Impact of Bay-Delta Water Quality Standards on California's Electric Utility Costs

Prepared for
the Association of California Water Agencies

by
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Presented to
the State Water Resources Control Board
Bay-Delta Workshop

October 19, 1994

Sacramento, California

Issues Addressed in the Study

- How will alternative standards affect operations of California's hydroelectric system, in particular that of the Central Valley Project?

- How will changes in hydro generation affect the production and dispatch of non-hydro generated power?

- How will alternative standards affect Central Valley Project and State Water Project pumping in the Delta and their related demands for electricity?

- How will alternative standards affect agricultural groundwater pumping and its related demand for electricity?

- What changes in air pollution emissions will result from changes in hydropower availability and load patterns?

- And finally, what are the economic costs (or benefits) associated with the above-listed adjustments?

Methods Used			
Issue	**Model**	**Impact**	**Reference or Source**
CVP Hydropower	PROSIM / DWRSIM	Generation Resources	WRMI / DWR
CVP Pumping	PROSIM / DWRSIM	Pumping Load	WRMI / DWR
Groundwater Pumping	Econometric / CVPM	Agricultural Load	PG&E Data / US EPA
N. California Generation Costs	Elfin	System Energy Costs	CEC ER-94
N. California Air Quality	Elfin	Generation Emissions	CEC ER-94
N. California Capacity Needs	Econometric / PROSYM	System Capacity Additions	CPUC (PG&E) / WAPA (CVP)

Policy Alternatives Evaluated

- Base Case: D-1485 Conditions
- Alternative 1: EPA Proposal
- Alternative 2: SWRCB Staff
- Alternative 3: CUWA

Costs Equal Weighted Average of Water-Year Type Scenarios:

- Dry Conditions (20th Percentile)
- Median Conditions (50th Percentile)
- Wet Conditions (75th Percentile)

Comparison of Alternative Policy Proposals to the State Water Resources Control Board		vs. Base Case #1: D.1485		
Cases	Annualized Cost	NPV Cost 1995-2010	Annualized Cost Per AF	NPV Cost per AF
Alternative #1: EPA	$41.1 Million	$365 Million	$84	$744
Alternative #2: Staff	$46.4 Million	$412 Million	$72	$638
Alternative #3: CUWA	$46.4 Million	$412 Million	$82	$723

Findings and Recommendations

(1) **The results presented here demonstrate that past and proposed standards impose costs--not benefits--on the electric utility system,** unlike previous analyses of the impacts from Bay-Delta environmental protections (e.g., the winter-run salmon critical habitat designation).

(2) The cost impacts on the utility system are real and significant. **Net present value costs of some alternatives approach one-half billion dollars.**

(3) **The cost impacts are not spread uniformly among the state's citizens:**

- Hydropower impacts among CVP project customers
- Water pumping costs among agricultural sector
- Air quality costs among local residents near thermal generating plants

(4) **The assumptions used are conservative**; costs to the electricity system could be significantly greater than reported here:

- Increased groundwater pumping may be higher due to deliveries being shifted through the year and uncertainty of supply.
- Hydropower generation on the Merced and Tuolumne Rivers was assumed not to change due to the uncertainty over how standards at Vernalis will be met.
- Further restrictions on PG&E's fossil-fueled plants located on Suisun Bay have not been included.
- Impacts on the SWP power system and linkages to Southern California air quality changes were not analyzed due to the complexity of the relationships.

(5) **Releases from New Melones Reservoir alone apparently will not be able to meet the proposed standards on the San Joaquin River**; large releases from other local projects also could be necessary.

(6) **Many other environmental mitigation planning processes are currently under way** (e.g., Trinity River restoration, San Joaquin River Management Program, Central Valley Project Improvement Act, Endangered Species Act reviews). If these processes lead to **additive** rather than **concurrent** requirements, the cost impacts would be significantly greater than reported here.

(7) **The uncertainty about both the scientific basis, the economic effects and likely resolutions of so many issues points to the need for an <u>adaptive management</u> approach to Bay-Delta water quality issues.** The Board should establish a procedure to update the standards as new information and events warrant action.

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Final Report
October 7, 1994

Sacramento, California

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1.0 Summary and Conclusions

To date, economic impact analyses of alternative water quality standards for the San Francisco Bay/Sacramento-San Joaquin Delta (Bay-Delta) Estuary have not adequately addressed the potential impacts on California's electricity system. The purpose of this study is to evaluate the following issues:

- How will alternative standards affect operations of California's hydroelectric system, in particular that of the Central Valley Project?
- How will changes in hydro generation affect the production and dispatch of non-hydro generated power?
- How will alternative standards affect Central Valley Project and State Water Project pumping in the Delta and their related demands for electricity?
- How will alternative standards affect agricultural groundwater pumping and its related demand for electricity?
- What changes in air pollution emissions will result from changes in hydropower availability and load patterns?
- What are the economic costs (or benefits) associated with the above-listed adjustments?

A standardized set of power production and demand models were used to assess the impacts on these various aspects of the electric utility system. Hydrological simulation models of the CVP and SWP were used to determine changes in hydropower output and project pumping loads on those systems. Changes in hydropower generation in the Pacific Gas and Electric Co. (PG&E) system were estimated with a linear programming model. Changes in agricultural groundwater pumping were derived from analysis of historic loads and results from an agricultural production model. These impacts were input as changes in hydro generation and demand to the Elfin production-cost model of the Northern California planning area electricity system to determine changes in system costs and air emissions.

1.2 Findings and Recommendations

The principal findings and recommendations in this report are as follows:

(1) Previous analyses of the impacts from Bay-Delta environmental protections (e.g., the winter-run salmon critical habitat designation) incorrectly concluded that the state's electricity system benefits from more strict standards. The results presented here demonstrate that past and proposed standards impose costs--not benefits--on the electric utility system.

(2) The cost impacts on the utility system are real and significant. Net present value costs of some alternatives approach one-half billion dollars. Their size indicates that they should be included in any analysis used in balancing the merits and detractions of a proposed standard.

(3) The cost impacts are not spread uniformly among the state's citizens, and these impacts can not be translated into a single rate change for all utility customers. Direct impacts on hydropower generation are concentrated among CVP project customers;[3] increased water pumping costs are concentrated among the San Joaquin Valley's agricultural sector.

(4) This analysis relies on several assumptions that may prove inaccurate. If these assumptions fail to be true, costs to the electricity system are likely to be significantly greater than reported here. First, annual reductions in water supply deliveries were assumed to be translated directly into increased groundwater pumping. However, based on analysis of the impacts from the NMFS opinions, other factors including how deliveries are shifted through the year and how the uncertainty of supply increases appear to magnify the effect of regulatorily-reduced supplies on groundwater pumping loads. Second, hydropower generation on the Merced and Tuolumne Rivers was assumed not to change. Though unrealistic, this assumption was necessary because of the high degree of uncertainty over how standards at Vernalis will be met. Third, any further restrictions on PG&E's fossil-fueled plants located on Suisun Bay have not been included. Use of these assumptions tend toward underestimating the cost impacts associated with the various alternatives.

(5) Initial hydrological analyses show that releases from New Melones Reservoir alone will not be able to meet the proposed standards on the San Joaquin River; large releases from other local projects (e.g., Merced Irrigation District's Exchequer, Merced and Turlock

[3]Western Area Power Administration (Western) customers may see costs fall due to the interaction between seasonal shifts in CVP capacity and institutional and contractual constraints within the Northern California power industry that lead to decreased capacity purchases by Western while regional capacity requirements increase. Western explains this situation further in its report prepared for the Board staff.

2.0 How Electricity and Water Are Interconnected

California's electricity system is composed of a wide number of resources and is highly integrated. The Bay-Delta standards affect two aspects of this system in particular: hydropower generation and water pumping loads. To understand these effects, we first discuss the characteristics of the electricity system and the key economic components.

The demand, or the sum of hourly electrical requirements placed by customers on an electric utility, varies daily and throughout the year in predictable patterns. Figure 1 shows how hourly demand changes through the day. Winter demands in California are considerably lower than summer demands due to prevalence of air conditioning and reliance on natural gas for winter space heating. Daily demands peak in the afternoon or evening as people return from work, cool or heat their house and begin cooking and laundry. Due to the considerable changes in demand throughout the day, utilities rely on varying types of resources through the course of a day.[4]

Two key concepts are necessary to determine the economic value of the resources being used to meet these demand patterns. The first is *capacity*. Capacity is the amount of resources necessary to reliably meet demand at any given moment. That means that the required level of capacity equals the highest expected demand in a year plus a margin for error and possible outages. If, for example, the capability of a hydro resource is reduced as a result of lowered reservoir elevations (i.e., less storage), that resource's instantaneous ability to generate power will be decreased. When the capacity of a resource is reduced, the utility must either purchase or build replacement capacity. The annualized cost of electrical capacity usually is expressed in terms of dollars per kilowatt-year ($/kw-year).[5] As might be expected, the value of capacity is highest during summer afternoons and lowest during winter nights.

The second concept is *energy*. Energy is the total power consumption over a period of time. It equals the sum of all hourly loads over the entire time period (e.g., a year.) The cost of energy is typically measured in dollars or mills (tenths of a cent) per kilowatt-hour ($/KWh). The cost of providing energy typically varies through the day and the year; the lowest cost resources, called *baseload*, are used first and meet the lowest loads during *off-peak* periods. Figure 2 shows how these costs vary through the day and between seasons. As the loads increase, higher cost resources are added. On the Pacific Gas and Electric Co. system, incremental energy costs are often higher during the winter because natural gas prices rise during this season and maintenance

[4]Summer demands on the Pacific Gas and Electric system may swing as much as 6,000 megawatts from the nighttime low to afternoon peak. For a perspective, the Diablo Canyon 1 nuclear generating station is capable of producing 1,073 megawatts.

[5]The California Public Utilities Commission determines the value for capacity for payments to third-party Qualifying Facilities (QFs) in the annual Energy Cost Adjustment Clause hearings for each utility.

of the most efficient thermal plants is often scheduled then.[6] However, the daily swings in incremental energy costs are higher during the summer, varying as much as 50 percent.

Hydropower is an exception to the rule that low-cost resources are run constantly because it is reserved to meet *peak* demands due to limited energy availability. Hydropower is particularly valuable because it can readily and costlessly be turned on and off to match daily load swings--utilities employ it to meet the highest loads at low cost. Also, hydropower is used to displace fossil-fuel generation in urban areas during the hottest part of the day, thus decreasing air pollution emissions.

California has one of the largest hydroelectric power generation systems in the world, providing nearly one-fifth of the state's total generating capacity. The system produces "clean" energy and provides inexpensive peak power production. The total value of the state's hydropower production, as measured by the type of power it replaces (e.g. fossil fuels) exceeds $1.3 billion in a typical year.

The electric utilities in California currently seek to optimize the use of their available hydroelectric generation given existing operational constraints. If operational constraints change (e.g., different water release patterns) then the rest of the utility system will have to adjust to accommodate these new constraints. If the water available for release during a given period (e.g., a month) is reduced, then the production of energy is similarly reduced. This reduction of available energy, coupled with lower reservoir elevations, limits the ability of the hydroplant to meet peak loads on a sustained or recurring basis. In order to be in a position to meet recurring peak loads throughout a month, the available energy must be conserved by decreasing the amount of peak load met by the facility in any one hour. This in turn forces a reduction in the hydroplant's firm load-carrying capability. Given past experience, shifts in hydroelectric generation from summer peak periods to "around the clock" or baseload type of operation will tend to increase utility operating costs and to accelerate the acquisition of additional peaking resources.

A full economic analysis requires that the costs of both capacity and energy be considered. In the case of the water quality standards for the Bay-Delta, capacity will be affected by changes in hydropower capability and timing of pumping loads; energy will be impacted by timing and amount of reservoir releases, and changes in total amounts of water delivery and use that affect pumping loads. Standards will directly impact loads and power production along the Central Valley Project (CVP) and State Water Project (SWP) systems. Other hydropower plants may change their storage and release patterns as well, especially if flood control constraints change or requirements to provide flow relief in the Delta extend beyond the CVP and SWP. Additional groundwater pumping may increase system demands, particularly during peak summer months.

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[6]The incremental energy costs are operating costs of the last generating resource dispatched on the utility system. This generation resource is the one that will increase generation in response to increased electrical demands, or decrease generation as demands fall.

including how deliveries are shifted through the year and how the uncertainty of supply increases appear to magnify the effect of regulatorily-reduced supplies on groundwater pumping loads. For this reason, the increase in groundwater pumping could be significantly underestimated in this analysis.[8]

Second, we have excluded the changes in hydropower generation on the Merced and Tuolumne Rivers because of the uncertainty in where the additional flows required for meeting Vernalis standards will come from. With additional April and May release requirements of up to 600,000 acre-feet, significant economic costs will be incurred yet these have no been identified, much less estimated, in other analyses presented to EPA or the Board.[9]

Third, any further restrictions on PG&E's fossil-fueled plants located on Suisun Bay have not been included. PG&E currently restricts operations in May and June to reduce striped-bass losses. Meeting other species survival goals would lead to higher operational costs.[10]

3.1 Analytic Models

The following analytic resources were used to model the above systems:

DWRSIM was used to calculate water deliveries, power production and pumping load for the State Water Project. DWRSIM output was provided by the Department of Water Resources, and is the same as that provided to the Board and the U.S. Environmental Protection Agency (EPA) for their economic impact assessments of alternative standards.

PROSIM was used to calculate water deliveries, power production and pumping load for the Central Valley Project. PROSIM output was provided by Water Resources Management, Inc. (WRMI), and is calibrated to be consistent with the DWRSIM output.[11]

PG&EHELP, a linear programming simulation model of PG&E's hydroelectric resources, was developed to analyze impacts to the PG&E system. This model was developed so that sharing arrangements to meet alternative standards that include other projects in addition to the SWP and

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[8]See Appendix D for a discussion of the groundwater pumping estimates.

[9]See Appendix H for a discussion of the flow requirements on the San Joaquin River.

[10]See Appendix E for a discussion of existing and potential limitations on PG&E's thermal plants located in the Bay-Delta Estuary.

[11]Both DWRSIM and PROSIM are described in more detail in Appendix C.

3.2 Evaluating Water Quality Standard Alternatives in Water-Year Scenarios

Hydroelectric power impacts associated with the water quality alternatives proposed by the Board staff in its August 18, 1994 memo to the DWR were estimated.[1] These alternatives are summarized below:[17]

Alternative 1: Proposed by EPA. Relative to conditions under State Water Resources Control Board Decision 1485 (D-1485), annual SWP and CVP deliveries would be reduced by 1.09 million acre-feet in critically dry years and by 0.49 million acre-feet in average years. Average annual carryover storage would be reduced by 0.17 million acre-feet in the Sacramento Basin and by 0.73 million acre-feet in New Melones Reservoir.

Alternative 2: Proposed by the Board staff. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 1.56 million acre-feet in critically dry years and by 0.65 million acre-feet in average years. Average annual carryover storage would be reduced by 0.20 million acre-feet in the Sacramento Basin and by 0.67 million acre-feet in New Melones Reservoir.

Alternative 3: Proposed by California Urban Water Agencies. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 1.39 million acre-feet in critically dry years and by 0.57 million acre-feet in average years. Average annual carryover storage would be reduced by 0.25 million acre-feet in the Sacramento Basin and by 0.67 million acre-feet in New Melones Reservoir.

Alternative 4: Proposed by the California Department of Fish and Game. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 2.6 million acre-feet in critically dry years and by [not specified by DWR] in average years. Average annual carryover storage would be reduced by [not specified by DWR] million acre-feet in the Sacramento Basin and by [not specified by DWR] million acre-feet in New Melones Reservoir.[18]

Alternative 5: Proposed by David Schuster and Chuck Hansen. Relative to D-1485, annual SWP and CVP deliveries would be reduced by 0.80 million acre-feet in critically dry years and by 0.21 million acre-feet in average years. Average annual carryover storage would be reduced by 0.33 million acre-feet in the Sacramento Basin and by 0.63 million acre-feet in New Melones Reservoir. This alternative is currently being reformulated as Alternative 8.

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[17] This summary is based on preliminary results provided by DWR at the September 1, 1994 Board Workshop. Descriptions of these alternatives and preliminary hydrological results from DWRSIM for each alternative is provided in Appendix A.

[18] Initially, the DWRSIM model could not meet the flow requirements in all years for this proposal. The standards were reformulated for the model, but the results were not yet available as this report went to press.

4.0 Results

The alternatives are compared based on the aggregate costs of energy, capacity and air emissions. The energy costs for each alternative were estimated based on the weighted-average energy impacts from the three water-year scenarios over the 1995 to 2010 time horizon.[22] Added capacity needs and costs were based on:

(1) the estimate made by the Western Area Power Administration (Western) to meet obligations to Western's customers of the CVP under critically-dry water conditions;[23] and

(2) the added capacity needs imposed in dry years from increased agricultural pumping in the PG&E service area; these capacity costs are based on the current short-run capacity payments to QFs, escalated into the future.[24]

The emission costs are derived from values adopted by the CEC in its ***1994 Electricity Report.***[3; 4]

It is important to note that the hydrological models are not adequate for capturing the full effects of the daily flow requirements that determine the ability of hydro facilities to match daily load swings. How project pumping might be shifted through the year also will affect groundwater pumping levels. For example, the NMFS opinions appear to have created a large increase in agricultural pumping with relatively small decreases but significant shifts in water project deliveries. Estimates of groundwater pumping impacts need to be further refined as well with more detailed data. While the groundwater issue has been largely ignored by previous analyses, it may represent the largest single cost item to agriculture.

DWRSIM, were either taken directly from these year types or adjusted linearly to estimate changes in hydropower generation and groundwater pumping loads. The probability weights attached to each water year were 0.20 for dry years, 0.55 for median years and 0.25 for wet years.

[22]Assuming a 7 percent real discount rate per the U.S. Office of Management and Budget. (U.S. Office of Management and Budget, "Benefit-Cost Analysis of Federal Programs: Guidelines and Discount Rates," Circular A94, in Federal Register 53(519), November 19, 1992.)

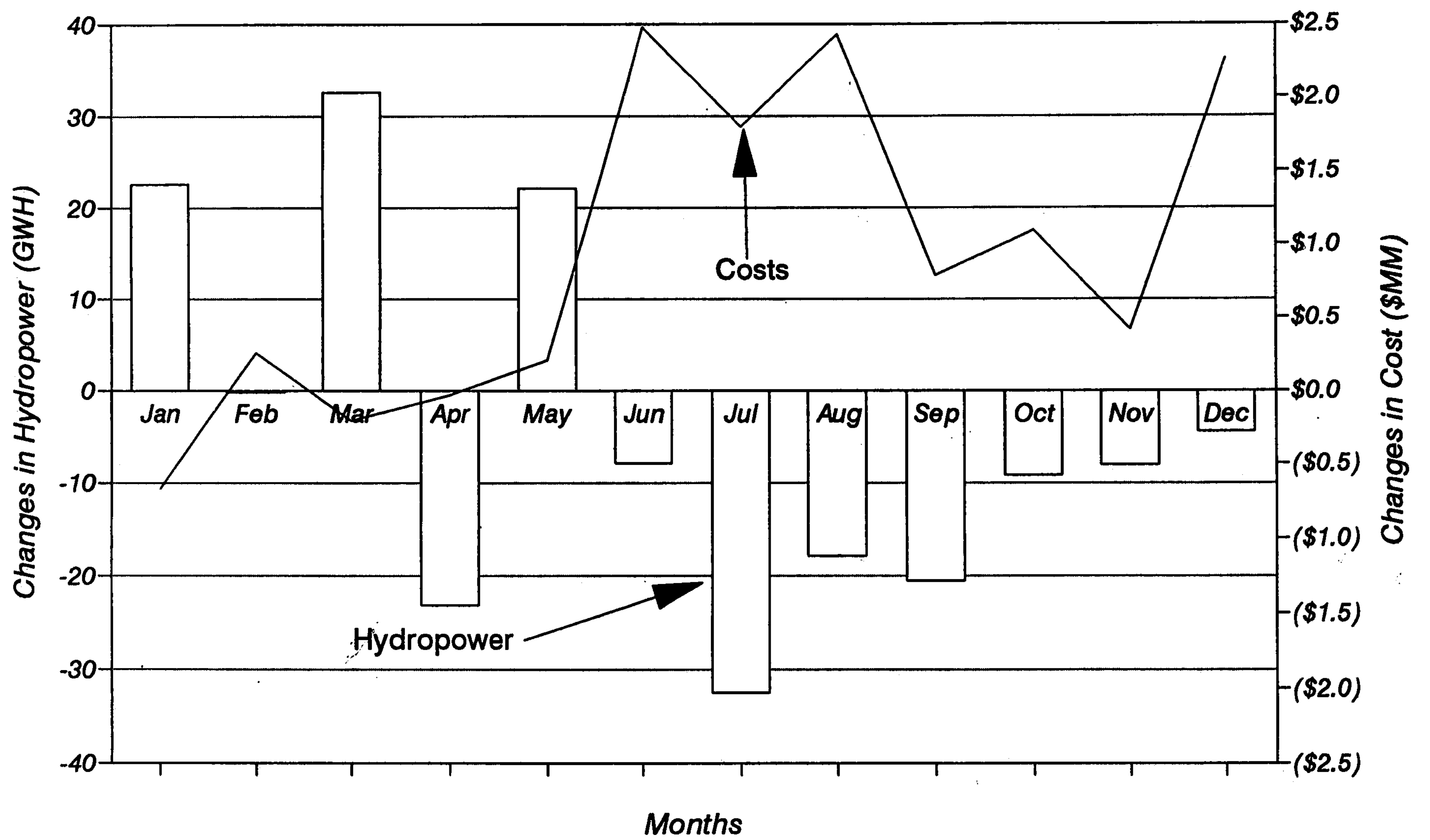
[23]These estimates will be presented in testimony submitted to the Board by Western and its consultants.

[24]Because the analysis presented here focuses on long-term impacts, a long-run capacity value may be more appropriate. The results from the recent Biennial Resource Plan Update bids accepted by the CPUC might be used, but these offers have been withdrawn with the recent deregulation proposals offered by the CPUC. The short-run values presented here are relatively consistent with the long-term offers and are non-controversial. A fossil-fueled combustion turbine is used as the capacity proxy.

Figure 3

Hydropower and Cost Impacts by Month

1995 Example for Alternative 1



of electricity planning concepts.[27] The benefits derived relied on increased availability of capacity in wet winter months rather than dry summer months, higher generation in two out of 55 water years that skewed the water history average, and failing to account properly for increased groundwater pumping in the San Joaquin Valley. In reality, the winter-run salmon CHD has resulted in significant costs. Measured losses to CVP hydropower generation alone have totaled $44 million net present value over the last six years.[9] Cost of meeting increased groundwater pumping loads amount to about $116 million over the same period. As a result, agricultural customers may have seen an additional $50 million annual increase in their energy bills.[28] Instead of net benefits, the total estimated cost to the California electricity system since 1989 has been about $160 million net present value.

[27]A more detailed critique of the Hydrosphere report is contained in Appendix G.

[28]See Appendix D for a discussion of groundwater pumping impacts.

STATE OF CALIFORNIA - CALIFORNIA ENVIRONMENTAL PROTECTION AGENCY PETE WILSON, Governor

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AUGUST 18 1994

To Whom It May Concern:

ALTERNATIVE STANDARDS FOR THE BAY-DELTA ESTUARY

The enclosed memorandum has been sent to the Department of Water Resources to request its assistance in estimating the water supply impacts of alternative standards for the Bay-Delta Estuary. The memorandum is being distributed for informational purposes.

The alternatives identified in the memorandum are preliminary and may change as the process proceeds. The subject of alternative standards for the Bay-Delta Estuary will be discussed at a workshop scheduled for September 1-2, 1994. Workshop notices were mailed under separate cover.

If you have any questions, please contact me at (916) 657-1873.

Sincerely,

Thomas Howard

Thomas Howard, Chief
Bay-Delta Unit

Alternative 2

This alternative should include:

1. The standards for the protection of agricultural and municipal uses in the 1991 Bay-Delta Plan;
2. The standards for the protection of Suisun Marsh contained in the water right permits of the DWR and the USBR;
3. Flows on the San Joaquin River at Vernalis for four weeks from April 17 through May 14 of 8,000, 7,000, 6,000, 5,000, and 4,000 cfs in wet, above normal, below normal, dry and critical years, respectively;
4. Maximum exports of 1,500 cfs for four weeks from April 17 through May 14;
5. Total exports for the rest of April through June not above 4,000 cfs in critical years, 5,000 cfs in dry years, and 6,000 cfs in below normal, above normal and wet years;
6. Total exports less than 9,200 cfs in July;
7. Fixed export constraints in April through July are eliminated when the Delta Outflow Index exceeds 50,000 cfs;
8. Close the Delta Cross Channel gates from November 1 through June 30;
9. Delta Outflow Indices as follows:

Year Type	Delta Outflow Index	
	12,000 cfs	7,000 cfs
Wet	2/1-6/30	...
Above Normal	2/1-6/30	...
Below Normal	3/15-6/15	3/1-3/14 and 6/16-6/30
Dry	4/1-6/10	3/1-3/31 and 6/11-6/30
Critical	4/15-5/15	3/15-4/14 and 5/16-6/15

10. Maximum CVP and SWP exports less than 30 percent of Delta inflow from February 1 through June 30 and 60 percent of Delta inflow from July 1 through January 30;
11. Flow on the San Joaquin River of 2,000 cfs from October 18 through October 31.

May	24,400	15,000	9,500	9,500
June	17,500	12,000	8,600	7,900
July	12,500	9,900	8,300	7,600
October	14,200	--	--	--
November	16,300	12,900	9,500	--
December	28,000	27,000	26,000	20,000

10. Delta Outflow Indices of 8,700, 7,800, 7,000, 6,200, 5,600, and 5,000 cfs in February, March, April, May, June and July of critical years;

11. Average Delta Outflow Indices (cfs) as follows:

Year Type	Aug	Sept	Oct	Nov	Dec
Wet	5,800	7,300	7,300	7,300	7,300
Above Normal	5,600	4,200	4,500	4,500	5,400
Below Normal	5,300	4,200	4,500	4,500	4,900
Dry	5,000	4,000	4,500	4,500	4,700
Critical	3,300	3,000	3,600	3,600	4,700

12. Average monthly exports (cfs) less than:

Year Type	Apr-Jul	Aug-Mar
Wet	6,400	7,900
Above Normal	5,400	7,100
Below Normal	4,400	6,500
Dry	3,400	6,000
Critical	1,600	5,000

(For standards # 9, 11, and 12, October through December should be classified based on the previous year's hydrologic index. Two of the standards in this alternative are expressed as daily standards (# 5 and 9). DWRSIM cannot directly model daily standards because it operates on a monthly time step. Please develop assumptions to model these daily standards and discuss these assumptions with me prior to beginning the study.)

Alternative 5

This alternative should include:

1. The standards for the protection of agricultural and municipal uses in the 1991 Bay-Delta Plan;

2. The standards for the protection of Suisun Marsh contained in the water right permits of the DWR and the USBR.

3. Delta Outflow Index from February 1 through June 30 of 12,000 cfs in wet, above normal, and below normal years and 7,000 cfs in dry and critical years;

1. Delta Outflow Indices (cfs) as follows:

Month	Wet	AN	BN	Dry	Critical
October	4,500	4,500	4,500	3,500	3,500
November	4,500	4,500	4,500	3,500	3,500
December	4,500	4,500	4,500	3,500	3,500
January	4,500	4,500	4,500	3,500	3,500
February	12,000	12,000	12,000	12,000	12,000
March	12,000	12,000	12,000	12,000	12,000
April	12,000	12,000	12,000	12,000	12,000
May	12,000	12,000	12,000	12,000	12,000
June	12,000	12,000	12,000	12,000	12,000
July	7,000	7,000	4,500	3,500	3,500
August	7,000	7,000	4,500	3,500	3,500
Sept	3,500	3,500	3,500	3,500	3,500

2. QWEST greater than zero cfs from February 1 through July 31, with the exception of the month of June where QWEST is greater than 4,000 cfs, and QWEST greater than 2,000 cfs from August 1 through January 31;

3. Flow on the San Joaquin River at Vernalis of 5,000 cfs from April 20 through May 10;

4. Exports limited to 2,000 cfs from April 20 through May 10;

5. Flow on the San Joaquin River at Vernalis of 2,000 cfs from October 18 through October 31;

6. Flow on the Sacramento River at Freeport of 13,000 cfs from April 15 to May 15;

7. Release 14,000 cfs from Keswick from May 1 through May 7;

8. Close the Delta Cross Channel gates from February 1 to June 30;

<u>Assumptions</u>

The assumptions listed below should be incorporated into the operation studies. Please consult with me if there are additional, significant assumptions that need to be made to complete the requested studies.

TABLE 1

SUMMARY OF COMPARATIVE WATER SUPPLY IMPACTS RELATIVE TO D-1485
(1000'S AF/Year)

PRELIMINARY
8/31/94

STATE WATER RESOURCES CONTROL BOARD STUDY	Critical Dry Period Average (May 1928 - October 1934)	71-Year Average (1922 - 1992)	Average Annual Carryover Storage Sacramento Basin	Average Annual Carryover Storage New Melones
ALTERNATIVE 1	-1093[1,3]	-490[2,3]	-174	-727
ALTERNATIVE 2	-1555[1,3]	-645[2,3]	-195	-672
ALTERNATIVE 3	-1386[1,3]	-569[2,3]	-253	-672
ALTERNATIVE 4	-2604[1,3]	-	-	-
ALTERNATIVE 5	-798[1,3]	-213[2,3]	-330	-626
ALTERNATIVE 6	-1807[1,3]	-994[2,3]	+484	-414

1. Includes adjustments due to upstream net Storage used and additional flows from Tuolumne and Merced River system to meet Vernalis pulse flows.
2. Includes adjustments due to additional flows from Tuolumne and Merced River system to meet Vernalis pulse flows.
3. Does not include potential water supply impact for "Take Limits."

DWR has two significant contracts with SCE to supply power from Oroville and other facilities.[10] The Power Contract signed in 1979 provides SCE with 485 MW of peak capacity in exchange for energy returned to DWR during off-peak periods. The capacity-for-energy exchange rate is determined by the costs of alternative generating capacity and natural gas prices. In 1983, the Capacity Exchange Contract provided another 225 MW of capacity to SCE in return for access to up to 600 MW during off-peak periods by DWR. Both of these contracts expire at the end of 2004. According to DWR staff, agreements between DWR and SCE will not be affected by water quality standards for the Bay-Delta Estuary.

Pacific Gas & Electric operates 71 plants with a total capacity of 3,900 MW. This makes it the largest investor-owned hydropower system in the world and the second largest of any kind in the United States [11]. The total electric load for the PG&E system exceeds 86,000 gigawatt-hours (GWh).* PG&E's hydropower plants meet about 28% of its total demand in a typical year.

PG&E's system is integrated with plants owned by several irrigation and water districts as well as the City and County of San Francisco (CCSF). These plants total 1,300 MW of capacity. In addition, a number of small hydro facilities owned by non-electric utilities (e.g., irrigation districts) and private investors, which are collectively referred to as third-party qualifying facilities, supply power to PG&E. Third-party qualifying facilities contribute less than 2 percent of the capacity in the PG&E hydro system.**

Other facilities. Several municipal utilities in northern California also produce sizable amounts of hydro power.*** The largest of these is the Sacramento Municipal Utility District (SMUD), which operates plants with 650 MW of capacity. Plants with an additional 300 MW of capacity are operated by members of the Northern California Power Agency (NCPA). The largest of these is the Lake Don Pedro power plant owned by the Modesto (MID) and Turlock Irrigation Districts (TID).

The Bay-Delta standards are likely to have the most significant impacts on hydropower facilities associated with the large reservoirs that sit at the bottom of the tributary watersheds to the Sacramento and San Joaquin Rivers. Most of these large reservoirs are owned by the USBR or DWR, the largest exception being Don Pedro. PG&E and SMUD probably would not have as

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*One gigawatt-hour equals a million kilowatt-hours (KWh).

**For QFs, we have not estimated how changes in flows requirements would affect their operations due to data limitations and, as a first approximation, assume that there are no changes in generation.

***The analysis presented here excludes the direct impact on these utilities of changes in hydrological conditions since Western and the other municipal utilities are presenting the results of their own studies in these proceedings.

Appendix C

Water Project, Hydropower and Electric Utility Simulation Models

Three models were used to simulate operations of the CVP, SWP, and PG&E hydropower systems. These are briefly discussed below.

C.1 DWRSIM

DWRSIM was used to simulate SWP operations. DWRSIM is known a *hydrological mass-balance* model because it attempts to balance the inflows and outflows for the Sacramento-San Joaquin Delta under a range of conditions and operational options. The model works on monthly time steps, simulating reservoir releases and project pumping based on a prescribed demand, a historic trace of water years, and various operational constraints and rules. DWRSIM changes the operations of the Oroville Reservoir and Clifton Court pumping station to meet the mass-balance constraints; it takes the operations of the CVP and other systems (e.g., CCSF and East Bay MUD) as given. Both DWRSIM and PROSIM used the 1922-1992 period as representative to the expected range and pattern of foreseeable water conditions.

C.2 PROSIM

PROSIM was used to simulate CVP operations, pumping loads and power generation.* It also is a mass-balance model similar to DWRSIM, and also uses monthly time steps. PROSIM controls operations of the CVP reservoirs on the Sacramento, Trinity, American, Calaveras, and Stanislaus Rivers and pumping at Tracy while taking the operations of the SWP and other systems as given. The model was calibrated to maintain consistency with DWRSIM output.

C.3 PG&EHELP

PG&E Hydroelectric Linear Program (PG&EHELP) is a linear program (LP) simulation model of the PG&E hydropower system. The model determines the water releases through powerhouses and spillways that will maximize the value of generated power while meeting operating constraints such as minimum stream flows, irrigation demands, maximum stream flows, and reservoir storage targets. Each independent watershed in the PG&E hydropower system is modeled. Pre-processor routines are used to automate the formulation of the LP submodels of each watershed.

PG&EHELP uses a one-month time step to maintain consistency with PROSIM, DWRSIM, and ELFIN output. The value of energy production is maximized with respect to water releases, subject to operational constraints--including continuity equations that describe the relationships

*Version 5.31 as modified by WRMI was used in this analysis.

of water flows from one reservoir to another--and price differentials between peak, partial-peak, off-peak, and super-off-peak production periods.* The model is solved using the LINDO optimization software.**

The physical units used in the model have been chosen to make the linear program solution more accurate and robust.*** The units used are hundreds of acre-feet of reservoir storage, hundreds of acre-feet per month of flow, and dollars per kilowatt-hour for electrical energy purchase prices.

The database for PG&EHELP was initially developed for a study of global climate change sponsored by EPA.[12] Core data come from the California Energy Commission's (CEC) *Electricity Report*, which provides individual unit capacity, average year generation, ownership, and river basin location.[13] The generation parameters for each unit was provided by PG&E in its *Common Forecasting Methodology* (CFM) filing with the CEC and information from other utilities and irrigation districts.[14] The CFM report shows generation by four categories: (1) PG&E-owned (2) irrigation and water districts, (3) City and County of San Francisco (which is sold to the Modesto and Turlock Irrigation Districts) and (4) Western. Requests to PG&E, USBR, CCSF, and various water and irrigation districts added information on median-year flows, minimum and maximum flow restrictions, reservoir storage and operational considerations, irrigation diversions, operational linkages between units, pump storage characteristics and calculation of kilowatt-hours (KWh) of generation per acre-foot (AF) released.[15-28]

As with any model, PG&EHELP uses several simplifying assumptions and represents an abstraction of reality. Principle assumptions are as follows:

- Optimization of the system assumes foresight of hydrologic events.

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*The system constraint equations are conceptually simple but there are a great number of them. For each powerhouse, there are minimum flow requirements for each of the four energy purchase price periods in each of twelve months. Thus there are 48 minimum flow requirements for each powerhouse. An additional 48 constraints are produced by the limitations on the maximum power generating flow that can pass through each powerhouse. There are often 12 more constraints set by the maximum river flow that is allowable below the powerhouses. Therefore there are at least 96 and often 108 or more constraints per powerhouse (not counting non-negativity constraints on all flows and storage volumes). For a watershed with 10 powerhouses this is around 1000 constraint equations.

**A FORTRAN pre-processor is used to automate the process of producing the constraint equations associated with each powerhouse and reservoir. Constraint data such as the minimum streamflow per month per energy purchase period are produced by a spreadsheet pre-processor in tabular form. These data are read by the FORTRAN pre-processor, which then generates the constraint equations.

***The SIMPLEX linear program solution method used in LINDO will suffer from round-off errors if there is too large of a range in magnitudes of the model parameters.

- Water releases of other systems (as well as energy purchase prices and capacity payments) are taken as given. In reality other systems may modify their operating behavior if they can anticipate or negotiate PG&E releases.

- Because power/storage relationships for each PG&E unit are not known, power plant production is assumed to be independent of reservoir level.

- Reservoir storage estimates do not account for inflow from small tributaries and groundwater. Similarly, reservoir release estimates do not account for evaporation and leakage.

- Where possible, maximum flow constraints are incorporated into the model, but for some facilities, this information was unavailable.

C.4 Elfin

The Elfin production-cost model was used to forecast operations of the PG&E system.* The basic data set assumptions were those used by the CEC in their ***1994 Electricity Report*** (ER 94) forecast of average system costs.[29] All the assumptions used are consistent with the CEC Committee Order on Supply Assumptions for ER 94.[30] The fundamental resource plan was that adopted for the ***1992 Electricity Report*** with the following updates and modifications:

Demand Forecast - The ER 94 demand forecast for the PG&E service area was used.[31]

Natural Gas Prices - The ER 94 utility (UEG) natural gas price forecast was used.[32]

Inflation - The ER 94 inflation assumptions were used.[33]

Purchase Energy and Capacity Availability and Prices - The CEC staff assumptions on the price and availability of Pacific Northwest, and Southwest energy and capacity availability and prices (as adopted in the Committee Order) were used.[34]

QF Prices - The CEC forecast of QF prices for each utility, updated for the ER 94 natural gas forecast, was used.

New Resources - The characteristics and costs for the CPUC's Biennial Resource Plan Update (BRPU) auction winners, as provided by the utilities to the CEC, were used. For PG&E, the AES Pacific/San Francisco Co. cogeneration facility replaces the Hunters Point Repowering in 1997.

*Version 1.98 was used.

Emissions - The values for out-of-state emissions were taken from the Committee Order, while the values for California emissions were taken from CEC staff testimony.[3; 4]

The changes in hydropower generation and pumping loads were estimated based on the analysis described elsewhere in this report and used as inputs into Elfin. Table C-1 shows the change in available annual energy resources due to the proposed alternatives. In each case, resources are reduced about 350 to 450 GWH in a median year.

C.5 Capacity Requirements and Valuation

Demand for increased capacity comes from two sources:

(1) reduced summertime generation capability on the CVP and
(2) increased agricultural pumping loads.

The required capacity additions were derived using standard electric utility planning methods, i.e., demand and supplies under dry hydrological conditions that limit hydropower generating capability.

The CVP capacity requirements and values were determined by the consultant for the Western Area Power Administration, R.W. Beck, using critically-dry water conditions. Table C-2 shows the expected additional capacity requirements to meet demand in July, and the annual net levelized cost to Western to purchase that capacity. constant throughout year

Attachment 5 Beck

Table C-2
CVP Capacity Additions and Costs[1]

Alternative	Capacity Additions	Annual Costs ($MM)
Alternative 1: EPA	116 MW	$14.0MM
Alternative 2: SWRCB Staff	163 MW	$21.3MM
Alternative 3: CUWA	165 MW	$21.2MM

1 - Paul Scheurmann, R.W. Beck, October 6, 1994.

The increased demand on the PG&E system from agricultural pumping is derived from the analysis in Appendix D, scaled to August demand levels. The value of capacity equals the short-run value adopted in PG&E's Energy Cost Adjustment Clause proceedings.[35] Table C-3 shows the increase in capacity requirements and costs due to increased agricultural pumping loads in dry years.* Added capacity starts at over 130 MW in 1995 and increases to over 150 MW by 2010; the cost increases from about $10 million a year to $20 million per year.

*Dry or critically dry conditions are the planning basis of electric utility capacity additions.

Table C-1
CHANGES IN POWER AVAILABILITY vs. D-1485

Alternatives	Generation CVP Hydro GWH	Loads CVP Pumping GWH	Agriculture GW Pumping 1995	2010		TOTAL GWH 1995	GWH 2010
1: EPA							
Median .55	-47.2	235.4	-531.4	-649.2		-343.2	-461.0
Dry .20	-19.7	261.6	-568.6	-649.2		-326.7	-407.4
Wet .25	-57.9	83.7	-509.0	-648.9		-483.2	-623.2
		[illegible]	533.24			374.9	
2: SWRCB Staff							
Median	-44.5	251.1	-547.3	-652.1		-340.7	-445.5
Dry	37.2	334.2	-603.4	-652.2		-232.0	-280.8
Wet	-93.3	116.6	-517.9	-651.9		-494.6	-628.5
3: CUWA							
Median	-64.2	249.2	-539.5	-650.7		-354.4	-465.6
Dry	38.3	322.8	-589.8	-650.7		-228.8	-289.6
Wet	-84.4	100.0	-513.5	-650.4		-497.9	-634.8

Note: Changes shown relative to total resource availability

Table C-3
Added PG&E Capacity Required for Agricultural Pumping

Year	D1485/NMFS MW	D1485/NMFS $MM	EPA v D1485 MW	EPA v D1485 $MM	SWRCB v D1485 MW	SWRCB v D1485 $MM	CUWA v D1485 MW	CUWA v D1485 $MM	PG&E SO#1 $/KW-Yr
1993	0	$0.0	0	$0.0	0	$0.0	0	$0.0	$67.00
1994	112	$7.7	112	$7.7	112	$7.7	112	$7.7	$69.27
1995	114	$8.1	134	$9.6	143	$10.2	140	$10.0	$71.35
1996	116	$8.5	136	$9.9	143	$10.5	140	$10.3	$73.34
1997	118	$8.9	137	$10.3	144	$10.9	141	$10.7	$75.62
1998	120	$9.4	138	$10.8	144	$11.3	142	$11.1	$78.34
1999	123	$10.1	139	$11.4	145	$11.9	143	$11.7	$81.87
2000	125	$10.6	140	$11.9	146	$12.4	144	$12.2	$84.81
2001	128	$11.3	141	$12.5	146	$12.9	144	$12.8	$88.38
2002	130	$12.0	142	$13.1	147	$13.5	145	$13.4	$92.00
2003	133	$12.7	144	$13.8	148	$14.2	146	$14.0	$95.77
2004	135	$13.5	145	$14.4	149	$14.8	147	$14.7	$99.60
2005	138	$14.3	146	$15.2	150	$15.5	148	$15.4	$103.78
2006	140	$15.2	148	$16.0	150	$16.3	149	$16.2	$108.35
2007	143	$16.2	149	$16.9	151	$17.2	150	$17.0	$113.34
2008	146	$17.4	151	$18.0	152	$18.2	152	$18.1	$119.66
2009	149	$18.5	152	$18.9	153	$19.1	153	$19.0	$124.36
2010	151	$19.7	154	$20.0	154	$20.1	154	$20.1	$130.45

Note: August Load Share = 17.6%

C.6 Water-Year Type Scenarios

The economic impacts of different policy alternatives will have different outcomes depending on the type of water--year conditions used. Reductions on water deliveries in drought years typically have larger relative impacts than in wet years when excess water is available to meet environmental goals. For this reason, relying on a simple average or a single median year to measure these impacts will usually give misleading results.

In this analysis, the impacts are based on three water-year scenarios: dry, median and wet. The corresponding water conditions were chosen to match the conditions used by PG&E in its CEC filings:[14]

- for a dry year, this represents the 20 percent exceedance level (i.e., that these conditions exceed historic flows in 20 percent of past years);
- for a median year, this is the 50 percent exceedance level; and
- for a wet year, this is the 75 percent exceedance level.

The monthly streamflows, generation and pumping levels equal the average at the midpoint of the corresponding decile for the 70 year water history from 1922 to 1991.*

These results are then weighted and averaged for energy and emission results. For capacity, the dry year impacts are used solely because these are the planning basis for electric utilities in California.

*For example, the 20 percent exceedance level equals the average of the years ranked by generation level from 11 to 17. This is done to smooth the large monthly fluctuations that may occur within a year but can greatly influence a deterministic model such as Elfin.

Appendix D

Estimation of Agricultural Groundwater Pumping

In the PG&E service territory, agriculture demands about 3,600 GWh in an average year; in SCE, the average demand is about 1,000 GWh. This represents about 3 percent of the load in these service areas. Upwards of 70 percent of this is related to groundwater pumping and is greatly affected by surface water availability.[36] PG&E customers are likely to bear the brunt of changes in surface water deliveries, and therefore most changes in groundwater pumping will occur in this service area.

D.1 Econometric Groundwater Pumping Model

As shown in Figure D-1, *Groundwater Pumping*, a significant relationships exists between groundwater pumping and both natural hydrological conditions and water project deliveries. Pumping loads increased as the Sacramento River Index decreased and as project deliveries decreased over the 1970 to 1992 period. The relationship between agricultural groundwater pumping and changes in water project deliveries similar to those might be created by the policy alternatives was modelled to estimate changes in electricity demand. An econometric analysis of the relationship between PG&E loads and various water use variables was developed to measure the impacts of physical and policy factors on agricultural groundwater pumping for the 1970 to 1992 period (*Ag.GWH*).* The variables included were as follows:

- The cumulative net difference of agricultural pumping loads from the 1970 level in GWh was used as a proxy for changes in groundwater levels in the Central Valley (*Cum.GWH*).** This indicator was used because no forecast of groundwater levels was readily available. A strong correlation was found between groundwater storage levels in the San Joaquin Valley and the cumulative net difference of loads.***[37]

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*A three-stage least-squares system of equations was estimated over 23 observations. The SHAZAM 7.0 econometric computer program output for the model is available upon request.

**The equation for the cumulative net pumping difference was:

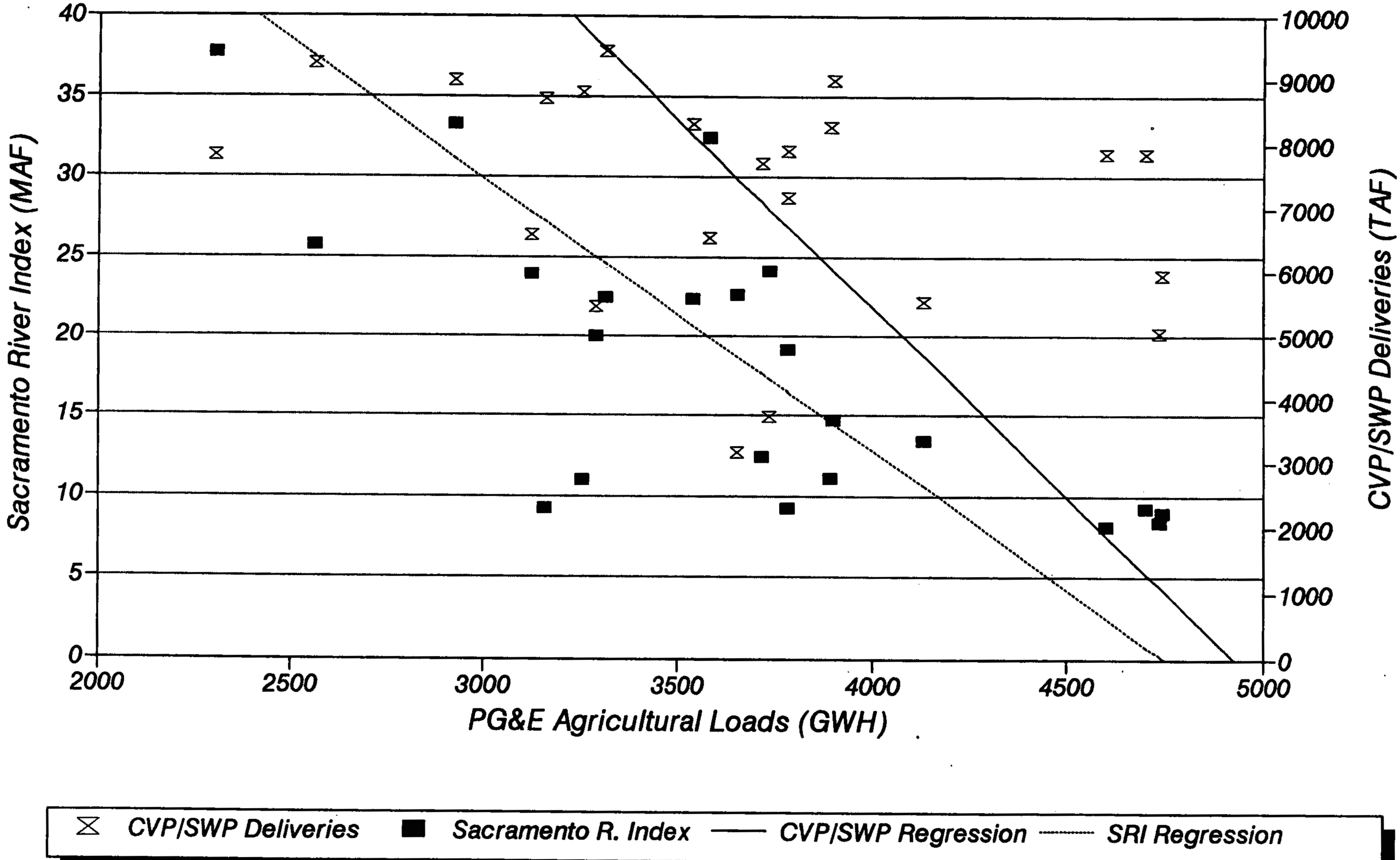
$$\text{Net Cumulative GWh}_t = (\text{GWh}_{t-1} - \text{GWh}_{1970}) + \text{Net Cumulative GWh}_{t-1}$$

*** $R^2 = -0.715$ for 1970 to 1989.

Figure D-1

Groundwater Pumping

Related to CVP/SWP & SRI - 1970-91



- The Sacramento River Index was used as a proxy for precipitation and local water availability (*SRI*).**** Figure D-2 shows the historic distribution of Sacramento River flows.

- Total CVP and SWP project deliveries measured imported water (*Project Water*).

- The imposition of the NMFS requirements was entered as a dummy variable beginning in 1989 (*NMFS*).

The estimated model was:

$$Ag\ GWH = 6869.2 - \underset{(5.76)}{915.95}\log(SRI) + \underset{(1.66)}{0.09822}\ Cum.GWH$$

$$- \underset{(2.18)}{0.10265}\ Project\ Water + \underset{(3.09)}{745.28}\ NMFS + error$$

$$R^2 = 0.781$$

However, this model implied too strong of a relationship between changes in groundwater levels and groundwater pumping; if the NMFS standard is not in place, the groundwater table rises rapidly, contrary to the pre-NMFS experience.** For this reason, new parameters were solved for assuming that the groundwater table would be relatively stable in median water years without the NMFS standard in place. The resulting equation used to forecast changes in groundwater pumping is:

$$Ag\ GWH = 6869.2 - 915.95\log(SRI) + 0.0192\ Cum.GWH$$

$$- 0.10265\ Project\ Water + 472.01\ NMFS + error$$

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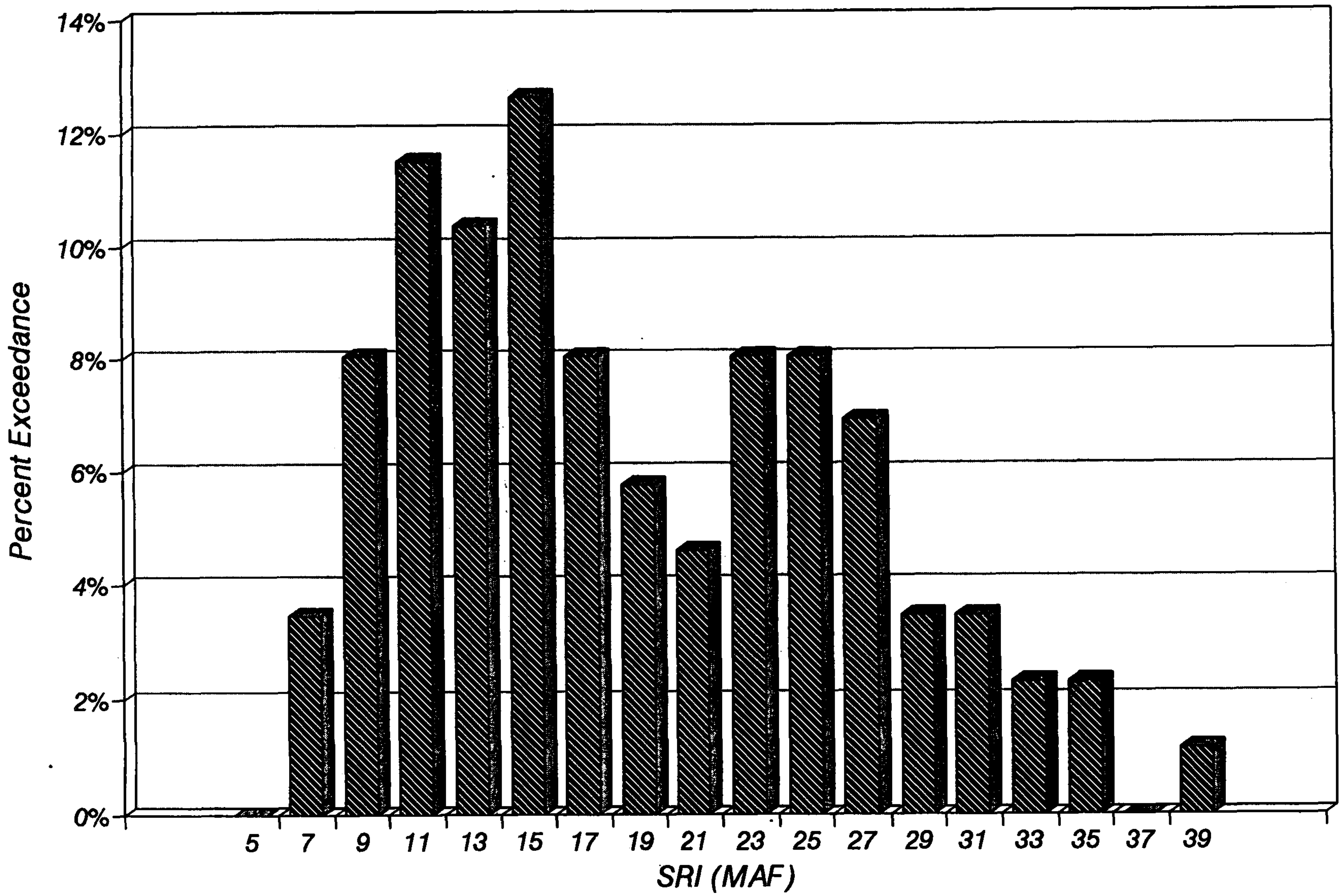
*The Sacramento River Index (SRI) has a strong correlation with the Tuolumne River flows of 0.921. The SRI was entered into the model as a logarithm to reflect how applied water rates decrease with increased precipitation at a diminishing rate.

**The NMFS opinion alone does not increase groundwater pumping--it affects the delivery of water to agriculture which in turn increases pumping. However, the inability to find this link in the aggregated annual data indicates that this influence probably occurs through seasonal shifting of water deliveries. This data was not yet available at the time this report was completed. The EPA standards could be expected to have a similar impact at the NMFS opinion, and to the extent that this occurs, the estimated impacts on agricultural pumping contained in this report are too low.

Figure D-2

Sacramento River Index Distribution

1906-1991



The model results imply certain responses by agricultural groundwater pumping to changing conditions or policies:

- a decrease of one million acre-feet (MAF) in the Sacramento River Index from median-year conditions* has lead to an increase of about 60 GWh or 1.5 percent in agricultural pumping load,

- a 50 percent curtailment of deliveries by the CVP and SWP increases agricultural loads by about 600 GWh or 15 percent,**

- the imposition of the winter-salmon and delta smelt flow requirements by the NMFS has added 470 GWh or 13 percent to agricultural loads since 1989,

- in 1995, the EPA standards would add 50 GWh to median-year pumping loads, above those from the NMFS requirements; and 88 GWh in dry years, and

- in 2010, the EPA standards would add 9 GWh in all water year types, assuming that groundwater pumping returns to 1994 levels, albeit from a deeper water table.

For example, drought conditions leading to curtailment combined with a reduction of 7 MAF in the Sacramento River Index from median conditions could increase average annual agricultural loads by about 975 GWh or over 25 percent for PG&E agricultural customers. Based on average agricultural rates in PG&E of 12.5¢ per KWh, costs to farmers would increase about $120 million.

D.2 CVPM Agricultural Production Model

The CVPM agricultural mathematical programming model is being used by the U.S. EPA to evaluate impacts on California agricultural from alternative water quality standards. CVPM relies on input assumptions about changes in surface water and groundwater deliveries and use. The input data for the CVPM was analyzed from two perspectives to assess the changes in groundwater pumping loads. The first relied on the changes in water project deliveries and their historical relation to past groundwater pumping loads. The second used the estimated changes in groundwater pumping directly to calculate the loads based on engineering equations.

The direct calculation of the change in groundwater pumping used a common engineering equation used to estimate required pump size for farming operations.[38] The total change in

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*The median SRI water-year type for the 1906 to 1992 time period is 15.8 MAF.

**Curtailment on the CVP and the SWP is defined as restriction of deliveries below current firm yield on these systems as defined by the relevant contracts.

agricultural groundwater pumping load for the Central Valley was estimated based on the equation:

$$Kilowatt\text{-}hours/Acre\text{-}foot = 1.0231 * (depth + 2.31*irrigation\ PSI)/pump\ efficiency$$

where depth is region specific plus 30 feet for drawdown, irrigation system pressures (PSI) were derived for each region based on cropping patterns, and an average pumping efficiency of 70 percent was used.* The input data and results from CVPM are shown in the three attached tables.

The CVPM estimate approximates that from the adjusted econometric model. Based on the estimate made from the CVPM model, groundwater pumping increases by 115 GWh in 1995 under median-year conditions and by 133 GWh in dry years; this falls to zero in 2010 based on the assumption that groundwater pumping is held to pre-EPA standard levels.

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*The CVPM groundwater input data for 1995 and 2010, and the estimates of irrigation pressures are included the attached tables.

DAU	Utility	1990	Ave.	1995 Base (D1485 & NMFS)			1995 EPA Standards			2010 Base (D1485 & NMFS)			2010 EPA Standards		
Sum		Lift(Ft)	PSI	Dry: Yr 7	Median	Wet	Dry: Yr 7	Median	Wet	Dry: Yr 7	Median	Wet	Dry: Yr 7	Median	Wet
Note:		(1)	(6)	(4)											
R1	PG&E	70	8.7	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43	8.43
R2	PG&E	100	8.7	75.95	75.58	75.73	75.95	75.58	75.73	75.95	75.58	75.73	75.95	75.58	75.73
R3	PG&E	95	8.7	75.70	73.41	73.18	75.70	73.41	73.18	75.70	73.41	73.18	75.70	73.41	73.18
R4	PG&E	40	8.7	30.04	27.49	30.73	30.04	27.49	30.73	30.04	27.49	30.73	30.04	27.49	30.73
R5	PG&E	40	8.7	102.41	99.23	100.95	102.41	99.23	100.95	102.41	99.23	100.95	102.41	99.23	100.95
R6	PG&E	120	8.7	151.47	151.47	151.47	151.47	151.47	151.47	151.47	151.47	151.47	151.47	151.47	151.47
R7	PG&E	80	8.7	47.03	45.31	45.07	47.03	45.31	45.07	47.03	45.31	45.07	47.03	45.31	45.07
R8	PG&E/SMUD	120	12.0	244.89	244.89	244.89	244.89	244.89	244.89	244.89	244.89	244.89	244.89	244.89	244.89
R9	PG&E	100	12.0	73.75	73.75	73.75	73.75	73.75	73.75	73.75	73.75	73.75	73.75	73.75	73.75
R10	PG&E	120	12.0	88.84	62.87	79.56	130.48	99.54	77.44	64.46	42.92	42.43	64.46	42.92	42.43
R11	MID	100	12.0	75.99	68.51	61.67	75.99	68.51	61.67	75.99	68.51	61.67	75.99	68.51	61.67
R12	TID	90	12.0	45.88	44.91	42.55	45.88	44.91	42.55	45.88	44.91	42.55	45.88	44.91	42.55
R13	PG&E	120	12.0	294.32	279.70	190.23	295.19	280.35	190.06	293.56	279.65	191.05	293.56	279.65	191.05
R14	PG&E	300	11.9	203.22	161.66	176.68	273.64	214.91	176.81	130.06	96.48	105.07	130.06	96.48	105.07
R15	PG&E	300	11.9	662.96	654.68	634.06	664.17	655.83	634.18	657.60	652.02	637.02	657.60	652.02	637.02
R16	PG&E	100	11.9	74.05	66.52	61.32	75.28	67.44	61.32	74.81	67.99	57.32	74.81	67.99	57.32
R17	PG&E	100	11.9	127.35	118.55	82.39	127.35	118.55	82.39	127.35	118.55	82.39	127.35	118.55	82.39
R18	SCE	150	11.9	364.41	360.41	344.27	366.31	361.84	344.28	364.37	361.41	339.47	364.37	361.41	339.47
R19	PG&E	300	11.9	233.05	145.80	99.02	241.37	156.84	102.24	143.26	113.31	110.50	143.26	113.31	110.50
R20	SCE	300	11.9	154.30	145.91	102.56	154.60	146.31	102.67	149.03	143.15	102.73	149.03	143.15	102.73
R21	SCE	350	11.9	636.88	540.70	289.57	644.04	550.18	292.34	567.97	514.38	298.22	567.97	514.38	298.22
Total				3,771	3,450	2,968	3,904	3,565	2,972	3,504	3,303	2,875	3,504	3,303	2,875
	PG&E			2,493	2,289	2,127	2,617	2,393	2,129	2,301	2,170	2,030	2,301	2,170	2,030
	SCE			1,156	1,047	736	1,165	1,058	739	1,081	1,019	740	1,081	1,019	740
	MID/TID			122	113	104	122	113	104	122	113	104	122	113	104
	SMUD														
	v. Median			321		(482)				201		(428)			
	EPA v. Base						133	115	4				0	0	0

CVPM Ag. Model Groundwater Pumping

Crop	Region (Thousand Acres) SR (7)	SJ	TL	Irr. Method Surface (8)	Sprinkler	Drip	Subsurf.
Grain	303	182	297	88.8%	10.8%	0.0%	0.4%
Rice	494	21	1	100.0%	0.0%	0.2%	0.0%
Cotton	0	178	1029	93.3%	6.5%	0.0%	0.0%
Sugar Beets	75	64	35	86.7%	13.3%	0.0%	0.0%
Corn	104	181	100	99.1%	0.0%	0.0%	0.9%
Field	155	121	135	89.5%	9.3%	0.7%	0.5%
Alfalfa	141	226	345	86.0%	13.0%	0.0%	0.9%
Pasture	357	228	44	81.8%	12.0%	0.0%	6.2%
Tomatoes	120	89	107	92.7%	6.5%	0.9%	0.0%
Truck	55	133	204	55.1%	29.5%	15.4%	0.0%
Almonds/Pistachios	101	245	164	39.2%	47.3%	13.2%	0.2%
Fruit	205	147	177	39.2%	47.3%	13.2%	0.2%
Citrus/Olives	18	9	181	11.5%	80.6%	7.9%	0.0%
Grapes	17	184	393	44.9%	12.7%	42.2%	0.3%
	2145	2008	3212				
Basin (HSA)							
Sacramento River				81.8%	14.2%	2.8%	1.3%
San Joaquin Valley				73.0%	18.4%	7.6%	1.0%
Tulare Lake				73.2%	18.4%	8.0%	0.3%
Ave.PSI	8.7	12.0	11.9	3	30	50	50

(7) CDWR Bulletin 160-93, T.7-12.
(8) CDWR Bulletin 160-93, T.7-8.

DAU	Utility	1990	Ave.	GW Pumping: (TAF) 1995 Base (D1485 & NMFS)			1995 EPA Standards			2010 Base (D1485 & NMFS)			2010 EPA Standards		
Sum		Lift(Ft)	PSI	Dry: Yr 7	Median	Wet	Dry: Yr 7	Median	Wet	Dry: Yr 7	Median	Wet	Dry: Yr 7	Median	Wet
Note:		(1)	(6)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)
R1	PG&E	70	8.7	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00
R2	PG&E	100	8.7	346.03	344.35	345.05	346.03	344.35	345.05	346.03	344.35	345.05	346.03	344.35	345.05
R3	PG&E	95	8.7	356.79	346.00	344.89	356.79	346.00	344.89	356.79	346.00	344.89	356.79	346.00	344.89
R4	PG&E	40	8.7	227.92	208.63	233.20	227.92	208.63	233.20	227.92	208.63	233.20	227.92	208.63	233.20
R5	PG&E	40	8.7	777.05	752.94	765.99	777.05	752.94	765.99	777.05	752.94	765.99	777.05	752.94	765.99
R6	PG&E	120	8.7	609.00	609.00	609.00	609.00	609.00	609.00	609.00	609.00	609.00	609.00	609.00	609.00
R7	PG&E	80	8.7	247.19	238.14	236.89	247.19	238.14	236.89	247.19	238.14	236.89	247.19	238.14	236.89
R8	PG&E/SMUD	120	12.0	943.00	943.00	943.00	943.00	943.00	943.00	943.00	943.00	943.00	943.00	943.00	943.00
R9	PG&E	100	12.0	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00	320.00
R10	PG&E	120	12.0	342.08	242.09	306.35	502.43	383.28	298.21	248.23	165.28	163.40	248.23	165.28	163.40
R11	MID	100	12.0	329.73	297.26	267.57	329.73	297.26	267.57	329.73	297.26	267.57	329.73	297.26	267.57
R12	TID	90	12.0	212.57	208.05	197.14	212.57	208.05	197.14	212.57	208.05	197.14	212.57	208.05	197.14
R13	PG&E	120	12.0	1133.33	1077.03	732.50	1136.67	1079.53	731.85	1130.41	1076.85	735.65	1130.41	1076.85	735.65
R14	PG&E	300	11.9	389.00	309.44	338.19	523.78	411.37	338.43	248.96	184.68	201.11	248.96	184.68	201.11
R15	PG&E	300	11.9	1269.00	1253.14	1213.68	1271.32	1255.35	1213.90	1258.74	1248.05	1219.35	1258.74	1248.05	1219.35
R16	PG&E	100	11.9	321.80	289.06	266.48	327.12	293.08	266.46	325.08	295.44	249.11	325.08	295.44	249.11
R17	PG&E	100	11.9	553.41	515.19	358.03	553.41	515.19	358.03	553.41	515.19	358.03	553.41	515.19	358.03
R18	SCE	150	11.9	1201.92	1188.72	1135.49	1208.16	1193.44	1135.51	1201.77	1192.01	1119.64	1201.77	1192.01	1119.64
R19	PG&E	300	11.9	446.08	279.09	189.54	462.01	300.22	195.71	274.21	216.90	211.51	274.21	216.90	211.51
R20	SCE	300	11.9	295.35	279.30	196.31	295.92	280.06	196.53	285.26	274.01	196.63	285.26	274.01	196.63
R21	SCE	350	11.9	1069.48	907.96	486.26	1081.49	923.89	490.91	953.76	863.77	500.79	953.76	863.77	500.79
Total				11,439	10,656	9,534	11,780	10,951	9,536	10,897	10,348	9,266	10,897	10,348	9,266
	PG&E			8,330	7,775	7,251	8,652	8,048	7,249	7,914	7,512	6,984	7,914	7,512	6,984
	SCE			2,567	2,376	1,818	2,586	2,397	1,823	2,441	2,330	1,817	2,441	2,330	1,817
	MID/TID			542	505	465	542	505	465	542	505	465	542	505	465
	SMUD			(5)											
	v. Median			782		(1,123)				550		(1,082)			
	EPA v. Base						341	294	3				0	0	0

(1) Per Steve Hatchett, CH2M Hill 7/6/94 add 30ft drawdown.
(2) Per Larry Dale, for US EPA 8/22/94; preliminary for three water-yr types.
(3) Per Dale; assumes pumping at equilibrium in 2010.
(4) KWH/AF = 1.0231 x (lift+draw+2.306 2*PSI)/efficieny; ave. efficiency=70%
(5) Assume that most pumping in R8 by PG&E ag. customers.
(6) Ave. PSI based on allocated irrigation methods and crops by region from Bulletin 160-93.

Appendix E

Potential Impacts on PG&E Thermal Plant Cooling Water Diversions

Two large PG&E natural-gas-fired thermal generating plants could be affected by the salinity standards. The Contra Costa facility situated in Antioch has 1,260 MW that relies on once-through cooling water drawn from the Delta. The Pittsburg facility has 1,302 MW that uses once-through cooling plus another 720 MW unit that relies on cycled-water. This latter plant is less likely to be affected by any diversion restrictions. Combined, the once-through units in the Bay-Delta region represent about 16 percent of PG&E's generating resources.

Currently, PG&E constrains operations at these two plants during April and May to reduce fish entrapment.[11, , p. 2-30] These months are also the lowest load periods of the year. If PG&E had to restrict generation during the summer months however, several problems could arise. First, these units are critical to maintaining voltage levels for PG&E's largest load centers in the Bay Area. The plants sit in the middle of the PG&E service area and act to boost the power delivered from the state's hydropower and imported energy from the Pacific Northwest. Second, the plants provide reliability in case the Bay Area is disconnected from the rest of the utility system's resources. The Contra Costa and Pittsburg plants must be up and running to fill these requirements.* On particularly hot days in the summer, system voltage can "sag" causing customer equipment failures if these units are not operating near full load. The alternative would be to either (1) build more generating capacity near the Bay Area that has a cooling water source independent of Delta water sources or (2) rely more on customer curtailments during peak load periods.

Changes in the intake restrictions at the PG&E plants in the Delta are not modelled here do to the uncertainty of the impacts. However, this issue should be examined in the future as more information is developed to assess the implications for the entire electricity system.

*On June 10, 1994, PG&E was just one "contingency" (i.e., one generating plant or transmission interconnection) away from shutting down its power grid in the Bay Area. This coincided with the generation restrictions at the Contra Costa and Pittsburg units.

Appendix F

Detailed Results for the Comparison of Alternatives to Base Case Conditions

The following tables show the annual cost and emission impacts from Elfin for each alternative evaluated in this report. The costs are broken out by energy and emissions. The emission data shows NOx, SOx, ROG, PM10 and carbon. Tables are included for expected conditions based on a weighted average of the three water-year types.

TABLE F-1. NET INCREASE IN EMISSIONS DUE TO EPA FLOWS. NORTHERN CALIFORNIA SYSTEM EXAMPLE					
	TONS PER YEAR: Probability Weighted(1)				
	NOx	SOx	PM10	ROG	Cx
1995	231.61	80.57	7.84	5.57	42,427.35
1996	208.46	58.66	7.96	6.02	46,983.95
1997	119.35	65.03	9.29	6.83	50,543.40
1998	85.72	59.78	8.49	5.48	57,037.20
1999	103.57	40.10	8.83	6.72	52,048.45
2000	119.80	57.46	8.96	5.83	55,491.43
2001	73.60	35.42	8.69	6.37	59,980.98
2002	117.11	49.53	8.61	5.51	60,619.40
2003	90.10	46.65	9.46	6.27	65,079.93
2004	73.66	10.19	8.89	7.01	70,244.85
2005	121.24	49.17	7.80	4.47	64,360.98
2006	135.05	43.52	8.70	5.27	64,640.23
2007	234.80	62.76	11.14	4.36	57,399.48
2008	113.23	58.86	8.70	4.92	65,113.00
2009	126.14	58.42	9.15	5.01	66,983.68
2010	155.61	70.30	9.29	5.02	67,790.03
2011	129.68	52.80	8.10	3.99	66,503.55
AVE	131.69	52.90	8.82	5.57	59,602.81

(1) 20% DRY, 55% NORMAL, 25% WET YEAR

Capacity
generator
NG compact

Something wrong

TABLE F-2. PRODUCTION COST IMPACT OF EPA FLOWS. NORTHERN CALIFORNIA			
	($ MILLION) (1)		
	Production	Emissions	Total
1995	$10.22	$2.21	$16.10 X
1996	$17.55	$2.23	$23.55
1997	$14.86	$2.36	$21.11
1998	$22.74	$2.43	$29.18
1999	$12.53	$2.70	$19.39
2000	$21.06	$2.93	$28.30
2001	$19.07	$2.93	$26.50
2002	$24.03	$3.51	$32.22
2003	$23.60	$3.64	$32.12
2004	$24.80	$4.18	$34.06
2005	$21.13	$4.28	$30.69
2006	$28.88	$4.57	$38.95
2007	$36.67	$3.55	$45.97
2008	$28.67	$4.61	$39.28
2009	$37.85	$5.23	$49.36
2010	$42.61	$5.63	$54.83
AVE	$24.14	$3.56	$32.60
NPV 11% OR	$152.55	$22.92	$208.67
(1) PROBABILITY WEIGHTED: 20% DRY, 55% NORMAL, 25 % WET.			

TABLE F-3. NET INCREASE IN EMISSIONS DUE TO SWRCB FLOWS. NORTHERN CALIFORNIA SYSTEM EXAMPLE					
	TONS PER YEAR: Probability Weighted(1)				
	NOx	SOx	PM10	ROG	Cx
1995	183.06	72.58	7.96	6.10	42,945.88
1996	199.31	62.85	8.41	6.47	47,770.50
1997	130.79	64.26	8.98	6.70	49,202.33
1998	92.42	64.97	9.40	6.77	53,618.53
1999	108.66	49.72	9.79	7.78	50,110.88
2000	172.13	64.77	10.13	7.34	54,759.95
2001	132.38	54.82	9.51	7.09	58,555.25
2002	126.01	62.67	9.81	7.01	57,489.20
2003	113.58	52.10	9.94	7.37	60,189.05
2004	92.83	10.51	8.61	7.17	58,550.63
2005	125.51	49.90	9.32	6.19	62,290.98
2006	152.23	56.13	9.62	6.40	61,348.70
2007	229.98	211.19	12.15	5.71	53,801.83
2008	135.45	67.98	8.95	5.16	62,458.30
2009	151.52	69.93	10.05	6.15	62,024.03
2010	163.17	69.20	10.04	6.13	65,993.20
AVE	144.31	67.72	9.54	6.60	56,319.33
(1) 20% DRY, 55% NORMAL, 25% WET YEAR					

TABLE F-4. PRODUCTION COST IMPACT OF SWRCB FLOWS. NORTHERN CALIFORNIA			
	$MILLION PER YEAR (1)		
	Production	Emissions	Total
1995	$10.98	$1.98	$12.95
1996	$16.37	$2.31	$18.67
1997	$10.88	$2.37	$13.25
1998	$23.19	$2.31	$25.50
1999	$17.48	$2.63	$20.11
2000	$19.22	$3.36	$22.58
2001	$17.63	$3.21	$20.84
2002	$22.75	$3.36	$26.11
2003	$24.07	$3.61	$27.67
2004	$20.56	$3.80	$24.36
2005	$21.89	$4.27	$26.16
2006	$27.62	$4.52	$32.15
2007	$29.73	$3.38	$33.11
2008	$26.77	$4.62	$31.38
2009	$32.28	$5.19	$37.47
2010	$33.08	$5.65	$38.73
AVE	$22.16	$3.53	$25.69
NPV	$143.74	$22.75	$166.50

(1) 20% DRY, 55% NORMAL, 25% WET YEAR

TABLE F-5. NET INCREASE IN EMISSIONS DUE TO CUWA FLOWS. NORTHERN CALIFORNIA SYSTEM EXAMPLE

	TONS PER YEAR: Probability Weighted(1)				
	NOx	SOx	PM10	ROG	Cx
1995	186.54	60.53	7.81	6.00	46,199.70
1996	213.81	58.93	7.40	5.41	47,843.18
1997	147.08	82.33	9.51	7.11	47,219.38
1998	139.47	84.87	9.12	6.07	51,649.85
1999	99.50	58.71	8.50	6.07	49,257.25
2000	150.52	77.30	9.18	5.91	53,632.40
2001	137.66	70.28	9.32	6.34	58,829.30
2002	131.25	67.53	8.46	5.38	58,369.25
2003	120.71	60.80	9.99	7.20	60,823.18
2004	96.24	16.14	8.23	6.66	59,034.05
2005	120.41	53.65	7.72	4.30	63,095.18
2006	147.36	54.25	8.27	4.84	61,570.10
2007	233.03	226.18	11.23	4.25	53,235.30
2008	130.97	70.37	7.90	3.89	63,157.60
2009	148.40	74.13	9.15	4.94	62,983.63
2010	179.22	90.87	9.35	4.76	65,136.45
AVE	148.88	75.43	8.82	5.57	56,377.24

(1) 20% DRY, 55% NORMAL, 25% WET YEAR

TABLE F-6. PRODUCTION COST IMPACT OF CUWA FLOWS. NORTHERN CALIFORNIA			
	$MILLION PER YEAR(1)		
	Production	Emissions	Total
1995	$11.13	$2.14	$13.27
1996	$15.88	$2.23	$18.11
1997	$13.14	$2.39	$15.53
1998	$22.29	$2.41	$24.69
1999	$13.42	$2.38	$15.80
2000	$20.31	$3.01	$23.32
2001	$15.56	$3.18	$18.74
2002	$19.92	$3.39	$23.30
2003	$26.59	$3.43	$30.02
2004	$25.07	$4.15	$29.22
2005	$21.63	$4.05	$25.68
2006	$29.35	$4.41	$33.76
2007	$31.85	$3.24	$35.09
2008	$27.41	$4.58	$32.00
2009	$34.57	$5.05	$39.62
2010	$37.71	$5.48	$43.19
AVE	$22.86	$3.47	$26.33
NPV	$145.53	$22.42	$167.95
(1) 20% DRY, 55% NORMAL, 25% WET YEAR			

Appendix G

Critique of the Electric Power Analysis in the Evaluation of Economic Impacts of the Winter-Run Salmon CHD

The ***Evaluation of Economic Impacts of Alternatives for Designation of Winter-Run Salmon Critical Habitat in the Sacramento River*** was done for NOAA and NMFS by Hydrosphere Resource Consultants and used in the Regulatory Impact Analysis (RIA).[8] The annual benefits to electricity generation and use would be $48.9 million according to the report. However, the Hydrosphere report made several mistakes that lead to incorrect conclusions about the impacts of the CHD on the state's electric power system. These problems occur because standard electric utility planning methods were not applied in the analysis.

(1) The PROSIM simulation used in the analysis shows a single two-year period (1936-37) increase of over 1,300 gigawatt-hours (GWh or million kilowatt-hours) per year. This power would be of little, if any, value to Northern California due to hydropower spill conditions. In addition, these changes were by far the largest in the simulation. Removing these two years alone as outliers from the average change in generation over the entire 55-year period (1922-1978) changes the increase hydropower from 18 GWH to a loss of 6 GWH.

(2) The energy output is not valued with time-period specific prices. As discussed in Section 2.0 above, the value of energy can vary significantly by season and time of day. The Hydrosphere report does not apply this principle in evaluating the economic impacts.

(3) Dry year impacts, while significant and of greater relative value to electric utilities, were not discussed in the report; only averages were conveyed. The impacts during drought periods were substantial in the 1929 to 1934 and 1976 to 1977 periods. In the first period, the average losses were 320 GWH per year; in the second, 524 GWH; these represent 10 to 20 percent of critically-dry period generation from the CVP.

(4) Electricity utility standard practice rate the capacity available from the hydro system in a critically dry year during the peak load month (i.e., July)--this usually equals the minimum expected capacity from a facility. The Hydrosphere report uses the change in average capacity as a measure of capacity value. This information was not available in the Hydrosphere report, but the decrease in generation in drought years indicates large potential losses in capacity as well.

(5) Only the change in groundwater pumping for Sacramento River exchange contractors was included due to a reliance on the PROSIM model as representative of these impacts. In fact groundwater pumping by other CVP contractors in the Sacramento and San Joaquin Valleys is not included in the PROSIM model, and these changes must be estimated from PG&E load data.

An examination of the recent electricity generation and use patterns shows how the Hydrosphere report reached misleading conclusions. Both hydropower generation and agricultural groundwater pumping have realized large cost impacts rather than benefits identified in the report.

In an effort to assure the survival of several salmon runs in the Sacramento River--particularly the winter-run--temperatures in the river must be held below about 56 degrees F. To meet this constraint, the Bureau releases cooler water from the bottom of Lake Shasta during the summer. Doing so required that the electricity-generation turbines be bypassed and power generation be foregone. In addition, cooler water was released through Trinity Dam to supplement these flows since 1991.

Both the Bureau and the Western have estimated the losses in energy and purchased-power replacement costs.* The latter represents energy that Western had to buy to meet its contract agreement with municipal utilities (e.g., SMUD) and irrigation customers. The energy losses have been about 13 percent of the total potential energy output from the unit. The added purchase power costs in net present value have amounted to about $44 million over the 1987-1993 period.** This calculation ignores the additional capacity purchases that Western made to make up any shortfalls during these periods, and any efficiency losses from reduced hydropower head.*** Capacity is of particular importance because most of these bypasses occurred during the summer when electricity demand is at its highest level.****

In addition, as discussed in Appendix D, agricultural groundwater pumping increased substantially in the same time period. Statistical analysis finds that agricultural loads have increased at least 470 GWH since 1988 due to the imposition of the NMFS opinions. Based on an average avoided energy cost of 2.5 cents per kilowatt-hour and $60 per kilowatt of capacity, the annual cost has been $17 million in added resource expenditures in the PG&E system alone. The net present value total through 1993 is about $106 million.

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*USBR, "Shasta Powerplant Bypass Data," Preliminary Draft, June 17, 1994; and James C. Feider, Area Manager, Western Area Power Administration, "Comments to SWRCB Bay/Delta Workshop," June 14, 1994.

**Assuming a 7 percent real discount rate per the U.S. Office of Management and Budget. (U.S. Office of Management and Budget, "Benefit-Cost Analysis of Federal Programs: Guidelines and Discount Rates," Curricular A94, in Federal Register 53(519), November 19, 1992.)

***The hydropower "head" is the distance that the water falls through the turbines--the higher the head, the higher the efficiency of the turbine.

****Capacity represents the ability to meet peak power demand.

Appendix H

Allocation of Flows to Meet San Joaquin River Standards

The DWRSIM and PROSIM hydrological models simulate the operation of a number of reservoirs to meet various flow and water quality standards in the Bay-Delta region. For the San Joaquin River basin, the sole reservoir simulated in either of these models is the U.S. Bureau of Reclamation's New Melones Dam on the Stanislaus River. If releases from New Melones are unable to meet San Joaquin River requirements, both PROSIM and DWRSIM assume that the additional flows will come from the Merced and Tuolumne Rivers (i.e., Lake McClure (a.k.a. Exchequer) and New Don Pedro Reservoir). This modelling has two important implicit assumptions that:

- the water rights holders on these two rivers will accommodate these flow increases by reducing their diversions in some unidentified manner; and

- these water rights holders, who are generally senior to the federal and state water projects, may be transferring water without compensation to those projects' contractors.

To evaluate the impacts on the Northern California generation system, changes in power generation with releases at Exchequer and Don Pedro should be estimated. The PG&EHELP model is created to accomplish this task. However, the large changes in releases assumed for these two projects create two problems. First, the large increases in flows in April and May cause larger swings in power generation for those two months than predicated in the model. But more importantly, the additional flows in April and May have no compensating decreases in releases in other months or surface water diversions elsewhere in the overall economic analysis being done by other analysts.

The increases in April and May flows from the PROSIM model for Alternative 1 (Proposed EPA standards) range from zero in one-third of the 70-year water history to nearly 300,000 acre-feet per month (equal to about 5,000 cubic feet per second (cfs)). The median level of releases is 60,000 acre-feet in each month, and the average over the 70-year period is 92,000 acre-feet per month. Figure H-1 shows the probability that certain additional releases in total for both months will be required. Figure H-2 shows how the added flows are distributed among historic Tuolumne River flows; the dark bars represent the additional flows needed to meet EPA standards. The figure shows that the increases tend to occur in drier years.

Neither the PROSIM nor the DWRSIM models reduce releases in other months because they do not have the operational rules for these reservoirs. The agricultural impact analysis currently being done by the EPA does not account for changes in water use or sources in these regions of the magnitude in the hydrological model results. Until an explicit and consistent assumption is made about the source of these additional water releases, the impacts on the hydropower system of these two rivers can not be estimated.

Figure H-1

Merced & Tuolumne Added Releases For April & May Under EPA Standards

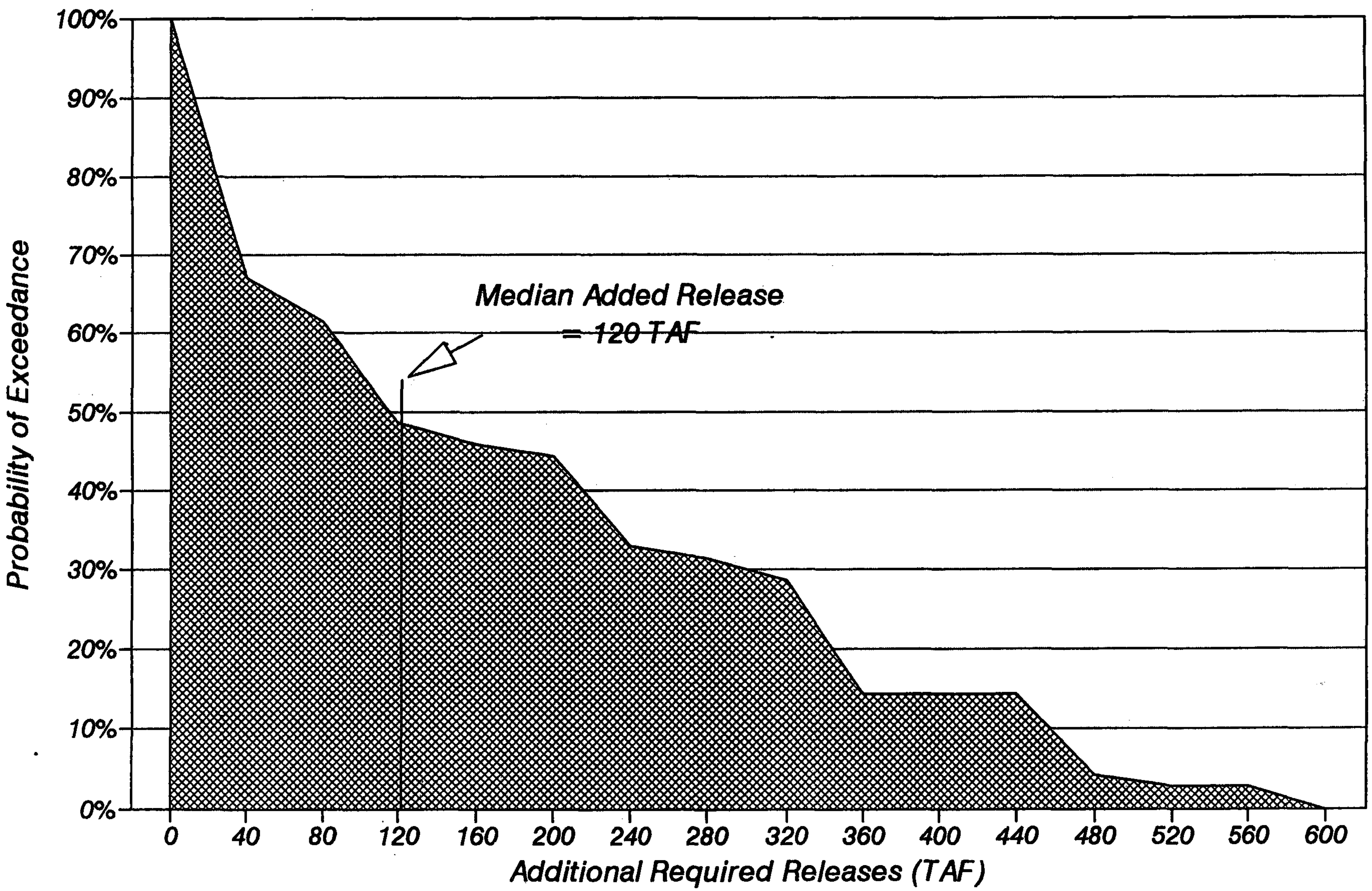
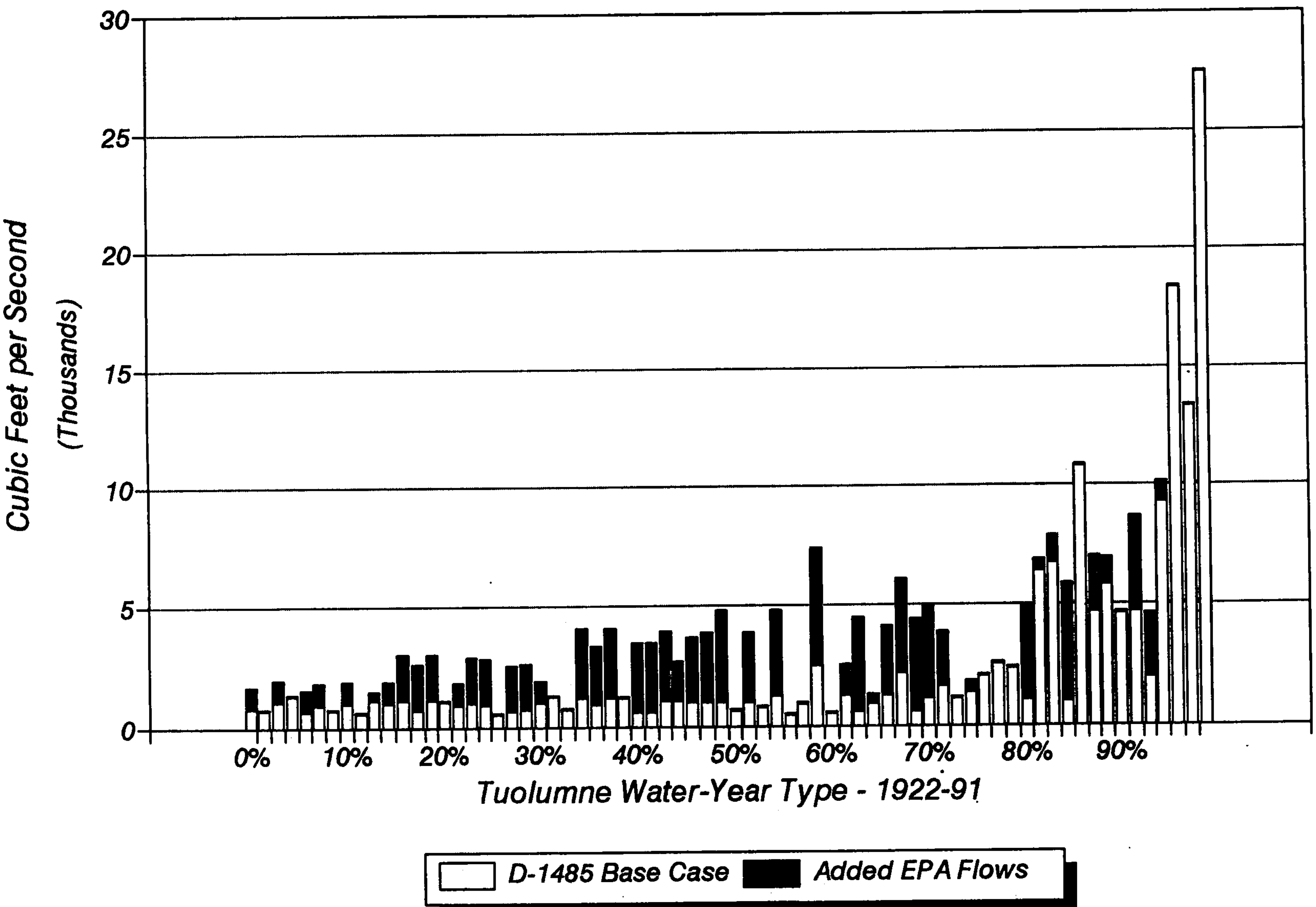


Figure H-2
Merced & Tuolumne D-1485 & EPA Flows For April & May Over Water-Year Type



To properly model the electricity impact, these added flows must come from one of three sources:

- reduced releases in other months from reservoirs on these streams;
- reduced diversions for urban water use from the Hetch Hetchy system;
- reduced surface water use in the Merced, Modesto and Turlock Irrigation Districts; and/or
- replacement of this water with increased groundwater pumping.

In addition, the flows from the Merced and Tuolumne Rivers used to meet the Vernalis standards may become available for pumping by the Central Valley and State Water Projects. This occurs if the Delta outflow remain at the same level and the Delta exports are not reduced by the amount of the flows provided from the Merced and Tuolumne. The flows from these rivers then essentially replace Sacramento River water in the Delta outflow and the projects are relieved to some extent of their export restrictions. In other words if standards in the Delta do not require that the increased San Joaquin flows empty into San Francisco Bay, that water becomes available to the CVP and SWP.

A key issue is whether water made available to the CVP and SWP via meeting the Vernalis standards is viewed as abandoned or as an effective water transfer from the upstream districts to the Delta exporters. If the water is abandoned, compensation is not necessarily compelled, except possibly under the "takings" clause of the U.S. Constitution. If the availability of the water is made as a transfer, then the upstream diverters would be compensated by the downstream diverters. Resolution of this issue depends on how these property rights are interpreted in the state Water Code.

References

1. Howard, Thomas, State Water Resources Control Board Division of Water Rights, Bay-Delta Unit, Sacramento, California. Memorandum. August 18, 1994.

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