Appendix A- Not available electronically.

Appendix B
Sierra Nevada Region
Customer Groups and Economic Regions

The list included in this appendix shows the Sierra Nevada Region customers with contracts expiring in the year 2004. The list indicates which customer group each customer is considered a part of for purposes of analysis. The list also shows which economic region each customer is located in. Some customers are not included in a subregion of the central and northern California region. Further discussion of the economic regions is included in Section 4.9.4 and in Appendix L.

Appendix C
Renewable Technology Cost Information Matrix

The development of the renewable technology matrix (RTM) was undertaken to determine the primary cost and performance characteristics of renewable technologies in the year 2005. These data were developed to provide input into a utility planning model (PROSYM), which used the cost and performance characteristics to select the most cost-effective generating alternatives to replace existing capacity, which may not be available in the future.

Ten different generating technologies were examined as part of this development effort:

- wind
- solar photovoltaic
- solar thermal
- geothermal
- biomass
- fuel cells
- battery storage
- hydropower
- pumped water storage
- compressed air storage.

The cost parameters examined for the different technologies include initial purchase cost, fixed O&M costs, variable O&M costs, and fuel cost, if applicable. The performance characteris tics initially examined include the capacity factor of the technology, an indication of whether or not the technology can produce firm power, an indication of how mature the technology is, and (if the technology consumes fuel) the heating value for the equipment.

C.1 Data Sources

Data on the cost and performance characteristics of the renewable energy sources were gathered from a variety of different sources:

- National Renewable Energy Laboratory Fact Sheet: http//www.nrel.gov/documents/erec_fact_sheets/rnwenergy.html
- Bonneville Power Administration (BPA). 1993. *Resource Programs Final Environ mental Impact Statement*. DOE/BP-2074, prepared for the U.S. Department of Energy by Bonneville Power Administration, Portland, Oregon.
- Stone & Webster Management Consultants Inc. 1993. *Resource Planning Guide, Volume 5: Reference Data*. Prepared for the Western Area Power Administration, Golden, Colorado.
- California Energy Commission (CEC). 1995. "Appendix A, Electricity Planning Assumptions." *1994 Electricity Report*. Sacramento, California.
- Burnham, L. 1993. *Renewable Energy: Sources for Fuels and Electricity*. Island Press, Washington, D.C.
- National Renewable Energy Laboratory. 1995 (draft). *Energy Resource Cost Data*. Prepared for the Western Area Power Administration, Golden Colorado.
- Wan, Y. H., and S. Adelman. 1994 (draft). *Distributed Utility Technology Cost, Performance and Environmental Characteristics.* National Renewable Energy Laboratory, Golden, Colorado.

C.2 Comprehensive Characteristics Matrix

Table C.1 presents a list of these renewable technologies with available cost and performance characteristics and the source of the data. The first column of Table C.1 provides an entry number to identify the individual line items in the table. Column 3 of the table provides a key which refers to the source of the data. The key is explained at the end of Table C.1.

C.3 Summary Matrices

While Table C.1 provided a useful first cut at examining the various characteristics for each technology, the utility planning model (PROSYM) that was used on the project needed input in the form of a single estimate for the cost and performance characteristics for each technology. PROSYM was run separately for 1995 and 2005 and therefore required unique inputs for these years. The inputs from Table C.1 used to generate data for each year are listed in Table C.2. The data for the years 1995 and 2005 are summarized in Tables C.3 and C.4, respectively.

Because the data needed to be combined from several sources, the following procedural steps were implemented:

Step 1:Data that appeared to be outliers from the other data were treated as missing values and removed from the analysis.

Step 2:Cells that had no values entered were treated as missing values and removed from the analysis.

Step 3:For entries that had a range of values in a single cell, the midpoint was chosen as the value for the entry. For example, if an entry indicated a range of values from 5,600 to 8,400, the midpoint value of 7,000 was used as representative of the range.

Step 4:The remaining values, including the new representative values from Step 3, were averaged together to obtain a single estimate for each technology, characteristic, and year of interest.

Table C.2 presents a list of entry numbers (as listed in column 1 of Table C.1) that were included in the averaging process for both 1995 and 2005. After examining Table C.2, it became obvious that there are many more sources of data available for generation costs in 1995 than in 2005, as might be expected. One issue that was not examined in this paper is what effect these sample sizes have on the uncertainty of the values presented in Tables C.3, C.4, C.5, and C.6.

C.4 Economic Normalization

While summary Tables C.3 and C.4 were useful for the project, one more step was required to ensure that the data were consistent with other data being used by the PROSYM model. Since all of the cost numbers used in the model were in 2005 dollars, all of the cost numbers needed to be updated in both Tables C.3 and C.4 to 2005 dollars. Upon examination of Table C.1, it is evident that various sources reported cost values using different base years for the dollars. To normalize the costs from the base years to 2005 dollars, it was assumed that there would be a 3-percent monetary inflation rate per year. The equation below was then applied to deter mine the multiplier for each entry, based upon the base year dollars used in that entry.

where n is the number of years from the base year to 2005.

After the original cost estimates from Table C.1 were updated to either 1995 or 2005 dollars, summary Tables C.3 and C.4 were regenerated as Tables C.5 and C.6, respectively.

Table C.1. Renewable and Emerging Technology Comprehensive Matrix

Entry	Renewable Technology	Data Source	Purchase Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)	Fuel Cost ($/MMBtu)	Production Cost ($/kWh)	Capacity Factor	HHV Heat Rate (Btu/kWh)
1	**Wind**	2	1,000			N/A	0.05-0.08	15-35	N/A
2	**Utility Scale**	4	1,072	18	1	N/A	0.059	27	
3	**San Gorgonio & Tehachapi - SCE**	5	797	14	7.4-12.5	N/A			
4	**Wind Park - SDG&E**	5	1,302	65	13	N/A			
5	**California**	6	1,000	21	d	N/A	0.053	24	
6	**NREL (1994 $)**	7	1,440	a	10	N/A	0.043-0.07		
7	**NREL (1993 $, 2005 est.)**	7	742	a	7	N/A	0.038		
8	**NREL (1993$)**	8	1,000	a	13	N/A		28	
9	**NREL (1993$, 2000 est.)**	8	950	a	10	N/A		30	
10	**NREL (1993$, 2010 est.)**	8	850	a	8	N/A		33	
11	**Utility/Variable Speed**	5	863	0	12.4	N/A			N/A
12	**California**	6	760	24	d	N/A	0.043	25	
13	**Residential**	4	3,900	20	1	N/A	0.136	35	N/A
14	**Photovoltaics**	2				N/A	0.25-0.50	15-20	N/A
15	**Utility Scale**	4	9,375	100	1.0	N/A	0.429	21	
16	**NREL (1993 $, no storage)**	7	5,600-8,400	a	15-45	N/A	0.44-0.66		
17	**NREL (92-93 $, no storage, 2005 est.)**	7	1,200-3,305	a	1.5-16	N/A	0.075-0.255		
18	**Centralized Solar PV - SDG&E**	5	7,000	10	3.1	N/A			
19	**Distributed Solar PV - SDG&E**	5	3,800	10.2	B	N/A			
20	**NREL (1990 $)**	8	4,680-7,380	a	4-11	N/A			
21	**NREL (1990$, 2000 est.)**	8	3,060-5,060			N/A			

22	**NREL (1990$, 2010 est.)**	8	2,300-3,300	a	1-4	N/A			
23	**Residential**	4	9,500	100	1.0	N/A	0.597	16	N/A
24	**Solar Thermal**					N/A	0.05-0.08		N/A
25	**Generic**	4	2,888	100	10	N/A	0.22	26	
26		5	3,780	51.6	N/A	N/A			
27	**Solar Central Receiver (60% CF)**	5	2,735-2,886	29.8-40.7	N/A	N/A			
28	**Solar Central Receiver (40% CF)**	5	2,200-2,569	23.3-30.4	N/A	N/A			
29	**First Plant (1995)**	6	3,000-4,000	a	13-19	N/A	0.080-0.161	8-15	
30	**NREL (1992 $)**	7	3,000-4,000	a	13-19	N/A	0.080-0.161		
31	**Advanced Receiver (2005-2010)**	6	1,800-2,500	a	8.0-12	N/A	0.045-0.082	32-43	
32	**NREL (1992$, 2005 est.)**	7	2,225-3,000	a	8.0-12	N/A	0.058-0.101		
33	**Parabolic Trough without Gas**	5	3,223	48.5	9.2	N/A			N/A
34	**NREL (1992$)**	7	2,800-3,500	a	18-25	N/A	0118-0.167		
35	**NREL (1992$, 2004 est.)**	7	2,000-2,400	a	13-20	N/A	0.079-0.117		
36	**Parabolic Trough w/Gas (current)**	5	2,678-3,500	37-55.5	3.8-9.2	2.83			9,332-10,800
37	**Present (1991)**	6	2,800-3,500	a	18-25		0.093-0.130	22-25	
38	**NREL (1991$)**	7	2,000-3,708	c	8.0-22.2	c	0.051-0.147		
39	**Parabolic Trough w/Gas (future)**	5	2,226	29.5	2.5	2.83			
40	**2000-2005**	6	2,000-2,400	a	13-20		0.065-0.093	22-27	
41	**PV Concentrator**	5	6,000	9.1-12.7	N/A	N/A			N/A

	(generic)								
42	**Stirling Dish**	5	1,406	30.4	N/A	N/A			N/A
43	**NREL (1992 $, 2005 est.)**	7	2,000-3,500	a	20-30	N/A	0.088-0.168		
44	**NREL (1995-2000 est.)**	8	3,000-5,000	a	25-50	N/A		16-22	
45	**NREL (2000-2005 est.)**	8	2,000-3,500	a	20-30	N/A		20-26	
46	**Solar Thermal Pond**	5	4,600	75	b	N/A			N/A
47	**Geothermal**	2	2,600			N/A	0.03-0.075	80	
48	**Generic**	3	3,000			N/A			
49	**Single Flash**	5	3,126	97	4.08	N/A			14,755
50	*Double Flash*	4	2,000	40	7.5	N/A	0.046	92	
51		5	2,875-3,200	97-243	6.2-9	N/A			12,830-17,691
52	**NREL (1992 $)**	7	1,217	a	5.0	N/A	0.019		
53	**Modular Binary**	4	2,400	48	9.0	N/A	0.056	92	
54	**Imperial & Mono Counties**	5	3,152-3,700	174	14	N/A			23,000
55	**NREL (1993 $)**	7	3,590	a	16	N/A	0.067		
56	**NREL (1993 $, 2005 est.)**	7	2,220	a	11	N/A	0.040		
57	**Steam**	4	1,600	13	1.3	N/A	0.024	95	
58	**Modular Double Flash**	4	1,600	40	5.0	N/A		92	
59	**Biomass**								
60	**MSW 200-400 Ton/Day**	4	4,000	140	15-15.4	-4.5	0.007	80	17,500
61	**MSW Generic**	5	5,886	144	13.5	-2.0			17,206
62	**RDF 400 Ton/Day**	4	4,000	140	15	-4.5	0.014	80	14,500
63	**Ag/Forest Waste**	5	1,286-2,086	24-28	4.2-4.6				15,205-19,154
64	**Fuel Cells**								
65	**Phosphoric Acid**	1	1,200						
66		4	1,800	16	2.0	2.0	0.062	80	8,300

67		5	1,968-2,986	7.6-7.7	11.0	2.83			8,300
68	**Molten Carbonate**	5	1,218-1,602	6.2-17.2	0.2-12.5	2.83			6,350-6,908
69	**NREL (2000 estimate)**	8	1,332	9.8	1.7				
70	**Gas/Biomass - SMUD**	6	849	23.3	6.6	2.6			7,087
71	**Battery Storage**	**8**	**830-1,080**	**a**	**7.6**				
72	**Hydro**	3	1,059-2,336			N/A	0.02-0.043	50-58	N/A
73		4	2,000	5	N/A	N/A	0.057	40	
74	**Pumped Hydro Storage**	5	546-1,050	4-7	9-9.3	Storage			N/A
75	**Lorella - LADWP**	5	340	10.8	2.9				
76	**Compressed Air Storage**	8	621	1.4	2.3	2.83			4,100-4,396

Sources:

1. Power-Gen ?94 Proceedings
2. NREL Fact Sheets
3. BPA Final Environmental Impact Statement Resource Programs, Volume 1: Environmental Analysis
4. Western Area Power Administration Resource Planning Guide, Volume 5: Reference Data; values are in 1993 $
5. Appendix A of the 1994 Electricity Report (ER 94), Electricity System Planning Assumptions; values in 1991 $

The installed costs do not include transmission costs.

- Renewable Energy: Sources for Fuels and Electricity, Island Press, 1993. Values in 1991 $
- NREL draft report for Western on conventional and renewable generating technologies.
- Draft NREL Report - "Distributed Utility Technology Cost, Performance and Environmental Characteristics"

Notes:

[a] - Fixed O&M costs included in variable O&M costs.

[b] - Included in fixed cost. Operation and maintenance costs were estimated in the EPRI TAG as a percentage of installed facility capital cost.

[c] - Fixed O&M and fuel costs included in variable O&M costs.

[d] - Variable O&M costs included with fixed costs.

CF = capacity factor

HHV = high heat value method

LADWP = Los Angeles Department of Water and Power

MSW = municipal solid waste

NREL = National Renewable Energy Laboratory

RDF = refuse-derived fuel

SCE = Southern California Edison

SDG&E = San Diego Gas and Electric

SMUD = Sacramento Municipal Utility District

Table C.2. Table C.1 Entries Included to Produce Tables C.3 and C.4

Technology	1995 Entries[a]	2005 Entries[a]
Wind	2-6, 8	7, 9-10
Solar Photovoltaics	14-16, 18-20	17, 21-22
Solar Thermal Solar Central Receiver Parabolic Trough without Gas Assist Parabolic Trough with Gas Assist Stirling Dish	27-30 33-34 36-38 42, 44	31-32 35 39-40 43, 45
Geothermal Single Flash Double Flash Modular Binary	49 50-52, 58 53-55	-- -- 56
Biomass Municipal Solid Waste/Refuse Derived Waste Agricultural/Forest Waste	60-62 63	-- --
Fuel Cells Phosphoric Acid Molten Carbonate	65-67 68-69	-- --
Hydropower	72-73	--
Pumped Hydropower Storage	74-75	--

Note: A dash (--) indicates that no data were available for averaging to obtain a summary value. [a] Entries are identified by line number from Table C.1.

Table C.3. 1995 Renewable and Emerging Technology Summary Matrix in Mixed Dollars

Renewable Technology	Purchase Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)	Fuel Cost ($/MMBtu)	Production Cost ($/kWh)	Capacity Factor
Wind	1102	19.7	7.8	0.00	0.056	26.3
Solar Photovoltaics	6641	24.0	8.3	0.00	0.451	19.3
Solar Thermal						
Solar Central Receiver	3051	15.5	8.0	0.00	0.120	11.5
Parabolic Trough without Gas	3187	24.3	15.4	0.00	0.143	--
Parabolic Trough with Gas	3982	15.4	14.3	2.83	0.106	23.5
Stirling Dish	4000	15.2	18.8	0.00	--	19.0
Geothermal						
Single Flash	3126	97.0	4.1	0.00	--	--
Double Flash	1964	62.5	6.3	0.00	0.033	92.0
Modular Binary	3139	74.0	13.0	0.00	0.062	92.0
Biomass						
Municipal Solid Waste/Refuse Derived Fuel	4629	141.3	14.6	-3.67	0.011	80.0
Agricultural/Forest Waste	3372	26.0	4.4	--	--	--
Fuel Cells						
Phosphoric Acids	1826	11.8	6.5	2.42	0.062	80.0
Molten Carbonate	1371	10.8	4.0	2.83	--	--
Hydro	1849	5.0	0.0	0.00	0.045	47.0
Pumped Hydro Storage	569	8.2	6.0	0.00	--	--

Notes: A dash (--) indicates that data is not available for these values.

Table C.4. 2005 Renewable and Emerging Technology Summary Matrix in Mixed Dollars

Renewable Technology	Purchase Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)	Fuel Cost ($/MMBtu)	Production Cost ($/kWh)	Capacity Factor
Wind	847	0.0	8.3	0.00	0.038	31.5
Solar Photovoltaics	3037	0.0	5.6	0.00	0.150	--
Solar Thermal						
Solar Central Receiver	2381	0.0	10.0	0.00	0.072	37.5
Parabolic Trough without Gas	2200	0.0	16.5	0.00	0.098	--
Parabolic Trough with Gas	2213	14.8	9.5	2.83	0.079	24.5
Stirling Dish	2750	0.0	25.0	0.00	0.128	23.0
Geothermal						
Single Flash	--	--	--	--	--	--
Double Flash	--	--	--	--	--	--
Modular Binary	2220	0.0	11.0	0.00	0.040	--
Biomass	--	--	--	--	--	--
Fuel Cells	--	--	--	--	--	--
Hydro	--	--	--	--	--	--
Pumped Hydro Storage	--	--	--	--	--	--

Notes:
A dash (--) indicates that data is not available for these values.

Table C.5. 1995 Renewable and Emerging Technology Summary Matrix in 2005 Dollars

Renewable Technology	Purchase Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)	Fuel Cost ($/MMBtu)	Production Cost ($/kWh)	Capacity Factor
Wind	1626	29.9	11.6	0.00	0.082	26.3
Solar Photovoltaics	9943	35.0	12.3	0.00	0.706	19.3

Solar Thermal						
Solar Central Receiver	4634	23.8	12.1	0.00	0.182	11.5
Parabolic Trough without Gas	4813	37.2	23.0	0.00	0.212	--
Parabolic Trough with Gas	4647	23.6	22.0	4.39	0.161	23.5
Stirling Dish	5948	23.3	27.9	0.00	--	19.0
Geothermal						
Single Flash	4792	148.7	6.3	0.00	--	--
Double Flash	2951	94.9	9.4	0.00	0.047	92.0
Modular Binary	4630	112.0	19.2	0.00	0.089	92.0
Biomass						
Municipal Solid Waste/Refuse Derived Fuel	6853	208.2	21.4	-5.35	0.015	80.0
Agricultural/Forest Waste	2585	39.9	6.7	--	--	--
Fuel Cells						
Phosphoric Acid	2692	17.4	9.9	3.61	0.089	80.0
Molten Carbonate	2071	16.3	6.1	4.34	--	--
Hydro	2666	7.2	0.0	0.00	0.064	47.0
Pumped Hydro Storage	872	12.5	9.2	0.00	--	--

Notes:
A dash (--) indicates that data is not available for these values.

Table C.6. 2005 Renewable and Emerging Technology Summary Matrix in 2005 Dollars

Renewable Technology	Purchase Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)	Fuel Cost ($/MMBtu)	Production Cost ($/kWh)	Capacity Factor
Wind	1222	0.0	12.0	0.00	0.055	31.5
Solar Photovoltaics	4703	0.0	8.3	0.00	0.238	--

Solar Thermal						
Solar Central Receiver	3590	0.0	15.1	0.00	0.108	37.5
Parabolic Trough without Gas	3271	0.0	24.5	0.00	0.146	--
Parabolic Trough with Gas	3393	22.6	14.6	4.39	0.121	24.5
Stirling Dish	4089	0.0	37.2	0.00	0.190	23.0
Geothermal						
Single Flash	--	--	--	--	--	--
Double Flash	--	--	--	--	--	--
Modular Binary	3201	0.0	15.9	0.00	0.058	--
Biomass	--	--	--	--	--	--
Fuel Cells	--	--	--	--	--	--
Hydro	--	--	--	--	--	--
Pumped Hydro Storage	--	--	--	--	--	--

Notes:
A dash (--) indicates that data is not available for these values.

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Appendix D
Hydrological Assumptions

The attached memorandum describes the major assumptions used by Water Resources Management Incorporated in its PROSIM modeling studies in support of the 2004 EIS.

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Appendix E
Recreation Resources Along River Reaches and the Sacramento-San Joaquin Delta

This appendix describes recreation resources along the reaches of the Sacramento, Trinity, American, and Stanislaus rivers and the Delta.

E.1 Sacramento River

The Sacramento River between Keswick Dam and the Delta is approximately 300 miles long. To facilitate the discussion of recreation, the river was divided into three reaches: Keswick Dam to Lake Red Bluff (upper reach), Lake Red Bluff to the confluence with the Feather River (middle reach), and Feather River to the Delta (lower reach).

The origin of visitors to the Sacramento River has been estimated for all river uses. Most visitors originate from Shasta, Tehama, Glenn, Butte, Colusa, Sutter, Yolo, and Sacramento counties (77 percent); followed by the San Francisco Bay Area (9 percent); Southern California (5 percent); the San Joaquin Valley (1.5 percent); other California counties (3.5 percent); and out of state (4 percent) (California 1982). Data on the origin of anglers show an even greater local visitation rate, with most visitors originating from the river counties (84 percent); followed by the San Francisco Bay Area (7.5 percent); Southern California (2.5 percent); San Joaquin Valley (2 percent); and other California counties and out of state (4 percent).

E.1.1 Upper Reach

Although most of the upper reach flows through private lands, public access is more readily available than along the middle and lower reaches. Fishing is the most popular water-dependent activity on this reach. Water-contact activities, such as swimming and tubing, are not popular in this reach because the water is cold and flows swiftly. Popular water-enhanced activities include picnicking and relaxing.

Total estimated use on the upper reach of the river in 1980 was 1.4 million recreation hours. Boat fishing was the most popular water-dependent activity, followed by swimming and beach use. Other water-enhanced activities include relaxing and camping.

Recent angler surveys conducted for the U.S. Fish and Wildlife Service (Service) indicate that salmon, steelhead, and trout were the most frequently caught fish species on the upper reach. From July 1, 1991, to June 1, 1992, fishing effort in this reach totaled approximately 261,300 hours. Fishing for salmon accounted for the largest percentage of fishing effort (48 percent), followed by trout (45 percent) and steelhead (4 percent).

E.1.2 Middle Reach

The middle reach, between Lake Red Bluff and the confluence with the Feather River, is a 160-mile segment of the river characterized by slower moving water and a meandering river channel lined with riparian thickets and orchards. Although most land along this reach is privately owned, public access is provided by counties through which the river passes and by the State of California. Private facilities, primarily fishing access points, marinas, and resorts, are located along the entire reach.

Water-dependent activities in this reach include boat and shore fishing and swimming and beach use. Water-contact activities, such as swimming and tubing, are popular in this reach because the water is relatively warm compared to the upper reach. Water-enhanced activities include camping and relaxing.

Total recreation use on the middle reach of the river was estimated at 1.3 million recreation hours in 1980. Fishing was the most popular water-dependent activity.

Angling surveys conducted for the Service on the middle reach indicate that this segment supports the widest variety of game fish. Salmon, steelhead, trout, American shad, striped bass, sturgeon, and catfish are typically caught on this reach. From July 1, 1991, to June 1, 1992, fishing effort in the middle reach totaled approximately 277,600 hours. Fishing for salmon accounted for approximately 30 percent of this effort, followed by striped bass (22 percent), American shad (19 percent), sturgeon (9 percent), steelhead (7 percent), catfish (4 percent), and trout (3 percent).

E.1.3 Lower Reach

The lower reach, between the confluence with the Feather River and Courtland, is an 80-mile segment of the river. The upper 20 miles are characterized by slow-moving water and a meandering river channel (California 1982). Near Sacramento, the character of the river changes because of urban influences, such as levees and commercial development along the river. Between Sacramento and Courtland, the river passes through agricultural areas.

The City and County of Sacramento and the State of California provide public access points along the lower reach. Private facilities, primarily marinas, are located along the entire reach. Fishing and boating are popular water-dependent activities on this reach. Water-contact activities, such as swimming and beach use, are also popular. Water-enhanced activities include picnicking and relaxing. Estimated use on the lower reach of the river in 1980 totaled 2.1 million visitor hours. Salmon, steelhead, American shad, striped bass, sturgeon, and catfish are caught on this reach. From July 1, 1991, to June 1, 1992, fishing effort in the lower reach totaled approximately 512,200 hours. Fishing for striped bass accounted for approximately 33 percent of this effort, followed by salmon (23 percent), sturgeon (17 percent), catfish (13 percent), steelhead (9 percent), and American shad (2 percent).

The quality of recreation on the river is sensitive to water and air temperatures and the presence of game fish because water-contact activities are affected by air and water temperature, and fishing activity occurs in response to the presence of fish in the river. Changes in flows do not normally affect recreation activities except when those changes may also affect water temperature. Water-dependent activities may occasionally be directly affected by lower flows as boating hazards, such as snags, are exposed.

E.2 Trinity River

The Trinity River between Lewiston Dam and its confluence with the Klamath River is a sinuous 110-mile-long mountain river. Recreation development areas along the river consist of commercial campgrounds, resorts, and lodges; public campgrounds and picnic areas; and fishing access sites. Approximately 34 developed recreation sites are located within a 0.5-mile corridor of the Trinity River.

Water-dependent and water-enhanced activities on the Trinity River include boating, kayaking, canoeing, rafting, tubing, fishing, swimming and wading, camping, gold panning, nature study, picnicking, and sightseeing.

Boating, kayaking, canoeing, and rafting were popular during the 1988-1992 drought when Trinity River flows were maintained and other river water levels were down. Boating access is limited to only a few pool areas of the Trinity River. Most of the river and access to the river is suitable for kayaking, canoeing, and rafting. More than 100 access points for kayaking, canoeing, and rafting are available on the 114-mile river reach. Almost the entire river is suitable for rafting.

Fishing is a major recreation attraction on the Trinity River. Resident and stocked sport fish include rainbow and brown trout. Anadromous fish such as king salmon, silver salmon, and steelhead rainbow trout spawn in the river primarily in fall and winter. Salmon runs peak in September and October, and steelhead run mainly in fall and winter. Warmwater species such as bass and sunfish are also found in the river. Most of the swimming, wading, and beach use occur between May and September. Water temperatures during summer vary from 57F at Lewiston Dam to 87F below the mainstem confluence with North Fork Trinity River. Swimming is popular at several sites.

Other passive activities often associated with camping or passing through (e.g., picnicking, nature study, hiking, and sightseeing) occur along the Trinity River.

Most of the water-dependent recreation on the Trinity River occurs between May and September. Because of the dispersed nature of recreation on the river, use has not been estimated for the entire river from Lewiston Dam to its confluence with the Klamath River. Several recreation surveys have been conducted for portions of the river from Lewiston Dam to the North Fork Trinity River confluence and in the Big Bar Ranger District. In 1977, total recreation use on the mainstem Trinity River from Lewiston Dam to the north fork was estimated to be 175,000 recreation hours during the summer recreation season. Camping, swimming, and fishing are the most popular activities along the river.

Approximately 51 percent of the visitors to the Trinity River in 1977 originated from the Trinity River Basin Region (Trinity, Shasta, and Humboldt counties), approximately 16 percent originated from the Sacramento Valley, 25 percent from the Bay/Delta Region, and approximately 9 percent from Southern California.

Flows in the Trinity River seldom fluctuate because they are regulated by releases from Lewiston Dam. Consequently, the impact of fluctuating flows on recreation quality and opportunities is uncertain. However, a recreation user survey conducted on the river during the 1976-1977 drought indicated that only 9 percent of the respondents recreated at the river because of the perception of adequate stream flows. The most common reasons identified for recreation on the Trinity River were good fishing conditions (18 percent) and proximity (17 percent). The user survey suggests that normal fluctuation of Trinity River flows does not substantially affect visitation.

E.3 American River

The American River Parkway, a 23-mile-long river corridor, crosses the Sacramento metropolitan area between Nimbus Dam and its confluence with the Sacramento River at Discovery Park. The parkway, managed by the Sacramento County Parks and Recreation Department, is recognized as one of the nation's premier urban parkways.

The river corridor, an approximately 6,000-acre open space area, consists of a broad river channel with dense riparian vegetation. It features 28 automobile access points and 68 access points for pedestrians, equestrians, and bicyclists. The Jedidiah Smith Trail provides bicycle, pedestrian, and equestrian trails from Discovery Park to the Folsom Lake. The parkway includes a series of 14 parks distributed on publicly owned lands.

Water-dependent recreation activities on the American River include rafting, boating, fishing, swimming, and wading. Water-enhanced activities include picnicking, hiking, bicycling, jogging, nature study, and equestrian recreation. Recreation along the river remains popular year-round.

Estimated use of the American River and its parkway totaled approximately 5.5 million visitors in 1988. Use is expected to increase to 7.5 million visitors by 2000 as the population of the Sacramento metropolitan area increases. Approximately 75 percent of parkway use occurs between March and September.

The American River supports a substantial anadromous fishery, including salmon and steelhead runs. From July 1, 1992, to June 30, 1993, the Service recorded approximately 163,000 angler hours. Of this total, salmon fishing accounted for approximately 46 percent of angler effort and steelhead fishing accounted for approximately 12 percent of angler effort. Trout and striped bass fishing each accounted for 7 percent of angler effort, and shad fishing accounted for 6 percent of total angler effort during this period.

Because the American River flows through a major urban area, recreation use remains high regardless of flows; however, water-dependent activities, such as rafting and fishing, are affected by the river's flow and temperature.

Seasonal American River temperatures and river flows affect commercial rafting. Rafting declines when ambient temperatures are cold, even during the peak recreation season. On the lower American River, a minimum stream flow of 2,000 cubic feet per second (cfs) is needed to support rafting, kayaking, and canoeing. Approximately 1,500 cfs is needed to support wading and swimming activities. Fishing success depends on the temperatures and flows of the river.

E.4 Stanislaus River

The reach of the Stanislaus River between New Melones Dam and its confluence with the San Joaquin River is 60 miles long. The river traverses primarily private agricultural and grazing land. Approximately 10 developed public parks and 6 undeveloped parks are provided on the Stanislaus River. Public access to the river is dispersed at numerous road crossings. Access for a white water rafting run is provided just below Goodwin Dam. The 4-mile-long white water run between Goodwin Dam and Knights Ferry is rated Class II-VI (advanced) with several difficult portages. Other river activities include fishing, swimming, picnicking, and camping.

In 1992, the U.S. Army Corps of Engineers estimated recreation use of the lower Stanislaus River below Goodwin Dam at 1.095 million visitor hours. Use at recreation facilities on or near the Stanislaus River has increased substantially since 1980 because of increased park development along the river. Most of the riverside parks are believed to serve local county residents; however, Caswell Memorial State Park is considered a regional park capable of attracting non-local visitation. The quality of recreation on the Stanislaus River is affected by river flows. White water rafting below Goodwin Dam occurs when major flows are not diverted for irrigation. Use at developed parks along the river is also believed to be affected by river flows.

E.5 The Delta

Many water-dependent and water-enhanced activities occur in the Bay-Delta Region. The California Department of Water Resources recently estimated annual use in the Delta at 12 million user days. Fishing, one of the most popular activities in the Bay-Delta Region, accounts for an estimated 15 percent of total recreation visits. The most important activity in the region is boating (not including fishing), accounting for an estimated 17 percent of all visits, followed by fishing, relaxing (12 percent), sightseeing (11 percent), and camping (8 percent). An estimated 77 percent of recreationists in the Bay-Delta Region originate from the local area.

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Appendix F
Archaeological and Historical Resources

Tables F.1 through F.4 in this appendix contain lists of archaeological and historical sites in the areas surrounding the Lewiston Reservoir, Keswick Reservoir, Lake Natoma, and Tulloch Reservoir.

Table F.1. Cultural Properties Surrounding Lewiston Reservoir[a] (NOT AVAILABLE)

Table F.2. Cultural Properties Surrounding Keswick Reservoir[a] (NOT AVAILABLE)

Table F.3. Cultural Properties Surrounding Lake Natoma[a] (NOT AVAILABLE)

Table F.4. Cultural Properties Surrounding Tulloch Reservoir[a] (NOT AVAILABLE)

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[a] Cultural property information was provided from a records search completed at the Central California Information Center, Department of Anthropology, California State University, Stanislaus.

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Appendix G
Incremental Power Resources

Emphasis is placed on the likely alteration of generation patterns resulting from changes in how the Sierra Nevada Region dispatches its hydroelectric resources. In addition to these Federal hydroelectric facilities, there is a much broader system of electric generation and transmission that the Sierra Nevada Region interacts with in its marketing program. For perspective, Sierra Nevada Region power makes up less than 10 percent of the total power marketed in northern and central California. However, Sierra Nevada Region's interactions could extend over the entire West Coast and into the interior Desert Southwest. The Sierra Nevada Region has also historically been active in the Pacific Northwest with purchases and exchanges of power.

The western states include hundreds of power plants that may contribute energy to the Sierra Nevada Region and its customers. The Sierra Nevada Region's marketing plan is likely to affect only those generation resources that might be used to firm its Federal hydropower or make up for lost generation or capacity. In 2004, the total annual Western Systems Coordinating Council (WSCC) load is projected to be nearly 834,000 gigawatt hours (GWh). By comparison, Sierra Nevada and its customers have a total load of

27,000 GWh, about 3 percent of the total WSCC load. Complicating matters further, nearly 30 percent of the energy production in the PROSYM model is comprised of a blend of market resources. These resources represent contracts from other regions, inter-area power and energy exchanges, and economy purchases. Approximately 2 percent of all generation in the WSCC is directly modeled in PROSYM as technology-specific generation resources, making it difficult to link Sierra Nevada Region actions with changes in the operation of specific thermal power plants. Therefore, for the purposes of estimating air quality implications of the various alternatives, only the differences between alternatives are analyzed. Estimates of the relative emission factors representing incremental resources are applied to differences in hourly hydroelectric output, which is described as follows.

If there is a change in the PROSYM model for these external power purchases, the operators of these power plants will not necessarily change their operations. The operators may elect instead to market this displaced power to other customers at either the same or a slightly altered rate. This in turn will cause changes in the purchase of power from other plants, inducing a "domino effect" from Sierra Nevada's decision on how they operate their hydroelectric resources or altering purchasing patterns. These changes will ripple through the WSCC and may result in changes in the operation of power plants far removed from the northern California region.

Incremental resources are a function of season and peak/off-peak times during the day and are represented by combinations of CT and CCCT resources. Marginal heat rates serve as a basis for determining market power rates in PROSYM and are used to estimate the effective time-of- use incremental resource. The average marginal heat rates by month and peaking period are shown in Table G.1.

Table G.1. Marginal Heat Rates and Incremental Market Resources (NOT AVAILABLE)

The power market is assumed to be an open market condition. In this market, the Sierra Nevada Region and its customers are assumed to have the same market access and the same price structure in their power purchases. As a result, if the Sierra Nevada Region chooses not to purchase additional power from other suppliers to meld with its hydroelectric resources, Sierra Nevada Region customers can go into the market and buy power from the same suppliers at the same price.

Exactly how power transactions will contractually take place in 2005 is unknown. Power markets are evolving that may allow more competitive wholesale and retail purchases of electricity. These changes will likely give more consumers access to more electricity suppliers. Decisions by Sierra Nevada on how to market its power are not likely to affect the outcome of how these markets develop.

The marginal heat rates used in the PROSYM analysis reveal market conditions that are likely to shape the incremental power generating resources comprised of each resource.

This forms the basis for determining the incremental resources, by time of use, for the incremental provider of power for each region, calculated as follows:

- A 20 percent "transaction cost" is subtracted from the equivalent marginal heat rate to account for transmission losses and markups imbedded in the delivered cost of energy. This approximates the average power production technology for each time-of-use period in which economy purchases are aggregated.
- Equivalent heat rates greater than 10,000 Btu/kWh are assumed to be provided by CT resources; equivalent heat rates of 7,500 Btu/kWh or less are assumed to be provided by CCCT power plants. Equivalent heat rates between these extremes are scaled proportionately. The fractional contribution for each of these technologies is the number of hours during the total time period in which the incremental technology is represented by either a CT or a CCCT.
- Regardless of the outcome from the scaling algorithms described above, a minimum 10 percent average CT resource is assumed during any on-peak period. This takes into account that CT resources are anticipated to be dispatched at least some fraction of time to meet peak load during each month.
- A weighted average takes into account that for each 168-hour week, there are 75 hours on-peak (6 am - 9 pm weekdays) and 93 hours off-peak.

The incremental resources derived from these procedures are given in Table G.1. All off-peak production would be CCCT. The annual average CT fraction of the market resource amounts to 26 percent. CCCTs account for 74 percent of the market resource.

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Appendix H
Air Quality Regulatory Structure

Air quality requirements are promulgated and regulated by Federal, State, and local officials. This appendix describes the air quality regulatory structure in the study area. This includes Federal and State standards applicable in California and the other regions that may be directly or indirectly affected by Sierra Nevada Region's marketing decisions.

H.1 Federal Air Quality Regulations

At the Federal level, the Clean Air Act (42 USC 7401-7671q) is the primary source of regulatory requirements. The Clean Air Act calls for the EPA to promulgate regulations and standards to limit ambient air concentrations and control emissions of "criteria" air pollutants. Criteria pollutants are defined as particulate matter less than 10 microns in diameter (PM10), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), and lead. Additionally, emissions of hazardous air pollutants are closely regulated.

The Federal regulations set National Ambient Air Quality Standards (NAAQS) for the criteria air pollutants (Table H.1) and require the states to promulgate regulations to either achieve or maintain compliance or "attainment" with those standards. States may promulgate their own ambient air quality standards that are more restrictive than national standards. Each State is required to submit a State Implementation Plan detailing how that State intends to achieve or maintain attainment with all air quality standards. See 40 CFR 51 for requirements for preparation, adoption, and submission of State Implementation Plans.

The Clean Air Act primarily regulates "major sources" of pollutants. When an area is in nonattainment for one of the primary standards, the level of pollutant emissions that define a major source becomes more stringent. Table H.2 lists the emission levels for a source to be designated a major source of a pollutant in a nonattainment area. A major source can be an individual stationary source or a group of stationary sources that are located on contiguous or adjacent properties, under common control which exceeds the given emission levels in a nonattainment area.

Table H.1. National Ambient Air Quality Standards

Pollutant	**Time Period**	**Primary (mg/m^3)**	**Secondary (mg/m^3)**
CO	8 h	10,000	---
	1 h	40,000	---
NO_2	Annual	100	100
O_3	1 h	235	235
PM10	Annual	50	50
	24 h	150	150
SO_2	Annual	80	---
	24 h	365	---
	3 h	---	1,300

Primary standards = levels of air quality necessary to protect the public health.
Secondary standards = levels of air quality necessary to protect public welfare from the adverse effects of a pollutant.

Major sources of pollutants are required to obtain operating permits from their local regulatory agency. Depending on the levels of nonattainment of the region issuing these permits, a utility may be required to retrofit additional air pollution control equipment above that required as a minimum under the Clean Air Act. Utilities are additionally subject to the provisions of the Acid Deposition Control provisions of the Clean Air Act. As a part of these provisions, coal- fired utility plants are required to reduce the level of

SO_2 emissions based on the plant size, location, and past emissions. Further, operators of all fossil fuel-fired boilers are required to reduce emissions of nitrogen oxides. In some instances, this requires the installation of new burners that can meet emission standards.

Table H.2. Emission Levels for Designation as a Major Source

Pollutants	Nonattainment Status	Annual Potential Emissions
All pollutants	NA	>100 tons/yr of any pollutant
O_3	Marginal or Moderate	>100 tons/yr of VOCs or NO_x
	Serious	>50 tons/yr of VOCs or NO_x
	Severe	>25 tons/yr of VOCs or NO_x
	Extreme	>10 tons/yr of VOCs or NO_x
CO	Serious	>50 tons/yr
PM10	Serious	>70 tons/yr
Hazardous Pollutants	NA	>10 tons/yr of any hazardous pollutant
		>25 tons/yr for all hazardous pollutants

NA = Not applicable.

When an area is categorized as in attainment with the NAAQS, the construction of a new, or extensive modification to an existing, plant will fall within the Prevention of Significant Deterioration regulations. These regulations are designed to ensure that new powerplants meet requirements similar to those of existing plants in nonattainment areas, thereby maintaining the compliant state of air quality existing in the area. New (or modified) sources in an attainment area are typically required to install best available control technology (BACT) to minimize emissions.

When an area is categorized as not in attainment of the NAAQS, then construction of any new powerplant, or extensive modifications to an existing powerplant, will require the utility to comply with New Source Review (NSR) provisions, which typically require installation of lowest-achievable-emission-rate (LAER) control technologies to minimize plant emissions. LAER differs from BACT in that LAER does not require the consideration of environmental, energy, or economic impacts.

In the event that a State Implementation Plan does not meet the Federal requirements for achieving attainment with the primary NAAQS within the legislatively mandated time period, the EPA is required to promulgate a Federal Implementation Plan.

H.2 California Air Quality Regulations

California has enacted the California Clean Air Act (CCAA), which is designed to achieve the State ambient air quality standards at the earliest practicable date. California Ambient Air Quality Standards (CAAQS) (Table H.3) are more stringent than NAAQS for some pollutants and time periods. The CCAA prescribes a number of control strategies and requires that an Air Quality Management Plan (AQMP) be prepared by each of the State's air pollution control/management districts for submission to the California Air Resources Board (CARB). The CARB is responsible for setting State air standards, promulgating regulations relating to mobile sources of pollutants, reviewing AQMPs, and submitting them to the EPA as part of the State Implementation Plan.

Table H.3. California Ambient Air Quality Standards

Pollutant	Time Period	Standard (mg/m^3)
CO	8 h	10000
	1 h	23,000[a]
NO_2	1 h [b]	100
O_3	1 h	180[a]
PM10	Annual	30[a]
	24 h	50[a]
SO_2	24 h	105[a]
	3 h	655[a]

[a] California standard is more stringent than the national standard for this pollutant and time period.

[b] Time period not included in national standards for this pollutant.

In addition to the requirement to install BACT, or the best available retrofit control technology, new or modified major sources must additionally obtain offsets. These offsets (typically at a rate greater than 1:1) must be obtained from existing emission sources; in some districts, the offsets are themselves reduced to the emissions that a plant would generate assuming that BACT were installed. An additional difference between the Federal and State regulations is the difference between BACT and LAER. In some California air districts,

BACT has the same meaning as the Federal definition of LAER (i.e., environmental effects, energy usage, and economics need not be considered in the search for the best BACT).

H.3 Pacific Northwest States Air Quality Regulations

In the Pacific Northwest, the Washington State Department of Ecology, Oregon State Department of Environmental Quality, Idaho Division of Environmental Quality, and Montana Department of Environmental Quality have the authority to promulgate regulations and enforce clean air requirements in their respective states. Washington, Oregon, and Idaho have generally not adopted State ambient air quality standards that are more restrictive than national standards. Key exceptions to this are the Washington and Oregon maximum annual average SO_2 standard of 53 mg/m^3 and maximum 24-hour SO_2

standard of 260 mg/m^3; these standards are significantly more restrictive than the corresponding national standards. Montana has a number of ambient air quality standards that are more restrictive than national standards: a 1-hour CO standard of 26,000 mg/m^3, a 1-hour NO_2 standard of 600 mg/m^3, a 1-hour O_3 standard of 195 mg/m^3, a 24-hour PM10 standard of 100 mg/m^3, and SO_2 standards equivalent to those of Washington and Oregon.

H.4 Desert Southwest States Air Quality Regulations

In the Desert Southwest region (Nevada and Arizona), both states follow the California model, with the State government coordinating efforts typically by county health/environmental departments who have the responsibility to promulgate and authority to enforce air quality regulations. State ambient air quality standards are nearly identical to national standards.

H.5 EPA Proposal for More Restrictive Ambient Air Quality Standards

On November 27, 1996, the EPA released proposed new national air quality standards for particulate matter (soot) and ground-level ozone (smog).(1) Because of the significance of the proposal, EPA is seeking broad public comment on its recommended approach and on the need for any changes to the particulate matter and ozone standards. Once a final regulation is issued in June 1997, it will be among the first major environmental rules reviewed by Congress under the new Small Business Regulatory Enforcement and Fairness Act.

The new particulate matter standard calls for regulation of particles with an aerodynamic diameter of 2.5 mm or smaller. Current regulations limit the concentration of particles with an aerodynamic diameter of 10 mm or smaller (PM10) to 50 mg/m^3 annually and 150 mg/m^3 per 24 hour period. The proposed new regulation maintains the current standards for PM10 and also limits the concentrations of particles with an aerodynamic diameter of 2.5 mm or smaller (PM2.5) to 15 mg/m^3 annually and 50 mg/m^3 per 24 hour period.

The current ozone standard is 235 mg/m^3 or 0.12 parts per million (ppm) measured over 1 hour. The proposed new standard is 0.08 ppm measured over eight hours. EPA also is seeking comments on several other options, including a range of ozone concentrations from 0.07 parts per million measured over eight hours to 0.12 parts per million measured over 1 hour.

The proposed new standards also specify the way in which attainment of the new standards would be measured. The new standards could affect the attainment status for particulates and ozone in a number of air quality districts in California and throughout the broader study region. Implementation of the new standards should not change the conclusions reached in this EIS; however, more stringent air quality standards could result in some improvement in the marketability of non-thermal renewable resources (i.e., solar, wind, geothermal) and cleaner natural gas-fired power resources.

(1) This proposal was issued by the EPA just prior to publication of this EIS. Information on this proposed revision to air quality standards was obtained through the EPA's electronic bulletin board system (the Technology Transfer Network [TEN] at http://www.epa.gov/airlinks). This proposed action will be published in the *Federal Register*.

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Appendix I
Energy Generation for PROSYM Cases

Table I.1. Energy Production (GWh) (NOT AVAILABLE)

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Appendix J
Stage Contents Relationships for Regulating Reservoirs

Figure J.1. Lewiston Stage Contents Relationship (NOT AVAILABLE)

Figure J.2. Keswick Stage Contents Relationship (NOT AVAILABLE)

Figure J.3. Natoma Stage Contents Relationship (NOT AVAILABLE)

Figure J.1. Lewiston Stage Contents Relationship (NOT AVAILABLE)

Figure J.4. Tulloch Stage Contents Relationship (NOT AVAILABLE)

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Appendix K
Power Costs for Utility,
Agriculture, and Other Customers

Table K.1 below shows the spreadsheet used to calculate power costs for each of the cases run within the five alternatives. The first row lists how CVP operations were treated within each case. "Economic" refers to allowing economic criteria to establish hydropower operations within PROSYM. The peak cases almost all correspond to the peaking alternative. The renewables cases are also operated under peaking conditions. Two renewables cases are included because "Renew 2" is a sensitivity case that excludes biomass-fueled powerplants. This sensitivity case is used to estimate impacts to air quality and non-CVP land use, solid wastes, and water quality. The sensitivity case was developed because impacts from biomass dominate the environmental consequences of the renewables alternative, but there is uncertainty about the precise mix of technologies that would be used with a policy to promote renewables. The last column is the preferred alternative.

The allocation cases are shown in cases 19 through 24. All of these are based on the no-action alternative with the hydropower allowed to follow the load.

Figures K.1 through K.4 compare the total power costs across the alternatives.

Table K.1. Power Cost Calculations[1] (NOT AVAILABLE)

Figure K.1. Power Costs for Agriculture Customers (NOT AVAILABLE)

Figure K.2. Power Costs for Other Customers (NOT AVAILABLE)

Figure K.3. Power Costs for Utility Customers (NOT AVAILABLE)

Figure K.4. Power Costs for Total Customers (NOT AVAILABLE)

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Appendix L
Socioeconomic Impacts in Specific Economic Regions

Socioeconomic impacts in four economic regions are discussed below. These regions are the San Francisco Bay area, the Sacramento metropolitan statistical area, the Shasta County economic region, and the Kern County economic region. Additional discussion of socio economic impacts is provided in Anderson et al. 1996. Minor changes in the power cost analysis have caused the 2004 EIS economic impact results to vary slightly from those in Anderson et al. 1996.

L.1 San Francisco Bay Area Economic Region

The potential economic effects of Sierra Nevada's actions on the San Francisco Bay Area Economic Region are extremely small in relation to the size of the economy potentially affected, and, although they are calculable, they are not significant. Estimated employment effects range from about 150 new jobs to 100 job losses, depending on the alternative. Alternatives calling for Sierra Nevada to offer the CVP-Washoe hydroelectric resource as a peaked resource, and supplementing its resources with spot market energy purchases, result in generally positive economic impacts. Alternatives calling for Sierra Nevada to make substantial purchases of power generated from current renewable resource technologies (solar, wind, geothermal) generally result in the most negative economic impacts. The preferred alternative has a generally neutral economic impact. Increasing the CVP power allocations to the utility customer group or decreasing them to the other customer group tends to result in positive economic impacts. Figures L.1 through L.3 illustrate the effects of the respective alternatives on the region's output, employment, and labor income.

L.2 Sacramento Economic Region

The potential economic effects of Sierra Nevada's actions on the Sacramento Economic Region are extremely small in relation to the size of the economy potentially affected, and, although they are calculable, they are not significant. Estimated employment effects range from about 80 new jobs to 200 job losses, depending on the alternative. Alternatives calling for Sierra Nevada to offer the CVP-Washoe hydroelectric resource as a peaked resource, and supplementing its resources with spot market energy purchases, result in generally neutral economic impacts. Alternatives calling for Sierra Nevada to make substantial purchases of power generated from current renewable resource technologies (solar, wind, geothermal) generally result in the most negative economic impacts. The preferred alternative has a generally positive economic impact. Increasing the CVP power allocations to the utility customer group or decreasing them to the other customer group tends to result in positive economic impacts. Figures L.4 through L.6 illustrate the effects of the respective alternatives on the region's output, employment, and labor income.

L.3 Shasta County Economic Region

The potential economic effects of Sierra Nevada's actions on the Shasta County Economic Region are extremely small in relation to the size of the economy potentially affected, and, although they are calculable, they are not significant. Estimated employment effects range from about 150 new jobs to 250 job losses, depending on the alternative. Alternatives calling for Sierra Nevada to offer the CVP-Washoe hydroelectric resource as a peaked resource, and supplementing its resources with spot market energy purchases, result in generally neutral economic impacts. Alternatives calling for Sierra Nevada to make substantial purchases of power generated from current renewable resource technologies (solar, wind, geothermal) generally result in the most negative economic impacts. The preferred alternative has a generally positive economic impact.

Increasing the CVP power allocations to the utility customer group or decreasing them to the other customer group tends to result in positive economic impacts. Figures L.7 through L.9 illustrate the effects of the respective alternatives on the region's output, employment, and labor income.

L.4 Kern County Economic Region

For Kern County a more detailed analysis was conducted. The complete analyses are described in Section 4.9.4.1.

Figure L.1. 2005 Regional Output Impacts by Alternative in the Bay Area Economic Region (NOT AVAILABLE)

Figure L.2. 2005 Regional Employment Impacts by Alternative in the Bay Area Economic Region (NOT AVAILABLE)

Figure L.3. 2005 Regional Labor Income Impacts by Alternative in the Bay Area Economic Region (NOT AVAILABLE)

Figure L.4. 2005 Regional Output Impacts by Alternative in the Sacramento Region (NOT AVAILABLE)

Figure L.5. 2005 Regional Employment Impacts by Alternative in the Sacramento Region (NOT AVAILABLE)

Figure L.6. 2005 Regional Labor Income Impacts by Alternative in the Sacramento Region (NOT AVAILABLE)

Figure L.7. 2005 Regional Output Impacts by Alternative in the Shasta County Region (NOT AVAILABLE)

Figure L.8. 2005 Regional Employment Impacts by Alternative in the Shasta County Region (NOT AVAILABLE)

Figure L.9. 2005 Regional Labor Income Impacts by Alternative in the Shasta County Region (NOT AVAILABLE)

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Appendix M
Projected Air Resource Impacts

In assessing air resource impacts, six cases were considered:

- No-action
- Maximum hydro baseload operation of the hydroelectric resource with no additional power purchases (baseload)
- Maximum hydro peaking operation of the hydroelectric resource with no additional power purchases (peaking)
- Peaking operation of the hydroelectric resource with 50 MW of renewables purchased, one-fourth of which is biomass (renewables with biomass)
- Peaking operation of the hydroelectric resource with 50 MW of renewables purchased, none of which is biomass (renewables without biomass)
- Preferred.

In addition, air resource impacts are considered for both average and adverse water years for the CVP system (See Section 4.10).

Air resource impacts were assessed by quantitatively estimating the difference in pollutant emissions between the alternatives. This was done for annual average emissions and for emissions as a function of month and time of day. Impacts were assessed for the following pollutants: oxides of nitrogen (NO_x), sulfur dioxide (SO_2), particles with aerodynamic diameters of less than 10 mm (PM-10), carbon monoxide (CO), and volatile organic compounds (VOC). NO_x is a key pollutant because it is important in the formation of ozone. As discussed in Section 3.4, ozone pollution represents a significant problem throughout California, including the greater Sacramento area.

The following subsections contain discussions about the annual emissions, seasonal and diurnal variations in emissions, and differences between average and adverse years.

M.1 Annual Emissions

An assessment of the difference between alternatives in the annual emissions of NO_x, SO_2, CO, PM-10, and VOCs is given in Table M.1. The peaking alternative has a slight decrease in most pollutant emissions from the no-action alternative; the decrease in NO_x emissions repre sents the greatest change, about a 10 ton/year reduction. The peaking alternative tends to have slightly lower emission levels of pollutants because the increased use of hydroelectric resources during peaking periods displaces mostly combustion turbine (CT) resources, and the loss of hydroelectric resources during off-peak periods involves greater operation of combined cycle resources. The tendency of combined cycle combustion turbines (CCCTs) to emit slightly lower levels of pollutants per megawatt-hour than CTs results in an improved air quality impact. There is basically no difference in SO_2 emissions between the peaking and no-action alternatives because both alternatives involve the same level of operation of coal-fired powerplants (the primary source of SO_2 emissions) and CTs and CCCTs emit the same level of SO_2 per megawatt-hour.

Table M.1. Change in Pollutant Emissions from No-Action Alternative Levels for an Average Water Year (in tons/year)

	NO_x	SO_2	CO	PM-10	VOC
Peaking	-10	0	-3	0	0
Baseload	30	0	12	0	0
Renewables with Biomass	130	40	140	40	40
Renewables without Biomass	-80	-1	-30	-5	-4
Preferred	-2	0	-1	0	0

The baseload alternative shows a slight increase in NO_x and CO emissions from the no-action alternative. The preferred alternative shows a very slight decrease in NO_x and CO emissions from the no-action alternative. The renewables alternative with biomass has significantly higher emissions for all pollutants than the no-action alternative. The acquisition of 50 MW of renewable resources (resources that would not have been economical to use in the no-action alternative), consisting of 12.5 MW of biomass resources and 37.5 MW of non-polluting renewable resources, produces an increase in pollutant emissions over no-action levels. This is the result of the 12.5 MW of biomass resource emitting more pollutants to the atmosphere than the 50 MW of CT and CCCT resources that are displaced. Because of the nature of their fuel, biomass facilities have significantly higher levels of pollutant emissions that natural gas- fired facilities. While biomass resources can be made cleaner through the use of additional pollution controls, the deployment and use of additional controls in the year 2005 further escalates the cost of this already expensive resource. While a biomass resource may be an environmentally friendly resource from a land-use or waste disposal perspective, from an air quality standpoint it has pollutant emissions that are significantly dirtier than a natural-gas fired facility and are more comparable to those of a conventional coal-fired powerplant.

In contrast, the renewables alternative without biomass has significantly lower emissions than the no-action alternative. The acquisition of 50 MW of non-NO_x emitting renewable resources results in a decrease in pollutant emissions compared to no-action levels. This is the result of the 50 MW of renewable resources with no pollutant emissions displacing 50 MW of CT and CCCT resources.

The emission results can be put into perspective by looking at them in terms of the annual operation of powerplants. For the peaking alternative, the reduction in annual pollutant emis sions from the no-action level is relatively small, roughly equivalent to the output of a 15 MW of CCCTs operating at a 25-percent capacity factor. For the renewables alternative with bio mass, impacts are larger; the increase in annual NO_x emissions from the no-action level is equivalent to the output of about 240 MW of CCCTs operating at a 25-percent capacity factor, the increase in annual CO and PM-10 emissions is equivalent to the output of between 90 and 120 MW of a Northwest coal-fired powerplant operating at a 90-percent capacity factor, and the increase in annual SO_2 emissions is equivalent to the output of 2 MW of a Northwest coal- fired powerplant operating at a 90-percent capacity factor. For the renewables alternative without biomass, the reduction in annual pollutant emissions from the no-action level is equi valent to the output of between 100 and 160 MW of CCCT operation at a 25-percent capacity factor. In reality, changes in powerplant operation would probably not occur at any one powerplant, but would be spread among a series of powerplants. As a result, air quality impacts at any one location (either positive or negative) would be significantly constrained.

M.2 Seasonal and Diurnal Emission of Pollutants

Annual changes in pollutant emissions give only part of the story for characterizing air resour ces impacts. Within a given year, the season and the time of day during which emissions occur can also be significant in evaluating air resources impacts. Regulatory agencies recog nize this importance in their establishment of a number State and Federal ambient air quality standards that provide ambient pollutant concentration limits for exposure periods from 1 to 8 hours. These include NO_x (1-hour California standard), CO (1-hour and 8-hour California and Federal standards), and SO_2 (1-hour California and 3-hour Federal standards).

The seasonal variation in power demand for Sierra Nevada Region's customers is presented in Figure M.1. Diurnal variations in power demand for January, April, July, and October are given in Figure M.2.

Figure M.3 presents the hourly difference in July emissions of NO_x for each alternative. The zero line in the figure represents the no-action alternative's average daily July emission rate of NO_x; a point above zero indicates that for the given hour, the alternative being considered has emissions greater than the no-action alternative's average emission for the day. In this way, the plot for the no-action alternative should have exactly as much area above the zero line as below; other alternatives may have cumulative daily emissions that may be greater or less than for the no-action case.

All of the alternatives display low emissions rates at night. After 4 a.m., emissions rates begin to rise for all alternatives as power demands increase. This increase in emissions continues through the late afternoon. Emissions then decrease, corresponding to average decreases in power demands. While all the alternatives display this pattern, the magnitude of emissions differs from alternative to alternative.

Figure M.1. Seasonal Variation in Power Demand for Sierra Nevada Region's Customers (NOT AVAILABLE)

Figure M.2. Diurnal Variation in Power Demand for January, April, July, and October (NOT AVAILABLE)

Figure M.3. NO_x Emissions for an Average Weekday in July (NOT AVAILABLE)

The baseload alternative shows the greatest diurnal variation. At 4 a.m., the NO_x emission rate for the baseload alternative is 600 lb/h less than the daily average for the no-action alternative; while at 4 and 5 p.m., the NO_x emission rate for the baseload alternative approa ches 800 lb/h over the daily average for the no-action alternative. In contrast, the peaking alternative has a 4 a.m. NO_x emission rate that is 300 lb/h less than the daily average for the no-action alternative and a late afternoon NO_x emission rate that is about 200 lb/h above the daily average for the no-action alternative. At 5 p.m. the baseload alternative's NO_x emission rate exceeds the peaking alternative's by over 400 lb/h. This difference in hourly NO_x emissions is equivalent to the operation of 400 MW of CCCTs.

A close examination of the curves of the alternatives indicates a similarity in the shape of the curves for the baseload and no-action alternatives. This is the result of similarities between the PROSYM modeling assumptions used for these alternatives. Similarly, the peaking and two renewable alternatives also produce similarly shaped curves. The preferred alternative has slightly more diurnal variation in emissions than the peaking alternative, but less than the no- action alternative.

Figure M.4 presents the hourly difference in April emissions of NO_x for each alternative. The zero line in the figure represents the no-action alternative's average daily April emission rate of NO_x. In April, as compared to July, there is less of a variation in diurnal power demands so there is less difference between off-peak and on-peak emissions.

Figure M.4. Diurnal Variation in Nitrogen Dioxide Emissions for an Average Weekday in April (NOT AVAILABLE)

The baseload alternative shows the greatest diurnal variation. At 4 a.m., the NO_x emission rate for the baseload alternative is about 80 lb/h less than the daily average for the no-action alternative; while at 2 p.m., the NO_x emission rate for the baseload alternative is about 80 lb/h over the daily average for the no-action alternative. In contrast, at 4 a.m. the peaking altern ative has a NO_x emission rate that is 20 lb/h less than the daily average for the no-action alternative, and in the afternoon the NO_x emission rate is about 15 lb/h above the daily average for the no-action alternative. At the point of maximum baseload NO_x emissions, the baseload alternative's NO_x emission rate exceeds the peaking alternative's by over 250 lb/h. This difference in hourly NO_x emissions is equivalent to the operation of 250 MW of CCCTs, almost two-thirds the difference seen in July.

Because SO_x emissions come primarily for baseload thermal resources (i.e., coal-fired and biomass powerplants) that operate at constant levels throughout the year, there is little seasonal or diurnal variation in SOx emissions within each alternative.

Seasonal and diurnal differences in the emissions of CO, PM10, and VOCs are very similar. Because SOx emissions come primarily from baseload thermal resources (i.e., coal-fired and biomass powerplants) that operate at constant levels throughout the year, there is little seasonal or diurnal variation in SOx emissions within each alternative.

M.3 Difference Between Average and Adverse Years

In adverse water years, significantly less production of hydroelectric power can occur on the CVP system, and Sierra Nevada Region's customers are required to turn to thermal power resources to make up for this shortfall. The increase in average annual pollutant emissions for an adverse water year over those that occur in an average water year for the no-action alternative is given in Table M.2.

Table M.2. Increase in the No-Action Alternative's Air Pollutant

Emissions for an Adverse Water Year

Pollutant	NO_x	SO_2	CO	PM-10	VOC
Increase in Emissions (tons/year)	600	10	240	50	40

The change in emissions between average water years and adverse water years is much greater than the difference in emissions that occur between the alternatives within a given water year. The difference in NO_x emissions between the no-action and peaking alternative in an average water year is 10 tons/yr. The difference in no-action NO_x emissions for an average and adverse year is between one and two orders of magnitude greater, about 600 tons/year. The renewables alternative with biomass has 130 tons/year more NO_x emissions than the no-action alternative in an average year; a little more than one-fifth the difference between average and adverse year estimates for the no-action alternative. Similar results hold for other pollutants.

Within an adverse year, the reduction in hydroelectric resources is the same across all alternatives. The differences in pollutant emissions between the various alternatives are effectively the same as during average water years. So while the pollutant emissions for the no-action alternative in an adverse year might be much greater than during an average year, differences between the alternatives are the same.

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PAGE TOC FIGURES TABLES PAGE

Appendix N
Land Use, Water Quality, and Solid Waste Impact Factors

This appendix presents various land-use, water quality, and solid waste impact factors used in this 2004 EIS, as shown in Table N.1 through N.14. The impact factors are multiplied by quantities of generation produced by the PROSYM model. The products of these calculations are the estimated impacts shown in Sections 4.11, 4.12, and 4.13.

The information in the remaining tables reviews the references and reported impact factors used in developing the impact factors for this 2004 EIS. The information is presented by generating technology and by literature source. A variety of pollutants are listed to indicate the breadth of the types of impacts that may be anticipated from various technologies. The generating technologies reviewed include pulverized coal, atmospheric fluidized bed coal, coal gasification combined cycle, hydroelectric, simple-cycle combustion turbine (CT), combined- cycle combustion turbine (CCCT), municipal solid waste burner, agricultural residue burner, wood waste and forest products-fired generation, geothermal, solar photovoltaic, wind, and nuclear generation.

Only rather broad types of impacts are analyzed in this 2004 EIS. The analysis included acres of land required to site new capacity, and solid waste and waste water produced by powerplant operation. These impact types tend to be more universally applicable than specific pollutants such as a particular heavy metal, which are more directly related to a specific technology design, fuel type, and operating practices.

N.1 References

The following is a list of reference documents used to develop the impact factors:

1. Andrews, James C. Jr. "Incinerator Ash Disposal in the Tampa Bay Area." In *Municipal Waste Combustion: the Second Annual International Conference of the Air and Waste Management Association*, pp. 284-298, April 15-19, 1991, Tampa, Florida. Air and Waste Management Association, Pittsburgh, Pennsylvania.

In this paper, Andrews discusses the operation of four municipal solid waste generating facilities in the Tampa Bay area including detailed information on the relationship between fuel, solid waste generation, and electricity generation.

2. Baechler, M. C., D. H. Fickeisen, and P. L.Hendrickson. 1990. *Environmental Effects and Mitigation for Energy Resources*. Prepared for Bonneville Power Administration by Pacific Northwest Laboratory, Richland, Washington.

The aim of this document was to aid in conducting environmental reviews and obtain ing descriptive and numeric information regarding nine generating technologies, con servation, and transmission systems.

3. Bonneville Power Administration (BPA). 1988. *Development of Combustion Turbine Capital and Operating Costs*. DOE/BP-63056-1, prepared for Bonneville by Fluor Daniel Inc., Irvine, California.

This document presents cost and performance data for a phased development of a combined-cycle generating station. Though intended to be generic, specific technolo gies and locations are used (for example, General Electric Model MS7001F at the Boardman coal-fired plant site).

4. Fluor Daniel Inc. 1992. *Environmental Data for Thermal Resources.* Bonneville Power Administration, Portland, Oregon.

Data were collected from vendors, technical publications, and Fluor Daniel internal sources. The document presents brief descriptions followed by tables of numeric data for 26 generating systems. Data developed by Kaiser Engineers are also presented in tabular form for six technologies.

5. Merdes, Robert S. 1991. "The Neutralysis System." In *Municipal Waste Combustion: the Second Annual International Conference of the Air and Waste Management Association*, pp. 642-651, April 15-19, 1991, Tampa, Florida. Air and Waste Management Association, Pittsburgh, Pennsylvania.

This article is a report of audit results from a Neutralysis test plant located in a suburb of Brisbane Australia.

6. Ottinger, Richard L., D. R. Wooley, N. A. Robinson, D. R. Hodas, S. E. Babb. 1990. *Environmental Costs of Electricity*. Pace University Center for Environmental Legal Studies, Oceana Publications, New York.

This document reviews studies that quantify the externality costs of environmental damage caused by electric power services. The primary sources for data used here were documents seven and eight below.

7. Kaiser Engineers Power Corporation. 1983. *Bonneville Power Administration, Compara tive Electric Generation Study, Coal Fired Power Plants*. Prepared for the Bonneville Power Administration, Portland, Oregon.

See item 3 above.

8. U.S. Department of Energy (DOE). 1983. *Energy Technology Characterizations Hand book: Environmental Pollution and Control Factors*. DOE/EP-0093, Washington, D.C.

This is a comprehensive compendium of tabular information concurring the entire cycle of energy production for eight generating technologies. Unfortunately this edition (the third) is the last to be published and no future updates are planned (per conversation with staff at U.S. Department of Energy).

9. U.S. Department of Energy (DOE). 1988. *Energy Technologies & The Environment: Environmental Information Handbook*. DOE/EH-0077, prepared for DOE by Argonne National Laboratory.

This document supplements document seven above. The entire cycle of energy produc tion is discussed for eight technologies; unfortunately, it does not include natural gas generators. Data are primarily included as part of the text and specific numeric data are spotty.

10. Western Area Power Administration. 1995. *Energy Planning and Management Program Environmental Impact Statement* (EPAMP). DOE/EIS-0182, Western Area Power Administration, Golden, Colorado.

This document includes detailed descriptions of Western's entire system as well as detailed information on the environmental impacts of various electricity generating technologies.

Since data in the source documents came in a variety of units, conversions to consistent units were necessary. The following two documents were used to make those conversions:

11. Falk, Karl H. 1947. *Falk's Graphical Solutions to 100,000 Practical Problems*. Columbia Graphs, Columbia, Connecticut.

12. Weast, Robert C. Ed. 1974. *CRC Handbook of Chemistry and Physics*. 51st Edition, Chemical Rubber Company, Cleveland, Ohio.

N.2 Acronyms Used in Tables

The following acronyms are used in the impact tables below.

BH
: baghouse ash

BOD
: biological oxygen demand

CCCT
: combined-cycle combustion turbine

EP
: electrostatic ash precipitation

MSW
: municipal solid waste

MW
: megawatt

MWH
: megawatt hour

ppm
: parts per million

SCT
: simple-cycle combustion turbine

SR
: sulfur removal

TDS
: total dissolved solids

TOC
: total organic carbon

TRS
total reduced sulfur
TSP
total suspended particulates
TSS
total suspended solids
UHC
unburned hydrocarbons
VOC
volatile organic compounds

Table N.1. Impact Factors Selected for Use in the Analysis (NOT AVAILABLE)

Table N.2. Reported Impact Factors for Pulverized Coal Powerplants (NOT AVAILABLE)

Table N.3. Reported Impact Factors for Atmospheric Fluidized Bed Coal Powerplants (NOT AVAILABLE)

Table N.4. Reported Impact Factors for Coal Gasification, Combined-Cycle Powerplants (NOT AVAILABLE)

Table N.5. Reported Impact Factors for Hydroelectric Powerplants (NOT AVAILABLE)

Table N.6. Reported Impact Factors for Simple-Cycle Combustion Turbine Powerplants (NOT AVAILABLE)

Table N.7. Reported Impact Factors for Gas-Fired Combined-Cycle Combustion Turbine Powerplants (NOT AVAILABLE)

Table N.8. Reported Impact Factors for Agricultural Residue Burning Powerplants (NOT AVAILABLE)

Table N.9. Reported Impact Factors for Municipal Solid Waste Burning Powerplants (NOT AVAILABLE)

Table N.10. Reported Impact Factors for Wood Waste and Forest Products-Fired Powerplants (NOT AVAILABLE)

Table N.11. Reported Impact Factors for Geothermal Powerplants (NOT AVAILABLE)

Table N.12. Reported Impact Factors for Solar Generation (NOT AVAILABLE)

Table N.13. Reported Impact Factors for Wind Generation (NOT AVAILABLE)

Table N.14. Reported Impact Factors for Nuclear Powerplants (NOT AVAILABLE)

Appendix O
2004 Power Marketing Program
Draft Environmental Impact Statement
Comments and Lead Agency Responses

O.1 Written Comments Received

O.1.1 State of California, Department of Parks & Recreation

Comment No.:D001-01

Comment: It appears that reservoir levels could fluctuate more radically at certain times, potentially affecting recreational uses by grounding floating property and expos ing water users to underwater hazards. Western should consider the possible effects to recreational users.

Response: Recreational uses at the reservoirs will not experience conditions noticeably dif ferent from those presently occurring, regardless of which alternative compo nent values are selected for inclusion in Western's 2004 Power Marketing Plan. Maximum ramping speeds for the change in flow rates through penstocks or control gates will not change, and maximum and minimum reservoir levels will likewise remain at presently allowable elevations. The 2004 EIS analyzes potential power marketing program effects on regulating reservoirs only because water operations rather than power operations affect the main storage reservoirs.

O.1.2 Department of the Interior, Office of Environmental Policy and Compliance

Comment No.:D002-01

Comment: Page 1.9, 2nd paragraph - Reclamation is the lead agency for the Interior's PEIS. FWS is a cooperating agency for the PEIS. Reclamation and FWS are co-leads for implementation of the CVP Improvement Act.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-02

Comment: Page 2.9, Baseload Operation - Tulloch Reservoir has a required flood control reservation and cannot be held at full pool in all months.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-03

Comment: Page 3.6, 2nd paragraph, 1st sentence - The total CVP storage is about 11.9 million acre feet rather than the 10.66 stated. This storage would include Millerton Reservoir and San Luis Reservoir, but not Whiskeytown Reservoir.

Response: The final 2004 EIS has been modified to encompass total CVP storage including Whiskeytown Reservoir.

Comment No.:D002-04

Comment: Page 3.7, Table 3.1 - The operating location of J.F. Carr Powerplant should be Clear Creek Tunnel, and for Spring Creek Powerplant should be Spring Creek Tunnel.

Response: Table 3.1 has been corrected to reflect this comment.

Comment No.:D002-05

Comment: Page 3.11, 1st sentence - The maximum powerplant release for Shasta is about 18,000 cfs.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-06

Comment: Page 3.12, 1st paragraph, 2nd sentence - In addition to providing water to the west side of the San Joaquin Valley, San Luis Reservoir also provides agricultural, municipal, and industrial water to the San Felipe Division through the Pacheco Pumping Plant.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-07

Comment: Page 3.13, 1st paragraph - On an annual cycle, Tulloch Reservoir fluctuates about 10 TAF, but only about 4 TAF are used to nullify daily fluctuations due to peaking operations. Tulloch is lowered about 10 TAF each winter for flood control operations. The operations studies were not reviewed, but 10 TAF should not have been used as space available for peaking operations.

Response: The final 2004 EIS text has been modified to reflect this comment. The modeled operations remained within the fluctuation limits specified above.

Comment No.:D002-08

Comment: Page 3.15, last paragraph, last sentence - Trinity Powerplant generates about 400 kWh/acre-foot only when there is a storage of 2 TAF at Clair Engle.

Response: This sentence has been changed to read: "Trinity Powerplant generates between 175 and 425 kWh per acre-foot, depending on reservoir water surface elevation."

Comment No.:D002-09

Comment: Page 3.17, last paragraph, 2nd sentence - Production at Carr varies with the surface elevation at Whiskeytown Reservoir and ranges from 540 to 565 kWh/acre feet.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-10

Comment: Page 3.18, 2nd paragraph, 2nd sentence - The Coordinated Operations Agree ment does not identify minimum Keswick flows, and release from Keswick can vary daily during summertime temperature control operations and flood operations.

Response: The reference should have been to Central Valley Project Operations Criteria and Plan, October 1992. The final 2004 EIS has been modified to include this change.

Comment No.:D002-11

Comment: Page 3.18, 4th paragraph, 1st sentence - The operation of the American River Division is dictated by more than just the water quality criteria and flood con trol operations. Other CVP purposes which determine operations are water supply, Delta flow requirements, and minimum fishery flow requirements.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-12

Comment: Page 3.19, 2nd paragraph - While San Luis Reservoir and O'Neill Reservoir are capable of being operated in a "standard pump-storage mode," this is not typically done.

Response: The final 2004 EIS text has been modified to reflect this comment.

Comment No.:D002-13

Comment: Page 3.19, 3rd paragraph, 2nd sentence - This division is also operated for water supply and seepage problems.

Response: The final 2004 EIS text has been modified to reflect this comment.

Comment No.:D002-14

Comment: Page 3.19, 4th paragraph, 5th sentence - Only 4 TAF of Tulloch Reservoir are available for preventing flow fluctuations on the Stanislaus River. It is not known how this may affect the studies if 10 TAF were assumed.

Response: The final 2004 EIS text has been modified to reflect this comment. This change does not affect modeling results.

Comment No.:D002-15

Comment: Page 3.20, System Losses - The CVP transmission system loss is 4% rather than 1.6%.

Response: Recent calculations by Sierra Nevada Region's transmission system planners show CVP transmission system losses to be 1.6 percent. The 4-percent loss figure is correct for the Western/PG&E integration contract (2948A) accounting purposes.

Comment No.:D002-16

Comment: Page 3.21, CVP Water Resources - Assumptions of flows to and from the regulating reservoirs under the average and adverse conditions should be explicitly shown for each regulating reservoir.

Response: This section is a discussion of the affected environment and simply describes the function of regulating reservoirs in the CVP. For additional information about flow assumptions, see Response to Comment No. D002-27.

Comment No.:D002-17

Comment: It is not clear how the operation of Whiskeytown Reservoir was considered in this analysis. It is used for regulation of peaking power flows from both Carr and Spring Creek Powerplants, but its operation is not addressed in this descrip tion. Whiskeytown Reservoir may have been operated similarly under all alternatives, but this is not stated.

Response: Whiskeytown Reservoir was not considered to be a regulating reservoir for the purposes of this report, and it was operated similarly for all alternative cases modeled. Although Whiskeytown Reservoir regulates flows from Carr Power plant, due to its size, it is not affected overall by hourly flows. The final 2004 EIS has been clarified in response to this comment.

Comment No.:D002-18

Comment: Page 3.21, 1st paragraph, 3rd sentence - Note that 1986 was not considered a drought year.Low-level releases for temperature control began in 1987.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-19

Comment: Page 3.21, Keswick Reservoir - This states that pool levels in Keswick Reser voir can vary by as much as 13 feet. Under normal operating conditions, pool levels in Keswick Reservoir only fluctuate by 8 feet.

Response: This statement is correct. However, for the purposes of this analysis, regulat ing reservoirs were permitted to fluctuate within the maximum allowable range to determine the magnitude of potential impacts for evaluation. In the final 2004 EIS analyses, Keswick was limited to a 11 foot fluctuation (elevation 576 ft to 587 ft) to reflect cooling water constraints at Spring Creek Powerplant; therefore, no change in the EIS text is needed.

Comment No.:D002-20

Comment: Page 3.23, 1st paragraph, 4th sentence - The statement that cold water releases are made from December through June appears to be switched. It is more likely that cold water releases would be made from about June through December.

Response: The final 2004 EIS has been modified to reflect this comment.

Comment No.:D002-21

Comment: Page 3.23, Lake Natoma, last sentence - Under normal operating conditions, Lake Natoma pool fluctuations generally do not exceed 4.5 feet.

Response: This statement is correct. However, for the purposes of this analysis, regulat ing reservoirs were permitted to fluctuate within the maximum allowable range to determine the magnitude of potential impacts for evaluation.

Comment No.:D002-22

Comment: Page 3.23, 3.4.4, Tulloch Reservoir - As noted above, the 10 TAF fluctuation is for annual lowering for flood operations. Typical daily fluctuations do not exceed 4 TAF or about 3 feet. Also, while no temperature criteria have been established to date, temperature control is a consideration in New Melones and Tulloch operations.

Response: The final 2004 EIS has been modified to reflect suggested changes in the flood control operations description.

Comment No.:D002-23

Comment: Page 3.27, Table 3.2 - It is not clear if the column "Affected by Fluctuations" refers to fluctuations in the main reservoir, regulating reservoir, or downstream river. This should be clarified.

Response: Table 3.2 has been clarified in response to the comment.

Comment No.:D002-24

Comment: Page 3.27, Table 3.2, Kokanee Salmon - The table shows that the salmon are not in CVP reservoirs, but also states that they are stocked in Shasta, Whiskeytown, and Clair Engle. Which is correct?

Response: The table has been corrected.

Comment No.:D002-25

Comment: Page 3.28, Table 3.2, Striped Bass - The table shows that the bass are not in CVP reservoirs. Striped bass are found in San Luis Reservoir.

Response: Table 3.2 has been corrected.

Comment No.:D002-26

Comment: Page 4.20, Table 4.7 - The daily fluctuations for Tulloch Reservoir should be checked. Daily fluctuations should not exceed 3 feet.

Response: The 2004 EIS has been clarified in response to the comment.

Comment No.:D002-27

Comment: Page 4.4, PROSYM Production Cost Model - The text did not address the flow assumptions into and out of the regulating reservoirs and how hourly flows are calculated. Since the maximum generating capacity marketed by Western is computed based on these flows, they need to be fully explained.

Response: Monthly CVP generation was determined based on output from the PROSIM model. As discussed in Sections 4.1, 4.2, and 4.3.1.1, hourly CVP generation output from PROSYM was converted to hourly flow volumes out of the respec tive CVP generating facilities and into the regulating reservoirs and rivers. The referenced assumptions are contained in the 2004 EIS modeling reports (Western 1997).

Comment No.:D002-28

Comment: Page 4.26, 3rd paragraph - The operation of Tulloch Reservoir needs some clar ification. First, river temperatures are a concern, especially at low storage in New Melones. Although Reclamation does not actually operate Tulloch, Tri- Dam Project operates the reservoir at Reclamation's direction. Tri-Dam Project has cooperated with Reclamation in some severe drought years and reoperated Tulloch in an attempt to cool the Stanislaus River. This was not considered as a normal type of operation.

Response: The final 2004 EIS text has been modified to clarify this concern.

Comment No.:D002-29

Comment: In the description of the reservoir [Tulloch] levels, wintertime operations are normally at about 498 to 501 feet for flood control. Elevation of 510 is gross pool; in the summer, the typical operating range is about 506.5 feet to 509.5 feet.

Response: The final 2004 EIS has been modified to reflect this comment.

O.1.3 Sacramento Municipal Utility District

Comment No.:D003-01

Comment: Western should specifically identify its underlying purpose for selling Federal power, which is to repay the U.S. Treasury for Federal investment in the CVP. Given the increased scrutiny and criticism of the Federal power program, West ern should document the success of its repayment record and identify the benefit of the Federal power program to the U.S. Treasury in this DEIS. The Purpose and Need Statement is important as it provides the standard of accomplishment against which the merit of the alternatives are measured. SMUD requests that its input (10/28/93 letter) to the Purpose and Need Statement be incorporated in the DEIS.

Response: Regarding the 10/28/93 letter addressing the Purpose and Need Statement, SMUD suggested the following be included:

a) Repaying the Federal investment in the CVP through the sale of CVP power generation at cost-based rates to preference customers;

b) Providing leadership in implementation of DOE policy and programs, including encouraging efficient use of CVP power by preference customers;

c) Reducing the adverse environmental impacts of energy production; and

d) Maintaining rates at the lowest level possible consistent with repayment objectives and prudent business practices.

Western took these suggestions into consideration in finalizing the Purpose and Need Statement. Purposes of the proposed action, listed on page 1.3 of the draft 2004 EIS, include "to be consistent with the Sierra Nevada Region's statu tory and other legal constraints," which addresses SMUD suggestions "a" and "d" and "to protect the human and natural environment," which addresses SMUD suggestions "b" and "c."

Comment No.:D003-02

Comment: The alternatives described for the amount and type of power to be marketed are not completely developed descriptions of a cohesive power product, but rather are described in terms of a range of unassembled hydro output and purchase component options. This creates a lack of clarity in terms of how much total power would be marketed under each alternative, during what season, at what capacity factor, and what approximate cost. The "tent stake" alternatives need to be better developed to provide meaningful limits for the DEIS evaluation, and to Western's possible decisions.

Response: While developing the alternatives for the draft 2004 EIS, Western realized that there is a distinction between the elements of its marketing program that may affect the environment and some of the parts that are most important from a marketing perspective. As required by NEPA, Western must analyze the ele ments that are most likely to affect the environment. A tent stakes approach was employed. That is, Western designed alternatives to test the boundaries of actions that might be taken with hydropower operations, power purchases, and customer group allocations to determine the magnitude of environmental impacts that might be expected. The farther out the tent stake is pushed (a metaphor for stating that the more extreme the action assessed) the larger the tent becomes, encompassing the actions that Western may take in developing products and services. The Sierra Nevada Region intentionally focused on the more extreme cases to identify any threshold levels of significant environmental impact that might exist. This approach, especially in the draft 2004 EIS, was designed to maximize the Sierra Nevada Region's flexibility in combining com ponents for putting together a marketing plan rather than pinpointing a particu lar marketing strategy. The final EIS incorporates a preferred alternative that approximates the action the Sierra Nevada Region is likely to take. However, the marketing plan is being developed in a public process prescribed under the Administrative Procedure Act.

Comment No.:D003-03

Comment: Western needs to more fully develop the option of Western allocating Federal resources, like reserves and other ancillary services, to customers developing renewables.

Response: The Sierra Nevada Region agrees that specific types of products and services would be needed to support the development of renewables. If the Sierra Nevada Region chooses to enter into these arrangements, the needs will vary from customer to customer, and from renewable energy project to project. The option of allocating Federal resources to customers developing renewables can be further explored in the marketing plan public process. As long as the Sierra Nevada Region's actions fall within the hydropower operations and power pur chases that have been assessed in the 2004 EIS, there should be no further need for environmental assessment of the products and services needed to support the project. This is one reason the tent stakes approach was selected for the draft EIS. Allocations that promote or encourage power generation from renewable resources will not create new environmental impacts that have not been addressed in the 2004 EIS unless new resources are developed. For new renew able resources, the renewable resource itself may require further assessment in its own NEPA process depending on the circumstances of its development.

Comment No.:D003-04

Comment: There is presently a two-tier energy pricing rate, contrary to the characteriza tion presented in the no-action alternative. This and other methods of disaggre gating costs have a positive environmental impact, as customers can make more efficient resource decisions when costs are disaggregated so their true impacts can be identified. The DEIS needs to provide more support for the power pro duction costs, and estimate the rates to customers without which economic impact to customer groups cannot be calculated.

Response: A tiered rate results from a rate design that affects individual customers in dif ferent ways, depending on their load factor. A single average composite rate was therefore used to better represent customer groups. Individual customers were not analyzed. Although the Sierra Nevada Region is currently using a two-tier energy pricing rate, a composite power cost figure was used in the no- action and action alternatives analyses to represent the average revenue expected from CVP customers. This approach is useful in analyzing the socioeconomic effects of the alternatives. The subject of the 2004 EIS process is the develop ment and adoption of Sierra Nevada Region's Power Marketing Plan to market power from the CVP and Washoe Project beyond the year 2004. Rates are not analyzed as part of this EIS process, except as average power costs. Rate issues will be addressed within Sierra Nevada Region's long-established public ratemaking process.

Comment No.:D003-05

Comment: There would be substantial adverse economic effects to the utility customer group and the millions of customer-owners represented if Western were to decrease allocations to utility customers and increase allocations to end users, such as agricultural customers. Western power provides a significant benefit to its customers compared to market alternatives. Western should revise this conclusion to reflect the reality that any decrease in allocation of Western power to utility customers will have significant adverse economic impacts.

Preference resale utility customers are most effective at spreading the benefit of Federal power to a wide group of citizens without including a profit component, as Western marketing criteria require. Agricultural customers already enjoy the benefits of Project Use power, assistance in repayment of the project debt, and a host of other CVP benefits. Utility customers as a group have built resource portfolios around the Western resource, and significant inefficiencies and costs would occur if changes in allocations among customers or customer groups occur.

Response: The Sierra Nevada Region agrees that reducing or eliminating allocations to particular customers could result in economic impacts to those customers. Impacts facing Western's customers arising from changes in allocations were analyzed in both the EPAMP EIS and the 2004 EIS. The results of the EPAMP analyses are summarized in the 2004 FEIS in sections 1.6.2 and 2.2.3. The nature of the impacts would likely change as the electric power market evolves and more access to power markets and transmission is afforded wholesale and retail customers. Additional access to transmission and the ability to make purchases from a variety of sources could ease the transition for customers that did not have such capabilities.

As with other analyses conducted in the 2004 EIS, the tent stakes analysis of allocations to customer groups is intended to address the full range of possible actions on Western's part to determine maximum potential environmental impacts. In the draft 2004 EIS, only small differences in impacts to customer groups were found among the alternatives analyzed. On a regional economic basis, these differences were minimal. Changes in the final 2004 EIS, including the assumption of wholesale and retail access to electric power markets, result in even less difference across the alternatives. The new findings are shown in Section 4.9.

Comment No.:D003-06

Comment: Page 3.74, Western asserts that Western and its customers have the same mar ket access and face the same price structures for supplemental power purchases. In reality, Western has several hundred megawatts of transmission to the Pacific Northwest, and spinning reserves from the CVP which enable Western to access resources more effectively than the customers otherwise could, once our own transmission resources are loaded. This assumption should be corrected.

Response: Sierra Nevada Region customers were modeled as groups, not individually. The statement that Sierra Nevada Region and its customers have similar market access is based on the fact that the Sierra Nevada Region utility customer group has market access and transmission rights (either through ownership or con tract), which collectively exceed the Sierra Nevada Region's rights. Sierra Nevada Region's utility customer class may currently access the Northwest and compete with the Sierra Nevada Region to purchase power from that region. To the extent that the utility industry is restructured, any advantages one group may have relative to another will be further reduced.

Comment No.:D003-07

Comment: The derivation of the information presented in Table 4.2 needs to be provided, including the assumptions for maintenance and reserve requirements. All rea sonable efforts in scheduling maintenance should be made to avoid the decrease in capacity available in a single month, like March which may have unnecessary detrimental impacts on Western's marketing efforts, and on the environment, as replacement capacity could otherwise be needed.

Response: The information contained in Table 4.2 was derived from hourly production cost analysis. In the analysis, the CVP units were dispatched into the Northern California preference load and Project Use load. The information represents the maximum hourly coincident generation for the CVP hydroelectric facilities after subtracting the coincident Project Use load. The various cases identified are as described in the draft 2004 EIS. The dispatch of the CVP system and the atten dant operating restrictions for environmental and water purposes are such that the loading of the individual CVP generators results in significant unloaded CVP capacity. This unloaded capacity is available for spinning reserves and reserves to replace units that may be unavailable due to maintenance or other reasons. As a result of model refinements in the final 2004 EIS (to better repre sent industry restructuring), the results noted in the draft 2004 EIS have been revised as noted in Table 4.2.

Comment No.:D003-08

Comment: Why were SMUD's suggestions at the scoping phase for the no-action alternative not used?

Response: SMUD suggested Western "consider as the ?no-action' alternative the marketing of CVP generation supplemented only by short-term and non-firm imports, and those existing contracts which extend beyond 2004." The SMUD letter of 10/28/93 continues, "This alternative meets Western's mandate with minimal action on Western's part, and works well with policy objectives encouraging the efficient use of CVP power by preference customers."

Western considered SMUD's suggestions. Western's "no-action" alternative, in accordance with NEPA, describes a continuation of present practices as closely as possible given future uncertainty. SMUD's suggested "no-action" alternative is considered in the draft 2004 EIS as Case 1c. Analyses of supplementing CVP hydropower with short-term and non-firm imports is further analyzed in the final 2004 EIS, not as the no-action alternative but in the action alternatives, including the preferred alternative.

Comment No.:D003-09

Comment: Concur with the analysis that shows the added benefit of operating the CVP hydro system as a peaking resource and with the inclusion of the additional peaking case (Case 1C) which appears to use a more pragmatic supplemental purchase strategy, but adequate detail is not provided. With Western's trans mission and spinning reserve resources, Western can find more flexible, short- term, attractive supplemental power supplies that would support CVP power sales, bringing more value to customers, and more certainty to CVP repayment. Indeed Congress directed the CVP participation in the Pacific Northwest- Southwest Intertie to do so.

Information should be included on the amount of time this peaking capacity can be sustained, and the hydrologic risk involved in that level of product, both with and without the supplemental purchases. In this way, the true usefulness of the resource, and related environmental impacts, can be determined.

Response: The time during which the CVP can sustain the peaking capacity level varies from month to month and is a function of both the energy produced by the project and the shape of the customer load. The capacity levels noted for the CVP generation are based on a 90-percent exceedance assumption. To the extent supplemental energy is available, the level of capacity available and /or the duration of availability is increased. The analysis performed was such that specific duration times for capacity availability were not determined. The dura tion was sufficient to meet the load requirements for which the capacity was being dispatched. These durations changed on a daily and monthly basis throughout the year. See the 2004 EIS modeling report (Western 1997) for modeling assumptions and results.

Comment No.:D003-10

Comment: The cost estimates for renewables are too optimistic, leading to an unrealisti cally high estimate of the level of renewables that Western could purchase and remain competitive.

Response: Section 2.3.6 of the final 2004 EIS has been revised to reflect this comment. These revisions, along with updates to energy market rates, reduce the maxi mum level of renewables that could be purchased or supported in the renew ables alternative.

Comment No.:D003-11

Comment: Western should more fully evaluate the alternative of providing incentives for preference customers to build renewables, rather than paying Western to pur chase renewables from third parties. Significant benefits to local air quality and economic development can result from this approach.

Response: The renewables alternative is designed to allow the Sierra Nevada Region to either purchase renewable resources directly or to support customers in their purchase or development of renewables. Specific project benefits would depend on the nature of specific technologies and the local circumstances of their siting. Such an analysis cannot be completed until specific projects are identified. The purpose of the EIS analysis is to assess the potential environmental impacts of the marketing plan, not the specific impacts of projects not yet designed or sited.

Comment No.:D003-12

Comment: Information on how long the capacity levels under each alternative can be sus tained, with and without supplemental purchase options, is needed for each alternative in order to obtain and convey meaningful results from the analysis.

Response: The time during which the CVP can sustain the peaking capacity level varies from month to month and is a function of both the energy produced by the project and the shape of the customer load. The capacity levels noted for the CVP generation are based on a 90-percent exceedance assumption. To the extent supplemental energy is available, the level of capacity available and /or the duration of availability is increased. The analysis performed was such that specific duration times for capacity availability were not determined. The dura tion was sufficient to meet the load requirements for which the capacity was being dispatched. These durations changed on a daily and monthly basis throughout the year. See the 2004 EIS modeling report (Western 1997) for modeling assumptions and results.

Comment No.:D003-13

Comment: The information in Table 4.7 is too sketchy to provide an understanding of the impact of each alternative on the cost of power products produced by Western. Because these costs are pivotal to the success of Western's marketing program and repayment capability, and to the customer's ability to supply their ratepayer-owners, Western should provide a more detailed breakdown of the estimated costs to supply the capacity and energy products it proposes to sell, on a per kW-month and kWh basis. The necessary assumptions for customer load and sales volume are made elsewhere in the DEIS, so the properly quali fied estimates can be made. Only then can an adequate impact to customer groups be evaluated accurately, an adequate environmental analyses be com pleted, and educated decisions on what to market be made by Western.

Response: The comment appears to refer to Figure 4.7, not Table 4.7. This information is available in the 2004 EIS modeling report (Western 1997) describing modeling assumptions and procedures.

Comment No.:D003-14

Comment: The discussion on page 4.40 concludes no significant impacts would result from any of the reallocation scenarios studied, and that minor beneficial impacts to the economy would result from decreased allocations to the utility customer group. Because the allocation options described on page 4.15 are not quanti fied, this conclusion is hard to understand. However, if the scope of the action Western is evaluating in this DEIS includes establishing allocation criteria, as is stated in Section 1.2 of the DEIS, then Western must clearly identify the impacts of the allocation criteria it is considering. Western has addressed impacts of reallocation and power product alternatives to the agricultural economy in great detail in Section 4.9.0, and overlooked or mischaracterized impacts to the utility customer group entirely. The utility customer group has many customers which rely on Western for a substantial amount of low cost hydro power. Substantial decreases in allocations of Western power to the utility customer group would increase for residential and commercial/industrial customers of publicly-owned utilities, clearly creating significant regional eco nomic impacts. Western should remove the alternative of decreasing allocations to utility customers, or, if Western determines it must evaluate this alternative, revise the analysis as suggested above.

Response: The potential impacts of changing allocation criteria and allocations have been determined by grouping customers into utility, agriculture, and other categories, and analyzing increases and decreases in allocation to each group relative to present conditions. The analyses in the final 2004 EIS, which reflect the total economic impact of shifting allocations between the three groups, have been updated. The new analyses show reduced differences in impacts between alter natives. See the analysis of allocations in the final 2004 EIS (Sections 2.3.9, 2.4, and 4.9) for the revised impact analysis. Western recognizes that there may be impacts to individual customers if their allocation is reduced or elimi nated. Also see Response to Comment No. D003-05.

O.1.4 City of Palo Alto

Comment No.:D004-03

Comment: It is unclear why the 450 and 900 MW levels of purchases and their associated 15 and 85 percent capacity factors were selected for both the peaking and base load sales alternatives. It would be more informative to model purchase levels that meet the needs of the project which vary significantly from month-to-month and year-to-year depending on hydrology, load, etc. More realistic assumptions need to be used in the analysis so the DEIS analysis is more representative of expected conditions. With Western's transmission and spinning reserve resources, Western can find more flexible, short term, attractive supplemental power supplies that would bring more value to customers.

Response: The 450 and 900 MW levels and associated capacity factors of 15 percent and 85 percent were selected only as a means of setting out tent stakes encompas sing reasonable ranges of potential purchases. It should be noted that Sierra Nevada Region sales to customers were modeled as a function of economic dis patch between Sierra Nevada Region power and other resources available to the customers. The different levels and types of purchases resulted in varying costs of melded Sierra Nevada Region power and hence the competitiveness of Sierra Nevada Region power relative to other sources. The intent of using this type of approach in the EIS is to allow the Sierra Nevada Region as much latitude as possible in its ultimate marketing plan. Note the EIS studies the boundaries within which the final marketing plan can be crafted. The preferred alternative is a scenario representative of what the final marketing plan might look like after further public input in the marketing plan public process.

Comment No.:D004-04

Comment: Concerned that Western's analysis of the renewable purchase option is too simplistic and optimistic and that it may create an expectation that Western should sacrifice its partners' (Customers') interests in retaining the economical resource that they have funded for many years in order to support large quantities of non-hydro renewable technology purchases.

Response: The Sierra Nevada Region elected to assess the potential impacts of a renewable resources option but has not identified particular renewable resource projects to support. The alternative is designed to allow the Sierra Nevada Region to either purchase renewables directly or to support customers' projects. Section 2.3.6 of the final 2004 EIS has been revised to reflect this comment. These revisions, along with updates to energy market rates, reduce the maximum level of renewables that could be purchased or supported in the renewables alternative.

Comment No.:D004-05

Comment: Western has seriously overestimated the amount of renewables it can purchase and remain competitive. The overestimate occurs through optimistic underesti mates of the costs of renewables not fully accounting for, among other things, either expensive California land costs or transmission costs and losses from lower land cost areas. Using Western's data, the melded cost of the equal MW share portfolio of wind, photovoltaics, geothermal, and biomass calculates out to $97.58/MWh in 2005. While this underestimated resource cost is not cheap, it rises an additional 40 mills if the 35% biomass energy (at a melded cost of $80.62/MWh) is removed.

Response: As discussed in Comment No. D003-10, cost assumptions about renewables were revisited, and updated information was used in the final 2004 EIS. These changes resulted in a purchase level of 50 MW in the final 2004 EIS as compared to 250 MW in the draft 2004 EIS. Estimated melded costs for the four renewable resources included in the draft 2004 EIS analysis amounted to $143.87/MWh with biomass and $136.06/MWh without biomass. The melded cost in the final 2004 EIS amounts to $165.25/MWh with biomass and $189.48/MWh without biomass.

Comment No.:D004-06

Comment: In interpreting the graph on 2.17 to mean that SNR could economically survive the purchase of 250 MW of renewable resource acquisition, Western is making 5 [7] noticeable errors:

1) Betting its survival on the possibly biased price estimates of renewable technology advocates. (It would be more reasonable to include a safety factor on the price estimates and to include the cost of land transmission and losses.)

2) Betting its survival on possibly biased future potential price reduction esti mates. (It would be more reasonable to use current state of the art pricing of these technologies.)

3) Using too old (high) a price estimate for the economy and firm energy markets. (With full scale competition expected before 2005, it would be more reasonable to assume a 26 mill rate for firm power and an economy rate of 21 mills in 2005.)

4) Looking at having intermittent renewable resources displacing firm market alternatives. (It would be more reasonable to use the economy market price for comparison or to add the cost of consuming the CVP's ability to firm intermittent resources to the effective renewable prices.)

5) Not recognizing that the environmentally preferable alternative of elimi nating biomass raises the renewable melded portfolio cost by 40% and thereby lowers Western's MW subsidizing capability by 40%. (Since bio mass has undesirable impacts it would make sense to recalculate the renewable portfolio cost without it prior to estimating how much renew able resource it takes to drive Western into an uncompetitive position.)

6) Not incorporating the CVPIA restoration fund charge in the effective Western rate tends to make Western rates look more attractive than they really are. (It would be more reasonable to include a 1.5 mill restoration fund adder in the Western rate.)

7) Not recognizing the rate impact of the Portland General Electric resource purchase that when blended with 18 mill CVP power will hold Western rates about 24 mills in 2005. (It would be more reasonable to add in the 6 mill impact of the PGE contract.)

Estimate that incorporating these refinements in the analysis leading to a revised Figure 2.4 will accurately portray the unfortunate reality that SNR will not be economically able to unilaterally subsidize the development of large amounts of expensive renewable resources.

Response: The data and assumptions used in the graph on page 2.17 (Fig. 2.4) have been extensively revised. The final 2004 EIS contains updated assumptions and data. Revised data resulted in the 250 MW level contained in the graph being reduced to 50 MW.

1&2)Renewable resource price assumptions have been changed. Information from the literature was used to develop the cost estimates. Specific land values and transmission charges are not incorporated into the costs. Information about specific project characteristics would be needed to do so.

3) Market rate projections for energy have been updated.

4) The final 2004 EIS uses the forecasted average annual market energy rate as the benchmark for determining the level of renewable resources that may be competitively melded with CVP resources. Use of this benchmark tends to recognize the nonfirm and inconsistent nature of the wind resource contained within the renewable category modeled. Note that the geothermal, photovoltaic, and biomass resources are normally more pre dictable in their generation patterns.

5) The renewables alternative without biomass has been adjusted to remove the biomass costs from the melded cost of the renewable resources. The revised analysis of the renewables alternative is shown in Section 4.2.5. For additional information see responses to Comment Nos. D003-03, D003-10, D003-11, D004-04, and D004-05.

6) Costs of the Restoration Fund have already been incorporated into the 2004 EIS analyses.

7) Western assumed all existing purchase power contracts would be modified or terminated after 2004.

Comment No.:D004-07

Comment: There is presently a two-tier energy pricing rate, contrary to the characteriza tion presented in the no-action alternative.

Response: A tiered rate results from a rate design that affects individual customers in dif ferent ways, depending on their load factor. A single average composite rate was therefore used to better represent customer groups. Individual customers were not analyzed. Although the Sierra Nevada Region is currently using a two-tier energy pricing rate, a composite power cost figure was used in the no- action and action alternative analyses to represent the average revenue expected from CVP customers. This approach is useful in analyzing the socioeconomic effects of the alternatives. The subject of the 2004 EIS process is the develop ment and adoption of Sierra Nevada Region's Power Marketing Plan to market power from the CVP and Washoe Project beyond the year 2004. Rates are not analyzed as part of this EIS process, except as average power costs. Rate issues will be addressed within Sierra Nevada Region's long-established public ratemaking process.

Comment No.:D004-09

Comment: On page 2.23, Western states the analysis of changing allocation levels for dif ferent customer groups in 2005 "was based on an assumption of a competitive wholesale electric market and a noncompetitive retail electric market." Events of the past two years point to the development of significant competitive alterna tives for the retail customers before 2005 and intense competitive pressures on Western's utility customers.

Response: The Sierra Nevada Region agrees and has changed the analysis accordingly. For more information see responses to Comment Nos. D003-05 and D003-14.

Comment No.:D004-10

Comment: On page 2.24, Western asserts that the difference between market wholesale rates and Western rates for utility customers is "relatively low." Yet the graph on page 2.17 shows Western rates with zero renewable purchases as $17/MWh and market prices for firm energy being $36/MWh, a difference of over 100%. Clearly this is not a minor difference, so this assertion and any dependent con clusions should be revised.

Response: The statement at the top of page 2.24 indicating a relatively low difference between Sierra Nevada Region rates and the wholesale market rates was based on a comparison of market rates available to the utility group and the PG&E partial requirements rates which formed the alternative to the Sierra Nevada Region rate for the agriculture and other customer groups. Note that in the final 2004 EIS, this differential has been minimized because of changes in assumptions about industry restructuring.

Industry restructuring is assumed to provide all customer groups with direct access to wholesale power markets, removing any differentials between customer groups.

Comment No.:D004-11

Comment: Page 2.24 claims decreases in Western allocations to utility customers will have positive economic effects. There would be substantial adverse economic effects to residential, commercial, and industrial customers of Utilities if their Western allocations were reduced. Request that Western revise this conclusion to reflect the reality that any decrease in allocation of Western power to Utility customers will have adverse economic impacts. This is true because Western power pro vides significant benefit to its customers compared to market alternatives. Shift ing allocation from Utility customer partners of Western to Agriculture (agri business) customers would merely increase the benefits to those businesses (shareholders) at the expense of the consumer-owned utility rate payers. With out any assistance from Western, the retail customers in SNR's service territory will be gaining significant cost advantages at the expense of utilities who must compete to market their power. To exacerbate that shift of benefits and costs by decreasing Utility allocations to increase end user allocations has grave unex amined consequences for the consumer-owned utility customers.

Response: The Sierra Nevada Region agrees and has changed the analysis accordingly. For more information see responses to Comment Nos. D003-05 and D003-14.

Comment No.:D004-12

Comment: On page 3.74, Western asserts that Western and its customers have the same market access and face the same price structures for supplemental power pur chases. In reality, Western has several hundred megawatts of transmission to the Pacific Northwest and spinning reserves from the CVP which enable Western to access resources more effectively than the customers otherwise could. This assumption should be corrected. Western should recognized this advantage and evaluate an alterantive which uses these resources to make short- term pruchases to support CVP sales. Request that a reasonable level of short- term and nonfirm purchases specifically tailored to meet the CVP resource needs to be evaluated in the DEIS.

Response: Sierra Nevada Region customers were modeled as groups, not individually. The statement that Sierra Nevada Region and its customers have similar market access is based on the fact that the Sierra Nevada Region utility customer group has market access and transmission rights (either through ownership or contract) which collectively exceed Sierra Nevada Region's rights. The Sierra Nevada Region's utility customer group may currently access the Northwest and com pete with the Sierra Nevada Region to purchase power from that region. To the extent that the utility industry is restructured, any advantages one group may have relative to another will be further reduced.

O.1.5 Northern California Power Agency

Comment No.:D005-01

Comment: The alternatives described for the amount and type of power to be marketed are not completely developed into a cohesive power product.

Response: See Response to Comment No. D003-02.

Comment No.:D005-02

Comment: The tent stake approach of the DEIS creates an enormous range of marketing plan possibilities; many of which are beneficial to Western's existing partners and many of which are not.

Response: The Sierra Nevada Region agrees that there are many marketing plan possibili ties. NEPA requires that the entire range of reasonable alternatives to a pro posed action be analyzed. Another approach would have been to analyze a number of complete, specific marketing plan alternatives, knowing that the final plan would not be exactly like any of the alternatives, and running the risk that the EIS analysis would not cover some aspect of the plan, thus requiring addi tional environmental analysis. The Sierra Nevada Region elected to utilize a tent stakes approach to ensure that all reasonable alternatives were addressed, and that the draft 2004 EIS could not be challenged on adequacy grounds. The final 2004 EIS focuses on a plan, and associated impacts, closer to what the Sierra Nevada Region believes will be the final plan after further refinement in the Administrative Procedure Act process. Further explanation is contained in the response to Comment No. D003-02.

Comment No.:D005-03

Comment: It is unclear why the 450 and 900 MW levels of purchases and their associated 15 and 85 percent capacity factors were selected for both the peaking and base load sales alternatives. It would be more informative to model purchase levels that meet the needs of the project which vary significantly from month-to-month and year-to-year depending on hydrology, load, etc. More realistic assumptions need to be used in the analysis so the DEIS analysis is more representative of expected conditions. With Western's transmission and spinning reserve resources, Western can find more flexible, short term, attractive supplemental power supplies that would bring more value to customers.

Response: The 450 and 900 MW levels and associated capacity factors of 15 percent and 85 percent were selected only as a means of setting out **approximate ranges** for potential purchases. It should be noted that Sierra Nevada Region sales to cus tomers were modeled as a function of economic dispatch between Sierra Nevada Region power and other resources available to the customers. The different levels and types of purchases resulted in varying costs of melded Sierra Nevada Region power and hence the competitiveness of Sierra Nevada Region power relative to other sources. The intent of using this type of approach in the EIS is to allow the Sierra Nevada Region as much latitude as possible in its ultimate marketing plan. Note the 2004 EIS studies the boundaries within which the final marketing plan can be crafted. The preferred alternative is a scenario representative of what the final marketing plan might look like after further public input in the marketing plan public process.

Comment No.:D005-04

Comment: Concerned that Western's analysis of the renewable purchase option is too sim plistic and optimistic and that it may create an expectation that Western should sacrifice its partners' (Customers') interests in retaining the economical resource that they have funded for many years in order to support large quantities of non-hydro renewable techonology purchases.

Response: The Sierra Nevada Region assessed the potential impacts of a renewable resources option but has not identified particular renewable resource projects to support. The alternative is designed to allow the Sierra Nevada Region to either purchase renewables directly or to support customer's projects, and to generic ally define the potential environmental impacts of renewable purchases. Speci fic projects would require additional analysis, including an assessment of eco nomic viability, and opportunities for public comment.

Comment No.:D005-05

Comment: Western has seriously overestimated the amount of renewables it can purchase and remain competitive. The overestimate occurs through optimistic underesti mates of the costs of renewables not fully accounting for, among other things, either expensive California land costs or transmission costs and losses from lower land cost areas. Using Western's data, the melded cost of the equal MW share portfolio of wind, photovoltaics, geothermal, and biomass calculates out to $97.58/MWh in 2005. While this underestimated resource cost is not cheap, it rises an additional 40 mills if the 35% biomass energy (at a melded cost of $80.62/MWh) is removed.

Response: As discussed in Comment No. D003-10, cost assumptions about renewables were changed in the final 2004 EIS. These changes resulted in a purchase level of 50 MW in the final 2004 EIS as compared to 250 MW in the draft 2004 EIS. Estimated melded costs for the four renewable resources included in the draft 2004 EIS analysis amounted to $143.87/MWh with biomass and $136.06/MWh without biomass. The melded cost in the final 2004 EIS amounts to $165.25/MWh with biomass and $189.48/MWh without biomass.

Comment No.:D005-06

Comment: In interpreting the graph on 2.17 to mean that SNR could economically survive the purchase of 250 MW of renewable resource acquisition, Western is making 5 [7] noticeable errors:

1) Betting its survival on the possibly biased price estimates of renewable technology advocates. (It would be more reasonable to include a safety factor on the price estimates and to include the cost of land transmission and losses.)

2) Betting its survival on possibly biased future potential price reduction esti mates. (It would be more reasonable to use current state of the art pricing of these technologies.)

3) Using too old (high) a price estimate for the economy and firm energy markets. (With full scale competition expected before 2005, it would be more reasonable to assume a 26 mill rate for firm power and an economy rate of 21 mills in 2005.)

4) Looking at having intermittent renewable resources displacing firm market alternatives. (It would be more reasonable to use the economy market price for comparison or to add the cost of consuming the CVP's ability to firm intermittent resources to the effective renewable prices.)

5) Not recognizing that the environmentally preferable alternative of elimi nating biomass raises the renewable melded portfolio cost by 40% and thereby lowers Western's MW subsidizing capability by 40%. (Since biomass has undesirable impacts it would make sense to recalculate the renewable portfolio cost without it prior to estimating how much renew able resource it takes to drive Western into an uncompetitive position.)

6) Not incorporating the CVPIA restoration fund charge in the effective Western rate tends to make Western rates look more attractive than they really are. (It would be more reasonable to include a 1.5 mill restoration fund adder in the Western rate.)

7) Not recognizing the rate impact of the Portland General Electric resource purchase that when blended with 18 mill CVP power will hold Western rates about 24 mills in 2005. (It would be more reasonable to add in the 6 mill impact of the PGE contract.)

Estimate that incorporating these refinements in the analysis leading to a revised Figure 2.4 will accurately portray the unfortunate reality that SNR will not be economically able to unilaterally subsidize the development of large amounts of expensive renewable resources.

Response: 1&2)Renewable resource price assumptions have been changed. Information from the literature was used to develop the cost estimates. Specific land values and transmission charges are not incorporated into the costs. Infor mation about specific project characteristics would be needed to do so.

3) Market rates have been updated.

4) The final 2004 EIS uses the forecasted average annual market energy rate as the benchmark for determining the level of renewable resources that may be competitively melded with CVP resources. Use of this benchmark tends to recognize the nonfirm and inconsistent nature of the wind resource contained within the renewable category

modeled. Note that the geothermal, photovoltaic, and biomass resources are normally more pre dictable in their generation patterns.

5) The renewables alternative without biomass has been adjusted to remove the biomass costs from the melded cost of the renewable resources. The revised analysis of the renewables alternative is shown in Section 4.2.5. For additional information see responses to Comments Nos. D003-03, D003-10, D003-11, D004-04, and D004-05.

6) Costs of the Restoration Fund have already been incorporated into the 2004 EIS analyses.

7) If the Portland General Electric contract remains in effect in its present form, it would add 6 mills to Sierra Nevada Region's rates and would reduce the differential between Sierra Nevada Region's anticipated rates and market rates. This would reduce the amount of renewables that could be purchased and still have CVP power priced at a competitive rate, but would have a negligible effect on the 2004 EIS conclusions.

Comment No.:D005-07

Comment: There is presently a two-tier energy pricing rate, contrary to the characterization presented in the no action alternative.

Response: See D003-04 Response.

Comment No.:D005-08

Comment: Agree with Section 4.2.4.4 that higher purchased energy costs in the disaggre gated cost case should result in less purchased power being used to meet load since customers can make better resource decisions when costs are disaggre gated so their true impacts can be identified.

Response: The analyses of effects of aggregating and disaggregating rates have been refined in the final 2004 EIS to incorporate more current projections of future power costs than were used in the draft 2004 EIS. The conclusion noted in the comment still holds.

Comment No.:D005-09

Comment: On page 2.23, Western states the analysis of changing allocation levels for dif ferent customer groups in 2005 "was based on an assumption of a competitive wholesale electric market and a noncompetitive retail electric market." Events of the past two years point to the development of significant competitive alterna tives for the retail customers before 2005 and intense competitive pressures on Western's utility customers.

Response: The Sierra Nevada Region agrees and has changed the analysis accordingly. For more information see responses to Comment Nos. D003-05 and D003-14.

Comment No.:D005-10

Comment: On page 2.24, Western asserts that the difference between market wholesale rates and Western rates for utility customers is "relatively low." Yet the graph on page 2.17 shows Western rates with zero renewable purchases as $17/MWh and market prices for firm energy being $36/MWh, a difference of over 100%. Clearly this is not a minor difference, so this assertion and any dependent con clusions should be revised.

Response: The statement at the top of page 2.24 indicating a relatively low difference between Sierra Nevada Region rates and the wholesale market rates was based on a comparison of market rates available to the utility class and the PG&E partial requirements rates which formed the alternative to the Sierra Nevada Region rate for the agriculture and other customer classes. Note that in the final 2004 EIS, this differential has been removed. Industry restructuring is assumed to provide all customer classes with direct access to wholesale power markets, removing any differentials between customer classes.

Comment No.:D005-11

Comment: Page 2.24 claims decreases in Western allocations to Utility customers will have positive economic effects. There would be substantial adverse economic effects to residential, commercial, and industrial customers of Utilities if their Western allocations were reduced. Request that Western revise this conclusion to reflect the reality that any decrease in allocation of Western power to Utility customers will have adverse economic impacts. This is true because Western power pro vides significant benefit to its customers compared to market alternatives. Shifting allocation from Utility customer partners of Western to Agriculture (agribusiness) customers would merely increase the benefits to those businesses (shareholders) at the expense of the consumer-owned utility rate payers. With out any assistance from Western, the retail customers in SNR's service territory will be gaining significant cost advantages at the expense of utilities who must compete to market their power. To exacerbate that shift of benefits and costs by decreasing Utility allocations to increase end user allocations has grave unex amined consequences for the consumer-owned utility customers.

Response: Please see responses to Comment Nos. D003-05, D003-14, and D004-09.

Comment No.:D005-12

Comment: On page 3.74, Western asserts that Western and its customers have the same market access and face the same price structures for supplemental power pur chases. In reality, Western has several hundred megawatts of transmission to the Pacific Northwest and spinning reserves from the CVP which enable West ern to access resources more effectively than the customers otherwise could. This assumption should be corrected. Western should recognized this advantage and evaluate an alternative which uses these resources to make short-term pur chases to support CVP sales. Request that a reasonable level of short-term and nonfirm purchases specifically tailored to meet the CVP resource needs to be evaluated in the DEIS.

Response: The statement that the Sierra Nevada Region and its customers have similar market access is based on the fact that the most utility customers of the Sierra Nevada Region have market access and transmission rights (either through own ership or contract) which in some cases exceed Sierra Nevada Region's rights. Currently, the utility class of customer may access the Northwest and compete with the Sierra Nevada Region to purchase power from that region. To the extent that the utility industry is restructured, any advantages one group may have relative to another will be further reduced. The suggestion to craft speci fic purchases to meet CVP resource needs and to evaluate them in the document was not performed since the purpose of the EIS is to consider a range of possi ble alternatives and not attempt to represent an optimum resource purchase scenario. Also see response to D004-3.

O.1.6 City of Redding

Comment No.:D006-01

Comment: On page 2.4, Summary of Environmental Impacts, Western stated that decreas ing the allocation to SNR's utility customers leads to the most positive economic impact while increasing the allocation to that group results in the most negative economic effects of the allocation scenarios. The result of this type of alloca tion change would have significant adverse economic impacts to the utility cus tomer group and, therefore, to the customers we serve. The customers served by utilities obtain significant economic benefit from Western power compared to other resources. Also, and maybe more importantly, the preference power util ity group have structured their power supply highly integrating the Western resource. This structure provides a highly efficient method of maximizing the benefit of Western power to as many diverse customers as possible. Suggest that Western reconsider its conclusion on the economic impacts of changing allocation between customer groups.

Response: The Sierra Nevada Region agrees and has changed the analysis accordingly. For more information see responses to Comment Nos. D003-05 and D003-14.

O.1.7 Tuolumne Public Power Agency

Comment No.:D007-01

Comment: Refer to Sections 3.0 and 4.0, which discuss environmental effects and environ mental consequences. Generally, there is very little in these sections which addresses the economic impacts that alternative marketing proposals will have on the customers of Western and the residents they serve. Specifically, there is no discussion of the economic impacts that the alternatives will have on the Counties of Origin. Our previous comments about the 2004 Plan have pointed out that the Counties of Origin have sacrificed much because of the Federal hydroelectric projects. Taking any further actions which will jeopardize our power allocations will inflict further harm on our already fragile economy. Believe the EIS must discuss these potential impacts and propose possible miti gation measures.

Response: Economic impacts were evaluated for groups of customers rather than for speci fic customers. No changes in entitlement rights to counties of origin were specifically evaluated because, by law, up to 25 percent of the power generated from the New Melones Powerplant within the CVP must first be offered to pref erence customers in Tuolumne and Calaveras counties. See Appendix A of the final 2004 EIS for further information about the legal and statutory framework.

O.1.8 Bay Area Rapid Transit District

Comment No.:D008-01

Comment: The FEIS needs to provide a sufficient basis for including power allocation cri teria in the 2004 Plan that recognize potential air quality and energy conserva tion benefits associated with electricity allocations to specific end-uses.

Response: Specific allocation criteria will be determined in the Administrative Procedures Act process, not the NEPA process.

Comment No.:D008-02

Comment: Pleased to see that Volume II of the DEIS recognizes the possible linkage between electricity end-use and air quality, page 2.8. However, the equally important relationship between energy conservation and end-use does not appear to be addressed. SNR should modify the DEIS as necessary so that it encom passes both energy use and air quality benefits, in connection with electricity end-use, as possible allocation criteria in the 2004 Plan.

Response: The text has been modified to include energy conservation in the example pro vided on page 2.8 of the draft 2004 EIS.

O.1.9 U.S. Environmental Protection Agency

Comment No.:D009-01

Comment: Policies such as contract length, ratesetting, and DSM have been analyzed and set in arenas outside the 2004 DEIS. In the case of the PMI, any decision applicable to SNR was apparently deferred pending, among other matters, com pletion of the 2004 Plan. Although the DEIS briefly mentions some of these related activities, the information provided on page 2.4 and Appendix A, is dif ficult for a reader unfamiliar with power planning and allocation to understand how these actions are interrelated and at what point(s) specific decisions affecting actual power contracts will be made. The DEIS is lacking a context which accounts for important related decisions, such as degree of DSM, length of contract terms, and rates. The DEIS states that many EPAMP provisions for power marketing and integrated resources planning are incorporated by refer ence, but provides no summary. Recommend that the FEIS provide an expanded version of components which describe, at a minimum, the decisions stemming from EPAMP and any other policy decisions which significantly frame SNR power marketing alternatives or rely on the 2004 Program for region-specific implementation.

Response: The description of the Energy Planning and Management Program EIS and in Sections 1.6.2 and 2.2.3 have been expanded to address the points raised in the comment.

Comment No.:D009-02

Comment: How decisions from the 2004 Program and related actions will be carried out is unclear. Recommend that the FEIS, in addition to indicating the preferred alternative, should very clearly identify the decisions which will be entered into the ROD and explain the next steps in implementation. Will certain issues not be resolved in the ROD but be left open for decision at a later date, or in a more specific context? For example, when or under what circumstances, does Western anticipate making decisions regarding purchase of additional power from other suppliers?

Response: Sections 1.1 and 2.2.3 have been expanded to address the points raised in the comment.

Comment No.:D009-03

Comment: Because of potential effects on customer's energy demands, determination of power costs and ratesetting are issues of particular interest. Although related to power marketing, these issues are not among the 2004 Program alternative com ponents other than consideration of aggregate or disaggregate costs of power.

Response: Rates and rate designs are set through a separately defined public process that has its own environmental review. Because a power marketing plan covers a span of many years, a number of rate setting actions can occur within that time span.

Comment No.:D009-04

Comment: Suggest that the FEIS briefly explain how CVP costs, including Restoration Fund and irrigation assistance affect power rates, and discuss potential effects which CVPIA implementation might have on future rates. Suggest that the FEIS explain how CVPIA implementation might affect the power requirements for project uses (pages 1.7 and 1.9).

Response: The effects of implementation of the Central Valley Project Improvement Act (CVPIA) are being analyzed in an EIS being prepared by the Department of the Interior, which is described in Section 1.6.1. Western is a cooperating agency on Interior's EIS, and may comment on issues such as the one raised in this comment within the CVPIA

EIS process. A set of CVP hydrological assump tions described in Chapter 3 and Appendix D anticipate a potential outcome of CVPIA implementation. However, CVPIA implementation is not part of the Sierra Nevada Region's proposed action and does not meet the purpose and need for the 2004 Power Marketing Program EIS. Thus, it is not appropriate to include a detailed analysis of the effects of the CVPIA in this 2004 EIS. West ern is required by law to adopt rates that will recover certain costs, including operation, restoration fund, and capital costs assigned to power for repayment. If, through CVPIA implementation actions the restoration fund charges to power users are changed (increased or decreased), Western's rates would increase or decrease commensurately to ensure cost recovery as required by law. The CVPIA restoration fund was assumed to be approximately $7 million in the 2004 EIS model analyses.

Comment No.:D009-06

Comment: Suggest that the FEIS discuss whether, in implementing the CVPIA, any adjust ments related to power operations have been made or are being considered in response to CVPIA Section 3406(b)(9) (a requirement to "develop and imple ment a program to eliminate, to the extent possible, losses of anadromous fish due to flow fluctuations caused by the operation of any CVP storage or regulat ing facility").

Response: The actions contemplated in the 2004 Power Marketing Program are secondary to potential water operations decisions made by the Bureau of Reclamation for fisheries enhancement. Reclamation changes in water operations may cause changes in Western's power operations. The effects of Western's actions are limited to the regulating reservoirs. Hydro operations for power generation were found to have no measurable effects on flows and temperatures below regulating reservoirs.

Comment No.:D009-07

Comment: The DEIS does not specifically explain the basis for concluding that power operations at Keswick (a regulating facility with 105,000 kW maximum oper ating capability) would not affect flows downstream. Is this facility operated solely for water supply and environmental requirements, and would the opera tional alternatives discussed in the DEIS have no effect at this facility? This should be clarified in the FEIS.

Response: The 2004 EIS states in Section 3.3.2 that "Keswick Reservoir is operated as a regulating reservoir for upstream power plants and eliminates downstream flow fluctuations in the Sacramento River related to power operations....The opera tion of Keswick Reservoir and Spring Creek Powerplant is coordinated to pre vent scouring of metal sludge deposited from the Iron Mountain Mine in the Spring Creek arm of the reservoir." Although power is generated at Keswick Dam, such generation is incidental to water operations that control downstream releases and operations would not change for purposes of electric generation.

Comment No.:D009-08

Comment: The statement on page 2.19 that "regulating dams are operated to maintain con stant releases downstream" (emphasis added) does not accurately characterize operations of these facilities and should be reworded in the FEIS.

Response: The words "maintain constant" has been replaced with the word "control."

Comment No.:D009-09

Comment: The modeling analysis concludes that under the peaking alternative the hydro power system could, in comparison with a baseload operations scenario, offset up to 941 MW of electric generating capacity from other sources (page 4.59). Conversely, the DEIS estimates that selecting the baseload alternative would mean that "up to 941 MW of replacement electric generating capacity...will eventually need to be built" (page 2.19). This calculation requires assumptions regarding certain future levels of demand management. The FEIS should explain assumed demand-management efforts, making distinctions between user groups if appropriate. Also, what levels of demand management does Western expect of its customers in integrated resources planning?

Response: In the draft 2004 EIS, the 941 MW of displaced electric generating capacity refers to the difference between what the hydropower system could produce if run as a peaking resource and what it would produce as a baseload resource. Only the timing of water releases running through the generators causes this change. The number in the final 2004 EIS has changed slightly from the draft to 898 MW.

For purposes of the NEPA analyses, all of the alternatives, including baseload and peaking, are assumed to meet the same load. The 898 MW of lost genera tion capacity available to meet load constitutes a loss of existing capacity that must be replaced with another resource to maintain system integrity and avail able capacity levels. DSM efforts are not related to this specific difference in capacity. Even though electric load must be met, this final 2004 EIS shows that 898 MW more of that load can be met by operating the CVP in a peaking operations mode versus a baseload mode.

Refer to the EPAMP EIS for an analysis of integrated resource planning and demand-side management.

Comment No.:D009-10

Comment: The alternatives analysis is framed principally for the year 2005. When the DEIS refers to impact analysis beyond that date, the timeframe is not clear (for example, page 2.19, in the reference to additional replacement capacity). The justification for the 2005 timeframe should be explained in the FEIS, particu larly when the duration of decisions (for instance, length of contracts), and potential effects of decisions made when marketing power will extend beyond 2005.

Response: The year 2005 is used because the power sales contracts expire at the end of 2004. New power sales contracts would begin in 2005. Earlier implementation of new contracts is not expected until after the PG&E integration contract 2948A expires or is modified, and it is expected to remain in effect until its scheduled expiration at the end of 2004. Western concluded that extending the impact assessments beyond this date would unnecessarily increase the complexity and uncertainty of the EIS analyses. The nature and negligible magnitude of impacts found for 2005 do not warrant further analyses of the succeeding years.

Comment No.:D009-11

Comment: Page 2.7 states that one element of analysis of "[p]otential effects of various products and services" is the "implicit effect that certain combinations of hydro power operations and power purchases have on product and service availability" (emphasis added). The reference to "implicit" effect needs explanation: What effects might different combinations of operations and power purchases have, and could certain customer groups be affected differently?

Response: This sentence is intended as a list of analytical approaches and has been rewrit ten to make its meaning more clear.

Comment No.:D009-12

Comment: The FEIS should explain policies regarding future allocation of power which has been under contract to military bases scheduled for closure before 2004.

Response: After 2004, allocations of power from base closures will be treated the same as any other federal power available for allocation. All federal power will be allo cated pursuant to allocation criteria developed through the marketing plan public process. This process will define the specific services to be offered to indivi dual power customers as well as the criteria for allocating resources to be marketed.

Comment No.:D009-13

Comment: A schematic drawing of the CVP and Washoe Project facilities described in the text (page 3.6) would be very helpful for portraying locations and interconnec tions.

Response: A drawing has been included in Section 3.2.

Comment No.:D009-14

Comment: Has the assumption been made that Stampede power would be integrated with the CVP for the purposes of marketing and pricing? Are there socioeconomic effects which distinguish this approach from a decision not to integrate the projects?

Response: The analysis in the 2004 EIS does not assume the integration of Stampede power with CVP power. The quantity of Stampede power is too small to affect the outcome of the 2004 EIS models. As stated in the introduction to Chap ter 3, the Sierra

Nevada Region has no operating discretion at the Washoe Project, and thus operating conditions will not change as a result of the 2004 Marketing Plan. Integrating Stampede power with CVP power does not mean costs and revenues related to Stampede power generation would become part of the CVP costs and revenues. A repayment plan for Washoe would be addressed during a separate public process. Socioeconomic impacts would not change, given that operation of the Stampede project would not change.

Comment No.:D009-15

Comment: On page 4.37, 2nd paragraph states that the no action alternative itself ("analy sis of the no action alternative") was modeled with "varying levels of capacity allocations...imposed on the baseline and marketing scenario." Presume that these variations were performed for analysis of the action alternatives in com parison with "no action." This should be clarified in the FEIS.

Response: The discussion has been rewritten for clarification. The text describes the analysis of allocations to customer groups.

O.2 Comments Received at the June 13, 1996, Public Hearing

O.2.1 R.M. Hairston & Company on behalf of Bay Area Rapid Transit District

Comment No.:D010-01

Comment: The EIS should allow for the possibility of allocations made by Western intended to maximize air quality benefits as well as energy efficiency benefits. Western should be certain that the statement in the FEIS is legally sufficient in scope to allow for the possibility of customer specific allocations intended to maximize air quality and energy efficiency benefits.

Response: The EIS neither precludes nor promotes allocations to customers who intend to maximize air quality and energy efficiency benefits. Specific allocations to customers will be defined under allocation criteria developed in the APA process.

O.2.2 Sacramento Municipal Utility District

Comment No.:D011-01

Comment: Concerned that the assumption on page S.6 that the cost of renewable resource technology will drop substantially between now and 2005; that the power mar ket will have substantially higher costs; and that we may be excluding some long-term power purchase contracts, which Western may or may not be able to relieve themselves of at prices higher than the market. All three of these factors would tend to decrease the amount of renewable technologies that Western can accommodate mixing into their existing hydroelectric system to achieve a wholesale price which is competitive with the market. Western should either (1) redo the renewable resource tent stake, incorporating updated assumptions on renewable technology costs which reflect an escalation based on what costs are today; or (2) use a market price assumption (25 percent lower than in the DEIS); and also include an element of firm power purchase commitments which do not currently exist.

Response: Section 2.3.6 of the final 2004 EIS has been revised to reflect this comment. These revisions, along with updates to energy market rate projections, have resulted in a reduction on the maximum level of renewables that could be pur chased or supported in the renewables alternative. The changes resulted in a purchase level of 50 MW in the final 2004 EIS as compared to 250 MW in the draft 2004 EIS. Estimated melded costs for the four renewable resources included in the draft 2004 EIS analysis amounted to $143.87/MWh with bio mass and $136.06/MWh without biomass. The melded cost in the final 2004 EIS amounts to $165.25/MWh with biomass and $189.48/MWh without bio mass. Analyses were completed based on the most likely conditions following the year 2004. Western assumed all existing purchase power contracts would be modified or terminated after 2004.

O.2.3 City of Palo Alto

Comment No.:D012-01

Comment: Western customers could be singled out to carry more of the national load for renewable resource development than we can handle in California's competitive environment. The renewable resource tent stake needs to be reexamined with the changes previously [D011-01] mentioned. The DEIS suggests a 250 MW fixed purchase level would be the most that could possibly be afforded under the market forecast. It is possible the cost for renewable resources could quad ruple over the next 8 years. The DEIS is very optimistic regarding renewable resources.

By committing to 250 MW of renewables you are committing SNR to two things: 1) the market essentially quadruples; and, 2) the price of renewables plummets. It seems risky to bet that future on both having to happen; not just one or the other but both.

It was unclear whether the cost of the CVPIA Restoration Fund was included. This is a volatile fund charge of several mills per kilowatthour. This cost already consumes much of what might be available to support other environ mentally beneficial programs.

Western is encouraged to examine the renewables tent stake, and to keep in mind the rapid development and changes that will be occurring in the California Legislature over the next couple of weeks.

Response: The 250 MW figure for renewables used in the draft 2004 EIS was not a com mitment to a firm number but an estimate of the quantity of power from renew able resources that could be included in Sierra Nevada Region's resource mix without exceeding market costs. As stated in the response to D011-01 above, the final 2004 EIS has been revised to update energy market rate projections and employ a more conservative estimate of future reductions in renewables costs. Together, these changes cause a reduction in the maximum level of renewables that could be purchased or supported in the renewables alternative to an estimated 50 MW.

CVPIA restoration fund charges to federal power users were factored in to the post-2004 analyses at a level comparable to that being charged presently to support the restoration fund (approximately $7 million per year).

Appendix P
Contractor Disclosure Statements

In accordance with 40 CFR 1506.5(c), contractors involved in the NEPA environmental review process must sign a statement, prepared by Sierra Nevada Region, certifying that the contractor has no financial or other interest in the outcome of the EIS. The disclosure statements for Pacific Northwest Laboratory/Battell, R. W. Beck, Woodward-Clyde Consultants, and Water Resources Management, Incorporated, are included in this section.