30	395	381	806	425	381	0	806	0	155.22	155.11
Morro12	326	35.0	999.7	6,538	22,146	6,120	34,804	41,652	0	38	41,690	6,886	28.69	41.70
Morro3	338	47.6	1,407.8	7,945	29,003	8,754	45,702	54,377	0	8	54,385	8,683	26.24	38.63
Morro4	338	53.3	1,576.8	8,898	32,015	8,754	49,667	59,026	0	10	59,036	9,369	25.95	37.44
Moss6	739	63.0	4,077.3	21,806	78,497	14,511	114,814	139,938	0	114	140,053	25,239	24.60	34.35
Moss7	739	74.4	4,816.9	25,761	90,595	14,511	130,867	159,699	0	246	159,945	29,078	24.16	33.21
Oakln123	192	0.4	6.2	68	741	419	1,228	809	419	0	1,228	0	130.03	130.06
Pitsbg5	325	43.0	1,224.9	6,912	25,289	8,423	40,624	43,517	0	0	43,517	2,893	26.29	35.53
Pitsbg6	325	39.8	1,132.4	6,390	27,409	8,423	42,222	43,211	0	0	43,211	989	29.85	38.16
Pitsbrg7	720	52.0	3,278.8	17,535	68,148	14,113	99,796	117,267	0	132	117,400	17,604	26.13	35.81
Pitsbu12	326	13.2	375.5	2,455	7,854	6,120	16,429	16,884	0	2	16,886	457	27.46	44.98
Pitsbu34	326	33.3	951.6	6,223	25,109	6,120	37,452	39,052	0	0	39,052	1,600	32.93	41.04
Potr456	168	0.6	8.9	98	1,049	1,152	2,299	1,147	1,152	0	2,299	0	128.24	128.30
Potrero3	207	72.8	1,320.0	7,449	27,467	5,361	40,277	40,820	0	57	40,878	601	26.45	30.97
Thermal	**6,332**	**44.3**	**24,581.0**	**141,797**	**510,361**	**144,841**	**796,999**	**883,409**	**18,634**	**902**	**902,948**	**105,949**	**26.53**	**35.98**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**563,003**	**0**	**0**	**563,003**	**119,229**	**10.75**	**33.24**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**840,857**	**0**	**0**	**840,857**	**741,759**	**0.00**	**35.21**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**87,927**	**0**	**0**	**87,927**	**-27,112**	**33.53**	**32.26**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**20,130**	**0**	**0**	**20,130**	**-5,704**	**0.00**	**41.00**
DSM & Solar	**518**	**0.3**	**12.7**	**39**	**0**	**186**	**225**	**430**	**0**	**0**	**430**	**205**	**3.08**	**33.99**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**524,310**	**124,082**	**780,544**	**881,554**	**0**	**0**	**881,554**	**101,010**	**23.88**	**32.07**
Total less QFs	**15,322**	**51.1**	**68,633.3**	**194,677**	**731,024**	**555,268**	**1,480,969**	**2,395,756**	**18,634**	**902**	**2,415,295**	**934,326**	**13.49**	**34.92**
Total	**19,531**	**56.2**	**96,119.6**	**326,829**	**1,255,334**	**679,350**	**2,261,513**	**3,277,310**	**18,634**	**902**	**3,296,849**	**1,035,336**	**16.46**	**34.11**

Table 3.12.10h Generation Cost and Revenues

Low Fuel Cost Case

Southern California Edison Units - 2006

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
ALA7HNT5	276	1.1	27.0	237	989	2,336	3,562	1,226	2,336	0	3,562	0	45.50	45.49
ALAMIT34	640	25.5	1,428.0	6,513	32,085	5,417	44,015	58,541	0	4	58,545	14,530	27.03	41.00
ALAMIT56	960	38.4	3,228.2	14,723	72,050	8,125	94,898	119,995	0	582	120,577	25,679	26.88	37.35
ANAHMCT	46	1.6	6.5	58	191	122	371	249	122	0	371	0	38.56	38.60
CWAT12	146	55.8	714.2	2,685	15,173	3,361	21,219	25,623	0	7	25,630	4,411	25.00	35.88
CWTRCC	512	59.8	2,681.1	10,081	51,494	5,677	67,252	97,295	0	105	97,399	30,147	22.97	36.33
ELSG1234	1,020	19.5	1,739.6	7,934	40,608	13,657	62,199	68,001	0	500	68,501	6,302	27.90	39.38
ELWOOD1	53	1.6	7.4	65	207	243	515	271	244	0	515	0	36.94	36.87
ETWAND34	670	35.9	2,109.3	9,620	47,429	7,100	64,149	79,464	0	122	79,586	15,437	27.05	37.73
ETWANDA5	138	1.1	13.2	116	490	439	1,045	607	438	0	1,045	0	45.82	45.85
HN12MA12	860	43.6	3,287.4	4,637	73,081	25,039	102,757	124,738	0	944	125,682	22,925	23.64	38.23
LNBCHCC	560	24.9	1,223.6	5,581	27,538	7,214	40,333	51,154	0	213	51,366	11,033	27.07	41.98
MNDALY3	140	1.2	15.1	132	554	393	1,079	686	393	0	1,079	0	45.59	45.58
ORMND1	750	33.8	2,222.4	10,136	48,982	7,135	66,253	86,950	0	294	87,244	20,991	26.60	39.26
ORMND2	750	32.8	2,154.8	9,827	47,916	7,135	64,878	84,859	0	114	84,973	20,095	26.80	39.43
REDNDO56	350	12.2	373.1	1,702	8,973	3,614	14,289	17,868	0	126	17,995	3,706	28.61	48.23
REDNDO78	960	40.8	3,434.2	15,662	75,294	9,913	100,869	127,895	0	187	128,082	27,213	26.49	37.30
VERNDSL	20	0.7	1.2	6	77	102	185	83	102	0	185	0	68.17	68.03
Thermal	**8,852**	**31.8**	**24,666.1**	**99,715**	**543,131**	**107,022**	**749,868**	**945,505**	**3,635**	**3,198**	**952,337**	**202,469**	**26.06**	**38.46**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**602,781**	**0**	**0**	**602,781**	**149,583**	**8.44**	**33.29**
Coal	**3,060**	**53.7**	**14,404.0**	**46,327**	**221,410**	**86,454**	**354,191**	**527,649**	**0**	**1,990**	**529,637**	**175,446**	**18.59**	**36.77**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**247,962**	**0**	**0**	**247,962**	**214,930**	**0.00**	**35.77**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**5,236**	**0**	**0**	**5,236**	**681**	**0.00**	**40.93**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**26**	**0**	**5,214**	**5,240**	**134,816**	**0**	**0**	**134,816**	**129,576**	**0.01**	**33.44**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**507,446**	**429,961**	**1,546,415**	**888,636**	**0**	**0**	**888,636**	**-657,779**	**41.90**	**33.35**
Total less QFs	**18,060**	**43.2**	**68,271.0**	**148,623**	**914,760**	**536,700**	**1,600,083**	**2,463,948**	**3,635**	**5,188**	**2,472,768**	**872,685**	**15.58**	**36.17**
Total	**22,682**	**47.8**	**94,918.4**	**757,631**	**1,422,206**	**966,661**	**3,146,498**	**3,352,584**	**3,635**	**5,188**	**3,361,404**	**214,906**	**22.97**	**35.38**

Table 3.12.10i Generation Cost and Revenues

Low Fuel Cost Case

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.6	0.8	6	88	165	259	94	165	0	259	0	112.23	113.25
ENCIN123	321	16.2	454.1	3,185	11,329	8,150	22,664	21,197	0	116	21,313	-1,351	31.96	46.94
ENCINA45	615	23.1	1,242.2	8,713	29,667	13,533	51,913	53,173	0	438	53,612	1,699	30.90	43.16
KRNYGT23	132	1.4	16.1	110	580	1,363	2,053	690	1,363	0	2,053	0	42.95	42.96
MRMARGT	39	1.3	4.4	30	146	403	579	176	403	0	579	0	39.91	39.91
NRISLGT1	19	0.7	1.2	8	114	196	318	122	196	0	318	0	105.16	105.17
NTCKRNGT	33	1.5	4.3	29	148	341	518	177	341	0	518	0	41.15	41.16
NVLNRIGT	42	1.8	6.6	45	209	434	688	254	434	0	688	0	38.62	38.66
STHBAY4	222	4.0	77.2	542	2,094	5,524	8,160	5,136	0	18	5,154	-3,006	34.15	66.78
STHBAYGT	19	2.4	4.0	27	113	196	336	140	196	0	336	0	35.30	35.35
STHBY123	468	46.2	1,895.1	13,293	42,411	13,863	69,567	73,682	0	124	73,806	4,239	29.39	38.95
TWOGTS	32	1.0	2.9	20	102	330	452	121	331	0	452	0	42.22	42.01
Thermal	**1,958**	**21.6**	**3,708.7**	**26,008**	**87,001**	**44,498**	**157,507**	**154,962**	**3,429**	**696**	**159,088**	**1,581**	**30.47**	**41.97**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**111,637**	**0**	**0**	**111,637**	**27,672**	**8.75**	**33.25**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**14,183**	**0**	**0**	**14,183**	**11,036**	**5.65**	**33.33**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**36,997**	**4,396**	**51,472**	**62,492**	**0**	**0**	**62,492**	**11,020**	**25.47**	**33.81**
Total less QFs	**2,514**	**34.0**	**7,492.1**	**28,884**	**115,902**	**99,833**	**244,619**	**280,782**	**3,429**	**696**	**284,908**	**40,289**	**19.33**	**37.57**
Total	**2,751**	**38.8**	**9,340.2**	**38,963**	**152,899**	**104,229**	**296,091**	**343,274**	**3,429**	**696**	**347,400**	**51,309**	**20.54**	**36.83**

Table 3.12.11a Generation Cost and Revenues

Municipal Utilities Participating in the Pool

Pacific Gas and Electric Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	25.2	751.5	6,384	14,830	6,687	27,901	26,155	0	254	26,409	-1,492	28.23	35.14
CCosta7	340	21.8	649.7	5,519	12,826	6,687	25,032	22,717	0	88	22,805	-2,227	28.24	35.10
HntrsPt1	56	0.3	1.3	13	65	220	298	78	220	0	298	0	61.32	60.94
HntrsPt2	107	4.6	42.8	276	1,061	3,549	4,886	1,550	3,329	7	4,886	0	31.25	36.40
HntrsPt3	107	4.1	38.2	246	966	3,549	4,761	1,386	3,369	6	4,761	0	31.78	36.49
HntrsPt4	163	60.7	866.0	5,415	17,540	6,181	29,136	24,776	4,307	53	29,136	0	26.51	28.67
Humbld12	105	34.9	320.7	2,055	8,604	4,778	15,437	8,887	6,431	120	15,437	0	33.23	28.08
Mobil123	45	0.2	0.8	8	73	289	370	81	289	0	370	0	104.09	103.85
Morro12	326	22.5	642.0	4,595	13,589	4,647	22,831	24,086	0	55	24,141	1,310	28.33	37.61
Morro3	338	36.1	1,068.4	6,920	21,201	6,648	34,769	37,806	0	4	37,810	3,041	26.32	35.39
Morro4	338	40.4	1,197.3	7,755	23,387	6,648	37,790	42,512	0	86	42,598	4,808	26.01	35.58
Moss6	739	49.2	3,182.5	19,900	58,912	11,020	89,832	102,336	0	360	102,696	12,864	24.76	32.27
Moss7	739	61.9	4,008.5	25,064	72,244	11,020	108,328	124,691	0	562	125,254	16,926	24.28	31.25
Oakln123	192	0.2	2.7	28	220	318	566	248	318	0	566	0	93.03	92.88
Pitsbg5	325	28.9	823.0	5,331	16,397	6,396	28,124	27,684	0	32	27,716	-408	26.40	33.68
Pitsbg6	325	35.5	1,011.3	6,550	23,258	6,396	36,204	33,910	0	0	33,910	-2,294	29.47	33.53
Pitsbrg7	720	33.5	2,113.7	13,216	42,403	10,718	66,337	70,553	0	160	70,713	4,376	26.31	33.45
Pitsbu12	326	10.1	287.7	2,059	5,746	4,647	12,452	10,078	2,342	32	12,452	0	27.13	35.14
Pitsbu34	326	25.0	712.9	5,103	17,946	4,647	27,696	25,689	2,007	0	27,696	0	32.33	36.03
Potr456	168	0.2	2.6	27	208	875	1,110	235	875	0	1,110	0	91.80	91.80
Potrero3	207	61.3	1,111.5	7,199	22,226	4,071	33,496	31,894	1,544	58	33,496	0	26.47	28.75
Thermal	**6,332**	**34.0**	**18,834.8**	**123,663**	**373,702**	**109,991**	**607,356**	**617,352**	**25,031**	**1,877**	**644,260**	**36,904**	**26.41**	**32.88**
Nuclear	**2,160**	**89.5**	**16,939.4**	**36,291**	**101,299**	**198,708**	**336,298**	**509,145**	**0**	**0**	**509,145**	**172,847**	**8.12**	**30.06**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**75,256**	**75,256**	**731,831**	**0**	**0**	**731,831**	**656,575**	**0.00**	**30.64**
Geo	**635**	**49.0**	**2,725.7**	**3,837**	**54,171**	**17,958**	**75,966**	**77,805**	**0**	**0**	**77,805**	**1,839**	**21.28**	**28.55**
PumpStorage	**1,174**	**4.7**	**488.1**	**0**	**0**	**19,619**	**19,619**	**15,786**	**0**	**0**	**15,786**	**-3,833**	**0.00**	**32.34**
DSM & Solar	**518**	**0.3**	**12.6**	**19**	**0**	**141**	**160**	**356**	**0**	**0**	**356**	**196**	**1.51**	**28.28**
QF	**4,209**	**74.5**	**27,486.3**	**100,357**	**506,369**	**94,229**	**700,955**	**780,257**	**0**	**0**	**780,257**	**79,302**	**22.07**	**28.39**
Total less QFs	**15,322**	**46.8**	**62,884.2**	**163,810**	**529,172**	**421,673**	**1,114,655**	**1,952,275**	**25,031**	**1,877**	**1,979,183**	**864,528**	**11.02**	**31.08**
Total	**19,531**	**52.8**	**90,370.5**	**264,167**	**1,035,541**	**515,902**	**1,815,610**	**2,732,532**	**25,031**	**1,877**	**2,759,440**	**943,830**	**14.38**	**30.26**

Table 3.12.11b Generation Cost and Revenues

Municipal Utilities Participating in the Pool

Southern California Edison Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
ALA7HNT5	276	0.4	9.3	74	341	1,774	2,189	415	1,774	0	2,189	0	44.50	44.48
ALAMIT34	640	12.3	687.4	3,268	15,472	4,114	22,854	26,966	0	105	27,070	4,216	27.26	39.38
ALAMIT56	960	27.4	2,307.9	10,972	51,809	6,170	68,951	81,638	0	628	82,266	13,315	27.20	35.64
ANAHMCT	46	0.7	2.8	23	82	92	197	105	92	0	197	0	37.29	37.23
CWAT12	146	54.9	702.2	2,681	12,969	2,552	18,202	23,716	0	15	23,730	5,528	22.29	33.80
CWTRCC	512	59.1	2,650.3	10,119	43,817	4,311	58,247	88,179	0	56	88,235	29,988	20.35	33.29
ELSG1234	1,020	10.6	949.1	4,512	21,976	10,371	36,859	34,063	0	427	34,489	-2,370	27.91	36.34
ELWOOD1	53	0.7	3.3	26	92	185	303	119	184	0	303	0	35.99	36.06
ETWAND34	670	17.2	1,011.5	4,809	23,067	5,392	33,268	37,013	0	290	37,303	4,035	27.56	36.88
ETWANDA5	138	0.3	3.4	27	124	334	485	151	334	0	485	0	44.69	44.54
HN12MA12	860	30.3	2,282.7	2,445	51,702	19,015	73,162	81,632	0	907	82,538	9,376	23.72	36.16
LNBCHCC	560	15.1	741.7	3,526	17,045	5,478	26,049	27,532	0	280	27,812	1,763	27.74	37.50
MNDALY3	140	0.4	4.9	39	178	299	516	217	299	0	516	0	44.50	44.56
ORMND1	750	23.5	1,544.1	7,341	34,359	5,418	47,118	54,514	0	181	54,694	7,576	27.01	35.42
ORMND2	750	24.3	1,598.8	7,601	35,568	5,418	48,587	55,998	0	209	56,207	7,620	27.00	35.16
REDNDO56	350	4.2	129.5	615	3,059	2,744	6,418	5,363	0	39	5,403	-1,015	28.38	41.73
REDNDO78	960	30.0	2,523.7	11,998	56,096	7,528	75,622	89,826	0	678	90,504	14,882	26.98	35.86
VERNDSL	20	0.3	0.6	2	33	77	112	35	77	0	112	0	60.95	60.34
Thermal	**8,852**	**22.1**	**17,153.2**	**70,078**	**367,789**	**81,272**	**519,139**	**607,482**	**2,760**	**3,815**	**614,053**	**94,914**	**25.53**	**35.64**
Nuclear	**2,326**	**88.9**	**18,109.4**	**1,939**	**113,761**	**228,145**	**343,845**	**542,879**	**0**	**0**	**542,879**	**199,034**	**6.39**	**29.98**
Coal	**3,060**	**70.8**	**18,980.3**	**51,561**	**223,676**	**65,654**	**340,891**	**595,798**	**0**	**834**	**596,633**	**255,742**	**14.50**	**31.43**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**25,085**	**25,085**	**218,952**	**0**	**0**	**218,952**	**193,867**	**0.00**	**31.58**
PumpStorage	**207**	**7.0**	**127.0**	**0**	**0**	**3,459**	**3,459**	**4,389**	**0**	**0**	**4,389**	**930**	**0.00**	**34.55**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**19**	**0**	**3,959**	**3,978**	**120,214**	**0**	**0**	**120,214**	**116,236**	**0.00**	**29.82**
QF	**4,622**	**65.8**	**26,647.4**	**462,489**	**499,721**	**326,518**	**1,288,728**	**799,695**	**0**	**0**	**799,695**	**-489,033**	**36.11**	**30.01**
Total less QFs	**18,060**	**41.3**	**65,333.5**	**123,597**	**705,226**	**407,574**	**1,236,397**	**2,089,714**	**2,760**	**4,649**	**2,097,120**	**860,723**	**12.69**	**32.06**
Total	**22,682**	**46.3**	**91,980.9**	**586,086**	**1,204,947**	**734,092**	**2,525,125**	**2,889,409**	**2,760**	**4,649**	**2,896,815**	**371,690**	**19.47**	**31.46**

Table 3.12.11c Generation Cost and Revenues

Municipal Utilities Participating in the Pool

San Diego Gas & Electric Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Fuel	Fixed	Total	Revenue in $000 Energy	Others Reserve	Spin	Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Avg. Rev.
DIVISGT	16	0.2	0.3	2	22	125	149	24	125	0	149	0	85.78	85.71
ENCIN123	321	4.5	125.6	1,021	2,978	6,190	10,189	5,590	0	19	5,609	-4,580	31.84	44.67
ENCINA45	615	10.0	538.7	4,378	13,085	10,277	27,740	22,550	0	380	22,930	-4,810	32.42	42.57
KRNYGT23	132	0.6	7.0	56	261	1,035	1,352	317	1,035	0	1,352	0	45.33	45.42
MRMARGT	39	0.5	1.7	14	57	306	377	71	306	0	377	0	41.80	42.01
NRISLGT1	19	0.3	0.5	4	36	149	189	40	149	0	189	0	80.56	80.00
NTCKRNGT	33	0.7	2.0	16	71	259	346	87	259	0	346	0	43.23	43.28
NVLNRIGT	42	0.7	2.4	19	78	329	426	97	329	0	426	0	40.02	39.92
STHBAY4	222	1.6	30.2	245	780	4,195	5,220	1,670	0	6	1,676	-3,544	33.98	55.57
STHBAYGT	19	1.8	2.9	23	85	149	257	108	149	0	257	0	36.90	36.73
STHBY123	468	22.4	918.5	7,465	21,144	10,528	39,137	33,972	0	366	34,338	-4,799	31.15	37.38
TWOGTS	32	0.4	1.1	9	41	251	301	49	252	0	301	0	44.46	44.14
Thermal	**1,958**	**9.5**	**1,630.9**	**13,252**	**38,638**	**33,793**	**85,683**	**64,575**	**2,604**	**771**	**67,950**	**-17,733**	**31.82**	**40.07**
Nuclear	**430**	**89.1**	**3,357.8**	**360**	**21,914**	**41,456**	**63,730**	**100,714**	**0**	**0**	**100,714**	**36,983**	**6.63**	**29.99**
DSM/SelfGen	**126**	**38.7**	**425.5**	**1,824**	**0**	**566**	**2,390**	**12,839**	**0**	**0**	**12,839**	**10,449**	**4.29**	**30.17**
QF	**237**	**88.9**	**1,848.2**	**7,656**	**37,402**	**3,339**	**48,397**	**55,758**	**0**	**0**	**55,758**	**7,361**	**24.38**	**30.17**
Total less QFs	**2,514**	**24.6**	**5,414.2**	**15,436**	**60,552**	**75,815**	**151,803**	**178,128**	**2,604**	**771**	**181,503**	**29,699**	**14.03**	**33.04**
Total	**2,751**	**30.1**	**7,262.4**	**23,092**	**97,954**	**79,154**	**200,200**	**233,886**	**2,604**	**771**	**237,261**	**37,060**	**16.67**	**32.31**

Table 3.12.11d Generation Cost and Revenues

Municipal Utilities Participating in the Pool

Pacific Gas and Electric Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	27.6	822.0	7,498	18,563	7,414	33,475	32,259	0	312	32,571	-904	31.70	39.62
CCosta7	340	23.5	701.2	6,396	15,869	7,414	29,679	28,180	0	104	28,283	-1,396	31.75	40.34
HntrsPt1	56	0.6	3.0	34	178	244	456	212	244	0	456	0	71.11	71.14
HntrsPt2	107	4.6	43.4	297	1,250	3,934	5,481	2,149	3,317	16	5,481	0	35.63	49.87
HntrsPt3	107	4.3	40.2	275	1,163	3,934	5,372	1,902	3,468	2	5,372	0	35.80	47.40
HntrsPt4	163	60.6	864.8	5,738	20,102	6,853	32,693	28,161	4,487	45	32,693	0	29.88	32.62
Humbld12	105	35.5	326.2	2,220	10,039	5,298	17,557	10,683	6,775	99	17,557	0	37.59	33.06
Mobil123	45	0.5	2.0	23	224	321	568	247	321	0	568	0	121.42	121.08
Morro12	326	26.8	764.5	5,839	18,541	5,153	29,533	32,870	0	332	33,202	3,669	31.89	43.43
Morro3	338	36.5	1,081.4	7,444	24,609	7,370	39,423	44,363	0	57	44,420	4,997	29.64	41.08
Morro4	338	41.3	1,222.9	8,418	27,332	7,370	43,120	49,786	0	68	49,854	6,734	29.23	40.77
Moss6	739	49.6	3,212.3	21,316	68,237	12,218	101,771	116,861	0	295	117,155	15,384	27.88	36.47
Moss7	739	60.1	3,890.3	25,814	80,590	12,218	118,622	138,227	0	501	138,727	20,105	27.35	35.66
Oakln123	192	0.3	4.4	50	413	353	816	463	353	0	816	0	106.04	106.19
Pitsbg5	325	32.5	926.5	6,378	21,136	7,092	34,606	35,059	0	39	35,098	492	29.70	37.88
Pitsbg6	325	34.0	966.9	6,656	25,503	7,092	39,251	37,733	0	0	37,733	-1,518	33.26	39.03
Pitsbrg7	720	32.9	2,072.3	13,751	47,674	11,883	73,308	79,348	0	128	79,476	6,168	29.64	38.35
Pitsbu12	326	10.2	292.1	2,232	6,682	5,153	14,067	12,230	1,797	40	14,067	0	30.51	42.00
Pitsbu34	326	26.6	758.3	5,792	21,841	5,153	32,786	31,658	1,128	0	32,786	0	36.44	41.75
Potr456	168	0.5	7.7	87	715	970	1,772	802	970	0	1,772	0	104.62	104.56
Potrero3	207	61.4	1,112.7	7,660	25,522	4,514	37,696	36,114	1,505	77	37,696	0	29.82	32.53
Thermal	**6,332**	**34.5**	**19,114.9**	**133,918**	**436,183**	**121,951**	**692,052**	**719,307**	**24,365**	**2,115**	**745,783**	**53,731**	**29.82**	**37.74**
Nuclear	**2,160**	**89.5**	**16,939.4**	**40,237**	**112,606**	**220,312**	**373,155**	**583,297**	**0**	**0**	**583,297**	**210,142**	**9.02**	**34.43**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**83,437**	**83,437**	**838,492**	**0**	**0**	**838,492**	**755,055**	**0.00**	**35.11**
Geo	**635**	**49.0**	**2,725.7**	**4,254**	**64,518**	**19,910**	**88,682**	**88,351**	**0**	**0**	**88,351**	**-331**	**25.23**	**32.41**
PumpStorage	**1,174**	**4.8**	**490.3**	**0**	**0**	**21,752**	**21,752**	**18,856**	**0**	**0**	**18,856**	**-2,896**	**0.00**	**38.46**
DSM & Solar	**518**	**0.3**	**12.6**	**28**	**0**	**157**	**185**	**413**	**0**	**0**	**413**	**228**	**2.22**	**32.70**
QF	**4,209**	**74.5**	**27,486.3**	**111,268**	**577,212**	**104,473**	**792,953**	**885,599**	**0**	**0**	**885,599**	**92,646**	**25.05**	**32.22**
Total less QFs	**15,322**	**47.1**	**63,166.5**	**178,437**	**613,307**	**467,519**	**1,259,263**	**2,248,716**	**24,365**	**2,115**	**2,275,192**	**1,015,929**	**12.53**	**35.63**
Total	**19,531**	**53.0**	**90,652.8**	**289,705**	**1,190,519**	**571,992**	**2,052,216**	**3,134,315**	**24,365**	**2,115**	**3,160,791**	**1,108,575**	**16.33**	**34.60**

Table 3.12.11e Generation Cost and Revenues

Municipal Utilities Participating in the Pool

Southern California Edison Units - 2001

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
ALA7HNT5	276	0.5	11.6	100	483	1,967	2,550	583	1,967	0	2,550	0	50.45	50.48
ALAMIT34	640	13.4	748.4	3,814	19,055	4,561	27,430	33,402	0	102	33,504	6,074	30.56	44.77
ALAMIT56	960	27.8	2,337.6	11,913	59,563	6,841	78,317	94,368	0	888	95,256	16,939	30.58	40.75
ANAHMCT	46	0.9	3.6	32	120	103	255	152	103	0	255	0	41.84	41.87
CWAT12	146	51.2	654.2	2,684	14,408	2,830	19,922	25,550	0	45	25,596	5,674	26.13	39.12
CWTRCC	512	56.2	2,518.3	10,331	49,799	4,780	64,910	97,541	0	137	97,678	32,768	23.88	38.79
ELSG1234	1,020	10.6	946.5	4,824	24,864	11,499	41,187	40,293	0	575	40,868	-319	31.36	43.18
ELWOOD1	53	0.8	3.8	32	119	205	356	152	204	0	356	0	40.42	40.53
ETWAND34	670	20.2	1,185.2	6,040	30,152	5,978	42,170	49,562	0	412	49,974	7,804	30.54	42.16
ETWANDA5	138	0.5	6.6	57	278	370	705	334	371	0	705	0	50.93	50.84
HN12MA12	860	29.1	2,191.6	2,603	55,980	21,082	79,665	90,545	0	846	91,390	11,725	26.73	41.70
LNBCHCC	560	16.7	819.4	4,176	21,058	6,074	31,308	35,727	0	221	35,948	4,640	30.80	43.87
MNDALY3	140	0.6	7.3	63	306	331	700	369	331	0	700	0	50.59	50.55
ORMND1	750	24.7	1,622.5	8,268	40,398	6,007	54,673	66,971	0	162	67,133	12,460	30.00	41.38
ORMND2	750	23.8	1,561.2	7,956	39,225	6,007	53,188	63,947	0	179	64,126	10,938	30.22	41.08
REDNDO56	350	4.3	130.6	666	3,524	3,043	7,233	7,389	0	13	7,402	169	32.07	56.66
REDNDO78	960	30.4	2,554.2	13,017	64,017	8,346	85,380	103,390	0	474	103,864	18,484	30.16	40.66
VERNDSL	20	0.7	1.2	5	72	86	163	77	86	0	163	0	63.55	63.11
Thermal	**8,852**	**22.3**	**17,303.7**	**76,581**	**423,421**	**90,110**	**590,112**	**710,352**	**3,062**	**4,054**	**717,468**	**127,356**	**28.90**	**41.29**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,151**	**126,261**	**252,949**	**381,360**	**623,694**	**0**	**0**	**623,694**	**242,334**	**7.09**	**34.44**
Coal	**3,060**	**71.4**	**19,148.2**	**57,353**	**250,839**	**72,792**	**380,984**	**692,362**	**0**	**785**	**693,148**	**312,164**	**16.10**	**36.20**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**27,812**	**27,812**	**252,932**	**0**	**0**	**252,932**	**225,119**	**0.00**	**36.48**
PumpStorage	**207**	**7.0**	**127.3**	**0**	**0**	**3,835**	**3,835**	**5,196**	**0**	**0**	**5,196**	**1,361**	**0.00**	**40.81**
DSM/SelfGen	**2,114**	**21.8**	**4,031.0**	**14**	**0**	**4,390**	**4,404**	**138,662**	**0**	**0**	**138,662**	**134,258**	**0.00**	**34.40**
QF	**4,622**	**65.8**	**26,647.4**	**512,770**	**563,965**	**362,017**	**1,438,752**	**919,265**	**0**	**0**	**919,265**	**-519,487**	**40.41**	**34.50**
Total less QFs	**18,060**	**41.5**	**65,652.3**	**136,099**	**800,521**	**451,888**	**1,388,507**	**2,423,198**	**3,062**	**4,839**	**2,431,100**	**1,042,593**	**14.27**	**36.98**
Total	**22,682**	**46.5**	**92,299.6**	**648,869**	**1,364,486**	**813,905**	**2,827,259**	**3,342,463**	**3,062**	**4,839**	**3,350,365**	**523,106**	**21.81**	**36.27**

Table 3.12.11f Generation Cost and Revenues

Municipal Utilities Participating in the Pool

San Diego Gas & Electric Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.5	0.7	6	61	139	206	67	139	0	206	0	95.65	95.71
ENCIN123	321	6.1	171.0	1,475	4,668	6,862	13,005	9,183	0	16	9,199	-3,806	35.94	53.81
ENCINA45	615	12.0	644.0	5,558	17,575	11,395	34,528	29,762	0	361	30,122	-4,406	35.92	46.78
KRNYGT23	132	0.7	8.0	68	334	1,148	1,550	402	1,148	0	1,550	0	50.12	50.06
MRMARGT	39	0.8	2.7	23	101	339	463	124	339	0	463	0	46.43	46.44
NRISLGT1	19	0.6	1.0	8	81	165	254	89	165	0	254	0	89.80	89.90
NTCKRNGT	33	0.8	2.3	19	89	287	395	109	286	0	395	0	47.41	47.60
NVLNRIGT	42	0.9	3.3	28	119	365	512	146	366	0	512	0	44.56	44.38
STHBAY4	222	1.6	30.5	263	893	4,651	5,807	2,355	0	41	2,397	-3,410	37.94	78.58
STHBAYGT	19	1.5	2.5	21	79	165	265	100	165	0	265	0	40.42	40.32
STHBY123	468	24.9	1,019.3	8,798	26,178	11,673	46,649	44,111	0	342	44,453	-2,196	34.31	43.61
TWOGTS	32	0.5	1.4	12	56	278	346	67	279	0	346	0	48.51	48.20
Thermal	**1,958**	**11.0**	**1,886.6**	**16,279**	**50,234**	**37,467**	**103,980**	**86,515**	**2,887**	**760**	**90,162**	**-13,818**	**35.26**	**46.26**
Nuclear	**430**	**89.1**	**3,357.8**	**399**	**24,311**	**45,963**	**70,673**	**115,650**	**0**	**0**	**115,650**	**44,977**	**7.36**	**34.44**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,022**	**0**	**627**	**2,649**	**14,686**	**0**	**0**	**14,686**	**12,037**	**4.75**	**34.52**
QF	**237**	**88.9**	**1,848.2**	**8,486**	**41,915**	**3,701**	**54,102**	**64,195**	**0**	**0**	**64,195**	**10,093**	**27.27**	**34.73**
Total less QFs	**2,514**	**25.7**	**5,669.9**	**18,700**	**74,545**	**84,057**	**177,302**	**216,851**	**2,887**	**760**	**220,498**	**43,196**	**16.45**	**38.38**
Total	**2,751**	**31.2**	**7,518.1**	**27,186**	**116,460**	**87,758**	**231,404**	**281,046**	**2,887**	**760**	**284,693**	**53,289**	**19.11**	**37.48**

Table 3.12.11g Generation Cost and Revenues

Municipal Utilities Participating in the Pool

Pacific Gas and Electric Units - 2006

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
CCosta6	340	27.9	830.9	8,540	23,601	8,806	40,947	41,155	0	518	41,673	726	38.68	50.15
CCosta7	340	23.7	706.6	7,263	20,117	8,806	36,186	36,057	0	230	36,287	101	38.75	51.36
HntrsPt1	56	0.6	3.0	39	233	290	562	272	290	0	562	0	91.25	91.28
HntrsPt2	107	4.7	44.3	336	1,638	4,673	6,647	2,785	3,847	15	6,647	0	44.54	63.19
HntrsPt3	107	5.3	49.2	373	1,827	4,673	6,873	2,620	4,248	4	6,873	0	44.72	53.36
HntrsPt4	163	58.4	833.3	6,105	24,437	8,139	38,681	33,968	4,673	40	38,681	0	36.65	40.81
Humbld12	105	33.4	306.8	2,310	11,965	6,292	20,567	12,475	8,044	47	20,567	0	46.53	40.82
Mobil123	45	0.6	2.4	30	338	381	749	369	380	0	749	0	157.19	157.02
Morro12	326	23.8	679.3	5,786	20,851	6,120	32,757	37,028	0	458	37,486	4,729	39.21	55.18
Morro3	338	35.3	1,044.2	7,958	29,841	8,754	46,553	53,292	0	56	53,348	6,795	36.20	51.09
Morro4	338	39.7	1,174.1	8,949	33,023	8,754	50,726	58,317	0	100	58,417	7,691	35.75	49.75
Moss6	739	45.7	2,957.1	21,664	79,122	14,511	115,297	135,973	0	336	136,309	21,012	34.08	46.10
Moss7	739	56.7	3,673.4	26,912	95,827	14,511	137,250	163,121	0	427	163,548	26,298	33.41	44.52
Oakln123	192	0.2	4.1	53	485	419	957	537	420	0	957	0	132.00	131.94
Pitsbg5	325	32.5	924.2	7,044	26,512	8,423	41,979	43,790	0	41	43,831	1,852	36.31	47.43
Pitsbg6	325	35.3	1,006.0	7,667	33,435	8,423	49,525	48,639	0	0	48,639	-886	40.86	48.35
Pitsbrg7	720	36.9	2,327.5	17,052	67,564	14,113	98,729	110,999	0	276	111,276	12,547	36.35	47.81
Pitsbu12	326	11.2	318.6	2,714	9,185	6,120	18,019	16,838	1,136	44	18,019	0	37.34	52.98
Pitsbu34	326	28.8	821.4	6,996	29,834	6,120	42,950	42,719	231	0	42,950	0	44.84	52.01
Potr456	168	0.5	7.2	94	847	1,152	2,093	940	1,153	0	2,093	0	130.22	130.19
Potrero3	207	58.6	1,062.8	8,100	30,713	5,361	44,174	42,973	1,045	157	44,174	0	36.52	40.58
Thermal	**6,332**	**33.9**	**18,776.3**	**145,985**	**541,395**	**144,841**	**832,221**	**884,867**	**25,467**	**2,749**	**913,086**	**80,865**	**36.61**	**47.27**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**697,241**	**0**	**0**	**697,241**	**253,467**	**10.75**	**41.16**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**1,030,446**	**0**	**0**	**1,030,446**	**931,348**	**0.00**	**43.14**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**108,464**	**0**	**0**	**108,464**	**-6,575**	**33.53**	**39.79**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**24,126**	**0**	**0**	**24,126**	**-1,708**	**0.00**	**49.14**
DSM & Solar	**518**	**0.3**	**12.6**	**36**	**0**	**186**	**222**	**510**	**0**	**0**	**510**	**288**	**2.85**	**40.35**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**718,272**	**124,082**	**974,506**	**1,087,112**	**0**	**0**	**1,087,112**	**112,606**	**30.94**	**39.55**
Total less QFs	**15,322**	**46.8**	**62,828.6**	**198,862**	**762,058**	**555,268**	**1,516,188**	**2,745,654**	**25,467**	**2,749**	**2,773,873**	**1,257,685**	**15.29**	**43.74**
Total	**19,531**	**52.8**	**90,314.9**	**331,014**	**1,480,330**	**679,350**	**2,490,694**	**3,832,766**	**25,467**	**2,749**	**3,860,985**	**1,370,291**	**20.06**	**42.47**

Table 3.12.11h Generation Cost and Revenues

Municipal Utilities Participating in the Pool

Southern California Edison Units - 2006

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	**(MW)**	**(%)**	**(GWh)**	**Var**	**Fuel**	**Fixed**	**Total**	**Energy**	**Reserve**	**Spin**	**Total**	**Income**	**Cost**	**Rev.**
ALA7HNT5	276	0.5	11.6	115	591	2,336	3,042	706	2,336	0	3,042	0	61.10	61.13
ALAMIT34	640	12.6	704.5	4,034	22,103	5,417	31,554	40,843	0	199	41,041	9,487	37.10	58.26
ALAMIT56	960	26.2	2,200.0	12,597	68,693	8,125	89,415	109,888	0	565	110,453	21,038	36.95	50.21
ANAHMCT	46	1.2	4.8	49	194	122	365	243	122	0	365	0	50.23	50.21
CWAT12	146	36.7	469.4	2,173	13,880	3,361	19,414	22,721	0	31	22,752	3,338	34.20	48.47
CWTRCC	512	36.9	1,654.7	7,659	43,525	5,677	56,861	81,137	0	78	81,215	24,354	30.93	49.08
ELSG1234	1,020	10.1	904.6	5,180	29,283	13,657	48,120	47,166	0	679	47,845	-275	38.10	52.89
ELWOOD1	53	1.1	4.9	48	186	243	477	235	242	0	477	0	48.36	48.45
ETWAND34	670	20.3	1,192.4	6,827	37,566	7,100	51,493	61,286	0	279	61,566	10,073	37.23	51.63
ETWANDA5	138	0.5	6.6	65	340	439	844	405	439	0	844	0	61.68	61.64
HN12MA12	860	27.6	2,079.5	2,933	64,876	25,039	92,848	106,156	0	1,021	107,177	14,329	32.61	51.54
LNBCHCC	560	16.6	815.0	4,666	25,748	7,214	37,628	44,274	0	245	44,519	6,891	37.32	54.63
MNDALY3	140	0.6	7.8	78	399	393	870	476	394	0	870	0	61.16	61.18
ORMND1	750	24.7	1,620.6	9,279	50,426	7,135	66,840	83,481	0	227	83,708	16,868	36.84	51.65
ORMND2	750	24.0	1,576.1	9,024	49,149	7,135	65,308	80,407	0	510	80,917	15,609	36.91	51.34
REDNDO56	350	8.8	269.4	1,543	9,165	3,614	14,322	16,427	0	35	16,462	2,140	39.74	61.10
REDNDO78	960	27.9	2,346.0	13,433	72,009	9,913	95,355	118,323	0	776	119,099	23,744	36.42	50.77
VERNDSL	20	0.7	1.2	6	77	102	185	83	102	0	185	0	68.17	68.03
Thermal	**8,852**	**20.5**	**15,868.9**	**79,709**	**488,210**	**107,022**	**674,941**	**814,257**	**3,635**	**4,645**	**822,537**	**147,596**	**35.79**	**51.60**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**743,283**	**0**	**0**	**743,283**	**290,085**	**8.44**	**41.04**
Coal	**3,060**	**70.5**	**18,891.9**	**66,724**	**295,278**	**86,454**	**448,456**	**817,082**	**0**	**887**	**817,968**	**369,512**	**19.16**	**43.30**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**306,086**	**0**	**0**	**306,086**	**273,055**	**0.00**	**44.15**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**6,513**	**0**	**0**	**6,513**	**1,958**	**0.00**	**50.91**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**26**	**0**	**5,214**	**5,240**	**165,346**	**0**	**0**	**165,346**	**160,106**	**0.01**	**41.02**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**689,913**	**429,961**	**1,728,882**	**1,096,564**	**0**	**0**	**1,096,564**	**-632,318**	**48.74**	**41.15**
Total less QFs	**18,060**	**40.4**	**63,961.6**	**149,014**	**933,707**	**536,700**	**1,619,421**	**2,852,567**	**3,635**	**5,532**	**2,861,733**	**1,242,312**	**16.93**	**44.68**
Total	**22,682**	**45.6**	**90,609.0**	**758,022**	**1,623,620**	**966,661**	**3,348,303**	**3,949,131**	**3,635**	**5,532**	**3,958,297**	**609,994**	**26.28**	**43.65**

Table 3.12.11i Generation Cost and Revenues

Municipal Utilities Participating in the Pool

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.5	0.7	7	73	165	245	80	165	0	245	0	114.76	114.29
ENCIN123	321	8.2	230.7	2,201	7,839	8,150	18,190	13,984	0	150	14,134	-4,056	43.52	61.27
ENCINA45	615	14.2	762.7	7,278	25,180	13,533	45,991	42,295	0	837	43,132	-2,859	42.56	56.55
KRNYGT23	132	0.9	10.3	97	513	1,363	1,973	610	1,363	0	1,973	0	59.07	59.11
MRMARGT	39	0.9	3.1	29	138	403	570	167	403	0	570	0	54.59	54.75
NRISLGT1	19	0.6	1.0	9	97	196	302	107	195	0	302	0	107.69	108.08
NTCKRNGT	33	0.9	2.6	24	121	341	486	145	341	0	486	0	56.16	56.20
NVLNRIGT	42	0.9	3.4	32	147	434	613	179	434	0	613	0	52.54	52.65
STHBAY4	222	2.1	39.9	381	1,444	5,524	7,349	3,679	0	3	3,681	-3,668	45.72	92.26
STHBAYGT	19	1.4	2.3	22	89	196	307	110	197	0	307	0	47.65	47.62
STHBY123	468	30.0	1,231.4	11,750	38,132	13,863	63,745	63,641	0	546	64,187	442	40.51	52.12
TWOGTS	32	0.5	1.4	13	67	330	410	80	330	0	410	0	57.76	57.55
Thermal	**1,958**	**13.3**	**2,289.5**	**21,843**	**73,840**	**44,498**	**140,181**	**125,077**	**3,428**	**1,536**	**130,040**	**-10,141**	**41.79**	**55.30**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**137,776**	**0**	**0**	**137,776**	**53,810**	**8.75**	**41.03**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**17,558**	**0**	**0**	**17,558**	**14,411**	**5.65**	**41.27**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**50,678**	**4,396**	**65,153**	**76,652**	**0**	**0**	**76,652**	**11,499**	**32.87**	**41.47**
Total less QFs	**2,514**	**27.6**	**6,072.8**	**24,719**	**102,741**	**99,833**	**227,293**	**280,411**	**3,428**	**1,536**	**285,374**	**58,080**	**20.99**	**46.43**
Total	**2,751**	**32.9**	**7,921.0**	**34,798**	**153,419**	**104,229**	**292,446**	**357,063**	**3,428**	**1,536**	**362,026**	**69,579**	**23.76**	**45.27**

Table 3.12.12a Generation Cost and Revenues

Regulated Case

Pacific Gas and Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000				Revenue in $000				in $000	Energy $/MWh	
				Var	Fuel	Fixed	Total	Energy	Others: Reserve	Others: Spin	Total	Net Income	Avg. Var Cost	Avg. Rev.
CCosta6	340	27.5	817.6	8,403	23,222	8,806	40,431	40,057	0	516	40,573	142	38.68	49.63
CCosta7	340	24.0	714.1	7,340	20,299	8,806	36,445	35,436	0	265	35,701	-744	38.70	49.99
HntrsPt1	56	0.5	2.6	33	200	290	523	233	290	0	523	0	91.25	91.02
HntrsPt2	107	4.5	42.3	320	1,563	4,673	6,556	2,537	4,014	5	6,556	0	44.54	60.14
HntrsPt3	107	5.1	47.9	363	1,773	4,673	6,809	2,411	4,387	12	6,809	0	44.57	50.55
HntrsPt4	163	58.4	833.3	6,105	24,434	8,139	38,678	33,552	5,089	36	38,678	0	36.65	40.31
Humbld12	105	32.1	294.9	2,220	11,546	6,292	20,058	11,710	8,320	28	20,058	0	46.69	39.81
Mobil123	45	0.5	2.0	25	282	381	688	307	381	0	688	0	157.19	156.63
Morro12	326	24.2	690.4	5,881	21,190	6,120	33,191	37,097	0	438	37,535	4,344	39.21	54.36
Morro3	338	35.2	1,043.5	7,953	29,820	8,754	46,527	52,718	0	72	52,790	6,263	36.20	50.59
Morro4	338	39.8	1,179.0	8,986	33,169	8,754	50,909	57,904	0	145	58,049	7,140	35.75	49.23
Moss6	739	45.8	2,962.1	21,701	79,256	14,511	115,468	135,149	0	346	135,494	20,026	34.08	45.74
Moss7	739	56.9	3,680.4	26,963	95,992	14,511	137,466	161,233	0	353	161,586	24,120	33.41	43.91
NCCOMP06	500	86.7	3,797.1	39,555	67,579	5,078	112,212	153,327	0	0	153,327	41,115	28.21	40.38
NCCT06	500	15.9	695.6	8,012	18,299	5,078	31,389	26,311	0	0	26,311	-5,078	37.83	37.83
Oakln123	192	0.2	4.1	53	485	419	957	537	420	0	957	0	132.00	131.94
Pitsbg5	325	32.5	925.0	7,050	26,537	8,423	42,010	43,057	0	48	43,105	1,095	36.31	46.60
Pitsbg6	325	35.3	1,006.0	7,667	33,428	8,423	49,518	47,713	0	0	47,713	-1,805	40.85	47.43
Pitsbrg7	720	36.8	2,323.8	17,025	67,379	14,113	98,517	108,557	0	218	108,775	10,258	36.32	46.81
Pitsbu12	326	11.2	318.6	2,714	9,185	6,120	18,019	16,224	1,750	45	18,019	0	37.34	51.06
Pitsbu34	326	29.0	827.3	7,046	30,061	6,120	43,227	42,056	1,171	0	43,227	0	44.86	50.84
Potr456	168	0.4	5.6	72	651	1,152	1,875	723	1,152	0	1,875	0	130.22	130.27
Potrero3	207	58.6	1,062.1	8,095	30,683	5,361	44,139	42,489	1,496	154	44,139	0	36.51	40.15
Thermal	**7,332**	**36.2**	**23,275.2**	**193,582**	**627,033**	**154,997**	**975,612**	**1,051,338**	**28,470**	**2,681**	**1,082,488**	**106,876**	**35.26**	**45.29**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**691,207**	**0**	**0**	**691,207**	**247,433**	**10.75**	**40.80**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**1,016,782**	**0**	**0**	**1,016,782**	**917,684**	**0.00**	**42.57**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**107,505**	**0**	**0**	**107,505**	**-7,534**	**33.53**	**39.44**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**23,463**	**0**	**0**	**23,463**	**-2,371**	**0.00**	**47.79**
DSM & Solar	**518**	**0.3**	**12.6**	**33**	**0**	**186**	**219**	**501**	**0**	**0**	**501**	**282**	**2.61**	**39.67**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**718,272**	**124,082**	**974,506**	**1,077,434**	**0**	**0**	**1,077,434**	**102,928**	**30.94**	**39.20**
Total less QFs	**16,322**	**47.1**	**67,327.4**	**246,456**	**847,696**	**565,424**	**1,659,576**	**2,890,796**	**28,470**	**2,681**	**2,921,946**	**1,262,370**	**16.25**	**42.98**
Total	**20,531**	**52.7**	**94,813.7**	**378,608**	**1,565,968**	**689,506**	**2,634,082**	**3,968,230**	**28,470**	**2,681**	**3,999,380**	**1,365,298**	**20.51**	**41.88**

Table 3.12.12b Generation Cost and Revenues

Regulated Case

Southern California Edison Units - 2006

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
ALA7HNT5	276	0.4	9.4	94	480	2,336	2,910	573	2,337	0	2,910	0	60.88	60.83
ALAMIT34	640	12.4	695.0	3,979	21,826	5,417	31,222	39,245	0	180	39,426	8,204	37.13	56.73
ALAMIT56	960	26.0	2,184.8	12,510	68,210	8,125	88,845	107,497	0	593	108,090	19,245	36.95	49.47
ANAHMCT	46	1.0	4.0	41	162	122	325	203	122	0	325	0	50.23	50.37
CWAT12	146	36.8	470.4	2,177	13,885	3,361	19,423	22,399	0	26	22,425	3,002	34.14	47.67
CWTRCC	512	35.7	1,600.8	7,410	42,085	5,677	55,172	77,529	0	136	77,665	22,493	30.92	48.52
ELSG1234	1,020	9.9	881.5	5,048	28,580	13,657	47,285	44,011	0	489	44,501	-2,784	38.15	50.48
ELWOOD1	53	0.8	3.8	37	145	243	425	182	243	0	425	0	48.62	48.53
ETWAND34	670	20.2	1,184.0	6,780	37,099	7,100	50,979	59,597	0	260	59,857	8,878	37.06	50.55
ETWANDA5	138	0.5	5.5	54	283	439	776	337	439	0	776	0	61.60	61.61
HN12MA12	860	27.2	2,047.9	2,889	63,824	25,039	91,752	101,577	0	854	102,432	10,680	32.58	50.02
LNBCHCC	560	16.5	809.9	4,637	25,667	7,214	37,518	42,935	0	209	43,144	5,626	37.42	53.27
MNDALY3	140	0.6	7.3	73	375	393	841	447	394	0	841	0	61.27	61.23
ORMND1	750	24.6	1,616.0	9,253	50,240	7,135	66,628	82,576	0	341	82,918	16,290	36.82	51.31
ORMND2	750	24.3	1,596.4	9,141	49,699	7,135	65,975	80,360	0	495	80,854	14,879	36.86	50.65
REDNDO56	350	8.7	267.4	1,531	9,116	3,614	14,261	15,899	0	40	15,939	1,678	39.81	59.60
REDNDO78	960	27.8	2,333.9	13,363	71,559	9,913	94,835	114,822	0	916	115,738	20,903	36.39	49.59
SCCOMP06	4,000	72.2	25,285.6	187,271	516,529	40,625	744,425	1,098,963	0	0	1,098,963	354,538	27.83	43.46
VERNDSL	20	0.6	1.0	5	66	102	173	71	102	0	173	0	68.17	68.27
Thermal	**12,852**	**36.4**	**41,004.6**	**266,293**	**999,830**	**147,647**	**1,413,770**	**1,889,223**	**3,637**	**4,539**	**1,897,402**	**483,632**	**30.88**	**46.18**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**736,728**	**0**	**0**	**736,728**	**283,530**	**8.44**	**40.68**
Coal	**3,060**	**70.5**	**18,887.3**	**66,696**	**295,199**	**86,454**	**448,349**	**808,323**	**0**	**1,037**	**809,361**	**361,012**	**19.16**	**42.85**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**301,226**	**0**	**0**	**301,226**	**268,195**	**0.00**	**43.45**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**6,321**	**0**	**0**	**6,321**	**1,766**	**0.00**	**49.41**
DSM/SelfGen	**2,114**	**21.8**	**4,031.0**	**17**	**0**	**5,214**	**5,231**	**164,212**	**0**	**0**	**164,212**	**158,981**	**0.00**	**40.74**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**689,913**	**429,961**	**1,728,882**	**1,086,750**	**0**	**0**	**1,086,750**	**-642,132**	**48.74**	**40.78**
Total less QFs	**22,060**	**46.1**	**89,092.7**	**335,561**	**1,445,248**	**577,325**	**2,358,134**	**3,906,033**	**3,637**	**5,576**	**3,915,250**	**1,557,116**	**19.99**	**43.90**
Total	**26,682**	**49.5**	**115,740.1**	**944,569**	**2,135,161**	**1,007,286**	**4,087,016**	**4,992,783**	**3,637**	**5,576**	**5,002,000**	**914,984**	**26.61**	**43.19**

Table 3.12.12c Generation Cost and Revenues

Regulated Case

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.4	0.6	5	59	165	229	64	165	0	229	0	114.76	114.29
ENCIN123	321	7.8	220.6	2,104	7,518	8,150	17,772	13,064	0	97	13,161	-4,611	43.63	59.67
ENCINA45	615	13.9	749.5	7,151	24,789	13,533	45,473	41,614	0	679	42,293	-3,180	42.62	56.43
KRNYGT23	132	0.8	9.2	86	459	1,363	1,908	545	1,363	0	1,908	0	59.35	59.37
MRMARGT	39	0.8	2.7	25	123	403	551	149	402	0	551	0	54.80	54.98
NRISLGT1	19	0.5	0.8	8	81	196	285	89	196	0	285	0	107.69	107.23
NTCKRNGT	33	0.8	2.3	21	108	341	470	129	341	0	470	0	56.43	56.33
NVLNRIGT	42	0.8	3.0	28	131	434	593	159	434	0	593	0	52.78	52.82
STHBAY4	222	1.9	36.9	352	1,341	5,524	7,217	3,265	0	0	3,265	-3,952	45.89	88.48
STHBAYGT	19	1.2	2.0	19	76	196	291	94	197	0	291	0	47.62	47.47
STHBY123	468	29.5	1,210.7	11,553	37,435	13,863	62,851	61,369	0	619	61,988	-863	40.46	51.20
TWOGTS	32	0.4	1.1	10	54	330	394	65	329	0	394	0	58.16	58.56
Thermal	**1,958**	**13.1**	**2,239.3**	**21,362**	**72,174**	**44,498**	**138,034**	**120,606**	**3,427**	**1,395**	**125,428**	**-12,606**	**41.77**	**54.48**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**136,543**	**0**	**0**	**136,543**	**52,578**	**8.75**	**40.66**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**17,488**	**0**	**0**	**17,488**	**14,341**	**5.65**	**41.10**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**50,678**	**4,396**	**65,153**	**76,085**	**0**	**0**	**76,085**	**10,932**	**32.87**	**41.17**
Total less QFs	**2,514**	**27.4**	**6,022.6**	**24,238**	**101,075**	**99,833**	**225,146**	**274,637**	**3,427**	**1,395**	**279,459**	**54,313**	**20.81**	**45.83**
Total	**2,751**	**32.7**	**7,870.8**	**34,317**	**151,753**	**104,229**	**290,299**	**350,722**	**3,427**	**1,395**	**355,544**	**65,245**	**23.64**	**44.74**

Table 3.12.13a Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

Pacific Gas and Electric Units - 1998

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	**(MW)**	**(%)**	**(GWh)**	**Var**	**Fuel**	**Fixed**	**Total**	**Energy**	**Reserve**	**Spin**	**Total**	**Income**	**Cost**	**Rev.**
CCosta6	340	17.1	509.4	4,327	10,014	6,687	21,028	18,616	0	49	18,664	-2,364	28.15	36.64
CCosta7	340	13.9	412.5	3,504	8,063	6,687	18,254	15,242	0	52	15,294	-2,960	28.04	37.08
HntrsPt1	56	0.3	1.3	13	65	220	298	78	220	0	298	0	61.32	60.94
HntrsPt2	107	3.2	30.3	195	735	3,549	4,479	1,249	3,221	10	4,479	0	30.69	41.55
HntrsPt3	107	2.6	23.9	154	598	3,549	4,301	991	3,306	5	4,301	0	31.46	41.69
HntrsPt4	163	62.1	887.3	5,548	17,948	6,181	29,677	25,166	4,490	21	29,677	0	26.48	28.39
Humbld12	105	36.7	337.8	2,164	8,998	4,778	15,940	9,376	6,414	150	15,940	0	33.04	28.20
Mobil123	45	0.2	0.8	8	73	289	370	81	289	0	370	0	104.09	103.85
Morro12	326	16.6	475.2	3,401	9,925	4,647	17,973	18,450	0	38	18,487	514	28.04	38.91
Morro3	338	36.4	1,078.4	6,984	21,288	6,648	34,920	38,179	0	73	38,252	3,332	26.22	35.47
Morro4	338	42.3	1,252.2	8,110	24,372	6,648	39,130	43,812	0	93	43,905	4,775	25.94	35.06
Moss6	739	48.2	3,123.1	19,528	57,839	11,020	88,387	101,914	0	264	102,178	13,791	24.77	32.72
Moss7	739	61.6	3,988.9	24,942	71,991	11,020	107,953	125,064	0	458	125,522	17,569	24.30	31.47
Oakln123	192	0.2	3.8	40	314	318	672	354	318	0	672	0	93.03	93.16
Pitsbg5	325	23.1	658.1	4,262	13,126	6,396	23,784	23,094	0	25	23,119	-665	26.42	35.13
Pitsbg6	325	35.4	1,008.5	6,532	23,185	6,396	36,113	34,288	0	0	34,288	-1,825	29.47	34.00
Pitsbrg7	720	26.8	1,692.3	10,581	33,998	10,718	55,297	58,192	0	121	58,313	3,016	26.34	34.46
Pitsbu12	326	5.7	161.5	1,156	3,238	4,647	9,041	6,455	2,586	0	9,041	0	27.21	39.97
Pitsbu34	326	21.5	613.5	4,391	15,376	4,647	24,414	22,178	2,236	0	24,414	0	32.22	36.15
Potr456	168	0.2	2.6	27	208	875	1,110	235	875	0	1,110	0	91.80	91.80
Potrero3	207	63.3	1,146.8	7,428	22,910	4,071	34,409	32,524	1,827	58	34,409	0	26.45	28.41
Thermal	**6,332**	**31.4**	**17,407.8**	**113,295**	**344,264**	**109,991**	**567,550**	**575,538**	**25,782**	**1,417**	**602,733**	**35,183**	**26.28**	**33.14**
Nuclear	**2,160**	**89.5**	**16,939.4**	**36,291**	**101,299**	**198,708**	**336,298**	**496,399**	**0**	**0**	**496,399**	**160,101**	**8.12**	**29.30**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**75,256**	**75,256**	**739,808**	**0**	**0**	**739,808**	**664,552**	**0.00**	**30.98**
Geo	**635**	**49.0**	**2,725.7**	**3,837**	**54,171**	**17,958**	**75,966**	**78,280**	**0**	**0**	**78,280**	**2,314**	**21.28**	**28.72**
PumpStorage	**1,174**	**4.7**	**488.1**	**0**	**0**	**19,619**	**19,619**	**16,036**	**0**	**0**	**16,036**	**-3,583**	**0.00**	**32.85**
DSM & Solar	**518**	**0.3**	**12.6**	**19**	**0**	**141**	**160**	**358**	**0**	**0**	**358**	**198**	**1.51**	**28.44**
QF	**4,209**	**74.5**	**27,486.3**	**100,357**	**506,369**	**94,229**	**700,955**	**785,249**	**0**	**0**	**785,249**	**84,294**	**22.07**	**28.57**
Total less QFs	**15,322**	**45.8**	**61,457.2**	**153,442**	**499,734**	**421,673**	**1,074,849**	**1,906,419**	**25,782**	**1,417**	**1,933,614**	**858,765**	**10.63**	**31.04**
Total	**19,531**	**52.0**	**88,943.5**	**253,799**	**1,006,103**	**515,902**	**1,775,804**	**2,691,668**	**25,782**	**1,417**	**2,718,863**	**943,059**	**14.17**	**30.28**

Table 3.12.13b Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

Southern California Edison Units - 1998

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
ALA7HNT5	276	0.3	6.9	55	253	1,774	2,082	308	1,774	0	2,082	0	44.52	44.44
ALAMIT34	640	4.7	261.6	1,244	5,718	4,114	11,076	12,011	0	5	12,016	940	26.61	45.93
ALAMIT56	960	24.4	2,055.7	9,773	46,136	6,170	62,079	71,371	0	573	71,944	9,865	27.20	35.00
ANAHMCT	46	0.6	2.4	20	71	92	183	90	93	0	183	0	37.36	37.19
CWAT12	146	55.6	711.0	2,715	13,123	2,552	18,390	23,811	0	11	23,822	5,432	22.27	33.50
CWTRCC	512	50.8	2,278.5	8,699	38,031	4,311	51,041	76,751	0	74	76,826	25,785	20.51	33.72
ELSG1234	1,020	4.4	392.4	1,865	8,824	10,371	21,060	14,998	0	139	15,137	-5,923	27.24	38.58
ELWOOD1	53	0.7	3.2	25	88	185	298	113	185	0	298	0	35.73	35.76
ETWAND34	670	6.0	351.5	1,671	7,629	5,392	14,692	14,321	0	52	14,373	-319	26.46	40.90
ETWANDA5	138	0.2	2.2	17	81	334	432	98	334	0	432	0	44.82	44.75
HN12MA12	860	21.3	1,602.3	1,716	35,771	19,015	56,502	56,654	0	543	57,196	694	23.40	35.70
LNBCHCC	560	8.9	435.2	2,069	9,673	5,478	17,220	17,328	0	156	17,484	264	26.98	40.18
MNDALY3	140	0.3	3.7	29	133	299	461	162	299	0	461	0	44.52	44.38
ORMND1	750	30.4	1,994.0	9,480	44,078	5,418	58,976	67,904	0	392	68,296	9,320	26.86	34.25
ORMND2	750	31.8	2,086.7	9,921	46,507	5,418	61,846	71,292	0	610	71,902	10,056	27.04	34.46
REDNDO56	350	3.5	107.1	509	2,538	2,744	5,791	4,863	0	0	4,863	-928	28.46	45.42
REDNDO78	960	20.7	1,740.4	8,274	38,287	7,528	54,089	62,174	0	277	62,451	8,362	26.75	35.88
VERNDSL	20	0.3	0.5	2	30	77	109	32	77	0	109	0	60.95	61.54
Thermal	**8,852**	**18.1**	**14,035.1**	**58,084**	**296,971**	**81,272**	**436,327**	**494,281**	**2,762**	**2,832**	**499,875**	**63,548**	**25.30**	**35.42**
Nuclear	**2,326**	**88.9**	**18,109.4**	**1,939**	**113,761**	**228,145**	**343,845**	**529,807**	**0**	**0**	**529,807**	**185,962**	**6.39**	**29.26**
Coal	**3,060**	**71.2**	**19,075.7**	**51,812**	**224,788**	**65,654**	**342,254**	**587,616**	**0**	**755**	**588,373**	**246,119**	**14.50**	**30.84**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**25,085**	**25,085**	**218,282**	**0**	**0**	**218,282**	**193,197**	**0.00**	**31.49**
PumpStorage	**207**	**7.0**	**127.0**	**0**	**0**	**3,459**	**3,459**	**4,340**	**0**	**0**	**4,340**	**881**	**0.00**	**34.16**
DSM/SelfGen	**2,114**	**21.8**	**4,031.0**	**13**	**0**	**3,959**	**3,972**	**117,895**	**0**	**0**	**117,895**	**113,923**	**0.00**	**29.25**
QF	**4,622**	**65.8**	**26,647.4**	**462,489**	**499,721**	**326,518**	**1,288,728**	**782,241**	**0**	**0**	**782,241**	**-506,487**	**36.11**	**29.36**
Total less QFs	**18,060**	**39.4**	**62,310.8**	**111,848**	**635,520**	**407,574**	**1,154,942**	**1,952,221**	**2,762**	**3,587**	**1,958,572**	**803,629**	**11.99**	**31.39**
Total	**22,682**	**44.8**	**88,958.2**	**574,337**	**1,135,241**	**734,092**	**2,443,670**	**2,734,462**	**2,762**	**3,587**	**2,740,813**	**297,142**	**19.22**	**30.78**

Table 3.12.13c Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

San Diego Gas & Electric Units - 1998

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.2	0.3	2	22	125	149	24	125	0	149	0	85.78	85.71
ENCIN123	321	4.2	118.1	960	2,792	6,190	9,942	5,617	0	76	5,692	-4,250	31.77	48.21
ENCINA45	615	6.3	340.0	2,763	7,822	10,277	20,862	14,920	0	122	15,042	-5,820	31.13	44.25
KRNYGT23	132	0.5	6.2	49	228	1,035	1,312	277	1,035	0	1,312	0	44.90	44.82
MRMARGT	39	0.6	2.0	16	68	306	390	84	306	0	390	0	41.52	41.38
NRISLGT1	19	0.3	0.5	4	36	149	189	40	149	0	189	0	80.56	80.00
NTCKRNGT	33	0.6	1.7	14	60	259	333	74	259	0	333	0	42.84	43.02
NVLNRIGT	42	0.7	2.6	20	82	329	431	102	329	0	431	0	39.94	39.84
STHBAY4	222	1.6	30.4	248	784	4,195	5,227	1,774	0	10	1,783	-3,444	33.88	58.61
STHBAYGT	19	1.3	2.1	17	60	149	226	77	149	0	226	0	36.66	36.67
STHBY123	468	19.6	804.4	6,538	18,234	10,528	35,300	30,283	0	255	30,538	-4,762	30.79	37.96
TWOGTS	32	0.3	0.8	7	30	251	288	36	252	0	288	0	43.51	43.37
Thermal	**1,958**	**7.6**	**1,309.1**	**10,638**	**30,218**	**33,793**	**74,649**	**53,308**	**2,604**	**463**	**56,373**	**-18,276**	**31.21**	**41.07**
Nuclear	**430**	**89.1**	**3,357.8**	**360**	**21,914**	**41,456**	**63,730**	**98,246**	**0**	**0**	**98,246**	**34,516**	**6.63**	**29.26**
DSM/SelfGen	**126**	**38.7**	**425.5**	**1,823**	**0**	**566**	**2,389**	**12,479**	**0**	**0**	**12,479**	**10,090**	**4.28**	**29.33**
QF	**237**	**88.9**	**1,848.2**	**7,656**	**37,402**	**3,339**	**48,397**	**54,443**	**0**	**0**	**54,443**	**6,046**	**24.38**	**29.46**
Total less QFs	**2,514**	**23.1**	**5,092.4**	**12,821**	**52,132**	**75,815**	**140,768**	**164,033**	**2,604**	**463**	**167,098**	**26,330**	**12.75**	**32.30**
Total	**2,751**	**28.8**	**6,940.6**	**20,477**	**89,534**	**79,154**	**189,165**	**218,476**	**2,604**	**463**	**221,541**	**32,376**	**15.85**	**31.54**

Table 3.12.13d Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

Pacific Gas and Electric Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	18.3	545.1	4,972	12,302	7,414	24,688	22,986	0	61	23,047	-1,641	31.69	42.28
CCosta7	340	12.9	384.5	3,507	8,650	7,414	19,571	17,185	0	13	17,198	-2,373	31.62	44.73
HntrsPt1	56	0.6	3.0	34	178	244	456	212	244	0	456	0	71.11	71.14
HntrsPt2	107	3.6	33.6	230	935	3,934	5,099	1,844	3,254	1	5,099	0	34.71	54.99
HntrsPt3	107	3.0	27.7	190	791	3,934	4,915	1,512	3,399	4	4,915	0	35.36	54.69
HntrsPt4	163	61.7	880.4	5,842	20,439	6,853	33,134	28,519	4,564	51	33,134	0	29.85	32.45
Humbld12	105	37.9	349.0	2,375	10,641	5,298	18,314	11,430	6,765	119	18,314	0	37.29	33.09
Mobil123	45	0.5	2.1	24	229	321	574	252	322	0	574	0	121.42	121.15
Morro12	326	16.1	459.4	3,509	11,005	5,153	19,667	21,116	0	113	21,229	1,562	31.60	46.21
Morro3	338	36.8	1,089.1	7,497	24,687	7,370	39,554	43,995	0	33	44,028	4,474	29.55	40.43
Morro4	338	43.1	1,274.8	8,776	28,454	7,370	44,600	50,486	0	88	50,574	5,974	29.20	39.67
Moss6	739	48.1	3,114.5	20,666	66,184	12,218	99,068	115,787	0	332	116,119	17,051	27.89	37.28
Moss7	739	60.7	3,931.3	26,086	81,451	12,218	119,755	141,178	0	420	141,598	21,843	27.35	36.02
Oakln123	192	0.3	4.8	55	457	353	865	512	353	0	865	0	106.04	106.00
Pitsbg5	325	25.3	720.6	4,960	16,469	7,092	28,521	28,985	0	2	28,987	466	29.74	40.23
Pitsbg6	325	35.0	995.1	6,850	26,301	7,092	40,243	39,104	0	0	39,104	-1,139	33.31	39.30
Pitsbrg7	720	28.9	1,824.8	12,109	42,058	11,883	66,050	72,572	0	115	72,688	6,638	29.68	39.83
Pitsbu12	326	6.4	183.2	1,400	4,224	5,153	10,777	8,865	1,907	5	10,777	0	30.69	48.41
Pitsbu34	326	26.5	755.8	5,773	21,764	5,153	32,690	31,665	1,025	0	32,690	0	36.44	41.90
Potr456	168	0.5	7.7	87	715	970	1,772	802	970	0	1,772	0	104.62	104.56
Potrero3	207	62.8	1,139.0	7,841	26,101	4,514	38,456	36,802	1,582	73	38,456	0	29.80	32.37
Thermal	**6,332**	**32.0**	**17,725.4**	**122,783**	**404,035**	**121,951**	**648,769**	**675,809**	**24,385**	**1,430**	**701,624**	**52,855**	**29.72**	**38.21**
Nuclear	**2,160**	**89.5**	**16,939.4**	**40,237**	**112,606**	**220,312**	**373,155**	**562,719**	**0**	**0**	**562,719**	**189,564**	**9.02**	**33.22**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**83,437**	**83,437**	**852,235**	**0**	**0**	**852,235**	**768,798**	**0.00**	**35.68**
Geo	**635**	**49.0**	**2,725.7**	**4,254**	**64,518**	**19,910**	**88,682**	**89,331**	**0**	**0**	**89,331**	**649**	**25.23**	**32.77**
PumpStorage	**1,174**	**4.8**	**490.3**	**0**	**0**	**21,752**	**21,752**	**19,240**	**0**	**0**	**19,240**	**-2,512**	**0.00**	**39.24**
DSM & Solar	**518**	**0.3**	**12.6**	**28**	**0**	**157**	**185**	**418**	**0**	**0**	**418**	**233**	**2.22**	**33.10**
QF	**4,209**	**74.5**	**27,486.3**	**111,268**	**577,212**	**104,473**	**792,953**	**895,825**	**0**	**0**	**895,825**	**102,872**	**25.05**	**32.59**
Total less QFs	**15,322**	**46.0**	**61,776.9**	**167,302**	**581,159**	**467,519**	**1,215,980**	**2,199,752**	**24,385**	**1,430**	**2,225,567**	**1,009,587**	**12.12**	**35.63**
Total	**19,531**	**52.2**	**89,263.2**	**278,570**	**1,158,371**	**571,992**	**2,008,933**	**3,095,577**	**24,385**	**1,430**	**3,121,392**	**1,112,459**	**16.10**	**34.70**

Table 3.12.13e Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

Southern California Edison Units - 2001

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	**(MW)**	**(%)**	**(GWh)**	**Var**	**Fuel**	**Fixed**	**Total**	**Energy**	**Reserve**	**Spin**	**Total**	**Income**	**Cost**	**Rev.**
ALA7HNT5	276	0.5	11.6	100	483	1,967	2,550	583	1,967	0	2,550	0	50.45	50.48
ALAMIT34	640	5.7	316.5	1,613	7,863	4,561	14,037	16,750	0	71	16,821	2,784	29.94	53.15
ALAMIT56	960	25.3	2,124.4	10,826	54,007	6,841	71,674	84,368	0	608	84,975	13,301	30.52	40.00
ANAHMCT	46	1.0	4.0	35	133	103	271	169	102	0	271	0	41.89	41.94
CWAT12	146	52.2	667.0	2,736	14,683	2,830	20,249	25,418	0	12	25,430	5,181	26.12	38.13
CWTRCC	512	46.8	2,097.2	8,604	41,931	4,780	55,315	81,309	0	46	81,354	26,039	24.10	38.79
ELSG1234	1,020	5.4	479.0	2,441	12,362	11,499	26,302	21,810	0	152	21,962	-4,340	30.90	45.85
ELWOOD1	53	0.9	4.2	36	133	205	374	169	205	0	374	0	40.48	40.53
ETWAND34	670	7.5	440.2	2,243	10,801	5,978	19,022	20,258	0	34	20,292	1,270	29.63	46.10
ETWANDA5	138	0.5	6.6	57	278	370	705	334	371	0	705	0	50.93	50.84
HN12MA12	860	24.0	1,808.2	2,148	45,773	21,082	69,003	74,687	0	773	75,460	6,457	26.50	41.73
LNBCHCC	560	11.0	538.6	2,745	13,536	6,074	22,355	25,025	0	66	25,091	2,736	30.23	46.59
MNDALY3	140	0.6	7.3	63	306	331	700	369	331	0	700	0	50.59	50.55
ORMND1	750	29.7	1,951.1	9,943	48,657	6,007	64,607	76,705	0	593	77,298	12,691	30.03	39.62
ORMND2	750	31.3	2,053.9	10,467	51,506	6,007	67,980	81,073	0	423	81,495	13,515	30.17	39.68
REDNDO56	350	4.5	138.0	703	3,704	3,043	7,450	7,662	0	20	7,683	233	31.93	55.65
REDNDO78	960	22.4	1,885.6	9,609	46,773	8,346	64,728	77,138	0	212	77,350	12,622	29.90	41.02
VERNDSL	20	0.7	1.2	5	72	86	163	77	86	0	163	0	63.55	63.11
Thermal	**8,852**	**18.7**	**14,534.7**	**64,374**	**353,001**	**90,110**	**507,485**	**593,904**	**3,062**	**3,010**	**599,974**	**92,489**	**28.72**	**41.07**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,151**	**126,261**	**252,949**	**381,360**	**601,345**	**0**	**0**	**601,345**	**219,985**	**7.09**	**33.21**
Coal	**3,060**	**71.4**	**19,140.3**	**57,483**	**250,834**	**72,792**	**381,109**	**668,929**	**0**	**729**	**669,657**	**288,548**	**16.11**	**34.99**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**27,812**	**27,812**	**250,577**	**0**	**0**	**250,577**	**222,764**	**0.00**	**36.15**
PumpStorage	**207**	**7.0**	**127.3**	**0**	**0**	**3,835**	**3,835**	**5,091**	**0**	**0**	**5,091**	**1,256**	**0.00**	**39.98**
DSM/SelfGen	**2,114**	**21.8**	**4,031.0**	**14**	**0**	**4,390**	**4,404**	**134,097**	**0**	**0**	**134,097**	**129,693**	**0.00**	**33.27**
QF	**4,622**	**65.8**	**26,647.4**	**512,770**	**563,965**	**362,017**	**1,438,752**	**886,804**	**0**	**0**	**886,804**	**-551,948**	**40.41**	**33.28**
Total less QFs	**18,060**	**39.7**	**62,875.2**	**124,022**	**730,096**	**451,888**	**1,306,005**	**2,253,943**	**3,062**	**3,739**	**2,260,741**	**954,736**	**13.58**	**35.91**
Total	**22,682**	**45.1**	**89,522.6**	**636,792**	**1,294,061**	**813,905**	**2,744,757**	**3,140,747**	**3,062**	**3,739**	**3,147,545**	**402,788**	**21.57**	**35.13**

Table 3.12.13f Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

San Diego Gas & Electric Units - 2001

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Fuel	Fixed	Total	Revenue in $000 Energy	Others Reserve	Spin	Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Avg. Rev.
DIVISGT	16	0.5	0.7	6	61	139	206	67	139	0	206	0	95.65	95.71
ENCIN123	321	4.9	137.6	1,187	3,674	6,862	11,723	7,737	0	95	7,832	-3,891	35.34	56.94
ENCINA45	615	7.8	417.3	3,601	11,041	11,395	26,037	20,452	0	210	20,662	-5,375	35.09	49.52
KRNYGT23	132	0.7	8.0	68	334	1,148	1,550	402	1,148	0	1,550	0	50.12	50.06
MRMARGT	39	0.8	2.7	23	101	339	463	124	339	0	463	0	46.42	46.44
NRISLGT1	19	0.6	1.0	8	81	165	254	89	165	0	254	0	89.80	89.90
NTCKRNGT	33	0.8	2.3	19	89	287	395	109	286	0	395	0	47.41	47.60
NVLNRIGT	42	1.0	3.7	31	132	365	528	163	365	0	528	0	44.66	44.66
STHBAY4	222	1.6	30.8	266	889	4,651	5,806	2,400	0	27	2,427	-3,379	37.54	78.88
STHBAYGT	19	1.5	2.5	21	79	165	265	100	165	0	265	0	40.42	40.32
STHBY123	468	22.4	918.0	7,923	23,579	11,673	43,175	39,813	0	406	40,219	-2,956	34.32	43.81
TWOGTS	32	0.5	1.4	12	56	278	346	67	279	0	346	0	48.51	48.20
Thermal	**1,958**	**8.9**	**1,525.8**	**13,165**	**40,116**	**37,467**	**90,748**	**71,523**	**2,886**	**738**	**75,147**	**-15,601**	**34.92**	**47.36**
Nuclear	**430**	**89.1**	**3,357.8**	**399**	**24,311**	**45,963**	**70,673**	**111,496**	**0**	**0**	**111,496**	**40,823**	**7.36**	**33.20**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,022**	**0**	**627**	**2,649**	**14,125**	**0**	**0**	**14,125**	**11,476**	**4.75**	**33.20**
QF	**237**	**88.9**	**1,848.2**	**8,486**	**41,915**	**3,701**	**54,102**	**61,748**	**0**	**0**	**61,748**	**7,646**	**27.27**	**33.41**
Total less QFs	**2,514**	**24.1**	**5,309.1**	**15,586**	**64,427**	**84,057**	**164,070**	**197,144**	**2,886**	**738**	**200,768**	**36,698**	**15.07**	**37.27**
Total	**2,751**	**29.7**	**7,157.3**	**24,072**	**106,342**	**87,758**	**218,172**	**258,892**	**2,886**	**738**	**262,516**	**44,344**	**18.22**	**36.28**

Table 3.12.13g Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

Pacific Gas and Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	19.2	570.6	5,865	16,221	8,806	30,892	29,835	0	151	29,985	-907	38.71	52.55
CCosta7	340	15.0	447.4	4,598	12,798	8,806	26,202	24,582	0	201	24,783	-1,419	38.89	55.40
HntrsPt1	56	0.6	3.0	39	233	290	562	272	290	0	562	0	91.25	91.28
HntrsPt2	107	3.9	36.8	279	1,320	4,673	6,272	2,501	3,766	5	6,272	0	43.48	68.13
HntrsPt3	107	4.0	37.4	283	1,386	4,673	6,342	2,240	4,098	4	6,342	0	44.60	59.97
HntrsPt4	163	59.6	850.6	6,232	24,909	8,139	39,280	34,260	4,975	45	39,280	0	36.61	40.33
Humbld12	105	35.2	323.9	2,439	12,531	6,292	21,262	13,127	8,056	79	21,262	0	46.22	40.77
Mobil123	45	0.6	2.4	30	338	381	749	369	380	0	749	0	157.19	157.02
Morro12	326	16.5	472.0	4,020	14,488	6,120	24,628	27,211	0	141	27,352	2,724	39.21	57.95
Morro3	338	36.1	1,069.6	8,152	30,525	8,754	47,431	53,808	0	24	53,832	6,401	36.16	50.33
Morro4	338	40.8	1,208.0	9,207	33,923	8,754	51,884	59,258	0	66	59,324	7,440	35.70	49.11
Moss6	739	46.5	3,008.8	22,043	80,506	14,511	117,060	139,782	0	308	140,090	23,030	34.08	46.56
Moss7	739	56.8	3,676.0	26,931	95,995	14,511	137,437	165,000	0	366	165,366	27,929	33.44	44.99
Oakln123	192	0.3	4.8	63	576	419	1,058	639	419	0	1,058	0	132.00	132.02
Pitsbg5	325	25.5	725.6	5,530	20,848	8,423	34,801	35,960	0	14	35,974	1,173	36.35	49.58
Pitsbg6	325	34.8	991.1	7,554	32,986	8,423	48,963	48,212	0	0	48,212	-751	40.90	48.64
Pitsbrg7	720	31.0	1,954.5	14,319	57,024	14,113	85,456	96,272	0	223	96,495	11,039	36.50	49.37
Pitsbu12	326	7.3	208.2	1,774	6,044	6,120	13,938	12,358	1,580	0	13,938	0	37.54	59.35
Pitsbu34	326	29.9	853.9	7,273	30,900	6,120	44,293	43,746	547	0	44,293	0	44.71	51.23
Potr456	168	0.5	7.7	99	899	1,152	2,150	998	1,152	0	2,150	0	130.22	130.12
Potrero3	207	60.1	1,090.4	8,310	31,497	5,361	45,168	43,689	1,313	166	45,168	0	36.51	40.22
Thermal	**6,332**	**31.6**	**17,542.6**	**135,040**	**505,947**	**144,841**	**785,828**	**834,119**	**26,576**	**1,793**	**862,487**	**76,659**	**36.54**	**47.65**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**688,826**	**0**	**0**	**688,826**	**245,052**	**10.75**	**40.66**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**1,044,525**	**0**	**0**	**1,044,525**	**945,427**	**0.00**	**43.73**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**110,348**	**0**	**0**	**110,348**	**-4,691**	**33.53**	**40.48**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**24,346**	**0**	**0**	**24,346**	**-1,488**	**0.00**	**49.58**
DSM & Solar	**518**	**0.3**	**12.6**	**36**	**0**	**186**	**222**	**516**	**0**	**0**	**516**	**294**	**2.85**	**40.82**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**718,272**	**124,082**	**974,506**	**1,104,290**	**0**	**0**	**1,104,290**	**129,784**	**30.94**	**40.18**
Total less QFs	**15,322**	**45.9**	**61,594.8**	**187,917**	**726,610**	**555,268**	**1,469,795**	**2,702,680**	**26,576**	**1,793**	**2,731,048**	**1,261,253**	**14.85**	**43.91**
Total	**19,531**	**52.1**	**89,081.1**	**320,069**	**1,444,882**	**679,350**	**2,444,301**	**3,806,970**	**26,576**	**1,793**	**3,835,338**	**1,391,037**	**19.81**	**42.76**

Table 3.12.13h Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

Southern California Edison Units - 2006

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
ALA7HNT5	276	0.6	13.9	138	705	2,336	3,179	843	2,336	0	3,179	0	60.85	60.82
ALAMIT34	640	7.9	441.7	2,529	13,773	5,417	21,719	29,138	0	138	29,276	7,557	36.91	66.29
ALAMIT56	960	25.1	2,109.8	12,080	65,690	8,125	85,895	105,401	0	699	106,101	20,206	36.86	50.29
ANAHMCT	46	1.1	4.4	45	178	122	345	223	122	0	345	0	50.32	50.23
CWAT12	146	38.9	497.1	2,301	14,710	3,361	20,372	23,728	0	43	23,770	3,398	34.22	47.82
CWTRCC	512	33.0	1,477.8	6,840	39,721	5,677	52,238	74,718	0	171	74,889	22,651	31.51	50.68
ELSG1234	1,020	7.0	625.6	3,582	19,940	13,657	37,179	34,898	0	318	35,216	-1,963	37.60	56.29
ELWOOD1	53	1.0	4.6	46	178	243	467	225	242	0	467	0	48.39	48.49
ETWAND34	670	9.8	575.7	3,296	17,581	7,100	27,977	32,576	0	123	32,699	4,722	36.27	56.80
ETWANDA5	138	0.7	8.8	87	448	439	974	536	438	0	974	0	61.16	61.19
HN12MA12	860	23.4	1,758.8	2,481	54,501	25,039	82,021	91,833	0	623	92,456	10,435	32.40	52.57
LNBCHCC	560	13.3	650.4	3,724	20,156	7,214	31,094	35,943	0	293	36,236	5,142	36.72	55.72
MNDALY3	140	0.7	9.0	90	460	393	943	550	393	0	943	0	60.95	60.98
ORMND1	750	28.0	1,838.7	10,528	56,258	7,135	73,921	91,123	0	556	91,678	17,757	36.32	49.86
ORMND2	750	30.8	2,020.1	11,567	62,520	7,135	81,222	100,551	0	611	101,162	19,940	36.67	50.08
REDNDO56	350	5.8	176.9	1,013	5,920	3,614	10,547	12,189	0	99	12,288	1,741	39.20	69.48
REDNDO78	960	22.5	1,893.5	10,842	57,827	9,913	78,582	97,995	0	291	98,286	19,704	36.26	51.91
VERNDSL	20	0.7	1.2	6	77	102	185	83	102	0	185	0	68.17	68.03
Thermal	**8,852**	**18.2**	**14,107.9**	**71,195**	**430,643**	**107,022**	**608,860**	**732,553**	**3,633**	**3,965**	**740,150**	**131,290**	**35.57**	**52.21**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**732,934**	**0**	**0**	**732,934**	**279,736**	**8.44**	**40.47**
Coal	**3,060**	**70.9**	**19,007.7**	**67,396**	**297,311**	**86,454**	**451,161**	**814,758**	**0**	**819**	**815,577**	**364,416**	**19.19**	**42.91**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**304,805**	**0**	**0**	**304,805**	**271,774**	**0.00**	**43.97**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**6,432**	**0**	**0**	**6,432**	**1,877**	**0.00**	**50.27**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**26**	**0**	**5,214**	**5,240**	**163,440**	**0**	**0**	**163,440**	**158,200**	**0.01**	**40.54**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**689,913**	**429,961**	**1,728,882**	**1,082,783**	**0**	**0**	**1,082,783**	**-646,099**	**48.74**	**40.63**
Total less QFs	**18,060**	**39.4**	**62,316.5**	**141,172**	**878,173**	**536,700**	**1,556,045**	**2,754,922**	**3,633**	**4,784**	**2,763,338**	**1,207,293**	**16.36**	**44.29**
Total	**22,682**	**44.8**	**88,963.9**	**750,180**	**1,568,086**	**966,661**	**3,284,927**	**3,837,705**	**3,633**	**4,784**	**3,846,121**	**561,194**	**26.06**	**43.19**

Table 3.12.13i Generation Cost and Revenues

Base Fuel Cost Case - Long Run Average Heat Rate for Bids

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.5	0.7	7	73	165	245	80	165	0	245	0	114.76	114.29
ENCIN123	321	5.8	163.0	1,555	5,455	8,150	15,160	10,857	0	53	10,909	-4,251	43.02	66.95
ENCINA45	615	10.2	550.7	5,255	17,766	13,533	36,554	32,734	0	341	33,076	-3,478	41.80	60.06
KRNYGT23	132	0.9	10.3	97	513	1,363	1,973	610	1,363	0	1,973	0	59.07	59.11
MRMARGT	39	0.8	2.7	25	123	403	551	149	402	0	551	0	54.80	54.98
NRISLGT1	19	0.6	1.0	9	97	196	302	107	195	0	302	0	107.69	108.08
NTCKRNGT	33	0.8	2.3	21	108	341	470	129	341	0	470	0	56.43	56.33
NVLNRIGT	42	0.8	2.9	27	127	434	588	154	434	0	588	0	52.85	52.74
STHBAY4	222	2.1	40.7	389	1,477	5,524	7,390	3,831	0	7	3,838	-3,552	45.83	94.28
STHBAYGT	19	1.5	2.5	23	95	196	314	118	196	0	314	0	47.75	47.58
STHBY123	468	26.3	1,079.5	10,301	33,463	13,863	57,627	56,653	0	360	57,013	-614	40.54	52.81
TWOGTS	32	0.5	1.4	13	67	330	410	80	330	0	410	0	57.76	57.55
Thermal	**1,958**	**10.8**	**1,857.7**	**17,722**	**59,364**	**44,498**	**121,584**	**105,502**	**3,426**	**761**	**109,689**	**-11,895**	**41.50**	**57.20**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**135,754**	**0**	**0**	**135,754**	**51,789**	**8.75**	**40.43**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**17,365**	**0**	**0**	**17,365**	**14,218**	**5.65**	**40.81**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**50,678**	**4,396**	**65,153**	**75,819**	**0**	**0**	**75,819**	**10,666**	**32.87**	**41.02**
Total less QFs	**2,514**	**25.6**	**5,641.0**	**20,598**	**88,265**	**99,833**	**208,696**	**258,621**	**3,426**	**761**	**262,808**	**54,112**	**19.30**	**45.98**
Total	**2,751**	**31.1**	**7,489.2**	**30,677**	**138,943**	**104,229**	**273,849**	**334,440**	**3,426**	**761**	**338,627**	**64,778**	**22.65**	**44.76**

Table 3.12.14a Generation Cost and Revenues

Base Fuel Cost Case With PX Bids For Reserve Units

Pacific Gas and Electric Units - 2006

				Cost in $000				Revenue in $000				in $000	Energy $/MWh	
		Capacity							Others					
Category	Capacity (MW)	Factor (%)	Energy (GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Net Income	Avg. Var Cost	Avg. Rev.
CCosta6	340	27.9	830.9	8,540	23,601	8,806	40,947	41,408	0	519	41,927	980	38.68	50.46
CCosta7	340	23.7	706.6	7,263	20,117	8,806	36,186	36,304	0	230	36,534	348	38.75	51.70
HntrsPt1	56	0.6	3.0	39	233	290	562	596	0	0	596	34	91.25	200.00
HntrsPt2	107	4.7	44.3	336	1,638	4,673	6,647	2,932	3,700	15	6,647	0	44.54	66.51
HntrsPt3	107	5.3	49.2	373	1,827	4,673	6,873	2,775	4,091	7	6,873	0	44.72	56.57
HntrsPt4	163	58.4	833.3	6,105	24,437	8,139	38,681	34,252	4,390	40	38,681	0	36.65	41.15
Humbld12	105	33.4	306.8	2,310	11,965	6,292	20,567	12,525	7,994	48	20,567	0	46.53	40.99
Mobil123	45	0.6	2.4	30	338	381	749	538	211	0	749	0	157.19	228.94
Morro12	326	23.8	679.3	5,786	20,851	6,120	32,757	36,853	0	434	37,287	4,530	39.21	54.89
Morro3	338	35.3	1,044.2	7,958	29,841	8,754	46,553	52,926	0	56	52,982	6,429	36.20	50.74
Morro4	338	39.7	1,174.1	8,949	33,023	8,754	50,726	57,843	0	102	57,945	7,219	35.75	49.35
Moss6	739	45.7	2,957.1	21,664	79,122	14,511	115,297	136,098	0	336	136,435	21,138	34.08	46.14
Moss7	739	56.7	3,673.4	26,912	95,827	14,511	137,250	163,604	0	424	164,028	26,778	33.41	44.65
Oakln123	192	0.2	4.1	53	485	419	957	948	9	0	957	0	132.00	232.92
Pitsbg5	325	32.5	924.2	7,044	26,512	8,423	41,979	44,004	0	41	44,044	2,065	36.31	47.66
Pitsbg6	325	35.3	1,006.0	7,667	33,435	8,423	49,525	48,903	0	0	48,903	-622	40.86	48.61
Pitsbrg7	720	36.9	2,327.5	17,052	67,564	14,113	98,729	111,513	0	277	111,789	13,060	36.35	48.03
Pitsbu12	326	11.2	318.6	2,714	9,185	6,120	18,019	17,087	890	42	18,019	0	37.34	53.76
Pitsbu34	326	28.8	821.4	6,996	29,834	6,120	42,950	42,984	0	0	42,984	34	44.84	52.33
Potr456	168	0.5	7.2	94	847	1,152	2,093	1,461	629	4	2,093	0	130.22	202.91
Potrero3	207	58.6	1,062.8	8,100	30,713	5,361	44,174	43,261	756	157	44,174	0	36.52	40.85
Thermal	**6,332**	**33.9**	**18,776.3**	**145,985**	**541,395**	**144,841**	**832,221**	**888,815**	**22,670**	**2,732**	**914,214**	**81,993**	**36.61**	**47.48**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**690,878**	**0**	**0**	**690,878**	**247,104**	**10.75**	**40.79**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**1,034,605**	**0**	**0**	**1,034,605**	**935,507**	**0.00**	**43.32**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**108,703**	**0**	**0**	**108,703**	**-6,336**	**33.53**	**39.88**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**24,314**	**0**	**0**	**24,314**	**-1,520**	**0.00**	**49.52**
DSM & Solar	**518**	**0.3**	**12.6**	**36**	**0**	**186**	**222**	**511**	**0**	**0**	**511**	**289**	**2.85**	**40.43**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**718,272**	**124,082**	**974,506**	**1,089,658**	**0**	**0**	**1,089,658**	**115,152**	**30.94**	**39.64**
Total less QFs	**15,322**	**46.8**	**62,828.6**	**198,862**	**762,058**	**555,268**	**1,516,188**	**2,747,826**	**22,670**	**2,732**	**2,773,225**	**1,257,037**	**15.29**	**43.78**
Total	**19,531**	**52.8**	**90,314.9**	**331,014**	**1,480,330**	**679,350**	**2,490,694**	**3,837,484**	**22,670**	**2,732**	**3,862,883**	**1,372,189**	**20.06**	**42.52**

Table 3.12.14b Generation Cost and Revenues

Base Fuel Cost Case With PX Bids For Reserve Units

Southern California Edison Units - 2006

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	(MW)	(%)	(GWh)	Var	Fuel	Fixed	Total	Energy	Reserve	Spin	Total	Income	Cost	Rev.
ALA7HNT5	276	0.5	11.6	115	591	2,336	3,042	2,210	832	0	3,042	0	61.10	191.34
ALAMIT34	640	12.6	704.5	4,034	22,103	5,417	31,554	40,502	0	196	40,699	9,145	37.10	57.77
ALAMIT56	960	26.2	2,200.0	12,597	68,693	8,125	89,415	108,432	0	565	108,997	19,582	36.95	49.54
ANAHMCT	46	1.2	4.8	49	194	122	365	667	0	0	667	302	50.23	137.81
CWAT12	146	36.7	469.4	2,173	13,880	3,361	19,414	22,425	0	31	22,455	3,041	34.20	47.84
CWTRCC	512	36.9	1,654.7	7,659	43,525	5,677	56,861	80,148	0	78	80,225	23,364	30.93	48.49
ELSG1234	1,020	10.1	904.6	5,180	29,283	13,657	48,120	46,534	0	572	47,106	-1,014	38.10	52.07
ELWOOD1	53	1.1	4.9	48	186	243	477	677	0	1	678	201	48.36	139.79
ETWAND34	670	20.3	1,192.4	6,827	37,566	7,100	51,493	60,177	0	269	60,446	8,953	37.23	50.69
ETWANDA5	138	0.5	6.6	65	340	439	844	1,279	0	0	1,279	435	61.68	194.67
HN12MA12	860	27.6	2,079.5	2,933	64,876	25,039	92,848	104,478	0	1,000	105,478	12,630	32.61	50.72
LNBCHCC	560	16.6	815.0	4,666	25,748	7,214	37,628	43,847	0	240	44,087	6,459	37.32	54.10
MNDALY3	140	0.6	7.8	78	399	393	870	1,425	0	4	1,429	559	61.16	183.68
ORMND1	750	24.7	1,620.6	9,279	50,426	7,135	66,840	83,343	0	226	83,569	16,729	36.84	51.57
ORMND2	750	24.0	1,576.1	9,024	49,149	7,135	65,308	79,676	0	507	80,183	14,875	36.91	50.87
REDNDO56	350	8.8	269.4	1,543	9,165	3,614	14,322	16,427	0	35	16,462	2,140	39.74	61.10
REDNDO78	960	27.9	2,346.0	13,433	72,009	9,913	95,355	116,744	0	696	117,440	22,085	36.42	50.06
VERNDSL	20	0.7	1.2	6	77	102	185	240	0	0	240	55	68.17	196.72
Thermal	**8,852**	**20.5**	**15,868.9**	**79,709**	**488,210**	**107,022**	**674,941**	**809,231**	**832**	**4,420**	**814,482**	**139,541**	**35.79**	**51.27**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**736,435**	**0**	**0**	**736,435**	**283,237**	**8.44**	**40.67**
Coal	**3,060**	**70.5**	**18,891.9**	**66,724**	**295,278**	**86,454**	**448,456**	**809,415**	**0**	**888**	**810,303**	**361,847**	**19.16**	**42.89**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**304,798**	**0**	**0**	**304,798**	**271,766**	**0.00**	**43.97**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**6,437**	**0**	**0**	**6,437**	**1,882**	**0.00**	**50.31**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**26**	**0**	**5,214**	**5,240**	**163,995**	**0**	**0**	**163,995**	**158,755**	**0.01**	**40.68**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**689,913**	**429,961**	**1,728,882**	**1,086,353**	**0**	**0**	**1,086,353**	**-642,529**	**48.74**	**40.77**
Total less QFs	**18,060**	**40.4**	**63,961.6**	**149,014**	**933,707**	**536,700**	**1,619,421**	**2,830,311**	**832**	**5,308**	**2,836,450**	**1,217,028**	**16.93**	**44.33**
Total	**22,682**	**45.6**	**90,609.0**	**758,022**	**1,623,620**	**966,661**	**3,348,303**	**3,916,664**	**832**	**5,308**	**3,922,803**	**574,499**	**26.28**	**43.28**

Table 3.12.14c Generation Cost and Revenues

Base Fuel Cost Case With PX Bids For Reserve Units

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.5	0.7	7	73	165	245	153	92	0	245	0	114.76	218.57
ENCIN123	321	8.2	230.7	2,201	7,839	8,150	18,190	14,041	0	150	14,191	-3,999	43.52	61.52
ENCINA45	615	14.2	762.7	7,278	25,180	13,533	45,991	42,152	0	838	42,989	-3,002	42.56	56.36
KRNYGT23	132	0.9	10.3	97	513	1,363	1,973	1,721	252	0	1,973	0	59.07	166.76
MRMARGT	39	0.9	3.1	29	138	403	570	453	117	0	570	0	54.59	148.52
NRISLGT1	19	0.6	1.0	9	97	196	302	217	85	0	302	0	107.69	219.19
NTCKRNGT	33	0.9	2.6	24	121	341	486	427	59	0	486	0	56.16	165.50
NVLNRIGT	42	0.9	3.4	32	147	434	613	550	60	3	613	0	52.54	162.65
STHBAY4	222	2.1	39.9	381	1,444	5,524	7,349	3,686	0	2	3,687	-3,662	45.72	92.41
STHBAYGT	19	1.4	2.3	22	89	196	307	289	18	0	307	0	47.65	125.11
STHBY123	468	30.0	1,231.4	11,750	38,132	13,863	63,745	62,969	0	542	63,511	-234	40.51	51.58
TWOGTS	32	0.5	1.4	13	67	330	410	264	146	0	410	0	57.76	189.93
Thermal	**1,958**	**13.3**	**2,289.5**	**21,843**	**73,840**	**44,498**	**140,181**	**126,922**	**829**	**1,535**	**129,284**	**-10,897**	**41.79**	**56.11**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**136,484**	**0**	**0**	**136,484**	**52,519**	**8.75**	**40.65**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**17,395**	**0**	**0**	**17,395**	**14,248**	**5.65**	**40.88**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**50,678**	**4,396**	**65,153**	**76,027**	**0**	**0**	**76,027**	**10,874**	**32.87**	**41.14**
Total less QFs	**2,514**	**27.6**	**6,072.8**	**24,719**	**102,741**	**99,833**	**227,293**	**280,801**	**829**	**1,535**	**283,163**	**55,870**	**20.99**	**46.49**
Total	**2,751**	**32.9**	**7,921.0**	**34,798**	**153,419**	**104,229**	**292,446**	**356,828**	**829**	**1,535**	**359,190**	**66,744**	**23.76**	**45.24**

Table 3.12.15a Generation Cost and Revenues

Base Fuel Cost Case With Repowering Of Pitsbrg6 and Encn123

Pacific Gas and Electric Units - 2006

		Capacity		Cost in $000				Revenue in $000				in $000	Energy $/MWh	
	Capacity	Factor	Energy						Others			Net	Avg. Var	Avg.
Category	**(MW)**	**(%)**	**(GWh)**	**Var**	**Fuel**	**Fixed**	**Total**	**Energy**	**Reserve**	**Spin**	**Total**	**Income**	**Cost**	**Rev.**
CCosta6	340	28.5	848.2	8,718	24,120	8,806	41,644	41,783	0	448	42,231	587	38.72	49.79
CCosta7	340	25.4	756.2	7,772	21,509	8,806	38,087	37,963	0	284	38,247	160	38.72	50.58
HntrsPt1	56	0.6	3.0	39	233	290	562	272	290	0	562	0	91.25	91.28
HntrsPt2	107	6.1	57.6	436	2,156	4,673	7,265	3,569	3,687	9	7,265	0	45.01	62.13
HntrsPt3	107	6.1	56.8	430	2,135	4,673	7,238	3,169	4,055	14	7,238	0	45.16	56.02
HntrsPt4	163	60.4	862.0	6,315	25,204	8,139	39,658	36,753	2,856	49	39,658	0	36.57	42.69
Humbld12	105	34.0	312.5	2,352	12,150	6,292	20,794	13,136	7,596	63	20,794	0	46.41	42.24
Mobil123	45	0.7	2.7	36	395	381	812	430	382	0	812	0	157.19	156.93
Morro12	326	28.2	806.0	6,865	24,553	6,120	37,538	41,926	0	407	42,332	4,794	38.98	52.52
Morro3	338	37.2	1,100.5	8,387	31,371	8,754	48,512	54,927	0	94	55,021	6,509	36.13	50.00
Morro4	338	42.7	1,265.1	9,642	35,478	8,754	53,874	61,130	0	66	61,196	7,322	35.67	48.37
Moss6	739	48.4	3,133.5	22,956	83,751	14,511	121,218	145,109	0	203	145,311	24,093	34.05	46.37
Moss7	739	59.2	3,833.6	28,085	99,960	14,511	142,556	171,125	0	348	171,473	28,917	33.40	44.73
Oakln123	192	0.3	5.5	71	651	419	1,141	722	419	0	1,141	0	132.00	131.99
Pitsbg5	325	34.8	990.1	7,546	28,328	8,423	44,297	46,769	0	37	46,806	2,509	36.23	47.27
Pitsbg6r	400	42.5	1,489.8	11,355	44,954	4,063	60,372	69,967	0	231	70,198	9,826	37.79	47.12
Pitsbrg7	720	35.4	2,234.1	16,368	64,984	14,113	95,465	106,175	0	158	106,334	10,869	36.41	47.59
Pitsbu12	326	11.9	339.8	2,894	9,785	6,120	18,799	18,018	730	51	18,799	0	37.31	53.18
Pitsbu34	326	31.5	900.0	7,666	32,597	6,120	46,383	46,112	271	0	46,383	0	44.74	51.24
Potr456	168	0.6	8.0	104	941	1,152	2,197	1,045	1,152	0	2,197	0	130.22	130.14
Potrero3	207	60.3	1,094.0	8,338	31,554	5,361	45,253	45,946	0	119	46,065	812	36.46	42.11
Thermal	**6,407**	**35.8**	**20,098.9**	**156,375**	**576,809**	**140,481**	**873,665**	**946,046**	**21,438**	**2,581**	**970,063**	**96,398**	**36.48**	**47.20**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**699,216**	**0**	**0**	**699,216**	**255,442**	**10.75**	**41.28**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**1,077,133**	**0**	**0**	**1,077,133**	**978,035**	**0.00**	**45.10**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**112,202**	**0**	**0**	**112,202**	**-2,837**	**33.53**	**41.16**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**24,855**	**0**	**0**	**24,855**	**-979**	**0.00**	**50.62**
DSM & Solar	**518**	**0.3**	**12.7**	**39**	**0**	**186**	**225**	**534**	**0**	**0**	**534**	**309**	**3.08**	**42.21**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**718,272**	**124,082**	**974,506**	**1,122,317**	**0**	**0**	**1,122,317**	**147,811**	**30.94**	**40.83**
Total less QFs	**15,397**	**47.6**	**64,151.2**	**209,255**	**797,472**	**550,908**	**1,557,635**	**2,859,986**	**21,438**	**2,581**	**2,884,003**	**1,326,368**	**15.69**	**44.62**
Total	**19,606**	**53.4**	**91,637.5**	**341,407**	**1,515,744**	**674,990**	**2,532,141**	**3,982,303**	**21,438**	**2,581**	**4,006,320**	**1,474,179**	**20.27**	**43.49**

Table 3.12.15b Generation Cost and Revenues

Base Fuel Cost Case With Repowering Of Pitsbrg6 and Encn123

Southern California Edison Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
ALA7HNT5	276	0.7	16.5	165	839	2,336	3,340	1,003	2,337	0	3,340	0	60.71	60.68
ALAMIT34	640	15.1	844.6	4,836	26,388	5,417	36,641	42,708	0	163	42,871	6,230	36.97	50.76
ALAMIT56	960	27.6	2,323.7	13,305	72,527	8,125	93,957	112,102	0	766	112,868	18,911	36.94	48.57
ANAHMCT	46	1.5	6.1	61	241	122	424	302	122	0	424	0	49.93	49.92
CWAT12	146	39.3	503.0	2,328	14,871	3,361	20,560	24,448	0	48	24,496	3,936	34.19	48.70
CWTRCC	512	38.2	1,712.2	7,925	45,003	5,677	58,605	81,592	0	65	81,657	23,052	30.91	47.69
ELSG1234	1,020	11.8	1,055.8	6,045	34,153	13,657	53,855	50,321	0	490	50,811	-3,044	38.07	48.12
ELWOOD1	53	1.3	5.8	58	224	243	525	282	243	0	525	0	48.28	48.29
ETWAND34	670	22.9	1,342.5	7,687	42,142	7,100	56,929	65,541	0	269	65,810	8,881	37.12	49.02
ETWANDA5	138	0.6	7.7	76	394	439	909	470	439	0	909	0	61.38	61.36
HN12MA12	860	29.0	2,181.8	3,078	68,150	25,039	96,267	106,218	0	822	107,040	10,773	32.65	49.06
LNBCHCC	560	16.9	830.2	4,754	26,317	7,214	38,285	42,549	0	255	42,804	4,519	37.42	51.56
MNDALY3	140	0.8	9.8	98	500	393	991	598	393	0	991	0	60.84	60.90
ORMND1	750	27.1	1,777.9	10,180	54,992	7,135	72,307	85,794	0	348	86,142	13,835	36.66	48.45
ORMND2	750	25.5	1,677.8	9,607	52,279	7,135	69,021	81,157	0	156	81,313	12,292	36.88	48.46
REDNDO56	350	8.5	260.2	1,490	8,855	3,614	13,959	14,343	0	23	14,366	407	39.77	55.22
REDNDO78	960	29.2	2,452.2	14,041	75,154	9,913	99,108	116,634	0	755	117,390	18,282	36.37	47.87
VERNDSL	20	0.7	1.2	6	77	102	185	83	102	0	185	0	68.17	68.03
Thermal	**8,852**	**21.9**	**17,008.9**	**85,740**	**523,106**	**107,022**	**715,868**	**826,145**	**3,636**	**4,160**	**833,942**	**118,074**	**35.80**	**48.82**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**743,481**	**0**	**0**	**743,481**	**290,283**	**8.44**	**41.06**
Coal	**3,060**	**71.1**	**19,058.6**	**67,702**	**298,213**	**86,454**	**452,369**	**826,111**	**0**	**944**	**827,054**	**374,685**	**19.20**	**43.40**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**315,436**	**0**	**0**	**315,436**	**282,405**	**0.00**	**45.50**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**6,440**	**0**	**0**	**6,440**	**1,885**	**0.00**	**50.34**
DSM/SelfGen	**2,114**	**21.8**	**4,031.1**	**26**	**0**	**5,214**	**5,240**	**166,584**	**0**	**0**	**166,584**	**161,344**	**0.01**	**41.32**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**689,913**	**429,961**	**1,728,882**	**1,102,427**	**0**	**0**	**1,102,427**	**-626,455**	**48.74**	**41.37**
Total less QFs	**18,060**	**41.3**	**65,268.5**	**156,023**	**971,538**	**536,700**	**1,664,261**	**2,884,197**	**3,636**	**5,104**	**2,892,937**	**1,228,676**	**17.28**	**44.27**
Total	**22,682**	**46.3**	**91,915.8**	**765,031**	**1,661,451**	**966,661**	**3,393,143**	**3,986,624**	**3,636**	**5,104**	**3,995,364**	**602,221**	**26.40**	**43.43**

Table 3.12.15c Generation Cost and Revenues

Base Fuel Cost Case With Repowering Of Pitsbrg6 and Encn123

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.6	0.8	8	88	165	261	96	165	0	261	0	114.76	115.66
ENCINA45	615	17.9	965.1	9,209	31,750	13,533	54,492	50,340	0	491	50,831	-3,661	42.44	52.67
ENCN123R	400	21.0	734.3	7,007	22,384	4,063	33,454	36,355	0	4,210	40,564	7,110	40.03	55.24
KRNYGT23	132	1.2	14.0	131	693	1,363	2,187	824	1,363	0	2,187	0	58.88	58.86
MRMARGT	39	1.1	3.7	35	169	403	607	204	403	0	607	0	54.63	54.69
NRISLGT1	19	0.7	1.2	11	114	196	321	124	197	0	321	0	107.69	106.90
NTCKRNGT	33	1.2	3.4	32	161	341	534	194	340	0	534	0	56.27	56.40
NVLNRIGT	42	1.2	4.5	42	194	434	670	236	434	0	670	0	52.65	52.56
STHBAYGT	19	1.8	2.9	27	112	196	335	140	195	0	335	0	47.84	47.95
STHBY123	468	31.7	1,299.5	12,400	40,213	13,863	66,476	66,188	0	439	66,626	150	40.49	51.27
TWOGTS	32	0.9	2.5	23	122	330	475	145	330	0	475	0	57.94	58.00
Thermal	**1,815**	**19.1**	**3,031.9**	**28,925**	**96,000**	**34,887**	**159,812**	**154,846**	**3,427**	**5,140**	**163,411**	**3,599**	**41.20**	**52.77**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**137,864**	**0**	**0**	**137,864**	**53,899**	**8.75**	**41.06**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**17,934**	**0**	**0**	**17,934**	**14,787**	**5.65**	**42.15**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**50,678**	**4,396**	**65,153**	**76,475**	**0**	**0**	**76,475**	**11,322**	**32.87**	**41.38**
Total less QFs	**2,371**	**32.8**	**6,815.2**	**31,801**	**124,901**	**90,222**	**246,924**	**310,644**	**3,427**	**5,140**	**319,209**	**72,285**	**22.99**	**46.34**
Total	**2,608**	**37.9**	**8,663.4**	**41,880**	**175,579**	**94,618**	**312,077**	**387,119**	**3,427**	**5,140**	**395,684**	**83,607**	**25.10**	**45.28**

Table 3.12.16a Generation Cost and Revenues

Base Fuel Cost Case With 2000MW Coal Unit Added in SouthWest

Pacific Gas and Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
CCosta6	340	29.3	872.9	8,972	24,756	8,806	42,534	44,657	0	498	45,155	2,621	38.64	51.73
CCosta7	340	25.6	762.4	7,837	21,702	8,806	38,345	40,246	0	292	40,539	2,194	38.74	53.17
HntrsPt1	56	0.8	3.8	50	300	290	640	350	290	0	640	0	91.25	91.38
HntrsPt2	107	6.2	58.1	440	2,165	4,673	7,278	3,640	3,627	12	7,278	0	44.81	62.81
HntrsPt3	107	5.9	55.5	420	2,062	4,673	7,155	3,246	3,896	13	7,155	0	44.73	58.72
HntrsPt4	163	60.3	860.9	6,307	25,171	8,139	39,617	36,038	3,531	48	39,617	0	36.57	41.92
Humbld12	105	32.2	296.3	2,230	11,601	6,292	20,123	12,441	7,600	83	20,123	0	46.69	42.28
Mobil123	45	0.9	3.5	46	508	381	935	553	382	0	935	0	157.19	157.10
Morro12	326	27.6	788.3	6,714	24,240	6,120	37,074	45,869	0	359	46,228	9,154	39.27	58.65
Morro3	338	39.3	1,162.8	8,862	33,102	8,754	50,718	61,770	0	40	61,810	11,092	36.09	53.16
Morro4	338	43.4	1,286.0	9,801	36,059	8,754	54,614	66,931	0	145	67,075	12,461	35.66	52.16
Moss6	739	49.3	3,191.7	23,383	85,188	14,511	123,082	149,768	0	272	150,040	26,958	34.02	47.01
Moss7	739	59.7	3,865.1	28,316	100,776	14,511	143,603	174,384	0	493	174,877	31,274	33.40	45.25
Oakln123	192	0.5	9.0	116	1,066	419	1,601	1,182	419	0	1,601	0	132.00	132.07
Pitsbg5	325	35.3	1,005.5	7,663	28,730	8,423	44,816	48,375	0	92	48,467	3,651	36.19	48.20
Pitsbg6	325	36.3	1,032.5	7,869	34,340	8,423	50,632	51,287	0	0	51,287	655	40.88	49.67
Pitsbrg7	720	36.4	2,296.0	16,821	66,708	14,113	97,642	113,626	0	165	113,790	16,148	36.38	49.56
Pitsbu12	326	12.4	355.2	3,025	10,198	6,120	19,343	19,979	0	24	20,003	660	37.23	56.32
Pitsbu34	326	33.4	953.0	8,117	34,628	6,120	48,865	50,657	0	0	50,657	1,792	44.85	53.15
Potr456	168	0.7	10.2	133	1,198	1,152	2,483	1,331	1,152	0	2,483	0	130.22	130.23
Potrero3	207	60.6	1,099.0	8,376	31,689	5,361	45,426	45,428	0	156	45,584	158	36.46	41.48
Thermal	**6,332**	**36.0**	**19,967.7**	**155,498**	**576,187**	**144,841**	**876,526**	**971,758**	**20,897**	**2,692**	**995,344**	**118,818**	**36.64**	**48.80**
Nuclear	**2,160**	**89.5**	**16,939.4**	**47,789**	**134,323**	**261,662**	**443,774**	**729,101**	**0**	**0**	**729,101**	**285,327**	**10.75**	**43.04**
Hydro	**4,503**	**60.5**	**23,883.6**	**0**	**0**	**99,098**	**99,098**	**1,067,876**	**0**	**0**	**1,067,876**	**968,778**	**0.00**	**44.71**
Geo	**635**	**49.0**	**2,725.7**	**5,052**	**86,340**	**23,647**	**115,039**	**111,645**	**0**	**0**	**111,645**	**-3,394**	**33.53**	**40.96**
PumpStorage	**1,174**	**4.8**	**491.0**	**0**	**0**	**25,834**	**25,834**	**25,532**	**0**	**0**	**25,532**	**-302**	**0.00**	**52.00**
DSM & Solar	**518**	**0.3**	**12.7**	**45**	**0**	**186**	**231**	**536**	**0**	**0**	**536**	**305**	**3.55**	**42.27**
QF	**4,209**	**74.5**	**27,486.3**	**132,152**	**718,272**	**124,082**	**974,506**	**1,121,325**	**0**	**0**	**1,121,325**	**146,819**	**30.94**	**40.80**
Total less QFs	**15,322**	**47.7**	**64,020.0**	**208,384**	**796,850**	**555,268**	**1,560,502**	**2,906,448**	**20,897**	**2,692**	**2,930,034**	**1,369,532**	**15.70**	**45.44**
Total	**19,531**	**53.5**	**91,506.3**	**340,536**	**1,515,122**	**679,350**	**2,535,008**	**4,027,773**	**20,897**	**2,692**	**4,051,359**	**1,516,351**	**20.28**	**44.05**

Table 3.12.16b Generation Cost and Revenues

Base Fuel Cost Case With 2000MW Coal Unit Added in SouthWest

Southern California Edison Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
ALA7HNT5	276	1.0	23.0	229	1,169	2,336	3,734	1,397	2,337	0	3,734	0	60.86	60.84
ALAMIT34	640	21.5	1,204.1	6,894	38,113	5,417	50,424	68,977	0	268	69,245	18,821	37.38	57.51
ALAMIT56	960	29.8	2,508.9	14,366	78,329	8,125	100,820	128,057	0	957	129,014	28,194	36.95	51.42
ANAHMCT	46	1.9	7.7	78	307	122	507	385	122	0	507	0	50.26	50.26
CWAT12	146	41.6	532.2	2,463	15,781	3,361	21,605	27,227	0	20	27,247	5,642	34.28	51.20
CWTRCC	512	44.9	2,014.9	9,326	52,931	5,677	67,934	100,885	0	112	100,997	33,063	30.90	50.13
ELSG1234	1,020	14.7	1,309.6	7,498	43,184	13,657	64,339	72,065	0	572	72,637	8,298	38.70	55.47
ELWOOD1	53	1.5	7.1	71	273	243	587	344	243	0	587	0	48.51	48.52
ETWAND34	670	26.2	1,537.1	8,801	48,586	7,100	64,487	79,977	0	540	80,517	16,030	37.33	52.38
ETWANDA5	138	1.0	12.0	120	621	439	1,180	741	439	0	1,180	0	61.51	61.54
HN12MA12	860	32.6	2,458.1	3,467	76,795	25,039	105,301	131,628	0	1,110	132,738	27,437	32.65	54.00
LNBCHCC	560	20.6	1,008.3	5,774	31,884	7,214	44,872	56,001	0	340	56,342	11,470	37.35	55.88
MNDALY3	140	1.1	14.0	139	715	393	1,247	855	392	0	1,247	0	61.06	61.07
ORMND1	750	32.2	2,114.9	12,110	64,747	7,135	83,992	109,495	0	358	109,853	25,861	36.34	51.94
ORMND2	750	31.1	2,042.1	11,693	63,350	7,135	82,178	106,933	0	536	107,469	25,291	36.75	52.63
REDNDO56	350	10.1	309.4	1,771	10,520	3,614	15,905	20,963	0	48	21,011	5,106	39.73	67.92
REDNDO78	960	32.5	2,736.3	15,667	83,906	9,913	109,486	141,177	0	779	141,957	32,471	36.39	51.88
VERNDSL	20	0.9	1.6	8	99	102	209	107	102	0	209	0	68.17	68.59
Thermal	**8,852**	**25.6**	**19,841.1**	**100,475**	**611,310**	**107,022**	**818,807**	**1,047,214**	**3,635**	**5,640**	**1,056,491**	**237,684**	**35.87**	**53.06**
Nuclear	**2,326**	**88.9**	**18,109.4**	**2,555**	**150,219**	**300,424**	**453,198**	**776,725**	**0**	**0**	**776,725**	**323,527**	**8.44**	**42.89**
Coal	**3,060**	**70.9**	**19,000.9**	**68,165**	**297,901**	**86,454**	**452,520**	**858,729**	**0**	**4,721**	**863,450**	**410,930**	**19.27**	**45.44**
Hydro	**1,501**	**52.7**	**6,932.5**	**0**	**0**	**33,031**	**33,031**	**319,069**	**0**	**0**	**319,069**	**286,037**	**0.00**	**46.02**
PumpStorage	**207**	**7.1**	**127.9**	**0**	**0**	**4,555**	**4,555**	**6,935**	**0**	**0**	**6,935**	**2,380**	**0.00**	**54.21**
DSM/SelfGen	**2,114**	**21.8**	**4,031.2**	**60**	**0**	**5,214**	**5,274**	**173,016**	**0**	**0**	**173,016**	**167,742**	**0.01**	**42.92**
QF	**4,622**	**65.8**	**26,647.4**	**609,008**	**689,913**	**429,961**	**1,728,882**	**1,147,174**	**0**	**0**	**1,147,174**	**-581,708**	**48.74**	**43.05**
Total less QFs	**18,060**	**43.0**	**68,043.1**	**171,255**	**1,059,430**	**536,700**	**1,767,385**	**3,181,688**	**3,635**	**10,361**	**3,195,686**	**1,428,301**	**18.09**	**46.91**
Total	**22,682**	**47.7**	**94,690.5**	**780,263**	**1,749,343**	**966,661**	**3,496,267**	**4,328,862**	**3,635**	**10,361**	**4,342,860**	**846,593**	**26.71**	**45.83**

Table 3.12.16c Generation Cost and Revenues

Base Fuel Cost Case With 2000MW Coal Unit Added in SouthWest

San Diego Gas & Electric Units - 2006

Category	Capacity (MW)	Capacity Factor (%)	Energy (GWh)	Cost in $000 Var	Cost in $000 Fuel	Cost in $000 Fixed	Cost in $000 Total	Revenue in $000 Energy	Revenue in $000 Others Reserve	Revenue in $000 Others Spin	Revenue in $000 Total	in $000 Net Income	Energy $/MWh Avg. Var Cost	Energy $/MWh Avg. Rev.
DIVISGT	16	0.8	1.1	10	117	165	292	128	164	0	292	0	114.76	115.32
ENCIN123	321	10.5	294.8	2,813	10,163	8,150	21,126	19,777	0	224	20,002	-1,124	44.02	67.85
ENCINA45	615	19.3	1,040.4	9,928	34,374	13,533	57,835	60,049	0	1,270	61,318	3,483	42.58	58.94
KRNYGT23	132	1.4	16.3	153	813	1,363	2,329	966	1,363	0	2,329	0	59.19	59.19
MRMARGT	39	1.5	5.1	48	231	403	682	278	404	0	682	0	54.71	54.72
NRISLGT1	19	0.9	1.5	14	146	196	356	160	196	0	356	0	107.69	107.38
NTCKRNGT	33	1.5	4.3	40	201	341	582	241	341	0	582	0	56.10	56.05
NVLNRIGT	42	1.8	6.6	62	283	434	779	344	435	0	779	0	52.43	52.36
STHBAY4	222	3.0	58.8	561	2,226	5,524	8,311	5,566	0	0	5,566	-2,745	47.42	94.69
STHBAYGT	19	2.1	3.5	32	134	196	362	166	196	0	362	0	47.98	47.84
STHBY123	468	32.4	1,330.0	12,691	41,246	13,863	67,800	72,160	0	898	73,058	5,258	40.55	54.93
TWOGTS	32	1.1	3.1	29	150	330	509	179	330	0	509	0	58.38	58.50
Thermal	**1,958**	**16.1**	**2,765.4**	**26,381**	**90,084**	**44,498**	**160,963**	**160,014**	**3,429**	**2,392**	**165,835**	**4,872**	**42.11**	**58.73**
Nuclear	**430**	**89.1**	**3,357.8**	**474**	**28,901**	**54,590**	**83,965**	**143,848**	**0**	**0**	**143,848**	**59,883**	**8.75**	**42.84**
DSM/SelfGen	**126**	**38.7**	**425.5**	**2,402**	**0**	**745**	**3,147**	**18,602**	**0**	**0**	**18,602**	**15,455**	**5.65**	**43.72**
QF	**237**	**88.9**	**1,848.2**	**10,079**	**50,678**	**4,396**	**65,153**	**80,297**	**0**	**0**	**80,297**	**15,144**	**32.87**	**43.45**
Total less QFs	**2,514**	**29.7**	**6,548.8**	**29,257**	**118,985**	**99,833**	**248,075**	**322,464**	**3,429**	**2,392**	**328,285**	**80,210**	**22.64**	**49.61**
Total	**2,751**	**34.8**	**8,396.9**	**39,336**	**169,663**	**104,229**	**313,228**	**402,761**	**3,429**	**2,392**	**408,582**	**95,354**	**24.89**	**48.25**