REPORT

Impacts of Bay-Delta Water Quality Standards on CVP Power Production

Western Area Power Administration

October 18, 1994

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Impacts of Bay-Delta Water Quality Standards on CVP Power Production

Prepared for the
Western Area Power Administration
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EXECUTIVE SUMMARY

The Western Area Power Administration (Western) markets the power produced by the 10 power plants of the Central Valley Project (CVP) to 80 wholesale power customers throughout northern and central California. As changes in the water operations of the CVP system occur, the timing and levels of CVP electric production also vary, impacting Western's ability to meet its obligation to its power customer. This report identifies the various impacts that alternative standards suggested by the California State Water Resources Control Board (SWRCB) have on the CVP hydroelectric facilities, Western and its customers.

Each of the three alternatives for improving water quality in the Bay-Delta system are common in that each alternative results in the shifting of water releases and hence CVP hydro energy production to the winter and spring months at the expense of generation during the summer months. In relation to the base case, the annual energy production of the CVP project remains relatively unchanged in the alternatives studied. While the total annual energy produced remains relatively constant across the three alternatives, energy available for sale to Western's customers slightly increases due to the reduction in project pumping requirements (Project Use). The reduction in water exports from the Delta, provides an indirect benefit to CVP power customers in the form of reduced power consumption normally required for project pumping. Reduced Project Use increases availability of CVP hydro generation to serve Western's customers. This decrease in project pumping helps mitigate some of the other negative aspects of the various alternatives under consideration.

The reduction of energy production during the summer months produces a reduction in the firm load carrying capacity of the project (project capacity). This loss of capacity will result in major cost impacts on Western, result in a significant loss of operating flexibility and adversely impact Western's competitive position relative to other power providers.

The level of cost impacts to Western was estimated to range between $11.7 M and $18.5 M annually. When viewed over the next 18-year planning horizon (1995-2013), these costs will approach a quarter of a billion dollars. While this shifting of energy does have some near term benefits, its long-term impacts are negative.

In addition to the impacts associated with the changes in energy production, there are also secondary effects associated with each alternative. These include (1) the draw down of New Melones reservoir which can impact the ability of that project to provide reserves to the CVP system, (2) an increase in payments by power customers to the restoration fund as a result of decreases in water deliveries, and (3) reduced flexibility in the operation of the CVP hydroelectric facilities resulting in a long-term reduction of the competitiveness of the project.

In summary, the alternatives studied result in hydro power being shifted to non summer months which reduces its value. This reduction in value of power decreases Western's future marketing and operating flexibility and hence its ability to be competitive in a restructured electrical market.

BACKGROUND

The Central Valley Project (CVP) is a system of integrated multipurpose federal facilities which provide river regulation, flood control, water supply and power to the Central Valley of California. The CVP system has 10 power plants with an installed generating capacity of approximately 2,000 MW. The U.S. Bureau of Reclamation operates the CVP to meet project functions within the limits of the available water supply.

Western Area Power Administration (Western) is the marketing agent for the electric power produced by the CVP. CVP power is first used to meet Project Use, power which is required for the operations of the CVP water functions. Power in excess of Project Use is marketed to 80 whole power customers (municipalities, cooperatives, state and federal agencies, public utility districts and irrigation districts) in Northern California.

Current contracts between Western and its customers provides for the delivery of firm power (capacity and energy). Each customer is allocated firm capacity at a Contract Rate of Delivery (CRD) which is essentially constant over the life of the contract (provisions are provided for withdrawal under specific circumstances). The energy which accompanies the CRD is determined monthly in proportion to the ratio of the customer's monthly peak load to its CRD. This form of marketing results in relatively small changes in Western's monthly peak load requirements.

The California State Water Resources Control Board (SWRCB) is reviewing its 1991 Water Quality Control Plan for the Bay-Delta Estuary and evaluating a range of alternative standards. Five alternative standards have been proposed. The purpose of this report is to identify the various impacts these alternatives will have on the CVP hydroelectric facilities, Western and its customers.

STUDY METHODOLOGY

The SWRCB base case and alternative standards outlined in the letter from Thomas Howard to George Barnes dated August 18, 1994 were converted to water requirements or pumping restrictions in the delta by the Department of Water Resources (DWR). DWR then developed simulation studies which operated the CVP and State Water Project to meet each alternative standard over the 1922-1991 historical hydrologic period. Impacts for each alternative were estimated relative to a base case specified in the Board staff's memo, which assumed continued operations under D-1485.

Seventy years (1922-1991) of generation data for the CVP facilities were developed based on the output of Water Resources Management Inc. (WRMI) PROSIM program. This program models the water operation of the CVP system and was used to simulate reoperation of the CVP system based on the particular alternative to be analyzed.

The incidental unit generation from the PROSIM output was used to provide data for input into the PROSYM production cost model. The PROSYM model is a hourly production cost model which can be used to simulate the hour to hour operation of the CVP hydroelectric system. Both critical and average water conditions were modeled for the base case and each alternative. For study purposes, the critical year was defined as the year having the lowest July through December energy production for the CVP system, over the 70 years of history. An average year was made up of the monthly average of all the January's, to simulate an average January, and so on for February, etc. Thus, the average year is not a contiguous year, but an artificial year.

PROSIM output also supplied the basic data for the monthly Project Use load files which were unique to each case. The Project Use load file for each case was added to the hourly CVP Customer load file to form a composite load file. Therefore, each case was represented with a unique load file, based on the combined load shape of the CVP customer load and Project Use load.

The CVP system was modeled with special considerations for the reregulating capabilities of Keswick and Nimbus. That is, upstream projects were used for peaking, with Keswick and Nimbus reregulating to maintain a constant downstream flow. Additionally, the Trinity system was modeled using knowledge of current obligations which include refined operations caused by sediment contamination and water temperature requirements. Trinity, Carr and Spring Creek units were modeled with 50 percent of their available energy baseloaded and the remainder available for peaking. In order to simplify the analysis, all costs, prices and savings are assumed to be at 1994 levels.

ANALYSIS

The following three areas were addressed in the impact analysis:

- Capacity
- Energy
- Restoration Fund Payments
- Air Quality

Capacity

Two different perspectives were identified from which to determine the economic effects on capacity associated with changing Bay-Delta standards. The first, an "Institutional Perspective," considers Western's current obligations as dictated by its contracts with its customers, and the effect which each alternative has on Western's ability to meet those obligations. This perspective deals with direct impacts to Western. The second, a "Regional Perspective," views the impacts from an overall electric system perspective. This approach values the hydro resource in terms of a typical seasonal load curve. The Regional Perspective looks at the difference in capacity available to serve firm load on a regional or system basis rather than focusing solely on Western. The Institutional Perspective is bounded by fixed Western loads, while the Regional Perspective takes into account seasonal changes in the CVP capacity and loads. Both methods are potentially relative to Western.

The level of capacity usable in meeting customer loads over a given period is a function of the level of energy available during that period. In order for capacity to be firm, it must be available when called upon, including during critical water conditions. Therefore, capacity levels were modeled assuming a critical water year.

The detailed hourly hydro unit generation output of PROSYM provided for the determination of the project's firm load-carrying capacity for each month (the monthly level of capacity which is supported by project energy and usable in meeting daily load requirements.) The firm load carrying capacity for a month is the level of hydro capacity that is usable in meeting load, given the level of hydro energy available during that month. The difference between on-peak Project Use capacity and firm load carrying capacity is the capacity available to meet customer load (Attachment 1). The difference between each alternative's capacity and the base case's capacity was used as the estimate of the capacity gain or loss for a particular alternative. This process was repeated for each month of the critical year to determine monthly changes in capacity. Attachment 2 graphically represents the results of this analysis. This graph also illustrates the shifting of capacity from the summer months into the winter and spring periods.

In the analysis of the Institutional Perspective, the difference between the capacity available for customer load and Western's customer load requirements determines the resultant purchases needed to meet load in each month. Since the changes in the Bay-Delta water standards will be long term, long-term capacity purchase commitments in some form will eventually be required. The development of new capacity requires the long-term commitment of capital. Long-term capacity purchases are usually made based on an annual purchase rather than monthly. The maximum monthly difference during the critical year establishes the amount to be purchased annually (Annual Purchase) in order for Western to meet its current obligations as dictated by contracts with its customers. The difference between the Annual Purchase and each monthly purchase necessary to meet load is the amount of short-term capacity available for sale as surplus. Attachment 3 summarizes the results of the analysis. It was assumed that surplus capacity may be marketed, providing revenue to Western. An estimate of $12 per kW-Mo was used as the value of long-term capacity, with month to month surplus valued between $0.00 to $2.75 per kW-Mo (see Attachment 3 for price pattern). Netting the revenues derived by the sale of surplus capacity with the cost of the Annual Purchase, produced a net cost of capacity associated with each alternative. The difference in net cost of each alternative from the base case determined the relative net cost.

When viewed from the Institutional Perspective, Western derives a net benefit from the implementation of each of the alternatives studied to date, relative to the base case. This is a consequence of the shifting of capacity into winter months and Western's relatively constant monthly peak. That is, Western's margin between its obligations and CVP winter capacity is considerably greater than the margin between its obligation and CVP summer capacity. In each alternative, the shifting of energy to the winter months results in a proportionate shift of capacity. This shifting results in a decrease in the seasonality of the generation. As the seasonality of the generation is decreased (as is the case in each of the alternatives), Western's Annual Purchase requirements (as determined in the winter period) decrease. This decrease in Annual Purchase capacity is significant enough to offset the loss of hydro capacity during the summer months. See Figure A of Attachment 4. The annual net savings was estimated to be in the $5 M to $6 M range.

When viewed from the Regional Perspective, the Annual Purchase for each alternative is determined by how much summer hydroelectric capacity is lost relative to the base case. The amount of surplus capacity sales in each month was determined by adding the Annual Purchase to the difference in capacity available for customer load. As in the Institutional Perspective, a value of $12 per kW-Mo was used as the value of long-term capacity, and the month-to-month surplus capacity was valued from $0.00 to $2.75 per kW-Mo depending on when the surplus was available (Attachment 5). Surplus sales revenue were netted with the cost of the Annual Purchases to calculate a net cost of each alternative. An annual total ~~net~~ cost in the range of $17 M to $24 M is indicated. Net 14M - 21M

The net cost for the Regional Perspective is substantial because the perspective focuses on the overall impact of the change in operation at the time of the regional or system peak. Contrary to the shape of Western's present monthly peak curve, which is flat, the system curve demonstrates considerable seasonality. See Figure B of Attachment 4. Due to the seasonality of the curve, the need for capacity during the summer period is greater than at other times of the year. As the CVP output over the summer months is decreased, with output being shifted to non-summer months (as is the case with alternatives 1, 2, and 3), the value of the CVP capacity is reduced since the additional non-summer capacity has little or no value and the loss in the summer must be replaced at the time when capacity on the system is the least available.

Energy

An average year scenario was used to analyze the effects of the alternatives on CVP energy. The CVP hydro system was modeled in PROSYM (with average year capacity and energy) and was dispatched to meet a customer load, including average year Project Use loads. Energy requirements to meet load were divided into on-peak and off-peak to easily quantify the effects of project use and time of day pricing. Since the price of energy changes hourly, depending on on-peak and off-peak demand, varying on-peak and off-peak energy prices as well as variable seasonal energy prices were assumed. (See Cost Assumptions at the bottom of Attachment 6, page 2). A graphical representation of the results of this analysis is shown in Attachment 7. In the alternatives, there was a net benefit in the range of $3.2 M to $3.4 M annually. This increase in energy relative to the base case is primarily attributed to the decrease in project pumping requirements. This analysis is applicable to both the Institutional and the Regional Perspectives. A graphical representation of the results of this analysis is shown in Attachment 7. The seasonal shift in energy produced by the change in operations can be observed from this graphical representation.

Restoration Fund Payments

The CVP Improvement Act (CVPIA) created the CVP Restoration Fund (Fund), which provides for payment of up to $50 million annually for enhancement of the CVP project. Payment into the Fund is allocated among power and water customers. To the extent that contributions to the Fund from water users are reduced as a result of reduced water deliveries, the CVPIA provides for power customers increase their contributions to make up the difference.

Annual project water deliveries for 1922-1991 agricultural and municipal and industrial users were derived from the PROSIM analysis for the base case and each of the alternatives. The difference in the amount of water deliveries between each alternative and the base case was calculated. The agricultural and municipal and industrial rates for restoration fund payments as stipulated in the CVPIA were used to calculate the reduction in agricultural and municipal and industrial payments which would then become the responsibility of the power users. Results of this analysis are reported in Attachments 8 and 9. Based on the alternatives examined, reduction in water deliveries will result in additional payments to the Fund by power customers of $400,000 to $900,000 annually. However, based on water deliveries over the past ten years, the annual increase in powers' contribution to the Fund could be as high as $1.3 million. Further, during a critical dry period, this amount could increase to $2.0 million as a result of just the alternatives under consideration.

Air Quality

Due to the shifting of energy from the summer period into other times of the year, impacts on air quality are expected. The added availability of hydro generation during the non-summer period will tend to displace relatively efficient thermal power production. Whereas decreases in hydro energy during the summer can be expected to increase generation from less efficient thermal power plants. Thus, a negative impact on overall air quality can be expected. The report prepared by the Association of California Water Agencies addresses this issue in more depth and quantifies potential impacts.

ANALYTICAL RESULTS

To arrive at a bottom-line estimate of the economic effects to Western and its customers from each perspective, the cost of Annual Purchases and increased Restoration Fund costs were netted with revenues from surplus capacity sales and monthly energy savings to produce a total cost. This establishes a level field for comparing the three Alternatives (Attachments 8 and 9). The results of the Institutional and Regional Perspectives initially seem to be contradictory, but actually indicate the complicated nature of Western's resources and foretell the uncertainty of marketing them after 2004. The Institutional Perspective indicates that the alternatives will provide Western with a savings between $6.9 to $7.9 million annually. However, this amount may only be assumed over the near-term. The Regional Perspective more reasonably predicts the uncertainty in the way Western's resources will be marketed after 2004, with the alternatives costing, not saving, $11.7 to $18.5 million annually. When viewed over the next 18-year planning horizon, the total costs associated with implementation of an alternative will approach a quarter of a billion dollars.

ADDITIONAL CONSIDERATIONS

In addition to the above analytical work, there are a number of other impacts which should be considered in the discussion of the alternatives considering the impact each will have on CVP hydro production and Western customers. Each of these areas is briefly addressed in the following paragraphs.

New Melones Reservoir

Projected operations of the New Melones reservoir to meet proposed SWRCB alternative standards indicate that this reservoir could be drawn down to the minimum pool required for power generation, during dry and critical years. This would result in the loss of the generation at New Melones for the purpose of routine power production but maintains its availability to provide spinning/emergency reserves. When compared to the change in operation of the other CVP projects, the New Melones project demonstrated the largest change in month to month generation (See Attachment 10). The reason for this change is not clear at this point but nevertheless, the New Melones project seems to be shouldering a large percentage of the change in meeting alternative Bay-Delta standards.

By maintaining the minimum power pool in the reservoir, the generators are only available for power production (for short periods) during a system emergency. Use of the generator during an emergency, until thermal resources can be started, provides a valuable reliability product to the CVP electrical system. Efforts to maintain the minimum pool, as currently modeled, rather than complete draw down, as has occurred in the past, will enable Western to preserve some of the benefits of the resource.

Trinity River

Current modeling of the various alternatives for achieving the water quality standards in the Bay-Delta, assume that present diversions from the Trinity system remain unchanged. Present operations call for 341,000 ac-ft to be released into the Trinity River, with the remainder of the Trinity basin runoff available for diversion into the Sacramento River. These operating requirements for the Trinity River are under study with a potential result being the increase in the Trinity River in-stream flows to as much as 1.2 M ac-ft annually. To the extent that Trinity River in-stream requirements are increased, water available for diversion into the Sacramento River system and hence the Delta will be decreased.

Any reduction in diversions into the Sacramento River will result in the loss of electric energy production on the CVP system of approximately 1,100 kWh per ac-ft. For every 100,000 ac-ft diversions are cut, approximately 110 million kWh of CVP generation will be lost. This represents about two percent of the CVP energy generation in an average year. The replacement cost of this loss in generation (attributed to 100,000 ac-ft) is estimated to be $6.4 million per year.

If the adopted plan for the Bay-Delta does not recognize this potential loss of water, the plan could be outdated by the time it is implemented. It is recognized that the ultimate decision regarding Trinity River in-stream flow requirements is some time off (1995-1996), however, this does not mean that the issue should not be considered in the current Bay-Delta process. It is recommended that additional in-stream releases into the Trinity River be <u>assumed</u> in the analysis of the various Bay-Delta alternatives to identify sensitivities of Trinity related decisions directly impacting the Bay-Delta.

Project Use

As noted above, the reduction in exports from the Delta provides a benefit to CVP power customers in the form of an <u>assumed reduction</u> in power normally consumed for project pumping purposes. This assumption results in an increase in CVP hydro generation available to serve Western's customers. The decrease in project pumping helps mitigate some of the other negative aspects of the various alternatives under consideration. The modeling of the various alternatives all assume that this reduction in pumping is accomplished and is permanent. As modeled, Project Use load does not include new water transfers, new groundwater pumping, expanded cooperation between SWP/CVP pumping or any impacts of new third party sharing of environmental water obligations. Should the assumed savings not be available to Western, the impact of the various alternatives on Western could be substantially greater than has been approximated in the foregoing analysis. To the extent the adverse impacts identified are not mitigated via reduction in project pumping, Western and its power customers will be further adversely effected.

While not represented in the water system models, additional ground water pumping is expected to take place as a result of the implementation of an alternative. Currently, this type of pumping is not considered to be part of Project Use. Western's impact analysis is based on this fact and any effort to revise current policy is not acceptable.

Western's Power Marketing

Currently, Western has contracts to provide its customers approximately 1,450 MW of firm capacity with energy. With diversity, the Western peak varies in the 1,050 to 1,150 MW range each month. Due to the nature of the Western-Customer contracts, the customers tend to fully utilize their share of the CVP resource each month. This results in a peak load curve that does not vary much month to month or seasonally. That is, the Western peak in January is approximately the same as it is in July.

Due to this relatively constant peak requirement and the seasonality of the CVP power production, Western currently must purchase considerably more power in the fall and winter months than it needs to purchase in the spring and summer months. As noted previously, the potential increases in CVP output during the late fall and winter periods resulting from implementation of the alternatives, tends to reduce Western's current capacity purchases.

Existing contracts between Western and its customers expire in 2004. How Western will change its marketing program after 2004, is not known at this time with any certainty. In addition, contrary to CEC assumptions, Western's present contract with PG&E (2948A) also expires in 2004 and will not be renewed in its current form. To the extent Western decides to market power on a seasonal basis (which would tend to follow the CVP hydroelectric output), the implementation of one of the proposed alternatives will diminish the value of the CVP resource, by virtue of the decreases in its summer capacity. Summer capacity tends to be more valuable to utilities since their highest demands occur at that time of year. When the level of firm capacity Western has available to market is decreased over the peak demand period (summer), the overall value of the CVP resource (revenues to Western) will be reduced. As Western revenues decrease (without a commensurate decrease in costs), Western will be forced to raise rates, since its obligation to the federal government to repay project debt remains unchanged.

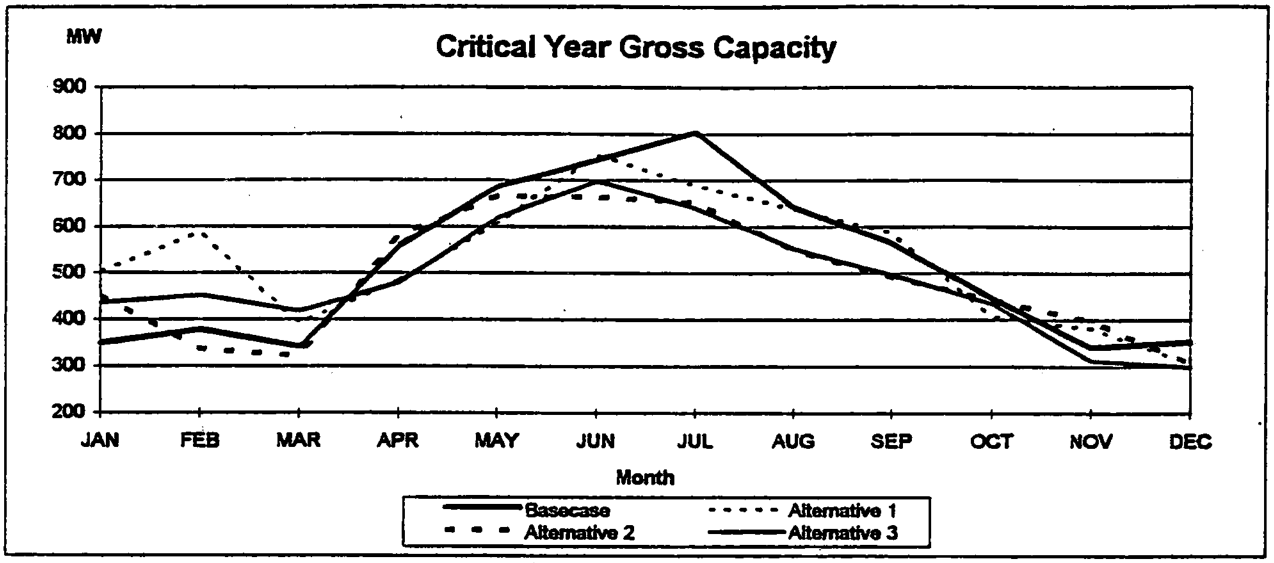
Currently, Western rates are marginally competitive with other wholesale power. As the resource value is decreased and additional CVP costs are added to Western's payment responsibilities (such as the Restoration Fund implemented via the CVPIA), the competitiveness of the CVP power product will be decreased. As with any product, if the fixed cost associated with the production of that product is recovered over fewer units, per unit costs increase, eventually resulting in the product becoming noncompetitive.

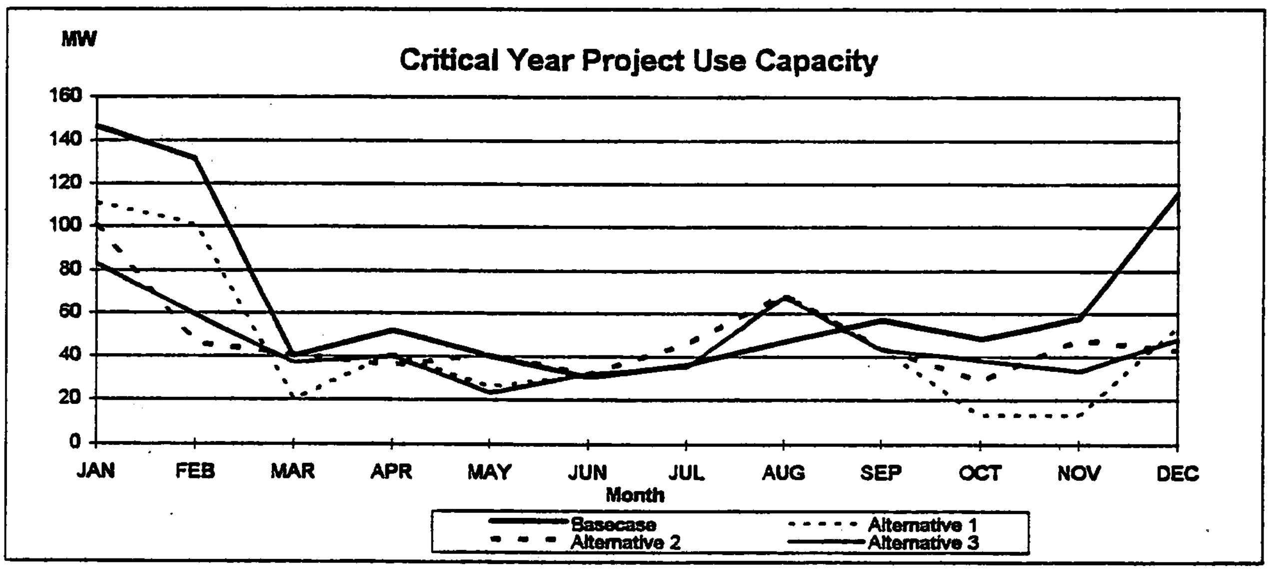
If Western's power is to remain competitive with other sources of power past 2004, it is imperative that the product be as flexible as possible. This means providing Western with the ability to maximize its CVP electrical output at times when it is most valuable (in summer peak). Any reduction in the CVP summer capacity will ultimately adversely impact Western. Alternatives that minimize the reduction in flexibility are preferred.

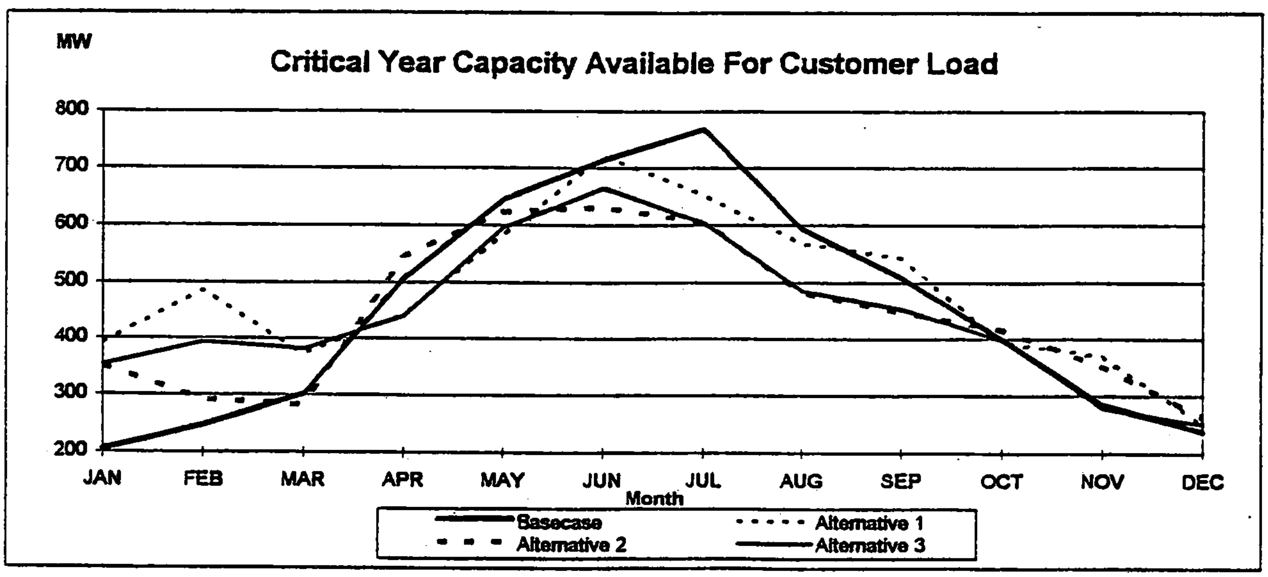
CONCLUSIONS

The results of the study indicate that over the long run the flexibility of the CVP hydroelectric generation will be adversely impacted. This impact will primarily be a result of the untimely release of water (from a power user perspective), shifting more valuable power from the summer months into non-summer months. The reduction in flexibility will result in less capacity being available for sale and the need to sell energy at times when its value is reduced. These impacts will tend to decrease Western's competitive position relative to other power providers.

Based on the work conducted, it appears that the negative impacts to the CVP system associated with Alternative 1 are somewhat less than those created by the other alternatives when viewed from a power perspective.


MW
Critical Year Gross Capacity
900
800
700
600
500
400
300
200
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
Month
Basecase
Alternative 1
Alternative 2
Alternative 3


MW
Critical Year Project Use Capacity
160
140
120
100
80
60
40
20
0
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
Month
Basecase
Alternative 1
Alternative 2
Alternative 3


MW
Critical Year Capacity Available For Customer Load
800
700
600
500
400
300
200
JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC
Month
Basecase
Alternative 1
Alternative 2
Alternative 3

Attachment 1
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Alternative Summary Report
Critical Year Capacity Breakdown

	Critical Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
CAPACITY MW (1)														
Basecase	1931	350	379	341	558	684	743	804	639	564	447	342	354	804
Alternative 1	1977	503	587	392	485	608	754	687	637	587	407	383	307	754
Alternative 2	1977	451	338	324	582	664	663	651	550	492	445	399	308	664
Alternative 3	1977	436	453	418	480	618	697	638	553	496	435	312	299	697
PU CAPACITY MW (2)														
Basecase	1931	146	131	40	52	40	30	36	47	57	48	58	116	146
Alternative 1	1977	111	101	20	41	26	32	35	69	44	13	13	54	111
Alternative 2	1977	101	46	41	36	41	32	46	69	44	29	48	43	101
Alternative 3	1977	83	59	37	40	23	32	35	68	43	38	33	48	83
CAPACITY AVAILABLE For Customer Load														
Basecase	1931	204	248	301	506	644	713	768	592	507	399	284	238	768
Alternative 1	1977	392	486	372	444	582	722	652	568	543	394	370	253	722
Alternative 2	1977	350	292	283	546	623	631	605	481	448	416	351	265	631
Alternative 3	1977	353	394	381	440	595	665	603	485	453	397	279	251	665
DIFFERENCE MW (3)														
Alternative 1		188	238	71	-62	-62	9	-116	-24	36	-5	86	15	-116
Alternative 2		146	44	-18	40	-21	-82	-163	-111	-59	17	67	27	-163
Alternative 3		149	146	80	-66	-49	-48	-165	-107	-54	-2	-5	13	-165

(1) Firm Load Carrying Capacity supported by project energy.
(2) Project Use on peak load.
(3) Relative to base case.

Attachment 3 page 1
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Alternative Summary Report
Critical Year Capacity Analysis: Institutional Perspective

Customer		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Load	MW	1168	1152	1160	1176	1241	1266	1209	1191	1169	1082	1180	1183	
Capacity Available for Customer Load														
Basecase	MW	204	248	301	506	644	713	768	592	507	399	284	238	
Alternative 1	MW	392	486	372	444	582	722	652	568	543	394	370	253	
Alternative 2	MW	350	292	283	546	623	631	605	481	448	416	351	265	
Alternative 3	MW	353	394	381	440	595	665	603	485	453	397	279	251	
Purchases Needed to Meet Load														
Basecase	MW	964	904	859	670	597	553	441	599	662	683	896	945	
Alternative 1	MW	776	666	788	732	659	544	557	623	626	688	810	930	
Alternative 2	MW	818	860	877	630	618	635	604	710	721	666	829	918	
Alternative 3	MW	815	758	779	736	646	601	606	706	716	685	901	932	
Annual Purchase														
Basecase	MW	964	964	964	964	964	964	964	964	964	964	964	964	
Alternative 1	MW	930	930	930	930	930	930	930	930	930	930	930	930	
Alternative 2	MW	918	918	918	918	918	918	918	918	918	918	918	918	
Alternative 3	MW	932	932	932	932	932	932	932	932	932	932	932	932	
Surplus Sales														
Basecase	MW	0	60	105	294	367	411	523	365	302	281	68	19	
Alternative 1	MW	154	264	142	198	271	386	373	307	304	242	120	0	
Alternative 2	MW	100	58	41	288	300	283	314	208	197	252	89	0	
Alternative 3	MW	117	174	153	196	286	331	326	226	216	247	31	0	
Annual Cost at $12/kWMo														**Total**
Basecase	$	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	11,568,000	$138,816,000
Alternative 1	$	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	11,160,000	$133,920,000
Alternative 2	$	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	11,016,000	$132,192,000
Alternative 3	$	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	11,184,000	$134,208,000
Suplus Sales Revenue														
Price $/kWMo		$1.50	$1.50	$1.50	$0.00	$0.00	$2.00	$2.75	$2.75	$2.75	$0.00	$1.50	$1.50	
Basecase	$	0	90,000	157,500	0	0	822,000	1,438,250	1,003,750	830,500	0	102,000	28,500	$4,472,500
Alternative 1	$	231,000	396,000	213,000	0	0	772,000	1,025,750	844,250	836,000	0	180,000	0	$4,498,000
Alternative 2	$	150,000	87,000	61,500	0	0	566,000	863,500	572,000	541,750	0	133,500	0	$2,975,250
Alternative 3	$	175,500	261,000	229,500	0	0	662,000	896,500	621,500	594,000	0	46,500	0	$3,486,500

Alternative Summary Report
Critical Year Capacity Analysis: Institutional Perspective

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Net Cost														
Basecase	$	11,568,000	11,478,000	11,410,500	11,568,000	11,568,000	10,746,000	10,129,750	10,564,250	10,737,500	11,568,000	11,466,000	11,539,500	$134,343,500
Alternative 1	$	10,929,000	10,764,000	10,947,000	11,160,000	11,160,000	10,388,000	10,134,250	10,315,750	10,324,000	11,160,000	10,980,000	11,160,000	$129,422,000
Alternative 2	$	10,866,000	10,929,000	10,954,500	11,016,000	11,016,000	10,450,000	10,152,500	10,444,000	10,474,250	11,016,000	10,882,500	11,016,000	$129,216,750
Alternative 3	$	11,008,500	10,923,000	10,954,500	11,184,000	11,184,000	10,522,000	10,287,500	10,562,500	10,590,000	11,184,000	11,137,500	11,184,000	$130,721,500
Relative Net Cost (Savings) Diff		Net cost Alt - Base												
Alternative 1	$	-639,000	-714,000	-463,500	-408,000	-408,000	-358,000	4,500	-248,500	-413,500	-408,000	-486,000	-379,500	($4,921,500)
Alternative 2	$	-702,000	-549,000	-456,000	-552,000	-552,000	-296,000	22,750	-120,250	-263,250	-552,000	-583,500	-523,500	($5,126,750)
Alternative 3	$	-559,500	-555,000	-456,000	-384,000	-384,000	-224,000	157,750	-1,750	-147,500	-384,000	-328,500	-355,500	($3,622,000)

Fig. A

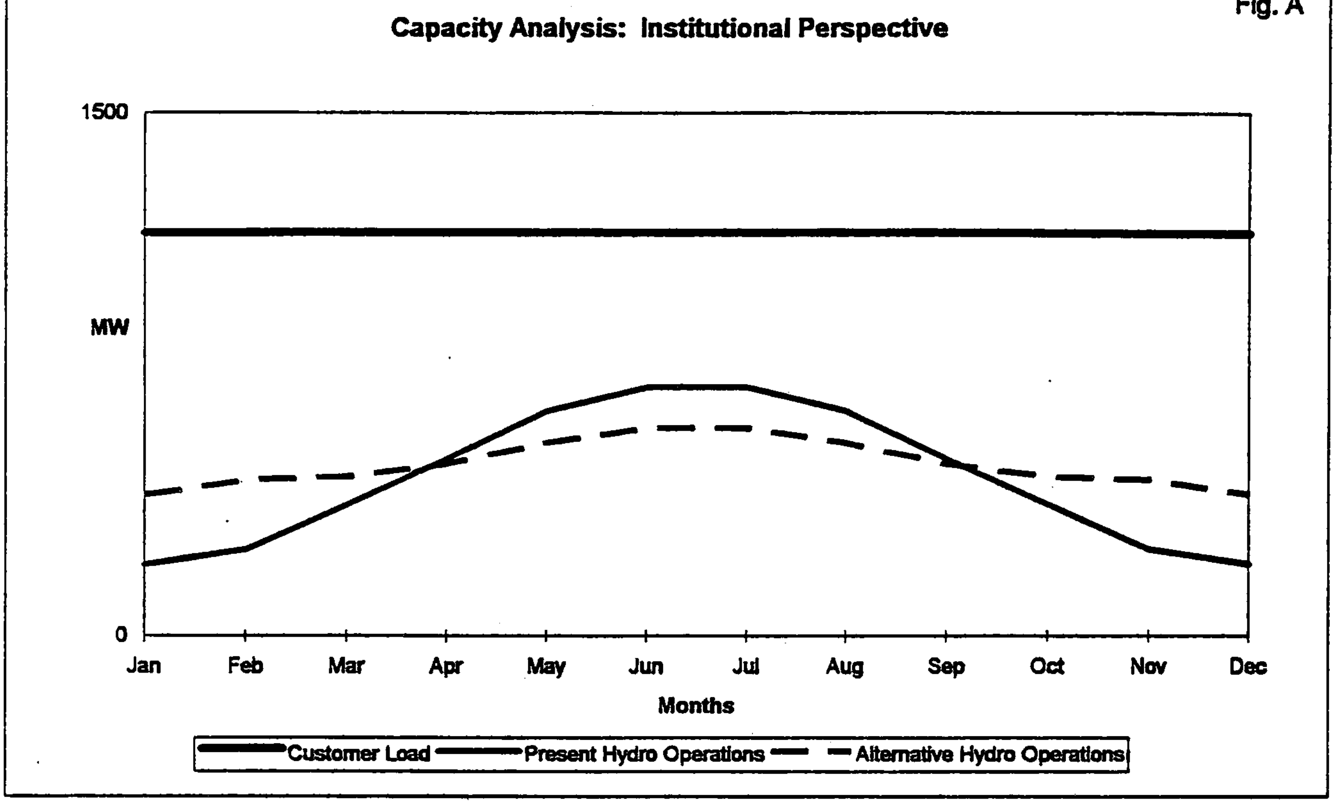
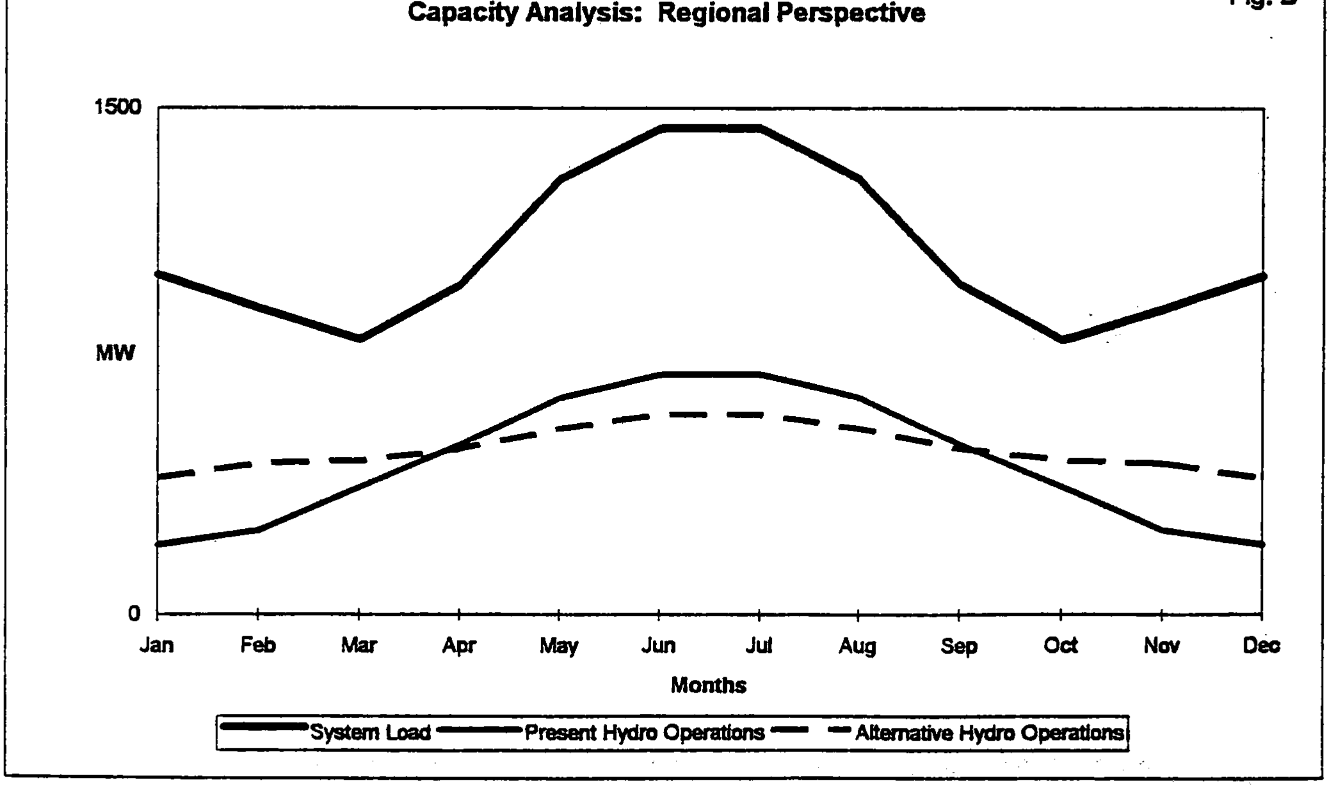

Capacity Analysis: Institutional Perspective
1500
MW
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Months
Customer Load
Present Hydro Operations
Alternative Hydro Operations

Fig. B


Capacity Analysis: Regional Perspective
1500
MW
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Months
System Load
Present Hydro Operations
Alternative Hydro Operations

Attachment 5
BDSUM.XLS
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Alternative Summary Report
Critical Year Capacity Analysis: Regional Perspective

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Annual Purchase														
Alternative 1	MW	116	116	116	116	116	116	116	116	116	116	116	116	
Alternative 2	MW	163	163	163	163	163	163	163	163	163	163	163	163	
Alternative 3	MW	165	165	165	165	165	165	165	165	165	165	165	165	
Surplus Sales														
Alternative 1	MW	304	354	187	54	54	125	0	92	152	111	202	131	
Alternative 2	MW	309	207	145	203	142	81	0	52	104	180	230	190	
Alternative 3	MW	314	311	245	99	116	117	0	58	111	163	160	178	
Annual Cost at $12/kWMo														**Total**
Alternative 1	$	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	1,392,000	$16,704,000
Alternative 2	$	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	1,956,000	$23,472,000
Alternative 3	$	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	1,980,000	$23,760,000
Suplus Sales Revenue														
Price $/kWMo		$1.50	$1.50	$1.50	$0.00	$0.00	$2.00	$2.75	$2.75	$2.75	$0.00	$1.50	$1.50	
Alternative 1	$	456,000	531,000	280,500	0	0	250,000	0	253,000	418,000	0	303,000	196,500	$2,688,000
Alternative 2	$	463,500	310,500	217,500	0	0	162,000	0	143,000	286,000	0	345,000	285,000	$2,212,500
Alternative 3	$	471,000	466,500	367,500	0	0	234,000	0	159,500	305,250	0	240,000	267,000	$2,510,750
Net Cost														
Alternative 1	$	936,000	861,000	1,111,500	1,392,000	1,392,000	1,142,000	1,392,000	1,139,000	974,000	1,392,000	1,089,000	1,195,500	$14,016,000
Alternative 2	$	1,492,500	1,645,500	1,738,500	1,956,000	1,956,000	1,794,000	1,956,000	1,813,000	1,670,000	1,956,000	1,611,000	1,671,000	$21,259,500
Alternative 3	$	1,509,000	1,513,500	1,612,500	1,980,000	1,980,000	1,746,000	1,980,000	1,820,500	1,674,750	1,980,000	1,740,000	1,713,000	$21,249,250

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Alternative Summary Report
Average Year Energy Breakdown

Average Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
Energy On-Peak MWh													
Basecase	166,520	173,192	174,691	204,880	261,929	281,935	333,507	333,446	208,190	190,551	157,120	136,148	2,622,108
Alternative 1	160,143	173,624	181,662	217,414	270,567	283,347	324,383	324,766	204,599	184,868	154,286	133,778	2,613,436
Alternative 2	157,336	167,770	170,219	219,551	277,473	279,941	318,141	321,441	206,396	186,816	160,285	137,392	2,602,761
Alternative 3	158,102	174,358	182,708	218,616	271,654	278,954	317,760	317,818	205,299	186,469	159,766	137,991	2,609,495
Energy Off-Peak MWh													
Basecase	159,905	172,464	143,665	174,031	219,182	277,034	364,530	303,904	203,579	133,631	132,603	169,201	2,453,729
Alternative 1	164,385	177,337	154,427	190,505	227,123	276,098	348,588	295,755	199,539	128,594	128,101	166,390	2,456,840
Alternative 2	159,456	163,927	140,106	190,858	235,051	273,208	342,093	285,463	206,299	134,485	138,172	174,483	2,443,598
Alternative 3	160,544	172,005	154,147	188,367	228,018	267,522	339,155	281,793	203,434	133,127	136,233	174,706	2,439,051
PU On-Peak MWh													
Basecase	55,100	44,200	50,200	57,800	49,100	59,700	85,900	85,500	49,000	44,500	41,800	48,700	671,500
Alternative 1	50,600	39,700	43,700	29,600	32,800	46,800	74,600	83,000	45,000	41,000	39,600	46,100	572,500
Alternative 2	49,500	36,600	42,100	34,100	36,700	52,600	69,800	66,000	47,900	41,700	37,800	44,300	559,100
Alternative 3	49,900	37,300	43,300	32,600	35,900	51,900	69,000	64,800	47,500	42,900	38,200	45,800	559,100
PU Off-Peak MWh													
Basecase	96,100	77,300	64,700	59,200	51,000	57,400	91,900	83,400	57,500	51,200	76,500	98,100	864,300
Alternative 1	103,200	77,000	63,700	30,000	34,300	44,900	77,200	83,300	54,900	49,500	73,900	96,700	788,600
Alternative 2	100,900	68,100	58,100	34,500	38,200	50,500	74,500	62,500	62,500	54,500	73,700	94,600	772,600
Alternative 3	101,100	68,800	61,300	33,100	37,200	49,800	71,500	62,000	60,900	54,600	72,800	96,900	770,000
Net On-Peak MWh													
Basecase	111,420	128,992	124,491	147,080	212,829	222,235	247,607	247,946	159,190	146,051	115,320	87,448	1,950,608
Alternative 1	109,543	133,924	137,962	187,814	237,767	236,547	249,783	241,766	159,599	143,868	114,686	87,678	2,040,936
Alternative 2	107,836	131,170	128,119	185,451	240,773	227,341	248,341	255,441	158,496	145,116	122,485	93,092	2,043,661
Alternative 3	108,202	137,058	139,408	186,016	235,754	227,054	248,760	253,018	157,799	143,569	121,566	92,191	2,050,395
Net Off-Peak MWh													
Basecase	63,805	95,164	78,965	114,831	168,182	219,634	272,630	220,504	146,079	82,431	56,103	71,101	1,589,429
Alternative 1	61,185	100,337	90,727	160,505	192,823	231,198	271,388	212,455	144,639	79,094	54,201	69,690	1,668,240
Alternative 2	58,556	95,827	82,006	156,358	196,851	222,708	267,593	222,963	143,799	79,985	64,472	79,883	1,670,998
Alternative 3	59,444	103,205	92,847	155,267	190,818	217,722	267,655	219,793	142,534	78,527	63,433	77,806	1,669,051

Alternative Summary Report
Average Year Energy Breakdown

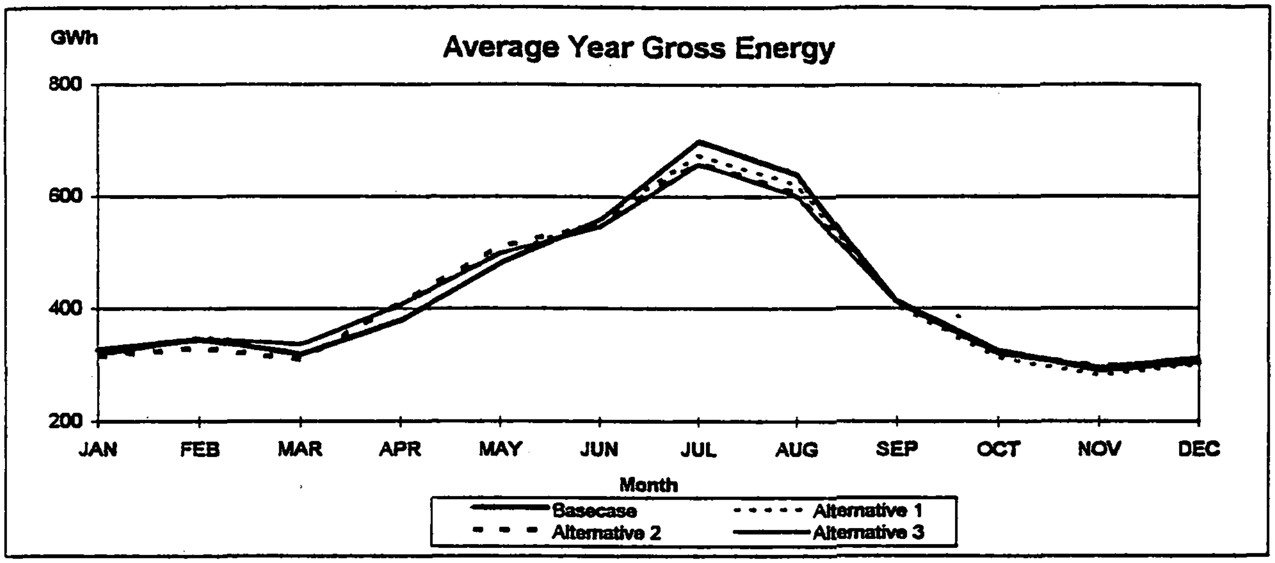
Average Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
Net Difference On-Peak MWh													
Alternative 1	-1,877	4,932	13,471	40,734	24,939	14,313	2,176	-6,180	409	-2,184	-633	230	**90,329**
Alternative 2	-3,584	2,178	3,628	38,371	27,944	5,107	734	7,494	-693	-935	7,166	5,644	**93,053**
Alternative 3	-3,218	8,066	14,918	38,936	22,926	4,819	1,152	5,072	-1,391	-2,482	6,247	4,743	**99,787**
Net Difference Off-Peak MWh													
Alternative 1	-2,620	5,173	11,761	45,674	24,641	11,564	-1,242	-8,049	-1,440	-3,337	-1,902	-1,411	**78,811**
Alternative 2	-5,249	663	3,040	41,526	28,669	3,074	-5,037	2,459	-2,280	-2,446	8,369	8,781	**81,569**
Alternative 3	-4,361	8,041	13,882	40,436	22,636	-1,912	-4,975	-711	-3,545	-3,904	7,330	6,705	**79,622**
Cost On-Peak ($)													
Alternative 1	52,562	-138,082	-377,196	-855,412	-523,709	-300,567	-56,563	160,680	-10,634	56,771	17,727	-6,437	**-1,980,860**
Alternative 2	100,352	-60,976	-101,595	-805,795	-586,820	-107,245	-19,079	-194,854	18,023	24,313	-200,642	-158,024	**-2,092,342**
Alternative 3	90,104	-225,834	-417,693	-817,650	-481,436	-101,203	-29,955	-131,877	36,156	64,532	-174,908	-132,807	**-2,322,570**
Cost Off-Peak ($)													
Alternative 1	57,636	-113,797	-258,746	-685,103	-369,611	-173,463	24,842	160,986	28,806	66,738	41,837	31,035	**-1,188,839**
Alternative 2	115,482	-14,577	-66,884	-622,896	-430,037	-46,110	100,742	-49,180	45,594	48,928	-184,118	-193,191	**-1,296,247**
Alternative 3	95,942	-176,904	-305,406	-606,542	-339,533	28,680	99,504	14,214	70,902	78,074	-161,262	-147,501	**-1,349,832**
Total Energy Cost ($)													
Alternative 1	110,197	-251,879	-635,943	-1,540,514	-893,319	-474,030	-31,721	321,666	18,172	123,509	59,564	24,598	**-3,169,700**
Alternative 2	215,834	-75,553	-168,480	-1,428,691	-1,016,856	-153,355	81,663	-244,034	63,617	73,241	-384,760	-351,214	**-3,388,589**
Alternative 3	186,046	-402,738	-723,099	-1,424,191	-820,968	-72,523	69,549	-117,663	107,058	142,606	-336,170	-280,308	**-3,672,402**

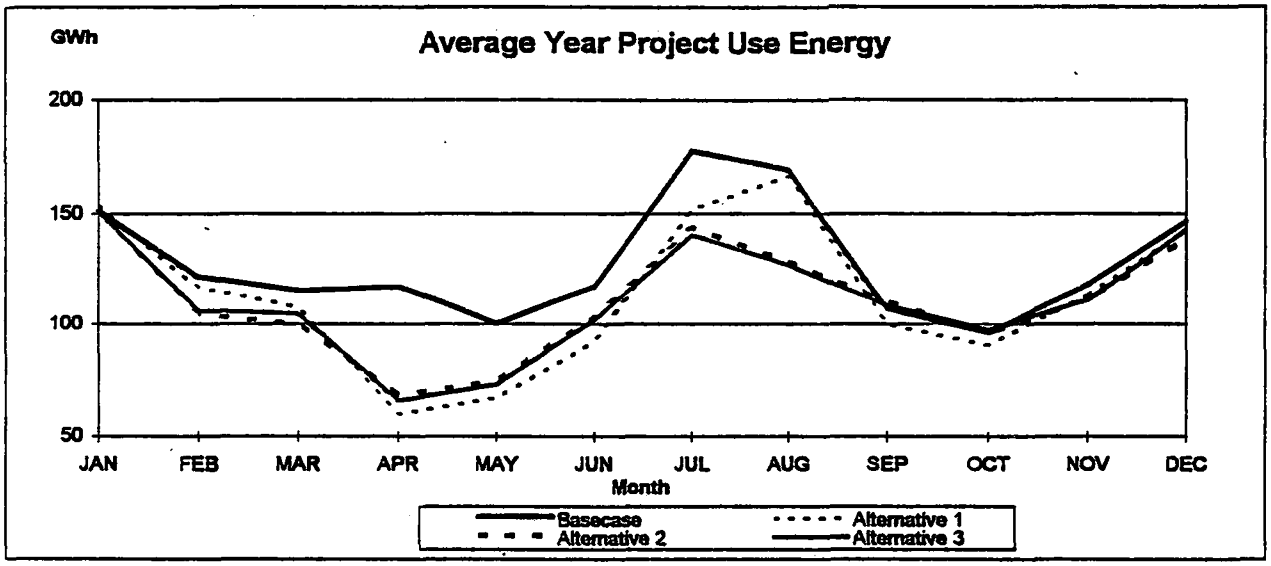
Cost Assumptions:

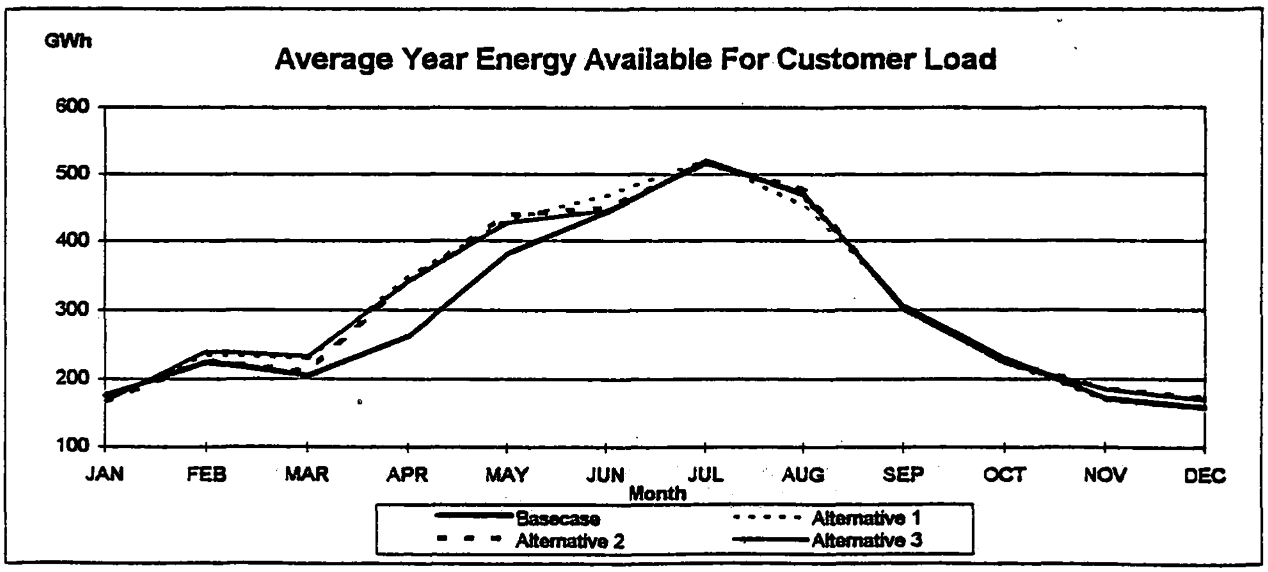
On-Peak Energy	Jan-Mar	$28/MWh	Off-Peak Energy	Jan-Mar	$22/MWh
	Apr-Jun	$21/MWh		Apr-Jun	$15/MWh
	Jul-Oct	$26/MWh		Jul-Oct	$20/MWh
	Nov-Dec	$28/MWh		Nov-Dec	$22/MWh

*** Project-Use load does not include new water transfers, new groundwater pumping, expanded cooperation between SWP/CVP pumping, or any impact of new third-party sharing of environmental water obligations.**

Attachment 7
BDSUM.XLS
10/17/94







Attachment 8
BDSUM.XLS
10/17/94

Alternative Summary: Institutional Perspective

Annual Capacity Savings		
Alternative 1	$	4,896,000
Alternative 2	$	6,624,000
Alternative 3	$	4,608,000
Surplus Sales Revenue		
Alternative 1	$	25,500
Alternative 2	$	(1,497,250)
Alternative 3	$	(986,000)
Energy Savings		
Alternative 1	$	3,169,700
Alternative 2	$	3,388,589
Alternative 3	$	3,672,402
Restoration Fund Costs		
Alternative 1	$	866,970
Alternative 2	$	614,574
Alternative 3	$	421,686
Total Savings		
Alternative 1	**$**	**7,224,230**
Alternative 2	**$**	**7,900,765**
Alternative 3	**$**	**6,872,716**

Annual impact. 1994 $

Attachment 9
BDSUM.XLS
10/17/94

Alternative Summary: Regional Perspective

Annual Capacity Costs

Alternative 1	$	16,704,000
Alternative 2	$	23,472,000
Alternative 3	$	23,760,000

Surplus Sales Revenue

Alternative 1	$	2,688,000
Alternative 2	$	2,212,500
Alternative 3	$	2,510,750

Energy Savings

Alternative 1	$	3,169,700
Alternative 2	$	3,388,589
Alternative 3	$	3,672,402

Restoration Fund Costs

Alternative 1	$	866,970
Alternative 2	$	614,574
Alternative 3	$	421,686

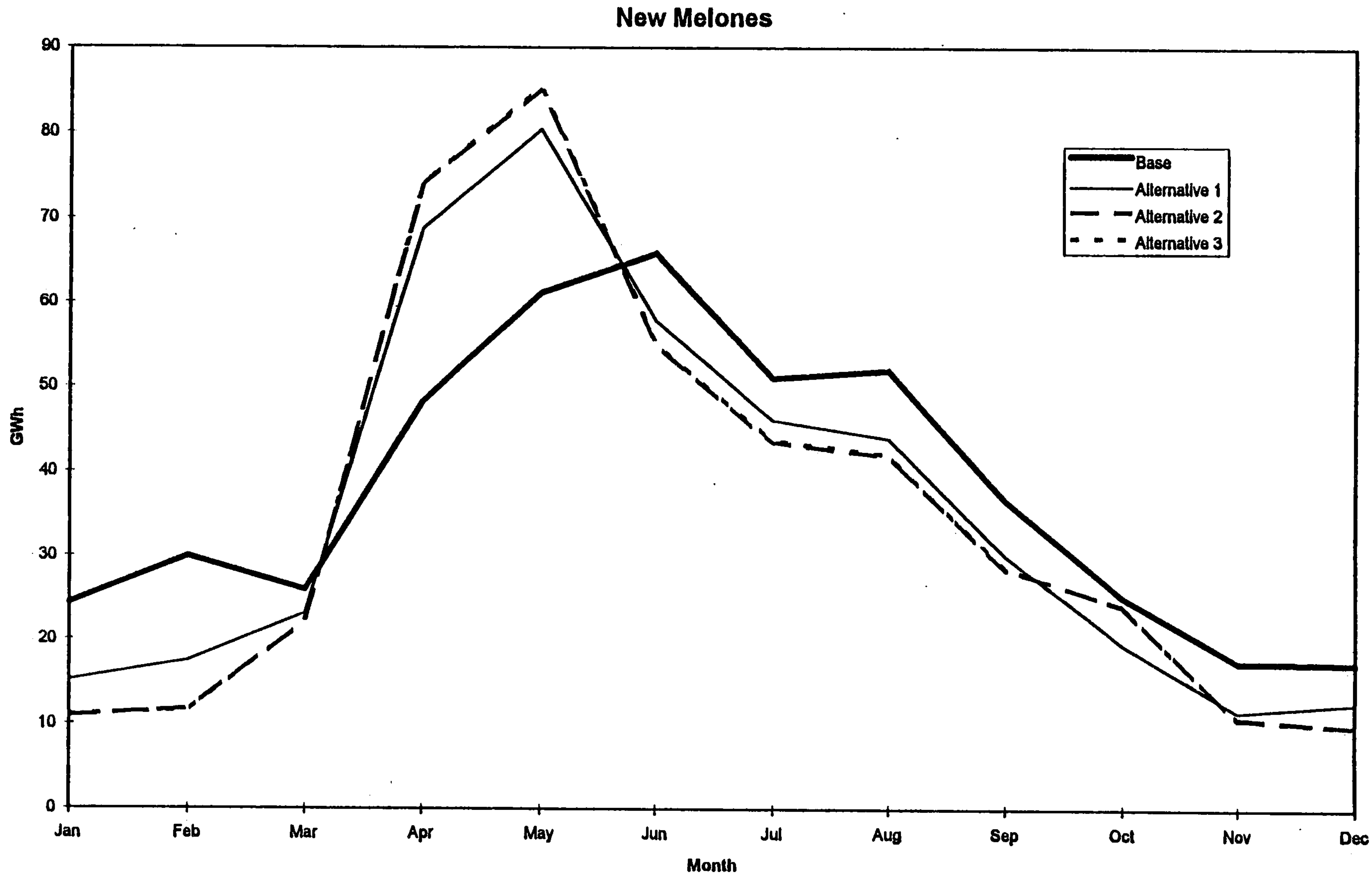
Total Cost

Alternative 1	**$**	**11,713,271**
Alternative 2	**$**	**18,485,485**
Alternative 3	**$**	**17,998,534**

Annual impact
1994 $

Attachment 10
AVGRAPH.XLS
10/17/94

Average Year Energy



Nov 30, 1994 Submittal

Attachment 9B
BDSUM.XLS 2/20/95

Alternative Summary: Regional Perspective

Annual Capacity Costs

Alternative 1	$	16,704,000
Alternative 2	$	23,472,000
Alternative 3	$	23,760,000
Alternative 4	$	-
Alternative 8	$	29,808,000

Surplus Sales Revenue

Alternative 1	$	2,854,500
Alternative 2	$	2,482,500
Alternative 3	$	2,755,250
Alternative 4	$	1,073,000
Alternative 8	$	3,519,150

Energy Savings

Alternative 1	$	3,169,700
Alternative 2	$	3,388,589
Alternative 3	$	3,672,402
Alternative 4	$	13,448,745
Alternative 8	$	2,668,589

Restoration Fund Costs

Alternative 1	$	2,832,000
Alternative 2	$	2,951,000
Alternative 3	$	2,984,000
Alternative 4	$	7,979,000
Alternative 8	$	1,853,000

Total Cost

Alternative 1	**$**	**13,511,801**
Alternative 2	**$**	**20,551,911**
Alternative 3	**$**	**20,316,348**
Alternative 4	**$**	**(6,542,745)**
Alternative 8	**$**	**25,473,261**