Power Resources

Appendix F

Trinity River Mainstem
Fishery Restoration

October 1999

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Appendix F

POWER RESOURCES

This appendix provides a summary of potential changes to Central Valley Project (CVP) power generation, project use, and the market value of CVP power that would result from the implementation of the alternatives considered in the Trinity River Mainstem Fishery Restoration Environmental Impact Statement/Environmental Impact Report (EIS/EIR). The EIS/EIR alternatives include a range of instream Trinity River flow requirements that would affect CVP facility and river operations and resulting CVP power generation and project use.

1.1 NO ACTION ALTERNATIVE COMPARED TO TRINITY EIS/EIR ALTERNATIVES

A brief discussion of the modeling background and impact assessment methodology used for analysis of the EIS/EIR alternatives is provided at the beginning of this appendix. A description of the assumptions and operational criteria used in the No Action Alternative, which serves as the base condition for the EIS/EIR impact analysis, follows the discussion. For each alternative, the model simulation results are presented showing the impacts to CVP power operations.

A significance criteria has been developed by R.W. Beck for the EIS/EIR and is provided as Attachment F1. The significance criteria is defined in the TEIS Impacts Study (Western, 1999). This significance criteria identifies "significant" impacts based on a 5 percent change in simulated output. The use of this significance threshold should be evaluated with care. The Projects Simulation Model (PROSIM) is a general operations and planning model used in comparative analysis. The PROSIM model is not a tool that is calibrated to exact CVP operations due to the level of accuracy of the input hydrology and complexity of CVP system operations.

1.1.1 Modeling Background

Two simulation models were utilized to investigate the impacts of alternatives on power operations in the CVP system. The two models are described below. New Melones power generation was assumed to be the same throughout the alternatives. The New Melones power generation came from the Central Valley Project Improvement Act (CVPIA) revised No Action Alternative.

The first model, U.S. Bureau of Reclamation's (Reclamation) PROjects SImulation Model (PROSIM), was used to evaluate the effects of alternative scenarios on CVP and State Water Project (SWP) system operations and water deliveries, as described in the Water Resources

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section. The PROSIM power module performs the power calculations. This power module was used to calculate monthly CVP generation, available capacity, and CVP project use energy and capacity.

The second model, a proprietary electric cost production model PROSYM, was used to perform the economic dispatch of the electric system to optimize the use of generation resources to meet a given load curve. PROSYM is a simulation program that models chronological electric production and is designed to be used for electric utility operating and planning studies. The program is designed to accommodate detailed hour-by-hour investigation of the operations of electrical generating resources.

1.1.2 Impact Assessment Methodology

Currently, CVP power is marketed under Contract 2948A, as described in the Affected Environment section. This contract provides for the integrated operation of the CVP generation with the Pacific Gas and Electric (PG&E) system. The contract expires at the end of 2004 and is not expected to be renewed. While the CVP has historically been operated, to the extent possible, to meet the requirements of this contract and to receive the benefits thereof, it is not expected to continue to be operated in this manner after contract termination in 2004. For the purposes of this study, it has been assumed that the CVP will be operated to meet authorized project purposes, which include providing water deliveries to water users, meeting fish and wildlife purposes, and power generation. Within given operating constraints, the CVP will be operated to maximize meeting load requirements of the CVP project use and preference customers.

The impacts associated with each alternative were viewed from the perspective of the change in available CVP power, rather than attempting to estimate the total cost of the power supply requirements for the CVP preference power customers under each of the various alternatives studied. The difference in on- and off-peak energy production and the difference in monthly generating capability between the alternatives and the No Action Alternative was evaluated to estimate the impacts associated with each alternative.

1.1.2.1 CVP Operations

PROSIM was used to simulate monthly CVP water facility operations. The model simulations were carried out for the period 1922 through 1990, using historical hydrology adjusted for a projected 2020 level of development. The simulation was conducted on a monthly time step using generalized reservoir operating rules and system criteria. The model simulation results are appropriate for the programmatic level of comparative analysis required for the EIS/EIR. The power information computed for each of the alternatives should only be interpreted in a comparative manner, and is only intended to provide an indication of the potential changes to CVP power generation, available capacity, and project use that would result from the implementation of the alternatives considered in the EIS/EIR.

1.1.2.2 Market Value of Power

The PROSYM electric production cost model used the output from the PROSIM model and power module to develop an estimate of the annual change in the market value of CVP power production for each alternative, as compared to the No Action Alternative. The CVP energy generation and associated generating capacity availability under average and adverse dry hydrologic conditions were developed for use with PROSYM.

Generation in an average year was based on a monthly average of the generation at each CVP powerplant over the 69 years of simulation from the PROSIM model. For example, the average January generation at Shasta was the average of the Shasta generation in each of the 69 Januarys; the average February generation at Shasta was the average of the Shasta generation at each of the 69 Februarys; and so on. Average project use and available CVP generating capabilities at each powerplant were calculated using the same process.

To determine the dry-year generation and capacities that provide a high level of system reliability, a level of hydroelectric production was chosen such that the CVP capacity would be available at least 90 percent of the time for any given month, barring equipment failure. To create this synthetic year, the energy generated in each month, over the 69-year simulation, was sorted into ascending order. A month and year were then selected such that the generation in that month would be exceeded 90 percent of the time. This was done by month such that the generation in the dry-year January would be exceeded in 90 percent of the Januarys, the generation in the dry-year February would be exceeded in 90 percent of the Februarys, and continued throughout the year. The capacity available from each powerplant and the required project use were defined to be the capacity and project use as reported by the PROSIM power model for each of the 90 percent exceedance months.

The resulting 12 months of energy levels developed for the EIS/EIR alternative analysis comprise a synthetic year that does not resemble any specific operating or chronological year within the 69-year simulation period. Similarity to a specific hydrologic year was not assumed to be important when the market value of the CVP capacity (i.e., level of capacity supported with energy) is being determined, since each month is evaluated independently of other months and the market will value the capacity available, and hence, the potential to offset additional capital expenditures in any month based on the applicable reliability criteria (i.e., 90 percent exceedance).

The use of this synthetic dry year is consistent with assumptions used in the Western Area Power Administration’s (Western) Sierra Nevada Region's (SNR) 2004 Marketing EIS. It should be noted that use of this methodology implies a certain level of risk for CVP preference power customers. This synthetic year is not designed to represent a worst-case year for generation or net available power for marketing, but is for use in the comparison of alternatives to the No Action Alternative.

The monthly available capacity and energy were dispatched by the model to determine hourly generation data. Hourly data are used to properly value energy by the time of day it is produced. Specifically, energy generated during on-peak, high-load periods has a higher value than energy produced in off-peak, low-load periods. Hourly data are also used to

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determine the actual load-carrying capacity of the hydropower system. The monthly capacity, as reported by the PROSIM model, is a "head dependent" capacity based on the average amount of storage in each reservoir for a month. In the determination of the load-carrying capability of the system the "head-dependent" capacity acts as a maximum, but the amount of energy generated at each powerplant is also taken into account, as well as the shape of the load curve into which the hydropower is dispatched and certain flow constraints and downstream regulation requirements. The load-carrying capability is the maximum level of sustainable energy production within a given load shape that results in minimizing the acquisition of additional capacity. Load-carrying capability may also be referred to as "capacity supported with energy."

To develop the hourly generation data, load curves were developed for the project use load and the customer load. The preference customer load used in the analysis was the total 1994 Northern California preference customer load, as supplied by Western. The project use load curve was developed by reshaping the historic 1995 project use load curve to meet the monthly on- and off-peak project use load estimates from the PROSIM model.

Hourly output from the PROSYM module was used to determine the levels of on- and off-peak energy production from the CVP that is available for sale (i.e., net of project use) assuming average hydrologic conditions. In this analysis, on-peak is defined as 7 a.m. to 10 p.m., Monday through Saturday, excluding holidays. The value of monthly capacity available for sale was determined based on the monthly maximum level of load-carrying capability (capacity supported with energy) available under adverse hydrologic conditions. In addition, the monthly capacity available without energy was also considered based on its potential value for providing reserves or other ancillary services.

The monthly available capacity and generation at each CVP powerplant was dispatched into a combination of the customer load and project use load using the PROSYM production cost model in order to create an hourly dispatch.

In addition to changes resulting from the termination of Contract 2948A, the recent restructuring of the electric utility industry will also play a significant role in how the CVP electrical facilities are operated in the future. Industry restructuring will allow entities, including CVP preference customers, who are now only able to access power supply from PG&E and Western, to access other energy suppliers and obtain the necessary transmission service. This universal market access has allowed many, if not all, of the CVP preference power customers to participate in power markets that currently were only available to utility customers. The analysis presented in the EIS/EIR is based on modeling assumptions that all of the CVP preference power customers have equal market access.

Separation of capacity prices and energy prices have been eliminated within the current deregulated industry structure within California. Given that the current market structure has only been in place for about 14 months, it is difficult to clearly determine the price impact of capacity shortages on an ongoing basis. Therefore, this analysis assumes that the decrease in CVP load-carrying capacity will ultimately result in construction of new generating capacity.

Since the analysis of the EIS/EIR assumes a 2020 level of development, one may expect that this future condition will be representative of a general long-term balance in electrical resources and loads and that any changes in the operation of the CVP generation will be reflected in the operation of the marginal system resource. That is, an increase or decrease in the output of a CVP generator, with its relatively low operating cost, will be offset by an equal and opposite change in the output of the resource then in operation having the highest operating cost. While conditions used in the analysis are generally reflective of future conditions, the price levels used in this analysis are expressed at 1997 levels in order to be consistent with other economic analyses conducted in the EIS/EIR. Due to the uncertainty involved, the level of technology involved in future generation resources, as well as their efficiencies, were assumed to remain at current levels.

CVP power generation is predominantly peaking in nature, and the system is energy-constrained during adverse water conditions. For this reason and since long-term load resource balance was assumed, capacity from the CVP was valued based on the assumption that any change in the CVP power capacity would be offset by a corresponding change in the level of construction of combined-cycle combustion turbines. As a result of the industry restructuring, it was assumed that future capacity additions would be made by private generation companies and that very little public financing would be involved in future capacity additions. Based on these assumptions, the value of capacity was estimated to be $8.99 per kilowatt-month. A detailed description of the assumptions regarding how the capacity value was estimated is presented in the TEIS Impacts Study conducted by Western (Western, 1999).

Capacity without energy (available capacity less capacity supported with energy) was also valued based on its ability to provide certain ancillary services, primarily spinning and installed reserves. The pricing history for these ancillary services in the new market environment has been very volatile, leading to substantial restructuring of these markets. Therefore, this analysis assumes to value ancillary service capacity at 20 percent of the value used for the capacity supported with energy. The value of energy produced by the CVP was estimated based on a marginal heat rate approach. To the extent that CVP power output is increased or decreased in a particular time period, an opposite change will occur in the output of the marginal unit that is operating at that same time.

The marginal heat rates for Northern and Southern California were reviewed. Since the Northern and Southern California prices tend to set the "market clearing price," it was assumed that imports from either the Pacific Northwest or Desert Southwest would tend to be priced at or near this market clearing price. Monthly time-of-day marginal production costs for these areas were derived based on regional gas prices and adjusted to reflect transmission losses for delivery to Northern California and assumes a 1.5 percent transaction adder by the producer. This resulted in the alternative energy source varying monthly and by time of day, on-peak versus off-peak. The monthly on- and off-peak values (1997 dollars) for energy used in this analysis are summarized in Table F-1. (All tables and figures are located at the end of this appendix.)

Effects on Western Customer's Cost of Power. The market will determine the value of the incremental change due to the increase or decrease of project output available for sale. Regardless of changes in project output, Western's revenue requirements remain essentially unchanged and, therefore, Western's per unit, cost-based rates will only change to reflect the net change in project output. Western's customers may be expected to continue to purchase CVP power if Western's rates are at or below comparable market rates. However, if CVP production is changed, a Western customer will experience a similar change in its share of CVP power, necessitating an equal adjustment in the other resources comprising its power supply. Presumably, in the long run, this change will be valued at prices determined in the market.

To the extent that CVP energy available for sale is decreased, Western's rates will increase, and the supply of CVP energy to each customer will decrease, requiring replacement by the customer at market rates. The effect of this two-part impact, an increase in Western rates and decrease in supply, on the customer may be estimated as follows. The total revenue requirement associated with each customer's share of CVP power will remain the same. Note that the per unit cost will increase, but total billing should not change. However, the cost associated with the balance of the customer's power supply will increase based on market prices. Assume that a customer receives 14 percent of its requirement from Western, with the remaining 86 percent being supplied from other resources. Should the portion supplied by Western decrease to 12 percent, the customer will now have a resource mix with 86 percent priced as above, 2 percent priced at market, and 12 percent priced at a higher CVP rate (i.e., the same total CVP cost divided by less energy). This will result in an increase in the customer's average cost of power equal to the cost of replacement power multiplied by the percentage decrease in CVP power used to meet the customer's load. For example, if the CVP supply were to be reduced from 14 percent to 12 percent, and the cost of replacement power was $25 per megawatt-hour (MWh), then the net change in the customer's cost of power would be 2 percent multiplied by 25 mills, or 0.5 mills.

Based on load forecasts for the year 2004 utilized in Western's SNR 2004 Marketing EIS, the net CVP energy available for sale in the No Action Alternative is approximately 14 percent of the total energy requirements for Western's customers. Thus, by assuming that 14 percent of an average Western customer's load is served with CVP energy, the impact of implementing any of the EIS/EIR alternatives may be estimated for the "average" Western customer. In addition to estimating the impact on the "average" customer, a similar analysis was conducted for a customer who received 85 percent of its energy requirements from Western. Currently, a number of customers receive all of their energy requirements from Western. The impact of implementing any of the EIS/EIR alternatives may also be estimated for "high-allocation" customers.

1.1.3 Model Results

1.1.3.1 No Action Alternative

Under the No Action Alternative, the CVP power generation facilities are operated in a manner similar to the operations discussed under the Affected Environment. CVP system operations are consistent with the criteria defined in the Long-term Central Valley Project Operations Criteria and Plan (U.S. Bureau of Reclamation, 1992). The details of the assumptions and criteria used in the simulation of CVP facilities in the No Action Alternative are discussed in the Water Resources section.

Power Generation. Simulated average annual generation at CVP powerplants in the Shasta and Trinity River Divisions for the 69-year simulation period is shown on Figure F-1 and presented in Table F-2. Simulated average annual generation at CVP powerplants in the American River and West San Joaquin Divisions for the 69-year simulation period is shown on Figure F-2 and presented in Table F-2. Total CVP power generation includes generation at Trinity Reservoir, Judge Francis Carr (Carr), Spring Creek Tunnel (Spring Creek), Shasta Reservoir, Keswick Reservoir (Keswick), Folsom Lake, Lake Natoma (Nimbus), New Melones Lake, and San Luis Reservoir powerplants and includes estimated transmission losses. Simulated average monthly total CVP generation for the long-term average, calendar years 1922-1990, and dry period, calendar years 1929-1934, is shown on Figures F-3 and F-4 and presented in Table F-3. The average annual total CVP generation for the long-term average for the No Action Alternative is 5,169 gigawatt-hours (GWh). The average annual total CVP generation for the dry period for the No Action Alternative is 2,946 GWh.

Available Capacity. Simulated average monthly available capacity in the No Action Alternative for the long-term average and dry period is shown on Figures F-5 and F-6 and presented in Table F-4. The simulated average monthly available capacity for the long-term average for the No Action Alternative is 1,603 MW. The simulated average available monthly capacity for the dry period for the No Action Alternative is 1,276 MW.

CVP Project Use Energy and Project Use Capacity. Simulated average monthly project use energy for the long-term average and dry period is shown on Figures F-7 and F-8 and presented in Table F-5. The simulated average annual project use energy for the long-term average for the No Action Alternative is 1,394 GWh. The simulated average annual project use energy for the dry period for the No Action Alternative is 901 GWh. Simulated average monthly on- and off-peak CVP project use energy for the long-term average is shown on Figures F-9 and F-10 and presented in Table F-6. Simulated average monthly on- and off-peak CVP project use energy for the dry period is shown on Figures F-11 and F-12 and presented in Table F-7. Simulated average monthly on- and off-peak CVP project use capacity requirements for the long-term average are shown on Figures F-13 and F-14 and presented in Table F-8. Simulated average monthly on- and off-peak CVP project use capacity requirements for the dry period are shown on Figures F-15 and F-16 and presented in Table F-9.

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Market Value of Power. For the evaluation of the market value of power, the long-term average energy available from PROSIM was used. The capacity values were based on the synthetic dry year discussed earlier in this section. PROSIM generation and Project Use values used in the synthetic year for the No Action Alternative analysis are presented in Tables F-10 through F-12. The annual energy available and capacity available for sale, based on the synthetic year, are presented in Table F-13. The average annual energy available for sale under the No Action Alternative is 3,779 GWh. Based on the 90 percent exceedance synthetic dry year, the capacity for sale with energy for the No Action Alternative is 747 MW and the capacity for sale without energy was 739 MW.

1.1.3.2 Maximum Flow Alternative

Power Generation. Simulated average annual generation at each powerplant for the Maximum Flow Alternative is shown on Figures F-1 and F-2 and presented in Table F-2. The minimum instream flow requirements are greater in the Maximum Flow Alternative than in the No Action Alternative for all water-year classes. For the long-term average, the storage levels at Trinity Reservoir are reduced as compared to the No Action Alternative due to these greater instream flow requirements and the low refill potential of the reservoir. As a result, generation is reduced at Trinity Reservoir. Trinity River Basin diversions are reduced to zero for all years. Subsequently, power generation at Carr is reduced to zero, and generation at Spring Creek, Shasta Reservoir, and Keswick are also reduced as compared to the No Action Alternative. Generation at Folsom Lake and Nimbus remain approximately the same. Generation at San Luis Reservoir increases slightly as a result of greater summer releases, as compared to the No Action Alternative. Simulated average monthly total CVP generation for the long-term average and dry period is shown on Figures F-3 and F-4 and presented in Table F-3. The reductions in average annual total CVP generation for the long-term average and dry period are 21 percent and 25 percent, respectively.

Available Capacity. Simulated average monthly available capacity in the Maximum Flow Alternative for the long-term average and dry period is shown on Figures F-5 and F-6 and presented in Table F-4. The average annual available capacity for the long-term average remains approximately the same under the Maximum Flow Alternative as compared to the No Action Alternative. Storage levels at Shasta Reservoir and Folsom Lake are reduced during the dry period, as compared to the No Action Alternative. As a result, available capacity during the dry period is reduced by 10 percent.

CVP Project Use Energy and Project Use Capacity. Simulated average monthly project use energy for the long-term average and dry period is shown on Figures F-7 and F-8, respectively, and presented in Table F-5. For both the long-term average and dry period, average annual Tracy exports are reduced due to the elimination of Tracy River Basin diversions. As a result, the long-term average and dry period average annual project use energy are reduced by 11 percent and 10 percent, respectively. Simulated average monthly on- and off-peak CVP project use energy for the long-term average is shown on Figures F-9 and F-10 and presented in Table F-6. Simulated average monthly on- and off-peak CVP project use energy for the dry period is shown on Figures F-11 and F-12 and presented in Table F-7. Simulated average monthly on- and off-peak project use capacity requirements for the long-term average are shown on Figures F-13 and F-14 and presented in Table F-8. Simulated average monthly on- and off-peak project use capacity requirements for the dry period are shown on Figures F-15 and F-16 and presented in Table F-9.

Market Value of Power. PROSIM generation and project use values used in the synthetic year for the Maximum Flow Alternative analysis are presented in Tables F-10 through F-12. The annual energy available and capacity available for sale, based on the synthetic year, are presented in Table F-13. The average annual energy available for sale decreases by 32 percent compared to the No Action Alternative, resulting in a reduction in energy value. Based on the 90 percent exceedance synthetic dry year, the capacity for sale with energy decreases by 10 percent, and the capacity for sale without energy increases by 3 percent. Table F-14 presents the change in the average annual market value of CVP power for the Maximum Flow Alternative as compared to the No Action Alternative. Based on the market value of power analysis, the net decrease in the value of CVP power production is approximately $26,036,000 per year. The allocation of the net decrease in the value of CVP power generation to the counties with preference power customers is presented in Table F-15. The cost of replacement power and the net effect on an "average" and a "high-allocation" Western customer is presented in Table F-16. A detailed discussion of the results of the value of power analysis is presented in the TEIS Impacts Study (Attachment F1).

1.1.3.3 Flow Evaluation Alternative

Power Generation. Simulated average annual generation at each powerplant for the Flow Evaluation Alternative is shown on Figures F-1 and F-2 and presented in Table F-2. The minimum instream flow requirements are greater in the Flow Evaluation Alternative than in the No Action Alternative for all water-year classes. For the long-term average, the storage levels at Trinity Reservoir are reduced as compared to the No Action Alternative due to these greater instream flow requirements and the low refill potential of the reservoir. As a result, generation is reduced at Trinity Reservoir. The minimum storage level at Trinity Reservoir is greater in the Flow Evaluation Alternative than in the No Action Alternative. Trinity River Basin diversions are reduced to maintain this higher minimum storage level. Subsequently, power generation at Carr, Spring Creek, and Keswick are also reduced. Generation at Shasta Reservoir, Folsom Lake, Nimbus, and San Luis Reservoir remain approximately the same. Simulated average monthly total CVP generation for the long-term average and dry period is shown on Figures F-3 and F-4 and presented in Table F-3. The reduction in average annual total CVP generation for the long-term average and dry period is 6 percent and 7 percent, respectively.

Available Capacity. Simulated average monthly available capacity in the Flow Evaluation Alternative for the long-term average and dry period is shown on Figures F-5 and F-6 and presented in Table F-4. The average annual available capacity for the long-term average and dry period remain approximately the same under the Flow Evaluation Alternative as compared to the No Action Alternative.

CVP Project Use Energy and Project Use Capacity. Simulated average monthly project use energy for the long-term average and dry period is shown on Figures F-7 and F-8 and

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presented in Table F-5. The long-term average annual average project use energy for the Flow Evaluation Alternative is approximately the same in the No Action Alternative. Under this alternative, average annual Tracy exports are reduced during the dry period. As a result, the dry period average annual project use energy is reduced by approximately 6 percent. Simulated average monthly on- and off-peak CVP Project use energy for the long-term average is shown on Figures F-9 and F-10 and presented in Table F-6. Simulated average monthly on- and off-peak CVP project use energy for the dry period is shown on Figures F-11 and F-12 and presented in Table F-7. Simulated average monthly on- and off-peak project use capacity requirements for the long-term average are shown on Figures F-13 and F-14 and presented in Table F-8. Simulated average monthly on- and off-peak project use capacity requirements for the dry period are shown on Figures F-15 and F-16 and presented in Table F-9.

Market Value of Power. PROSIM generation and project use values used in the synthetic year for the Flow Evaluation Alternative analysis are presented in Tables F-10 through F-12. The annual energy available and capacity available for sale, based on the synthetic year, are presented in Table F-13. The average annual energy available for sale decreases by 7 percent compared to the No Action Alternative, resulting in a reduction in energy value. Based on the 90 percent exceedance synthetic dry year, the capacity for sale with energy remains approximately the same, and the capacity for sale without energy increases by 8 percent. Table F-14 presents the change in the average annual market value of CVP power for the Flow Evaluation Alternative as compared to the No Action Alternative. Based on the market value of power analysis, the net decrease in the value of CVP power production is approximately $5,564,000 per year. The allocation of the net decrease in the value of CVP power generation to the counties with preference power customers is presented in Table F-15. The cost of replacement power and the net effect on an "average" and a "high-allocation" Western customer is presented in Table F-16.

1.1.3.4 Percent Inflow Alternative

Power Generation. Simulated average annual generation at each powerplant for the Percent Inflow Alternative is shown on Figures F-1 and F-2 and presented in Table F-2. The minimum instream flow requirements are greater in the Percent Inflow Alternative than in the No Action Alternative for the extremely wet, wet, and normal water-year classes. The minimum instream flow requirements are less in the Percent Inflow Alternative than in the No Action Alternative for the dry and critically dry water-year classes. For the long-term average, generation at Trinity Reservoir remains approximately the same. The minimum storage level at Trinity Reservoir is greater in the Percent Inflow Alternative than in the No Action Alternative; therefore, Trinity River Basin diversions are reduced to maintain this higher minimum storage level. Subsequently, power generation at Carr and Spring Creek are reduced. Generation at Shasta Reservoir, Keswick, Folsom Lake, Nimbus, and San Luis Reservoir remain approximately the same. Simulated average monthly total CVP generation for the long-term average and dry period is shown on Figures F-3 and F-4 and presented in Table F-3. The average annual total CVP generation for the long-term average and dry period remains approximately the same under the Percent Inflow Alternative as compared to the No Action Alternative.

Available Capacity. Simulated average monthly available capacity in the Percent Inflow Alternative for the long-term average and dry period is shown on Figures F-5 and F-6 and presented in Table F-4. The average annual available capacity for the long-term average and dry period remains approximately the same between the Percent Inflow Alternative and the No Action Alternative.

CVP Project Use Energy and Project Use Capacity. Simulated average monthly project use energy for the long-term average and dry period is shown on Figures F-7 and F-8 and presented in Table F-5. Under the Percent Inflow Alternative, average annual project use energy for the long-term average and dry period remains approximately the same as compared to the No Action Alternative. Simulated average monthly on- and off-peak CVP project use energy for the long-term average is shown on Figures F-9 and F-10 and presented in Table F-6. Simulated average monthly on- and off-peak CVP project use energy for the dry period is shown on Figures F-11 and F-12 and presented in Table F-7. Simulated average monthly on- and off-peak project use capacity requirements for the long-term average are shown on Figures F-13 and F-14 and presented in Table F-8. Simulated average monthly on- and off-peak project use capacity requirements for the dry period are shown on Figures F-15 and F-16 and presented in Table F-9.

Market Value of Power. PROSIM generation and project use values used in the synthetic year for the Percent Inflow Alternative analysis are presented in Tables F-10 through F-12. The annual energy available and capacity available for sale, based on the synthetic year, are presented in Table F-13. The average annual energy available for sale decreases by 4 percent compared to the No Action Alternative, resulting in a reduction in energy value. Based on the 90 percent exceedance synthetic dry year, the capacity for sale with energy decreases by 7 percent, and the capacity for sale without energy increases by 5 percent. Table F-14 presents the change in the average annual market value of CVP power for the Percent Inflow Alternative as compared to the No Action Alternative. Based on the market value of power analysis, the net decrease in the value of CVP power production is approximately $7,023,000 per year. The allocation of the net decrease in the value of CVP power generation to the counties with preference power customers is presented in Table F-15. The cost of replacement power and the net effect on an "average" and a "high-allocation" Western customer is presented in Table F-16.

1.1.3.5 State Permit Alternative

Power Generation. Simulated average annual generation at each powerplant for the State Permit Alternative is shown on Figures F-1 and F-2 and presented in Table F-2. The minimum instream flow requirements are less in the State Permit Alternative than in the No Action Alternative for all water-year classes. For the long-term average, storage levels at Trinity Reservoir are greater in the State Permit Alternative as compared to the No Action Alternative due to the decrease in minimum instream flow requirements. As a result, generation at Trinity Reservoir increases slightly. Trinity River Basin diversions are increased. Subsequently, power generation at Carr and Spring Creek are also increased. Generation at Shasta Reservoir, Keswick, Folsom Lake, Nimbus, and San Luis Reservoir remain approximately the same. Simulated average monthly total CVP generation for the long-term average and dry period is shown on Figures F-3 and F-4 and presented in Table F-3. The increase in average annual total CVP generation for the long-term average and the dry period is 4 percent and 9 percent, respectively.

Available Capacity. Simulated average monthly available capacity in the State Permit Alternative for the long-term average and dry period is shown on Figures F-5 and F-6 and presented in Table F-4. For the long-term average, storage levels at Trinity Reservoir and Folsom Lake increase as compared to the No Action Alternative resulting in an increase in available capacity. The average annual increase in available capacity for the long-term average is 4 percent. For the dry period, storage levels in Trinity Reservoir increase as compared to the No Action Alternative. The average annual increase in available capacity for the dry period is 11 percent.

CVP Project Use Energy and Project Use Capacity. Simulated average monthly project use energy for the long-term average and dry period is shown on Figures F-7 and F-8 and presented in Table F-5. Under the State Permit Alternative, the average annual project use energy for the long-term average remains approximately the same as compared to the No Action Alternative. During the dry period, average annual Tracy exports slightly increase. As a result, average annual project use energy for the dry period increases by approximately 8 percent as compared to the No Action Alternative. Simulated average monthly on- and off-peak CVP project use energy for the long-term average is shown on Figures F-9 and F-10 and presented in Table F-6. Simulated average monthly on- and off-peak CVP project use energy for the dry period is shown on Figures F-11 and F-12 and presented in Table F-7. Simulated average monthly on- and off-peak project use capacity requirements for the long-term average are shown on Figures F-13 and F-14 and presented in Table F-8. Simulated average monthly on- and off-peak project use capacity requirements for the dry period are shown in Figures F-15 and F-16 and presented in Table F-9.

Market Value of Power. PROSIM generation and project use values used in the synthetic year for the State Permit Alternative analysis are presented in Tables F-10 through F-12. The annual energy available and capacity available for sale, based on the synthetic year, are presented in Table F-13. The average annual energy available for sale increases by 5 percent compared to the No Action Alternative, resulting in a reduction in energy value. Based on the 90 percent exceedance synthetic dry year, the capacity for sale with energy remains approximately the same, and the capacity for sale without energy increases by 3 percent. Table F-14 presents the change in the average annual market value of CVP power for the State Permit Alternative as compared to the No Action Alternative. Based on the market value of power analysis, the net increase in the value of CVP power production is approximately $5,937,000 per year. The allocation of the net increase in the value of CVP power generation to the counties with preference power customers is presented in Table F-15. The cost of replacement power and the net effect on an "average" and a "high-allocation" Western customer is presented in Table F-16.

1.1.4 Criteria for Determining Significance

A significant power resource related impact was determined to occur when the implementation of an alternative would result in:

- A reduction in the dry year firm load-carrying capacity (CVP hydroelectric capacity supported with CVP hydroelectric energy available for sale) to preference customers of 50 MW or greater occurring during January, February, March, June, July, August, September, or December
- A reduction of 5 percent or more in the annual energy available for sale to preference customers during an average year
- A reduction of 5 percent or more in the energy available for sale to preference customers during any month of an average year
- Any decrease in the value of CVP power resulting in an increase in a preference customer's average power cost by $0.50 per MWh

1.2 EXISTING CONDITIONS COMPARED TO THE FLOW EVALUATION ALTERNATIVE

A description of the assumptions and operational criteria used in Existing Conditions, which serves as the base condition for the EIS/EIR impact analysis, can be found in the Water Resources section. For each alternative, the model simulation results are presented showing the impacts to CVP power operations.

1.2.1 Modeling Background

Reclamation's PROSIM was used to evaluate the effects of alternative scenarios on CVP and SWP system operations and water deliveries, as described in the Water Resources section. The PROSIM module performs the power calculations. This power module was used to calculate monthly CVP generation, available capacity, and CVP project use energy and capacity. The New Melones power generation data came from the CVPIA Draft Programmatic Environmental Impact Statement (PEIS) Recent Conditions Scenario for this Existing Conditions simulation and the CVPIA PEIS Revised No Action Alternative for the EIS/EIR Flow Evaluation Alternative.

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1.2.2 Impact Assessment Methodology

The impacts associated with each alternative were viewed from the perspective of the change in available CVP power, rather than attempting to estimate the total cost of the power supply requirements for the CVP preference power customers under each of the alternatives studied. The difference in on- and off-peak energy production and the difference in monthly generating capability between the Flow Evaluation Alternative and Existing Conditions was evaluated to estimate the impacts.

1.2.2.1 CVP Operations

PROSIM was used to simulate monthly CVP water facility operations. The model simulations were carried out for the period 1922 through 1990, using historical hydrology adjusted for a projected 1995 level of development for existing conditions and 2020 for the Flow Evaluation Alternative. The simulation was conducted on a monthly time step using generalized reservoir operating rules and system criteria. The model simulation results are appropriate for the programmatic level of comparative analysis required for the EIS/EIR. The power information computed for each of the alternatives should only be interpreted in a comparative manner, and is only intended to provide an indication of the potential changes to CVP power generation, available capacity, and project use that would result from the implementation of the alternative considered in the EIS/EIR.

1.2.3 Model Results

1.2.3.1 Existing Conditions

Under existing conditions, the CVP power generation facilities are operated in a manner similar to the operations discussed under the Affected Environment. CVP system operations are consistent with the criteria defined in the Long-term Central Valley Project Operations Criteria and Plan (October, 1992). The details of the assumptions and criteria used in the simulation of CVP facilities in existing conditions are discussed in the Water Resources section.

Power Generation. Simulated average annual generation at CVP powerplants in the Shasta and Trinity River Divisions for the 69-year simulation period is shown on Figure F-17 and presented in Table F-17. Simulated average annual generation at CVP powerplants in the American River and West San Joaquin Divisions for the 69-year simulation period is shown on Figure F-18 and presented in Table F-17. Total CVP power generation includes generation at Trinity Reservoir, Carr, Spring Creek, Shasta Reservoir, Keswick, Folsom Lake, Nimbus, New Melones Lake, and San Luis Reservoir powerplants and includes estimated transmission losses. Simulated average monthly total CVP generation for the long-term average, calendar years 1922-1990, and dry period, calendar years 1929-1934, is shown on Figures F-19 and F-20 and presented in Table F-18. The average annual total CVP generation for the long-term average for existing conditions is 5,217 GWh. The average annual total CVP generation for the dry period for existing conditions is 2,985 GWh.

Available Capacity. Simulated average monthly available capacity in existing conditions for the long-term average and dry period is shown on Figures F-21 and F-22 and presented in Table F-19. The simulated average monthly available capacity for the long-term average for existing conditions is 1,668 MW. The simulated average available monthly capacity for the dry period for existing conditions is 1,394 MW.

CVP Project Use Energy and Project Use Capacity. Simulated average monthly project use energy for the long-term average and dry period is shown on Figures F-23 and F-24 and presented in Table F-20. The simulated average annual project use energy for the long-term average for existing conditions is 1,401 GWh. The simulated average annual project use energy for the dry period for existing conditions is 882 GWh. Simulated average monthly on- and off-peak CVP project use energy for the long-term average is shown on Figures F-25 and F-26 and presented in Table F-21. Simulated average monthly on- and off-peak CVP project use energy for the dry period is shown on Figures F-27 and F-28 and presented in Table F-22. Simulated average monthly on- and off-peak CVP project use capacity requirements for the long-term average are shown on Figures F-29 and F-30 and presented in Table F-23. Simulated average monthly on- and off-peak CVP project use capacity requirements for the dry period are shown on Figures F-31 and F-32 and presented in Table F-24.

1.2.3.2 Flow Evaluation Alternative

Power Generation. Simulated average annual generation at each powerplant for the Flow Evaluation Alternative is shown on Figures F-17 and F-18 and presented in Table F-17. The Trinity River minimum instream flow requirements are greater in the Flow Evaluation Alternative than in existing conditions for all water-year classes. For the long-term average, generation at Trinity Reservoir remains approximately the same. Power generation at Carr and Spring Creek are reduced due to decreased Trinity River Basin diversions to the Central Valley. Generation decreases at Folsom Lake and Nimbus due to increased diversions upstream of Folsom Lake for a 2020 level of development in the Flow Evaluation Alternative as compared to a 1995 level of development for existing conditions. Generation at Shasta Reservoir, Keswick, and San Luis Reservoir remains approximately the same. Simulated average monthly total CVP generation for the long-term average and dry period is shown on Figures F-19 and F-20 and presented in Table F-18. The reduction in average annual total CVP generation for the long-term average and dry period is 6 percent and 8 percent, respectively.

Available Capacity. Simulated average monthly available capacity in the Flow Evaluation Alternative for the long-term average and dry period is shown on Figures F-21 and F-22 and presented in Table F-19. The average annual available capacity for the long-term average remains approximately the same under the Flow Evaluation Alternative as in existing conditions. Storage levels at Shasta and Folsom Lake are reduced during the dry period as compared to existing conditions. As a result, available capacity during the dry period is reduced by 10 percent.

CVP Project Use Energy and Project Use Capacity. Simulated average monthly project use energy for the long-term average and dry period is shown on Figures F-23 and F-24 and presented in Table F-20. Under this alternative, average annual project use energy for the long-term average and dry period remain approximately the same as in existing conditions. Simulated average monthly on- and off-peak CVP project use energy for the long-term average is shown on Figures F-25 and F-26 and presented in Table F-21. Simulated average monthly on- and off-peak CVP project use energy for the dry period is shown on Figures F-27 and F-28 and presented in Table F-22. Simulated average monthly on- and off-peak project use capacity requirements for the long-term average are shown on Figures F-29 and F-30 and presented in Table F-23. Simulated average monthly on- and off-peak project use capacity requirements for the dry period are shown on Figures F-31 and F-32 and presented in Table F-24.

1.3 REFERENCES

U.S. Bureau of Reclamation. 1992. Central Valley Project Operations Criteria and Plan. October.

Western Area Power Administration. 1999. TEIS Impacts Study. June.

TABLE F-1

ESTIMATED DELIVERED PRICE FOR MARGINAL ENERGY

Month	On-Peak Delivered Price ($/MW-hour)	Off-Peak Delivered Price ($/MW-hour)
Jan	$24.28	$22.40
Feb	$22.01	$20.00
Mar	$19.82	$18.88
Apr	$18.78	$15.92
May	$17.72	$13.59
Jun	$20.94	$18.23
Jul	$21.19	$19.29
Aug	$23.10	$20.92
Sep	$22.74	$20.30
Oct	$22.42	$20.21
Nov	$24.35	$22.30
Dec	$26.25	$24.39
Annual Average	$21.97	$19.70

Source:
Western, 1999.

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TABLE F-2

COMPARISON OF SIMULATED AVERAGE ANNUAL GENERATION AT CVP POWERPLANTS

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (GWh)					
Powerplant	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Trinity	435	385	423	434	444
Carr	481	0	348	404	587
Spring Creek	563	111	437	490	665
Shasta	2,045	1,987	2,037	2,043	2,051
Keswick	471	412	455	462	484
Folsom	629	626	629	629	630
Nimbus	71	71	71	71	71
San Luis	103	112	107	104	101
DRY PERIOD (CALENDAR YEARS 1928-1934) (GWh)					
Powerplant	**No-Action Alternative**	**Maximum Flow Alternative**	**Flow Evaluation Study Alternative**	**Percent Inflow Alternative**	**State Permit Alternative**
Trinity	269	270	251	258	276
Carr	292	0	205	286	414
Spring Creek	306	23	222	301	425
Shasta	1,308	1,075	1,279	1,307	1,320
Keswick	345	318	334	343	359
Folsom	382	378	383	382	380
Nimbus	48	49	49	48	48
San Luis	102	111	108	103	91

TABLE F-3

COMPARISON OF SIMULATED AVERAGE MONTHLY CVP GENERATION

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (GWh)					
	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	338	322	334	332	350
Feb	334	333	328	329	345
Mar	344	340	336	336	358
Apr	388	369	363	385	400
May	564	447	515	514	582
Jun	659	485	565	603	676
Jul	753	524	695	713	776
Aug	617	436	605	627	647
Sep	332	243	374	361	391
Oct	290	163	249	270	302
Nov	239	180	219	232	249
Dec	311	251	298	307	324
Average Annual Total	5,169	4,092	4,882	5,010	5,399
Percent Change from NAA		-21%	-6%	-3%	4%

DRY PERIOD (CALENDAR YEARS 1928-1934) (GWh)					
	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	135	126	130	140	139
Feb	120	132	117	126	122
Mar	217	211	199	208	230
Apr	255	255	248	267	266
May	393	315	353	359	414
Jun	540	376	428	476	539
Jul	559	371	507	529	619
Aug	417	284	437	482	499
Sep	238	148	264	293	302
Oct	181	102	158	149	177
Nov	122	85	123	124	125
Dec	123	81	117	123	125
Average Annual Total	3,300	2,485	3,081	3,276	3,556
Percent Change from NAA		-25%	-7%	-1%	8%

Notes:
Facilities include: Trinity, Carr, Spring Creek, Shasta, Keswick, Folsom, Nimbus, New Melones, and San Luis powerplants. Simulated generation includes losses.

TABLE F-4

COMPARISON OF SIMULATED AVERAGE MONTHLY AVAILABLE CAPACITY

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (MW)					
	No-Action Alternative	**Maximum Flow Alternative**	**Flow Evaluation Study Alternative**	**Percent Inflow Alternative**	**State Permit Alternative**
Jan	1,580	1,546	1,575	1,580	1,646
Feb	1,641	1,612	1,638	1,641	1,699
Mar	1,679	1,657	1,676	1,678	1,729
Apr	1,700	1,678	1,697	1,699	1,746
May	1,715	1,688	1,711	1,712	1,760
Jun	1,712	1,678	1,702	1,707	1,756
Jul	1,670	1,625	1,657	1,665	1,722
Aug	1,583	1,533	1,573	1,579	1,647
Sep	1,488	1,437	1,480	1,487	1,563
Oct	1,466	1,410	1,459	1,465	1,548
Nov	1,479	1,426	1,470	1,478	1,559
Dec	1,524	1,476	1,518	1,525	1,599
Average Annual Total	19,236	18,766	19,157	19,217	19,975
Percent Change from NAA		-2%	0%	0%	4%

DRY PERIOD (CALENDAR YEARS 1928-1934) (MW)					
	No-Action Alternative	**Maximum Flow Alternative**	**Flow Evaluation Study Alternative**	**Percent Inflow Alternative**	**State Permit Alternative**
Jan	1,333	1,229	1,320	1,343	1,450
Feb	1,389	1,310	1,376	1,400	1,504
Mar	1,459	1,411	1,445	1,467	1,565
Apr	1,494	1,445	1,478	1,500	1,594
May	1,493	1,443	1,480	1,498	1,594
Jun	1,468	1,410	1,452	1,472	1,577
Jul	1,405	1,300	1,380	1,408	1,522
Aug	1,294	1,162	1,269	1,300	1,421
Sep	1,192	1,008	1,167	1,204	1,332
Oct	1,150	976	1,125	1,165	1,299
Nov	1,146	972	1,121	1,162	1,294
Dec	1,182	1,004	1,161	1,198	1,329
Average Annual Total	16,004	14,670	15,775	16,117	17,480
Percent Change from NAA		-8%	-1%	1%	9%

TABLE F-5

COMPARISON OF SIMULATED AVERAGE MONTHLY CVP PROJECT USE

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (GWh)					
	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	147	145	147	148	146
Feb	118	114	115	119	117
Mar	114	110	114	115	118
Apr	90	82	87	89	93
May	97	83	94	96	98
Jun	114	89	109	114	120
Jul	133	97	120	131	137
Aug	123	104	120	122	124
Sep	108	97	107	107	109
Oct	101	84	102	100	100
Nov	118	108	114	117	118
Dec	133	127	133	133	133
Average Annual Total	1,394	1,241	1,362	1,390	1,412
Percent Change from NAA		-11%	-2%	0%	1%

DRY PERIOD (CALENDAR YEARS 1928-1934) (GWh)					
	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	151	152	152	151	150
Feb	124	117	116	125	122
Mar	82	78	75	85	86
Apr	43	37	37	42	56
May	56	47	52	56	65
Jun	52	35	47	51	70
Jul	69	44	58	66	86
Aug	83	66	79	82	87
Sep	90	73	86	91	87
Oct	55	43	53	54	56
Nov	75	67	71	74	74
Dec	110	102	111	111	111
Average Annual Total	990	860	937	986	1,049
Percent Change from NAA		-13%	-5%	0%	6%

TABLE F-6

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE ENERGY LONG-TERM AVERAGE - CALENDAR YEARS 1922-1990

ON-PEAK (GWh)

	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	59	58	59	59	58
Feb	47	46	46	48	47
Mar	45	44	46	46	47
Apr	36	33	35	36	37
May	39	33	38	38	39
Jun	46	35	44	46	48
Jul	53	39	48	52	55
Aug	49	42	48	49	49
Sep	43	39	43	43	44
Oct	40	34	41	40	40
Nov	47	43	46	47	47
Dec	53	51	53	53	53
Average Annual Total	558	496	545	556	565
Percent Change from NAA		-11%	-2%	0%	1%

OFF-PEAK (GWh)

	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	88	87	88	89	88
Feb	71	68	69	71	70
Mar	68	66	69	69	71
Apr	54	49	52	54	56
May	58	50	56	57	59
Jun	69	53	66	68	72
Jul	80	58	72	78	82
Aug	74	62	72	73	74
Sep	65	59	64	64	66
Oct	60	51	61	60	60
Nov	71	65	68	70	71
Dec	80	76	80	80	80
Average Annual Total	837	744	817	834	847
Percent Change from NAA		-11%	-2%	0%	1%

TABLE F-7

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE ENERGY DRY PERIOD - CALENDAR YEARS 1928-1934

ON-PEAK (GWh)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	60	61	61	60	60
Feb	49	47	46	50	49
Mar	33	31	30	34	35
Apr	17	15	15	17	22
May	23	19	21	22	26
Jun	21	14	19	20	28
Jul	28	18	23	26	34
Aug	33	26	31	33	35
Sep	36	29	35	36	35
Oct	22	17	21	21	22
Nov	30	27	29	30	29
Dec	44	41	44	44	44
Average Annual Total	396	344	375	394	420
Percent Change from NAA		-13%	-5%	0%	6%

OFF-PEAK (GWh)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	91	91	91	91	90
Feb	74	70	69	75	73
Mar	49	47	45	51	52
Apr	26	22	22	25	33
May	34	28	31	34	39
Jun	31	21	28	30	42
Jul	41	26	35	40	52
Aug	50	40	47	49	52
Sep	54	44	52	54	52
Oct	33	26	32	32	33
Nov	45	40	43	45	44
Dec	66	61	66	67	67
Average Annual Total	594	516	562	592	629
Percent Change from NAA		-13%	-5%	0%	6%

TABLE F-8

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE CAPACITY LONG-TERM AVERAGE - CALENDAR YEARS 1922-1990

ON-PEAK (MW)

	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	211	214	211	211	209
Feb	165	159	159	167	163
Mar	148	142	147	147	154
Apr	129	118	126	128	134
May	144	126	140	143	145
Jun	168	134	162	167	175
Jul	188	145	171	185	194
Aug	175	152	172	174	177
Sep	153	142	151	152	154
Oct	137	119	136	135	136
Nov	180	166	175	180	180
Dec	192	187	195	193	192
Average Annual Total	1,991	1,804	1,945	1,981	2,013
Percent Change from NAA		-9%	-2%	0%	1%

OFF-PEAK (MW)

	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	335	321	332	336	333
Feb	311	302	306	315	309
Mar	271	275	275	276	282
Apr	170	167	168	169	177
May	175	155	173	173	178
Jun	198	162	190	197	207
Jul	221	167	201	216	223
Aug	201	175	196	200	202
Sep	244	222	242	242	244
Oct	231	195	233	228	226
Nov	269	253	262	268	270
Dec	294	278	293	292	292
Average Annual Total	2,921	2,670	2,874	2,913	2,944
Percent Change from NAA		-9%	-2%	0%	1%

TABLE F-9

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE CAPACITY DRY PERIOD - CALENDAR YEARS 1928-1934

ON-PEAK (MW)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	231	240	234	231	226
Feb	175	159	154	176	163
Mar	114	106	111	120	119
Apr	80	74	74	81	95
May	101	84	93	100	111
Jun	92	67	89	93	114
Jul	118	81	102	113	136
Aug	130	104	129	130	136
Sep	133	115	127	136	131
Oct	92	78	89	90	93
Nov	116	113	108	118	119
Dec	175	157	181	178	170
Average Annual Total	1,560	1,380	1,492	1,567	1,613
Percent Change from NAA		-12%	-4%	0%	3%

OFF-PEAK (MW)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	323	320	331	324	332
Feb	327	318	323	334	328
Mar	211	206	182	223	212
Apr	94	85	79	86	115
May	106	87	98	105	118
Jun	104	79	99	104	132
Jul	127	84	109	122	146
Aug	143	118	135	146	148
Sep	211	172	208	211	205
Oct	134	101	130	123	124
Nov	196	186	195	197	186
Dec	261	243	254	263	248
Average Annual Total	2,237	2,000	2,142	2,237	2,292
Percent Change from NAA		-11%	-4%	0%	2%

TABLE F-10

90 PERCENT EXCEEDENCE SYNTHETIC DRY YEAR MONTHLY CVP GENERATION

PROSIM CAPACITY (MW)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	1,551	1,532	1,322	1,364	1,572
Feb	1,454	1,438	1,568	1,519	1,478
Mar	1,524	1,215	1,444	1,750	1,794
Apr	1,608	1,593	1,632	1,798	1,691
May	1,488	1,690	1,592	1,566	1,735
Jun	1,795	1,483	1,713	1,648	1,457
Jul	1,532	1,579	1,578	1,587	1,527
Aug	1,513	1,499	1,311	1,513	1,318
Sep	1,366	1,430	1,275	1,368	1,398
Oct	1,401	1,162	1,475	1,428	1,436
Nov	1,351	1,369	1,489	1,413	1,416
Dec	1,252	1,345	1,367	1,396	1,404
Average Annual Total	17,835	17,335	17,766	18,350	18,226
Percent Change from NAA		-3%	0%	3%	2%

TOTAL ENERGY (GWh)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	123	119	117	121	125
Feb	110	122	108	113	111
Mar	148	154	147	154	148
Apr	222	232	220	237	223
May	409	318	334	370	402
Jun	471	367	414	452	478
Jul	548	400	476	507	603
Aug	398	311	431	459	496
Sep	234	175	296	254	281
Oct	145	119	153	141	151
Nov	134	103	128	132	135
Dec	119	101	120	115	122
Average Annual Total	3,062	2,522	2,942	3,054	3,277
Percent Change from NAA		-18%	-4%	0%	7%

Source:
Western, 1999.

TABLE F-11

90 PERCENT EXCEEDENCE SYNTHETIC DRY YEAR ON- AND OFF-PEAK CVP PROJECT USE CAPACITY

MAXIMUM ON-PEAK (MW)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	215	261	208	247	218
Feb	51	25	92	204	71
Mar	88	157	117	151	121
Apr	60	48	152	125	118
May	70	91	48	94	145
Jun	184	102	62	170	93
Jul	109	62	63	122	176
Aug	106	58	93	124	127
Sep	109	102	107	108	110
Oct	108	110	107	106	105
Nov	94	88	108	195	111
Dec	96	133	250	110	95
Average Annual Total	1,290	1,237	1,407	1,756	1,490
Percent Change from NAA		-4%	9%	36%	16%

OFF-PEAK (MW)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	313	295	312	347	307
Feb	51	26	146	325	77
Mar	163	376	224	263	183
Apr	66	49	207	138	127
May	70	97	48	100	172
Jun	221	137	62	232	122
Jul	115	62	63	136	184
Aug	123	59	100	148	137
Sep	153	147	151	137	154
Oct	158	176	168	157	149
Nov	182	132	239	265	198
Dec	188	220	289	241	242
Average Annual Total	1,803	1,776	2,009	2,489	2,052
Percent Change from NAA		-1%	11%	38%	14%

Source:
Western, 1999.

TABLE F-12

90 PERCENT EXCEEDENCE SYNTHETIC DRY YEAR ON- AND OFF-PEAK CVP PROJECT USE ENERGY

ON-PEAK (GWh)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	59	58	60	64	59
Feb	9	4	21	49	10
Mar	28	56	37	45	32
Apr	12	11	45	29	28
May	12	20	9	20	39
Jun	48	27	9	47	24
Jul	25	12	10	29	44
Aug	26	11	22	31	30
Sep	26	23	25	21	24
Oct	27	31	31	28	28
Nov	26	19	32	44	31
Dec	28	29	55	32	31
Average Annual Total	325	302	355	441	380
Percent Change from NAA		-7%	9%	36%	17%

OFF-PEAK (GWh)	No-Action Alternative	Maximum Flow Alternative	Flow Evaluation Study Alternative	Percent Inflow Alternative	State Permit Alternative
Jan	89	87	90	96	88
Feb	13	6	31	73	15
Mar	42	84	55	68	48
Apr	17	16	67	44	42
May	17	30	14	30	59
Jun	72	41	13	71	36
Jul	37	18	15	44	66
Aug	39	16	33	47	46
Sep	38	35	38	32	36
Oct	41	47	46	42	41
Nov	39	28	48	66	47
Dec	42	44	82	48	47
Average Annual Total	487	452	533	662	570
Percent Change from NAA		-7%	9%	36%	17%

Source:
Western, 1999.

TABLE F-13

CVP ENERGY AND CAPACITY AVAILABLE FOR SALE

Alternative	Average Annual Energy (GWh)	90 Percent Exceedence Average Monthly Synthetic Dry Year Cpacity With Energy (MW)	Without Energy (MW)
No-Action	3,779	747	739
Maximum Flow	2,857	679	765
Flow Evaluation Study	3,525	730	800
Percent Inflow	3,625	700	780
State Permit	3,992	756	763

Source:
Western, 1999.

TABLE F-14

ANNUAL CHANGE IN MARKET VALUE OF CVP POWER COMPARED TO THE NO-ACTION ALTERNATIVE

	Change in Average Annual Energy (Million $)	Change in Average Annual 90 Percent Exceedence Synthetic Dry Year Capacity		Total Annual Change (Million $)
		With Energy (Million $)	Without Energy (Million $)	
Maximum Flow minus No-Action	-19,277	-7,325	566	-26,036
Flow Evaluation Study minus No-Action	-4,965	-1,906	1,307	-5,564
Percent Inflow minus No-Action	-2,853	-5,058	887	-7,023
State Permit minus No-Action	4,453	976	508	5,937

Source:
Western, 1999.

TABLE F-15

TRINITY EIS/EIR PREFERENCE CUSTOMER BENEFIT (COST) ALLOCATION BY COUNTY BASED ON CONTRACT RATE OF DELIVERIES (CRD)

County	CRD	Maximum Flow Alternative ($1,000)	Flow Evaluation Study Alternative ($1,000)	Percent Inflow Alternative ($1,000)	State Permit Alternative ($1,000)
Alameda	4.08%	-1,062	-227	-287	242
Butte	0.78%	-204	-44	-55	46
Calaveras	0.57%	-150	-32	-40	34
Contra Costa	0.46%	-121	-26	-33	28
Fresno	0.53%	-137	-29	-37	31
Glenn	0.28%	-72	-15	-19	16
Kern	2.26%	-588	-126	-159	134
Kings	1.28%	-333	-71	-90	76
Lassen	0.21%	-53	-11	-14	12
Mendocino	0.60%	-156	-33	-42	36
Merced	0.46%	-118	-25	-32	27
Placer	4.72%	-1,230	-263	-332	280
Plumas	1.54%	-401	-86	-108	91
Sacramento	26.10%	-6,796	-1,452	-1,833	1,550
San Francisco	0.00%	0	0	0	0
San Joaquin	2.47%	-642	-137	-173	146
Santa Barbara	0.36%	-93	-20	-25	21
Santa Clara	35.76%	-9,309	-1,989	-2,511	2,123
Shasta	8.72%	-2,271	-485	-613	518
Solano	2.32%	-603	-129	-163	138
Sonoma	0.32%	-84	-18	-23	19
Stanislaus	1.50%	-391	-84	-105	89
Trinity	1.23%	-321	-69	-87	73
Tulare	0.27%	-71	-15	-19	16
Tuolomne	0.60%	-156	-33	-42	36
Yolo	1.11%	-289	-62	-78	66
Yuba	1.48%	-384	-82	-104	88
Total	100.00%	-26,036	-5,564	-7,023	5,937

Source:
Western, 1999.

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TABLE F-16

COST OF REPLACEMENT POWER AND THE EFFECTS ON THE "AVERAGE" AND "HIGH ALLOCATION" WESTERN CUSTOMER

"AVERAGE" WESTERN CUSTOMER			
Alternative	**Percent CVP Energy Used in Customer Load**	**Average Replacement Rate ($/MWh)**	**Change in Customer's Total Cost of Power from NAA ($/MWh)**
No-Action	14.00%	---	---
Maximum Flow	10.59%	28.25	0.96
Flow Evaluation Study	13.06%	21.94	0.21
Percent Inflow	13.43%	45.50	0.26
State Permit	14.79%	27.91	(0.22)
"HIGH ALLOCATION" WESTERN CUSTOMER			
Alternative	**Percent CVP Energy Used in Customer Load**	**Average Replacement Rate ($/MWh)**	**Change in Customer's Total Cost of Power from NAA ($/MWh)**
No-Action	85.00%	---	---
Maximum Flow	64.27%	28.25	5.86
Flow Evaluation Study	79.30%	21.94	1.25
Percent Inflow	81.53%	45.50	1.58
State Permit	89.79%	27.91	(1.34)

Notes:
Average Replacement Rate represents the purchase of energy comparable to that lost or gained at market rates.
Source:
Western, 1999.

TABLE F-17

COMPARISON OF SIMULATED AVERAGE ANNUAL GENERATION AT CVP POWERPLANTS

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (GWh)		
Powerplant	**Existing Conditions**	**Flow Evaluation Study Alternative**
Trinity	435	423
Carr	480	348
Spring Creek	561	437
Shasta	2,052	2,037
Keswick	471	455
Folsom	665	629
Nimbus	75	71
San Luis	104	107
DRY PERIOD (CALENDAR YEARS 1928-1934) (GWh)		
Powerplant	**Existing Conditions**	**Flow Evaluation Study Alternative**
Trinity	272	251
Carr	293	205
Spring Creek	307	222
Shasta	1,324	1,279
Keswick	342	334
Folsom	415	383
Nimbus	53	49
San Luis	95	108

TABLE F-18

COMPARISON OF SIMULATED AVERAGE MONTHLY CVP GENERATION

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (GWh)		
	Existing Conditions	Flow Evaluation Study Alternative
Jan	347	334
Feb	345	328
Mar	350	336
Apr	401	363
May	566	515
Jun	653	565
Jul	751	695
Aug	617	605
Sep	331	374
Oct	300	249
Nov	242	219
Dec	316	298
Average Annual Total	5,217	4,882
Percent Change from EC		-6%

DRY PERIOD (CALENDAR YEARS 1928-1934) (GWh)		
	Existing Conditions	Flow Evaluation Study Alternative
Jan	141	130
Feb	126	117
Mar	228	199
Apr	274	248
May	390	353
Jun	525	428
Jul	554	507
Aug	440	437
Sep	222	264
Oct	182	158
Nov	127	123
Dec	128	117
Average Annual Total	3,339	3,081
Percent Change from EC		-8%

Notes:
Facilities include: Trinity, Carr, Spring Creek, Shasta, Keswick, Folsom, Nimbus, New Melones, and San Luis powerplants. Simulated generation includes losses.

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TABLE F-19

COMPARISON OF SIMULATED AVERAGE MONTHLY AVAILABLE CAPACITY

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (MW)		
	Existing Conditions	**Flow Evaluation Study Alternative**
Jan	1,653	1,575
Feb	1,705	1,638
Mar	1,733	1,676
Apr	1,750	1,697
May	1,761	1,711
Jun	1,756	1,702
Jul	1,721	1,657
Aug	1,649	1,573
Sep	1,567	1,480
Oct	1,554	1,459
Nov	1,566	1,470
Dec	1,606	1,518
Average Annual Total	20,022	19,157
Percent Change from EC		-4%

DRY PERIOD (CALENDAR YEARS 1928-1934) (MW)		
	Existing Conditions	**Flow Evaluation Study Alternative**
Jan	1,435	1,320
Feb	1,488	1,376
Mar	1,548	1,445
Apr	1,577	1,478
May	1,572	1,480
Jun	1,553	1,452
Jul	1,497	1,380
Aug	1,400	1,269
Sep	1,315	1,167
Oct	1,284	1,125
Nov	1,277	1,121
Dec	1,310	1,161
Average Annual Total	17,256	15,775
Percent Change from EC		-9%

TABLE F-20

COMPARISON OF SIMULATED AVERAGE MONTHLY CVP PROJECT USE

LONG-TERM AVERAGE (CALENDAR YEARS 1922-1990) (GWh)		
	Existing Conditions	**Flow Evaluation Study Alternative**
Jan	147	147
Feb	118	115
Mar	116	114
Apr	93	87
May	96	94
Jun	115	109
Jul	133	120
Aug	123	120
Sep	106	107
Oct	104	102
Nov	117	114
Dec	132	133
Average Annual Total	1,401	1,362
Percent Change from EC		-3%

DRY PERIOD (CALENDAR YEARS 1928-1934) (GWh)		
	Existing Conditions	**Flow Evaluation Study Alternative**
Jan	149	152
Feb	121	116
Mar	82	75
Apr	51	37
May	57	52
Jun	58	47
Jul	72	58
Aug	80	79
Sep	80	86
Oct	55	53
Nov	68	71
Dec	104	111
Average Annual Total	978	937
Percent Change from EC		-4%

TABLE F-21

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE ENERGY LONG-TERM AVERAGE - CALENDAR YEARS 1922-1990

ON-PEAK (GWh)	Existing Conditions	Flow Evaluation Study Alternative
Jan	59	59
Feb	47	46
Mar	46	46
Apr	37	35
May	39	38
Jun	46	44
Jul	53	48
Aug	49	48
Sep	43	43
Oct	42	41
Nov	47	46
Dec	53	53
Average Annual Total	560	545
Percent Change from EC		-3%

OFF-PEAK (GWh)	Existing Conditions	Flow Evaluation Study Alternative
Jan	88	88
Feb	71	69
Mar	69	69
Apr	56	52
May	58	56
Jun	69	66
Jul	80	72
Aug	74	72
Sep	64	64
Oct	62	61
Nov	70	68
Dec	79	80
Average Annual Total	840	817
Percent Change from EC		-3%

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TABLE F-22

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE ENERGY DRY PERIOD - CALENDAR YEARS 1928-1934

ON-PEAK (GWh)		
	Existing Conditions	Flow Evaluation Study Alternative
Jan	60	61
Feb	48	46
Mar	33	30
Apr	20	15
May	23	21
Jun	23	19
Jul	29	23
Aug	32	31
Sep	32	35
Oct	22	21
Nov	27	29
Dec	42	44
Average Annual Total	391	375
Percent Change from EC		-4%

OFF-PEAK (GWh)		
	Existing Conditions	Flow Evaluation Study Alternative
Jan	90	91
Feb	72	69
Mar	49	45
Apr	31	22
May	34	31
Jun	35	28
Jul	43	35
Aug	48	47
Sep	48	52
Oct	33	32
Nov	41	43
Dec	62	66
Average Annual Total	587	562
Percent Change from EC		-4%

TABLE F-23

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE CAPACITY LONG-TERM AVERAGE - CALENDAR YEARS 1922-1990

ON-PEAK (MW)	Existing Conditions	Flow Evaluation Study Alternative
Jan	212	211
Feb	167	159
Mar	151	147
Apr	136	126
May	145	140
Jun	170	162
Jul	189	171
Aug	176	172
Sep	151	151
Oct	139	136
Nov	177	175
Dec	193	195
Average Annual Total	2,006	1,945
Percent Change from EC		-3%

OFF-PEAK (MW)	Existing Conditions	Flow Evaluation Study Alternative
Jan	342	332
Feb	316	306
Mar	278	275
Apr	178	168
May	176	173
Jun	197	190
Jul	217	201
Aug	207	196
Sep	239	242
Oct	238	233
Nov	273	262
Dec	297	293
Average Annual Total	2,959	2,874
Percent Change from EC		-3%

TABLE F-24

COMPARISON OF SIMULATED AVERAGE MONTHLY ON- AND OFF-PEAK CVP PROJECT USE CAPACITY DRY PERIOD - CALENDAR YEARS 1928-1934

ON-PEAK (MW)	Existing Conditions	Flow Evaluation Study Alternative
Jan	238	234
Feb	177	154
Mar	117	111
Apr	93	74
May	98	93
Jun	105	89
Jul	121	102
Aug	126	129
Sep	121	127
Oct	92	89
Nov	109	108
Dec	165	181
Average Annual Total	1,562	1,492
Percent Change from EC		-4%

OFF-PEAK (MW)	Existing Conditions	Flow Evaluation Study Alternative
Jan	332	331
Feb	316	323
Mar	208	182
Apr	110	79
May	103	98
Jun	117	99
Jul	129	109
Aug	140	135
Sep	191	208
Oct	142	130
Nov	182	195
Dec	247	254
Average Annual Total	2,217	2,142
Percent Change from EC		-3%

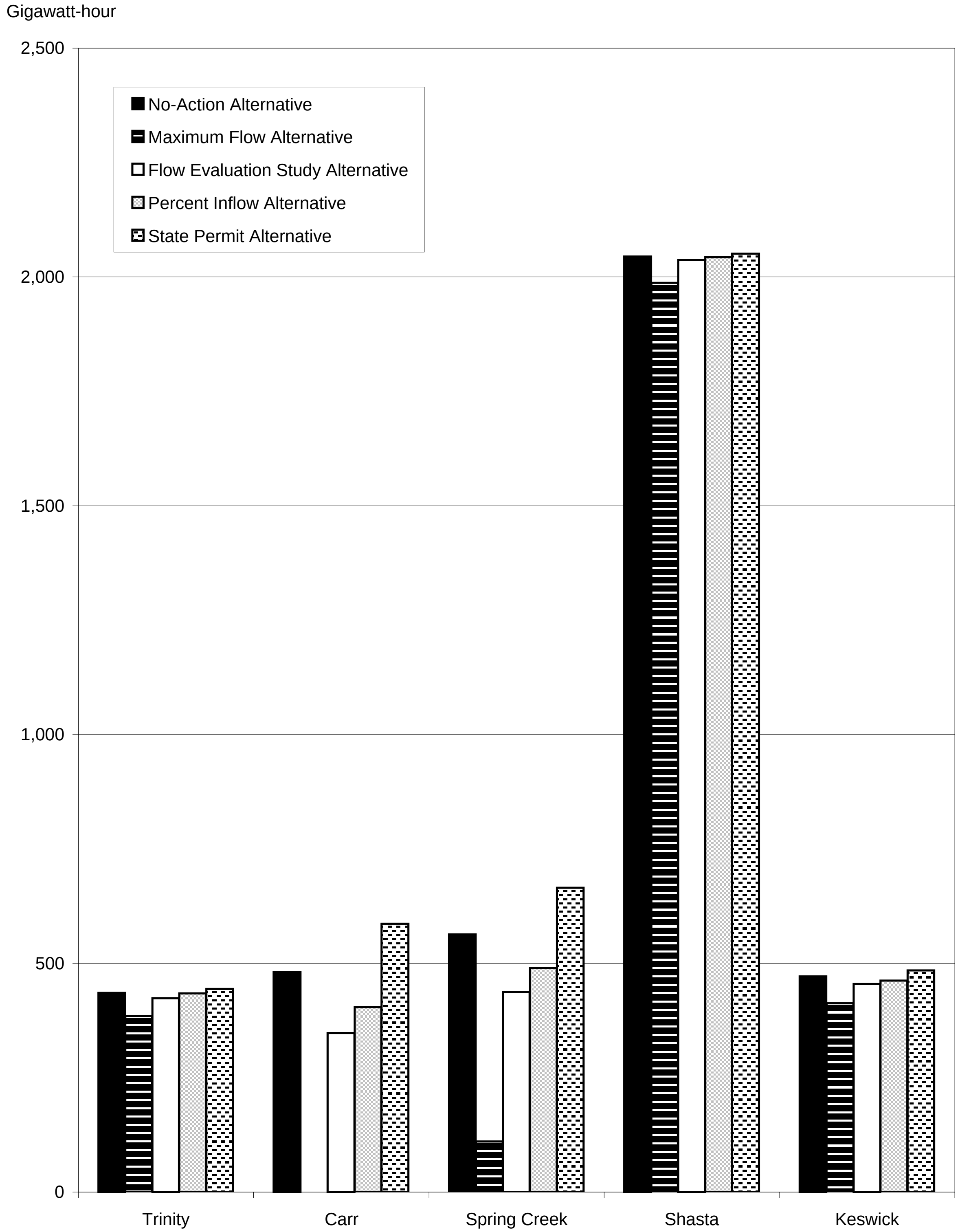

FIGURE F-1
SIMULATED AVERAGE ANNUAL GENERATION AT CVP POWERPLANTS IN THE SHASTA AND TRINITY RIVER DIVISIONS

RDD-SFO/992640002.XLS(Wpt105)

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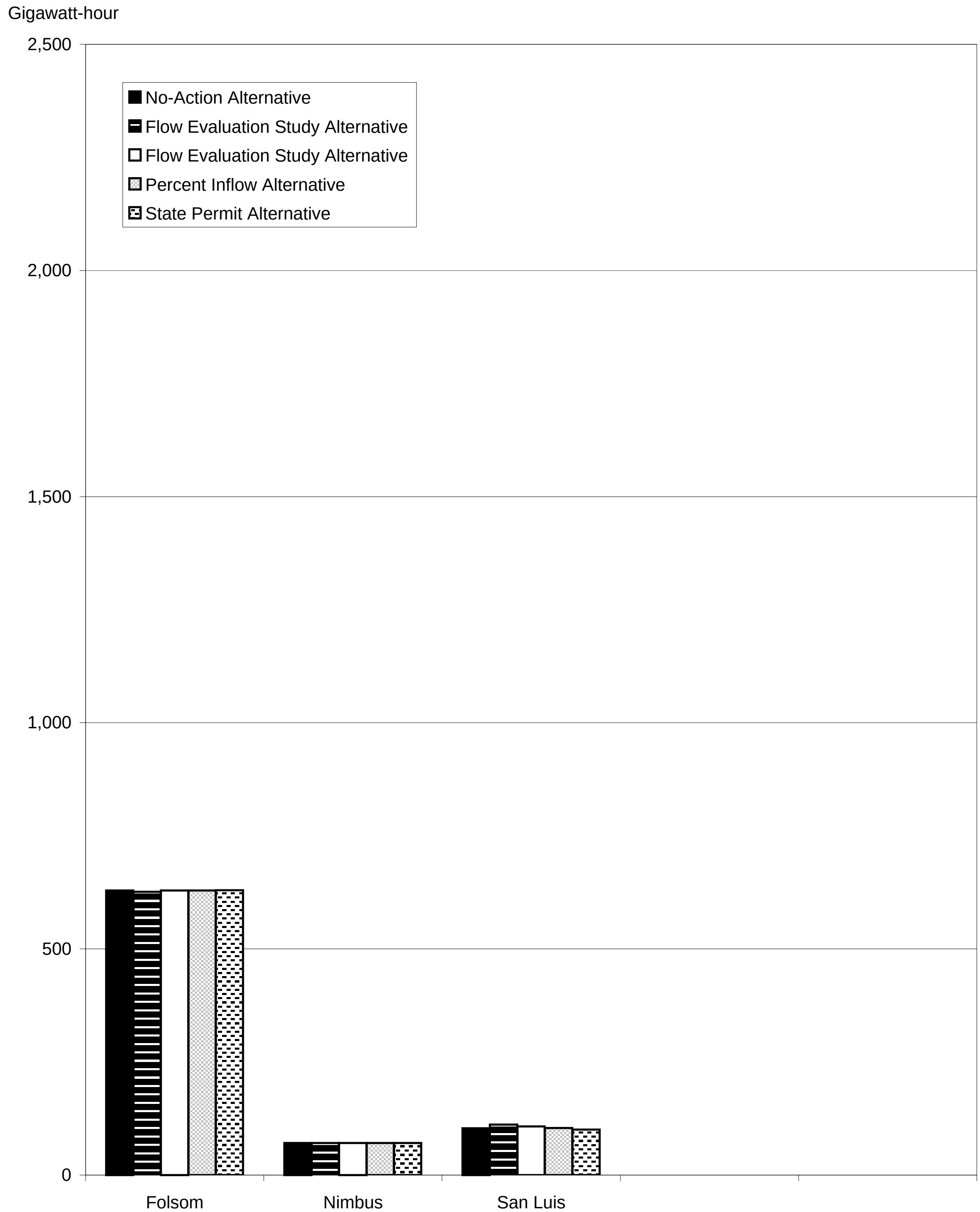

FIGURE F-2
SIMULATED AVERAGE ANNUAL GENERATION AT CVP POWERPLANTS IN THE AMERICAN RIVER AND WEST SAN JOAQUIN DIVISIONS

RDD-SFO/992640002.XLS(Wpt105)

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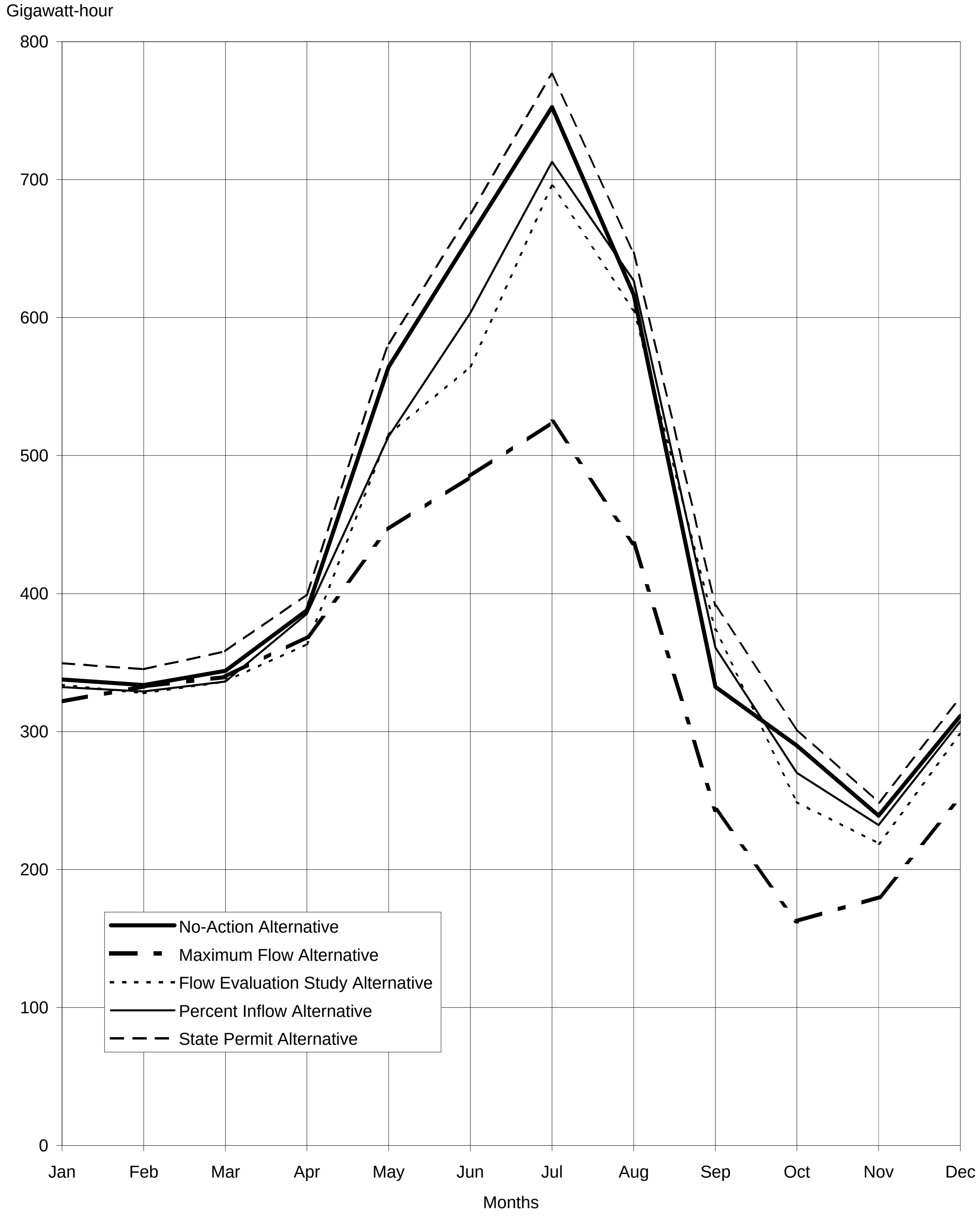

FIGURE F-3
SIMULATED AVERAGE MONTHLY CVP GENERATION
LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640002.XLS(Wpt105)

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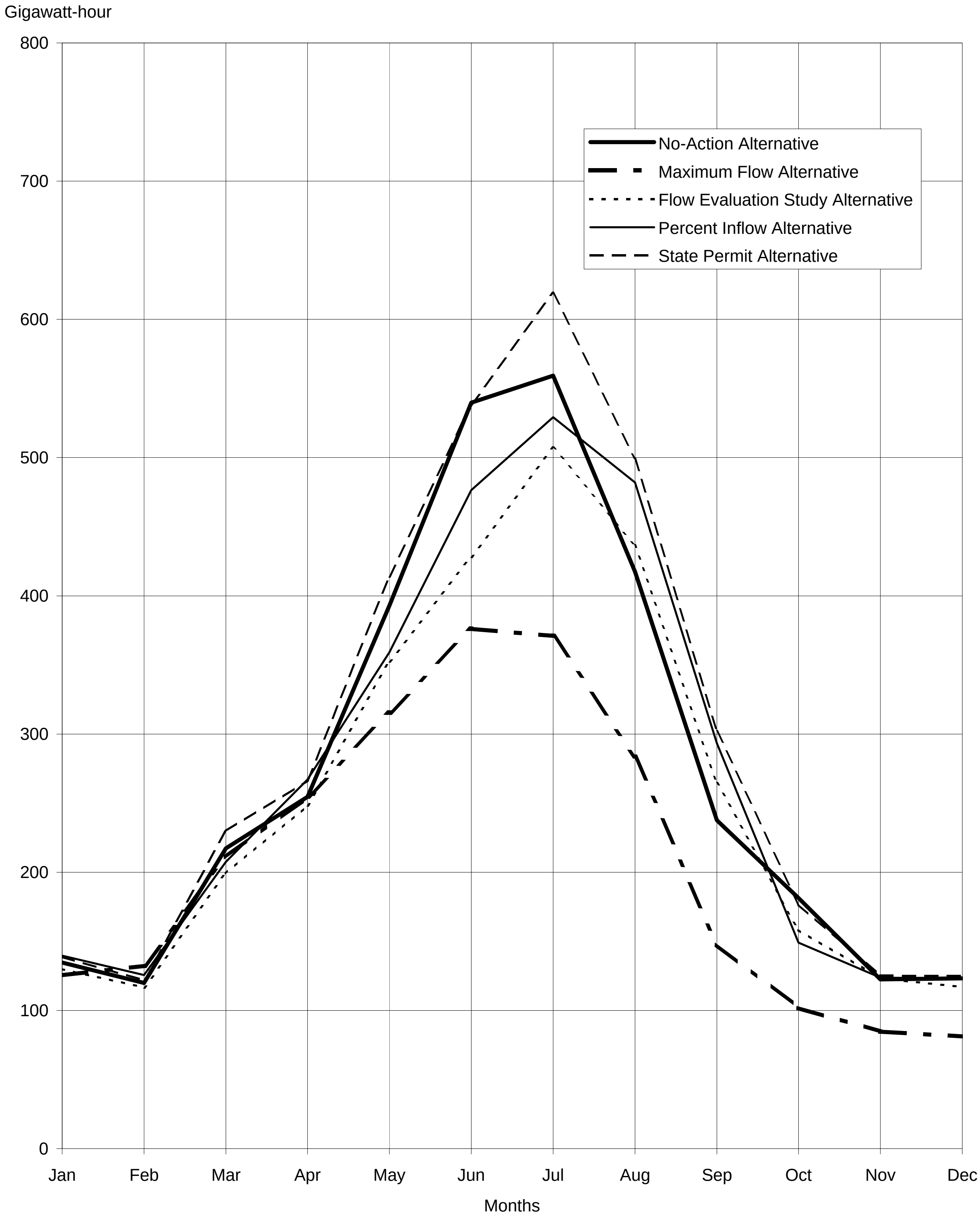

FIGURE F-4
SIMULATED AVERAGE MONTHLY CVP GENERATION
DRY PERIOD 1928-1934

RDD-SFO/992640002.XLS(Wpt105)

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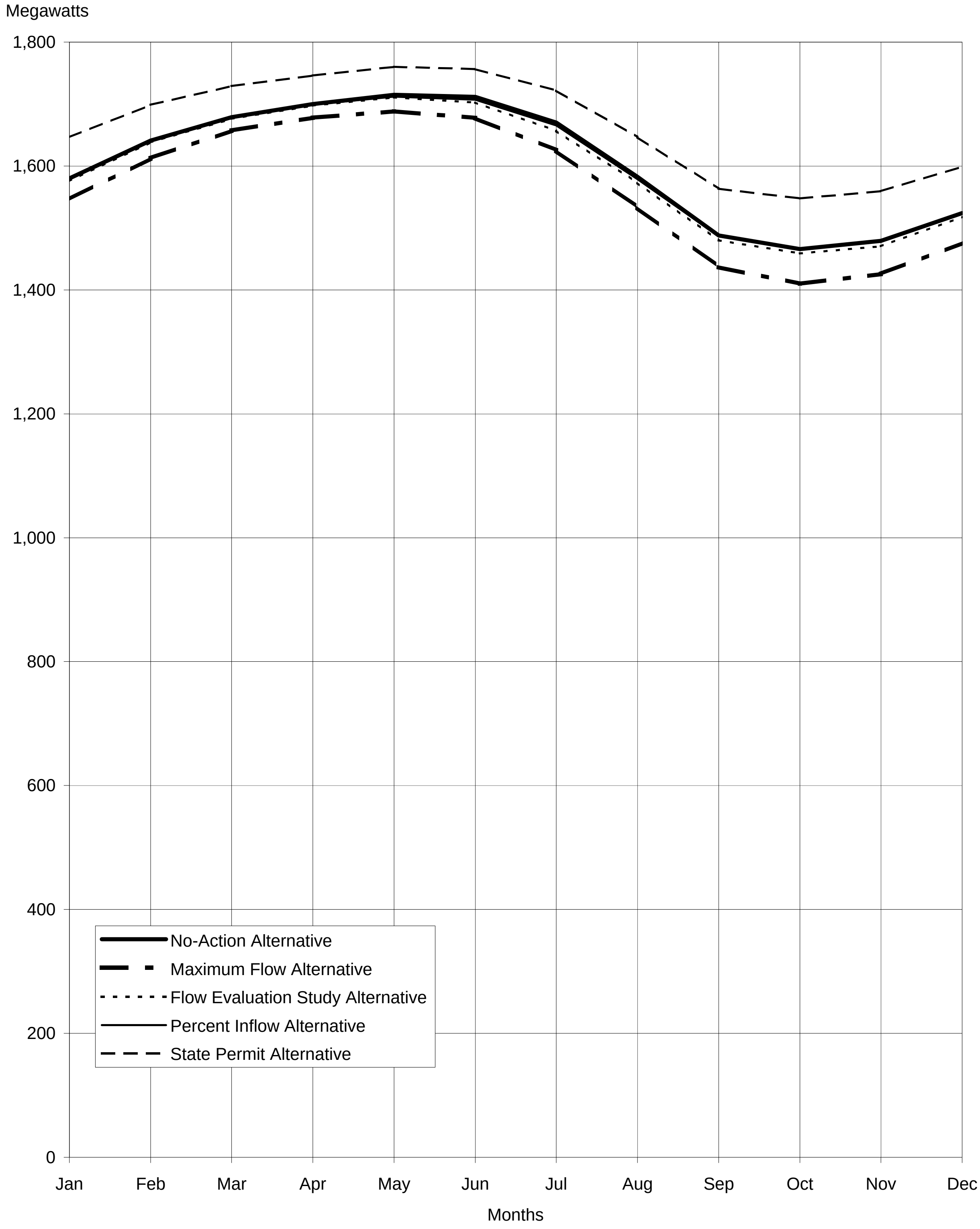

FIGURE F-5

SIMULATED AVERAGE MONTHLY AVAILABLE CAPACITY

LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640002.XLS(Wpt105)

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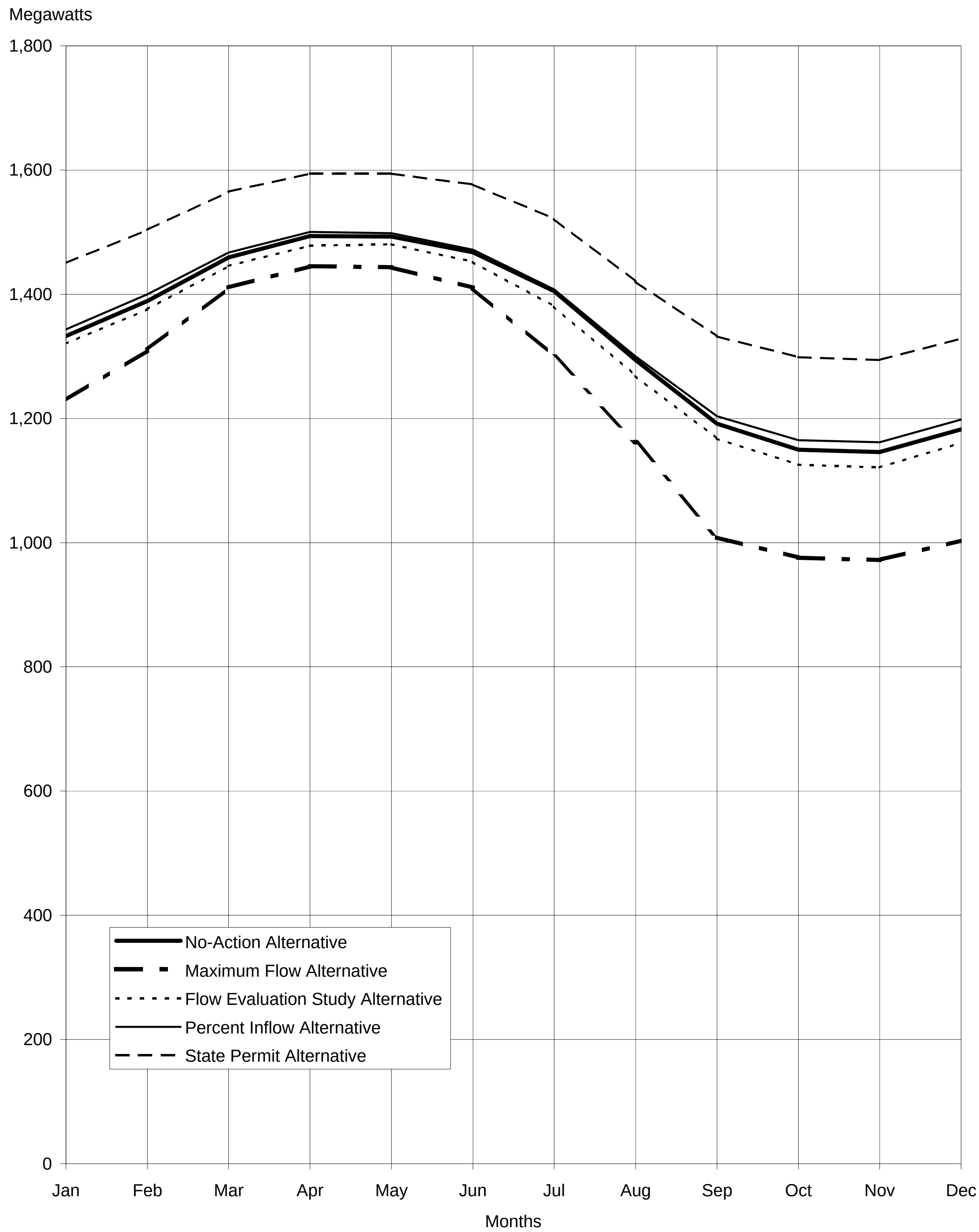

FIGURE F-6
SIMULATED AVERAGE MONTHLY AVAILABLE CAPACITY
DRY PERIOD 1928-1934

RDD-SFO/992640002.XLS(Wpt105)

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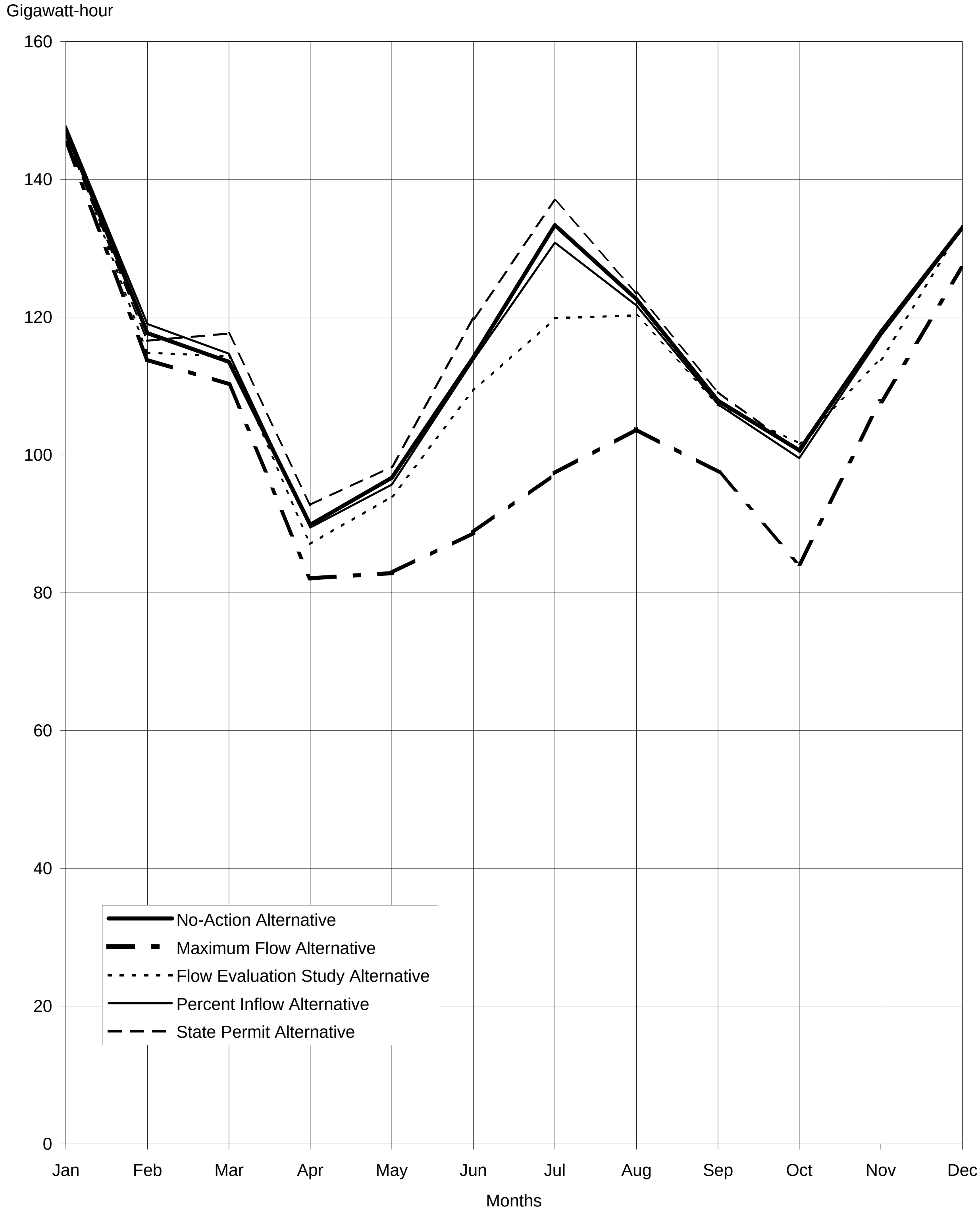

FIGURE F-7
SIMULATED AVERAGE MONTHLY PROJECT USE ENERGY LONG-TERM AVERAGE 1922-1990

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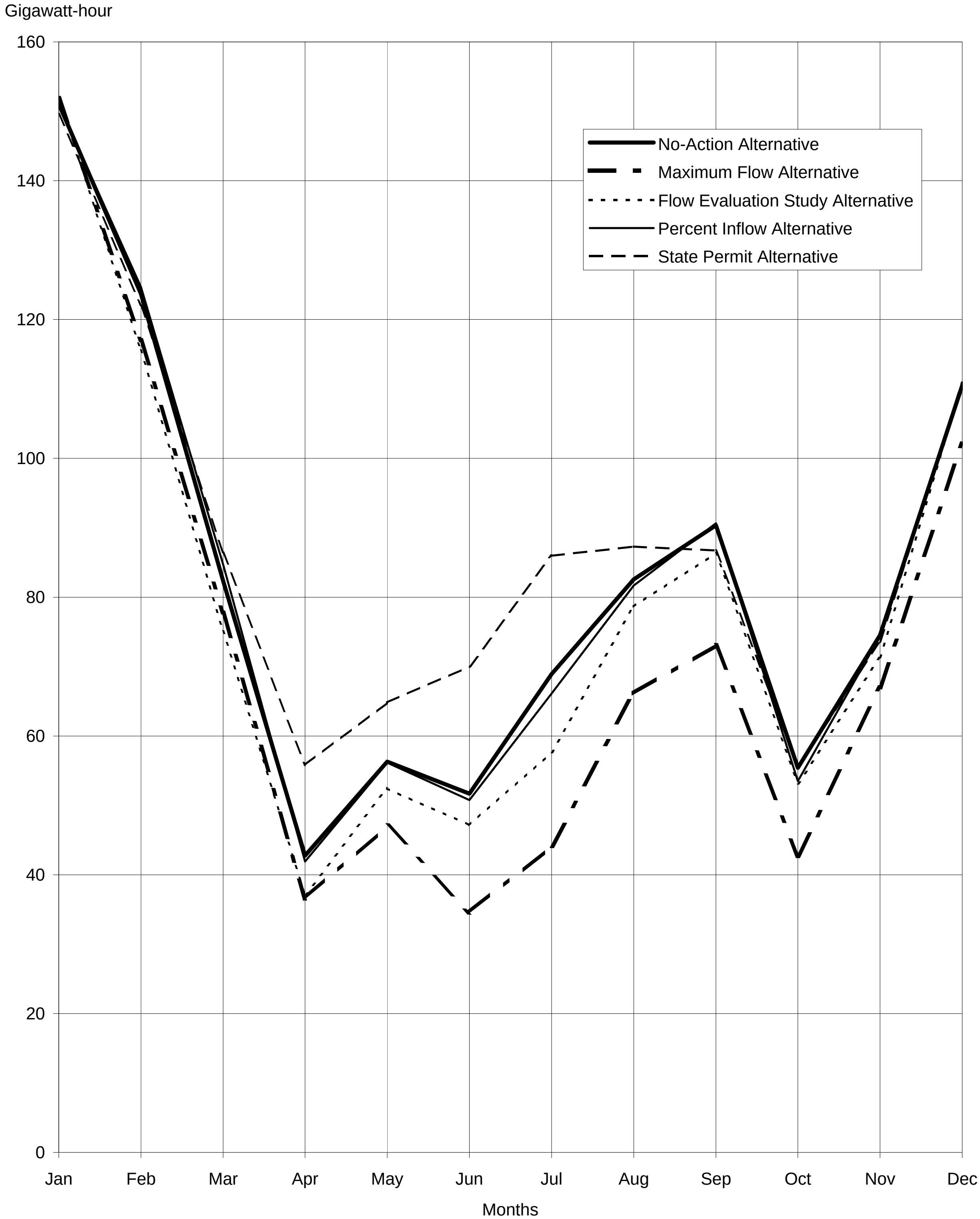

FIGURE F-8
SIMULATED AVERAGE MONTHLY PROJECT USE ENERGY DRY PERIOD 1928-1934

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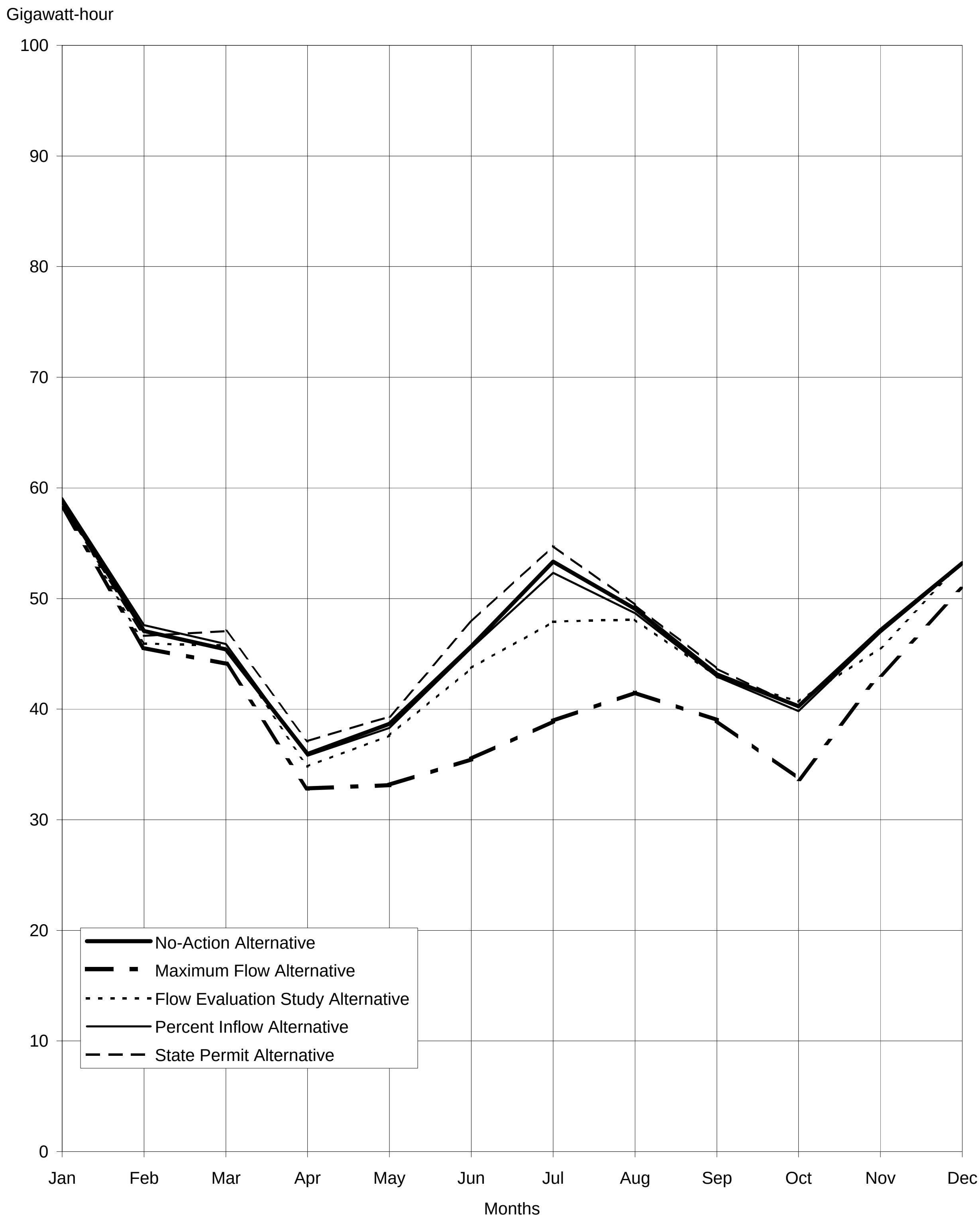

FIGURE F-9
SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE ENERGY LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640002.XLS(Wpt105)

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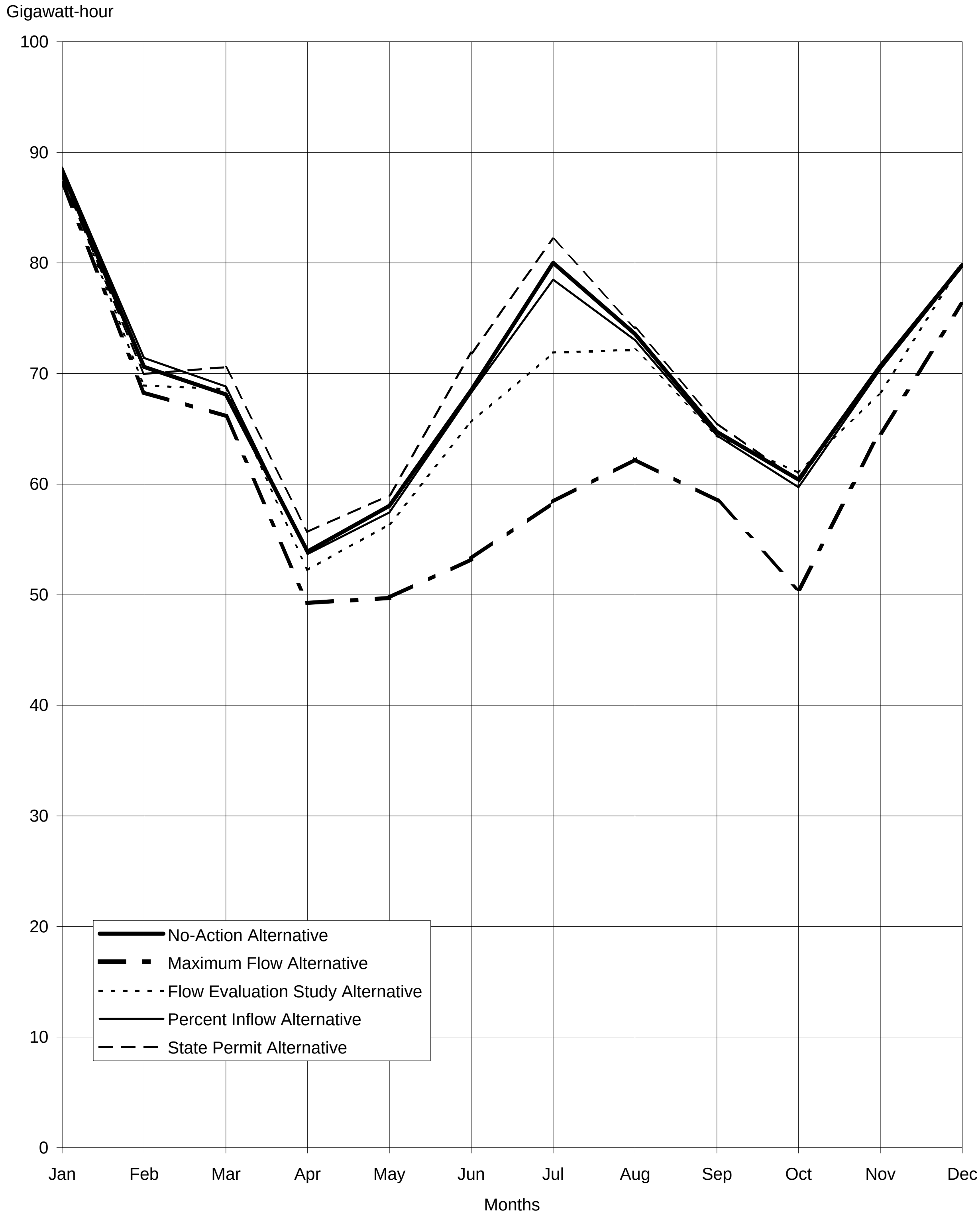

FIGURE F-10
SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE ENERGY LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640002.XLS(Wpt105)

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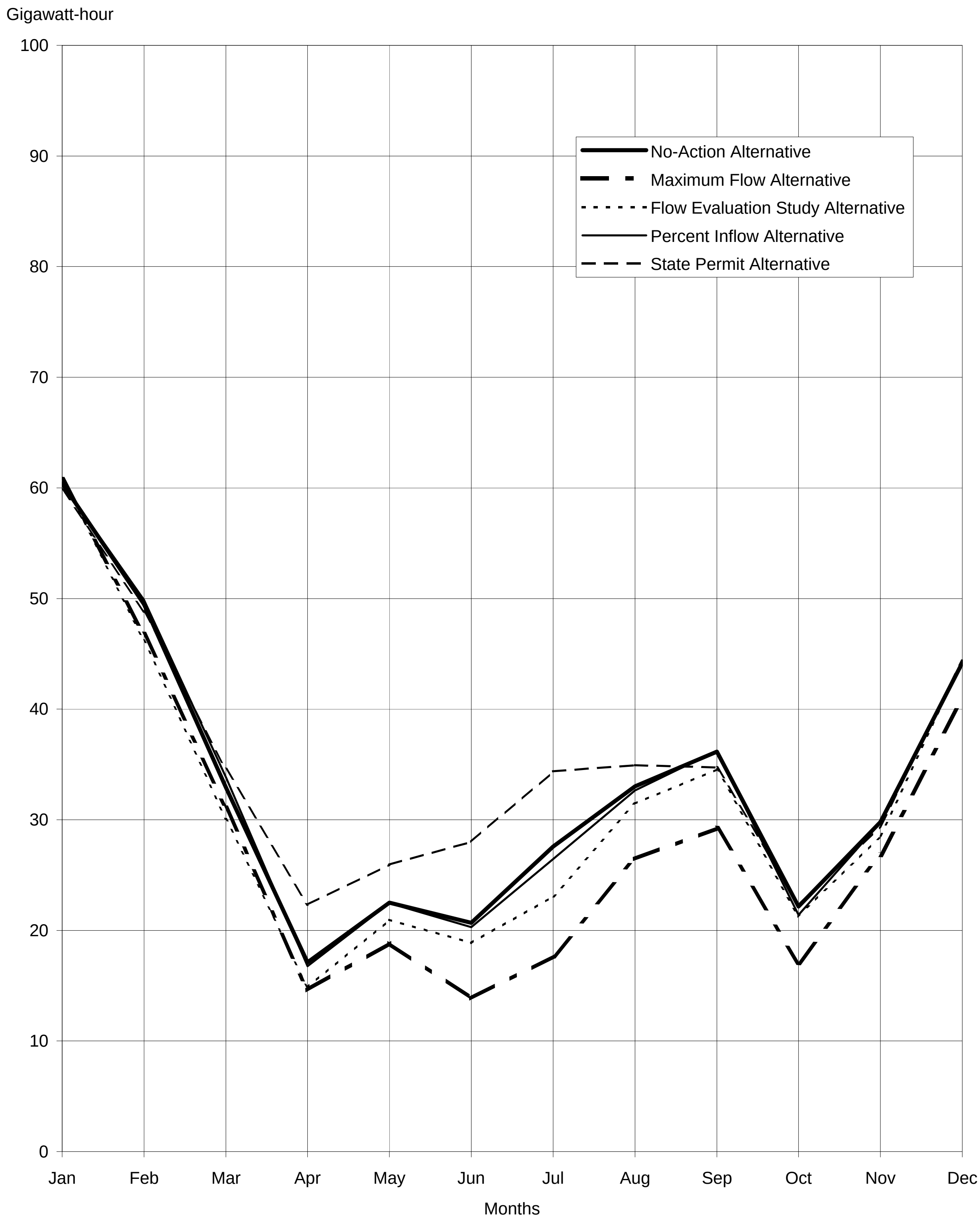

FIGURE F-11
SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE ENERGY DRY PERIOD 1928-1934

RDD-SFO/992640002.XLS(Wpt105)

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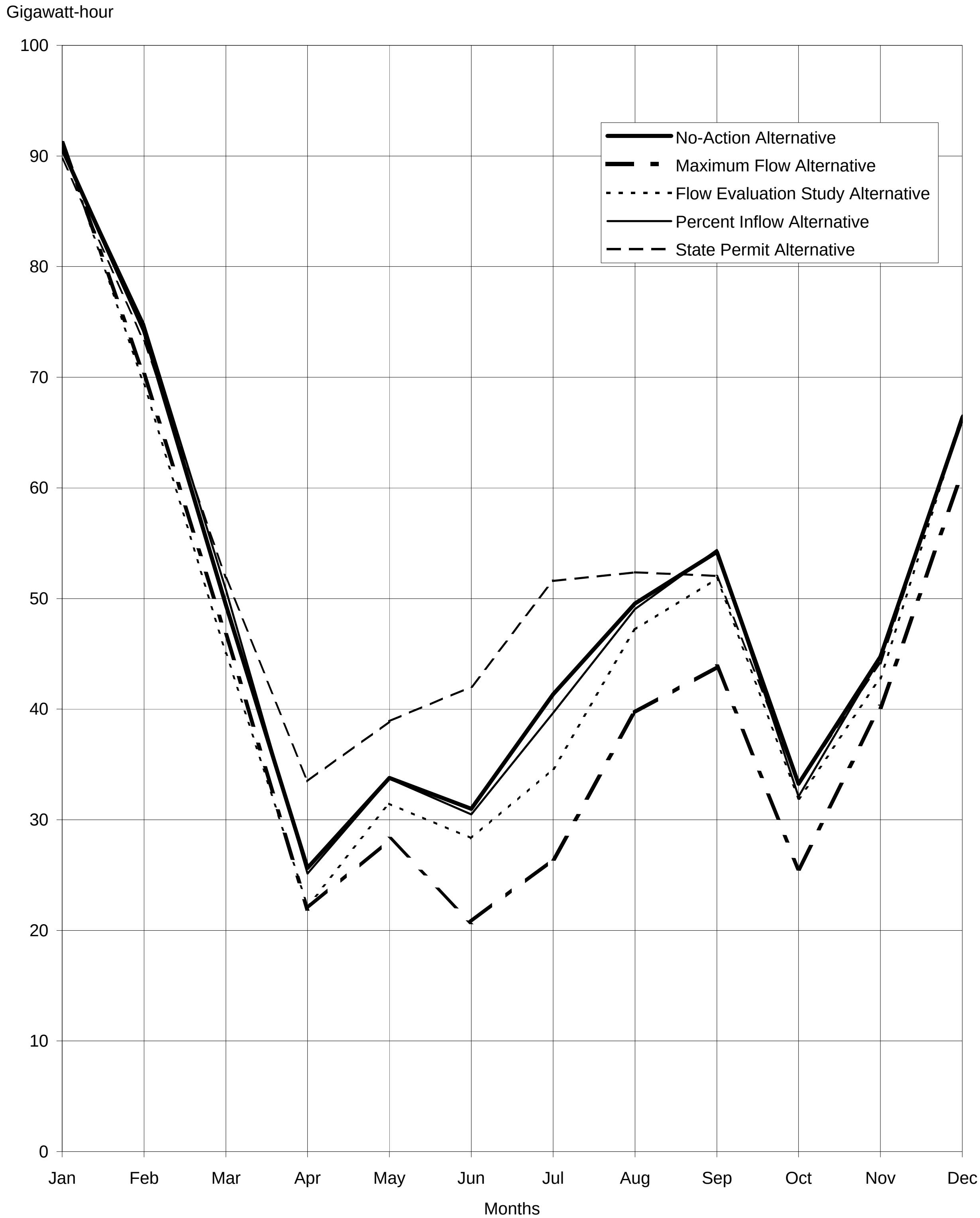

FIGURE F-12
SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE ENERGY DRY PERIOD 1928-1934

RDD-SFO/992640002.XLS(Wpt105)

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FIGURE F-13
SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE CAPACITY LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640002.XLS(Wpt105)

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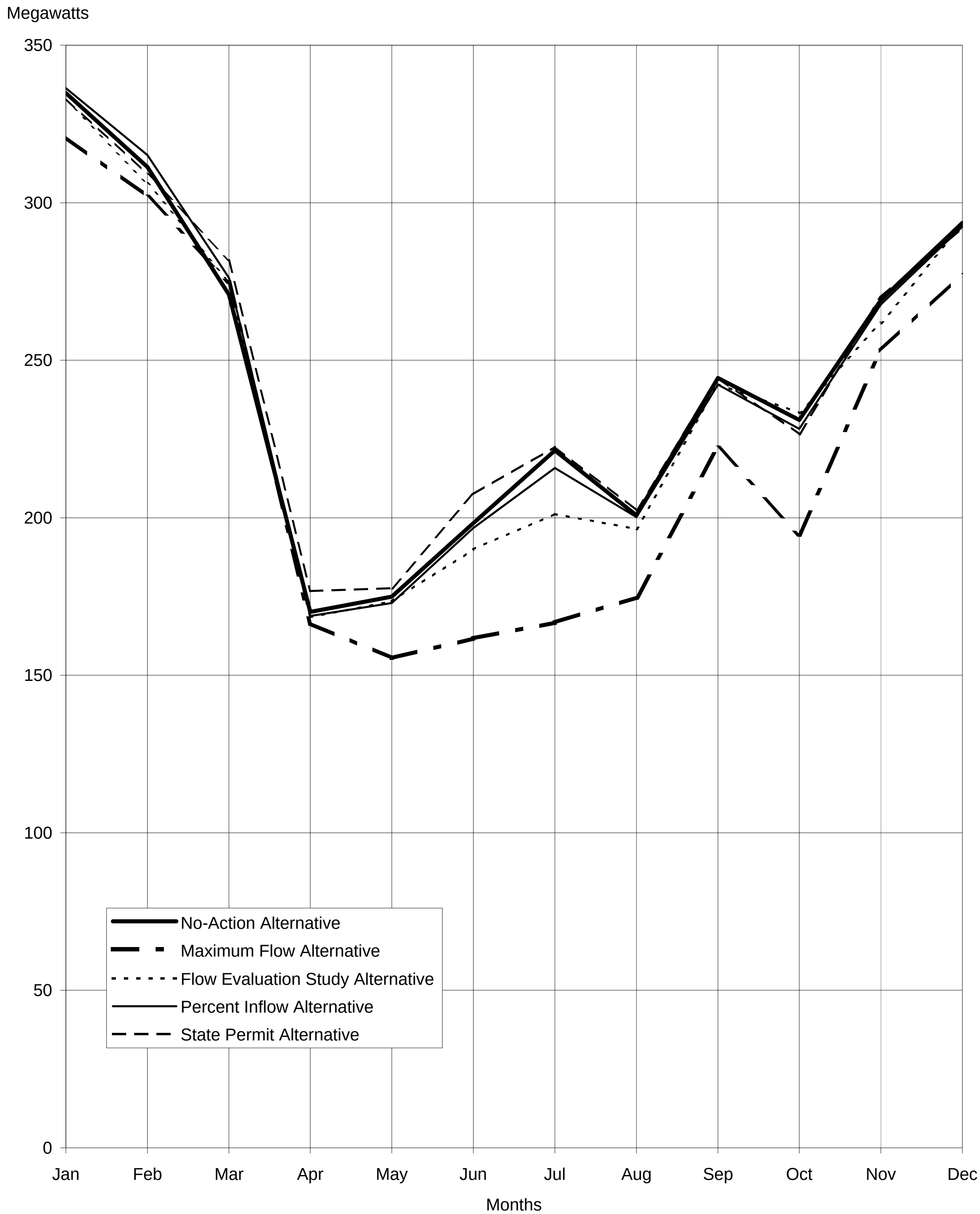

FIGURE F-14
SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE CAPACITY LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640002.XLS(Wpt105)

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FIGURE F-15
SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE CAPACITY DRY PERIOD 1928-1934

RDD-SFO/992640002.XLS(Wpt105)

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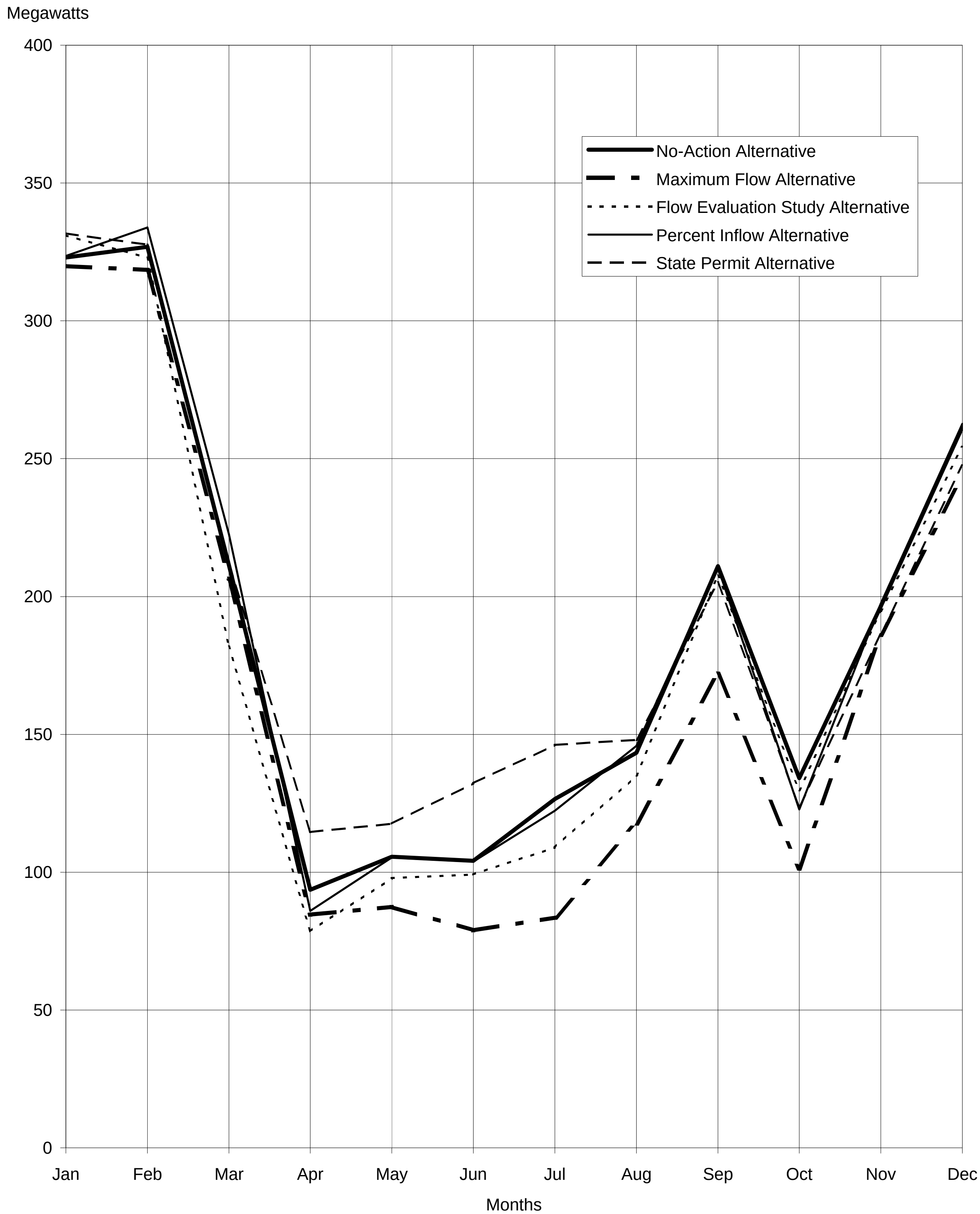

FIGURE F-16

SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE CAPACITY DRY PERIOD 1928-1934

RDD-SFO/992640002.XLS(Wpt105)

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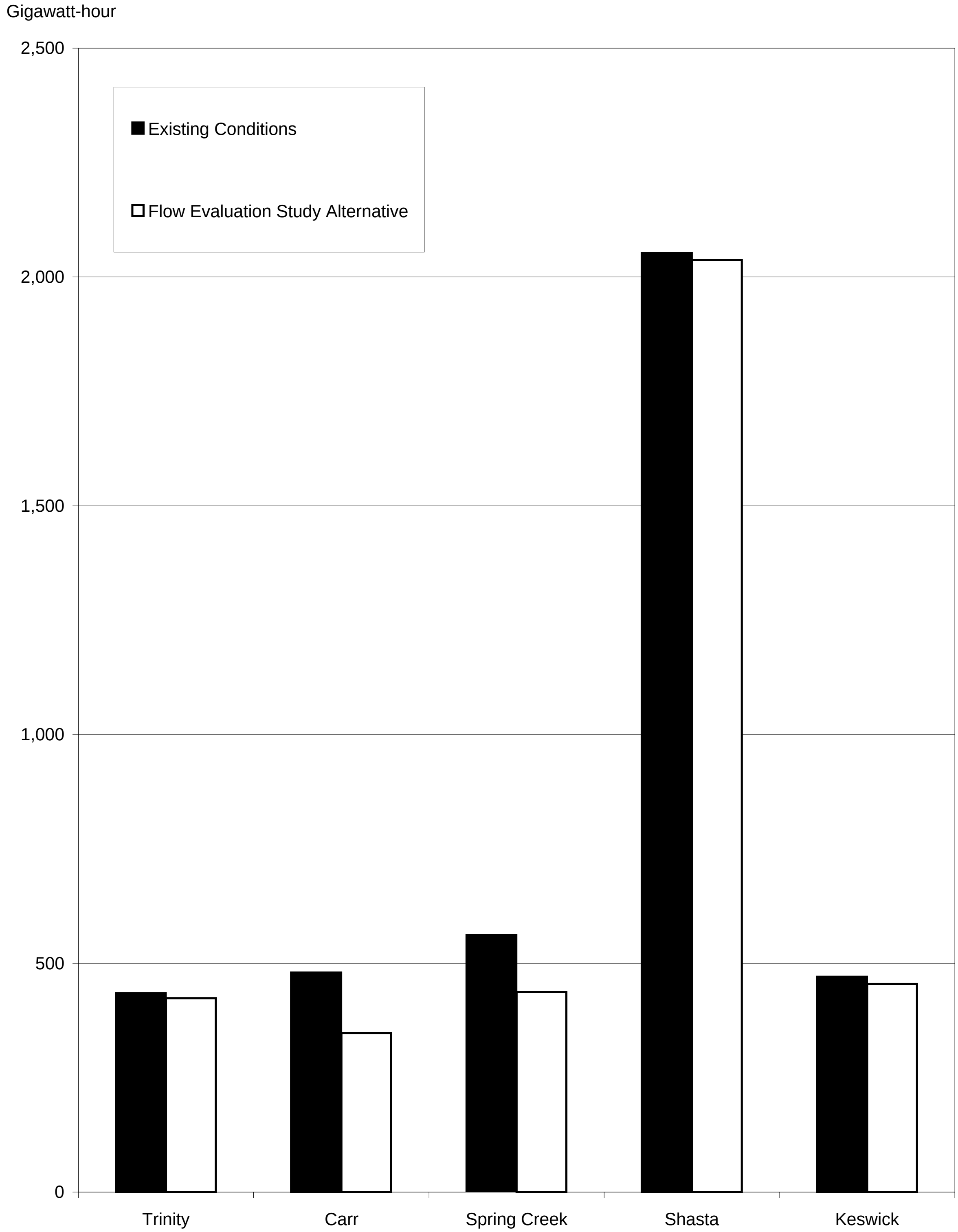

FIGURE F-17
SIMULATED AVERAGE ANNUAL GENERATION AT CVP POWERPLANTS IN THE SHASTA AND TRINITY RIVER DIVISIONS

RDD-SFO/992640005.XLS(Wpt107.xls)

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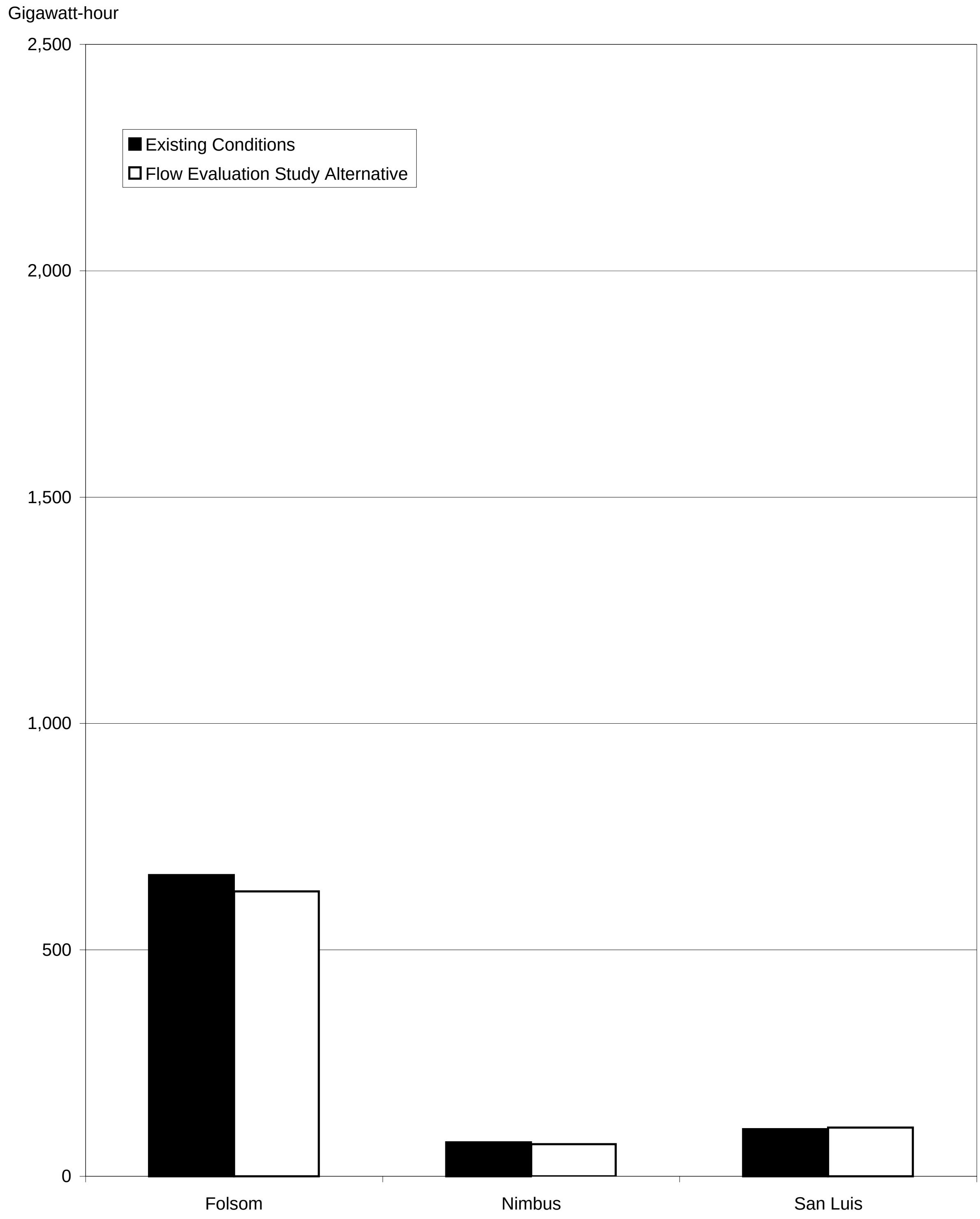

FIGURE F-18
SIMULATED AVERAGE ANNUAL GENERATION AT CVP POWERPLANTS IN THE AMERICAN RIVER AND WEST SAN JOAQUIN DIVISIONS

RDD-SFO/992640005.XLS(Wpt107.xls)

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FIGURE F-19
SIMULATED AVERAGE MONTHLY CVP GENERATION
LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640005.XLS(Wpt107.xls)

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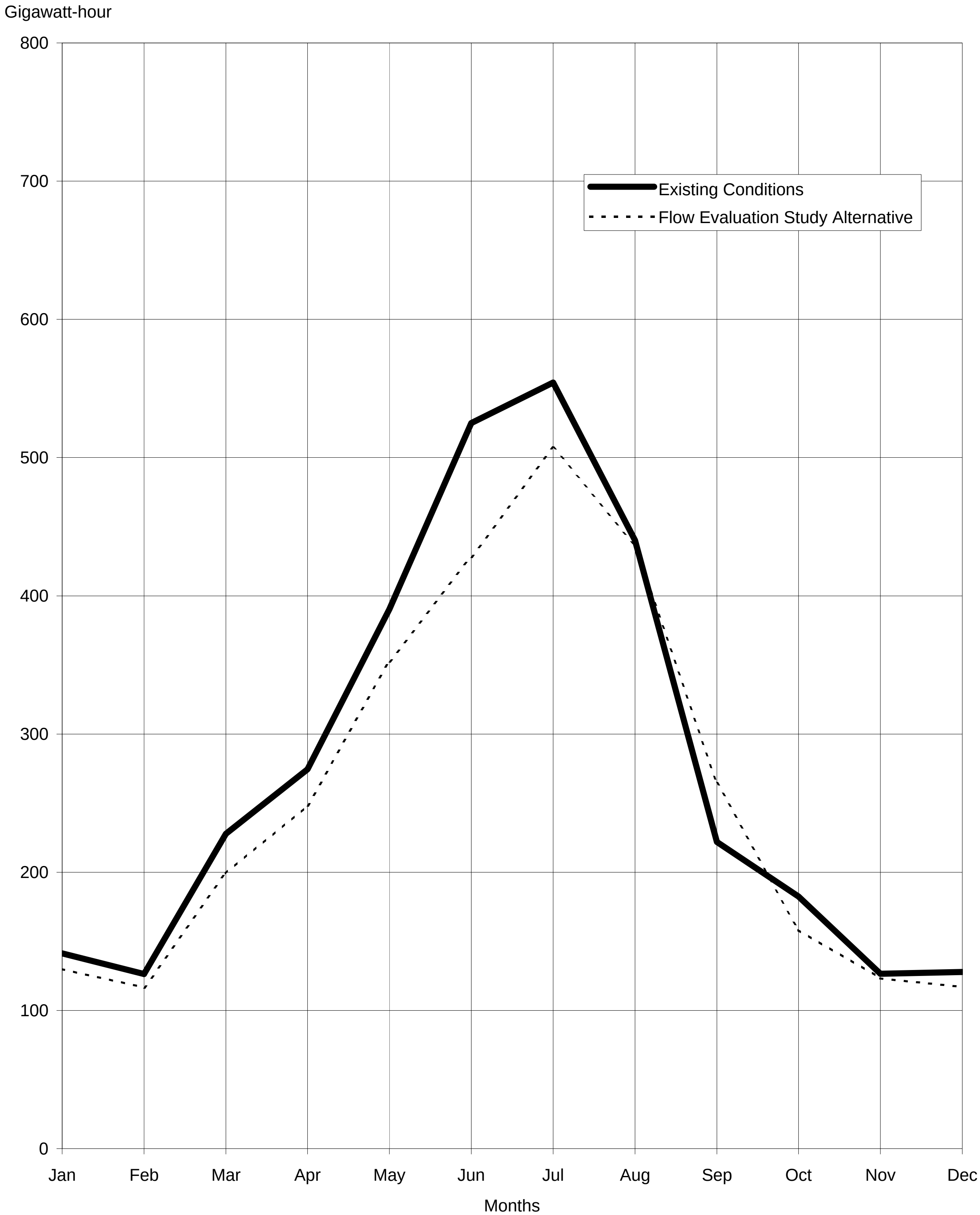

FIGURE F-20
SIMULATED AVERAGE MONTHLY CVP GENERATION
DRY PERIOD 1928-1934

RDD-SFO/992640005.XLS(Wpt107.xls)

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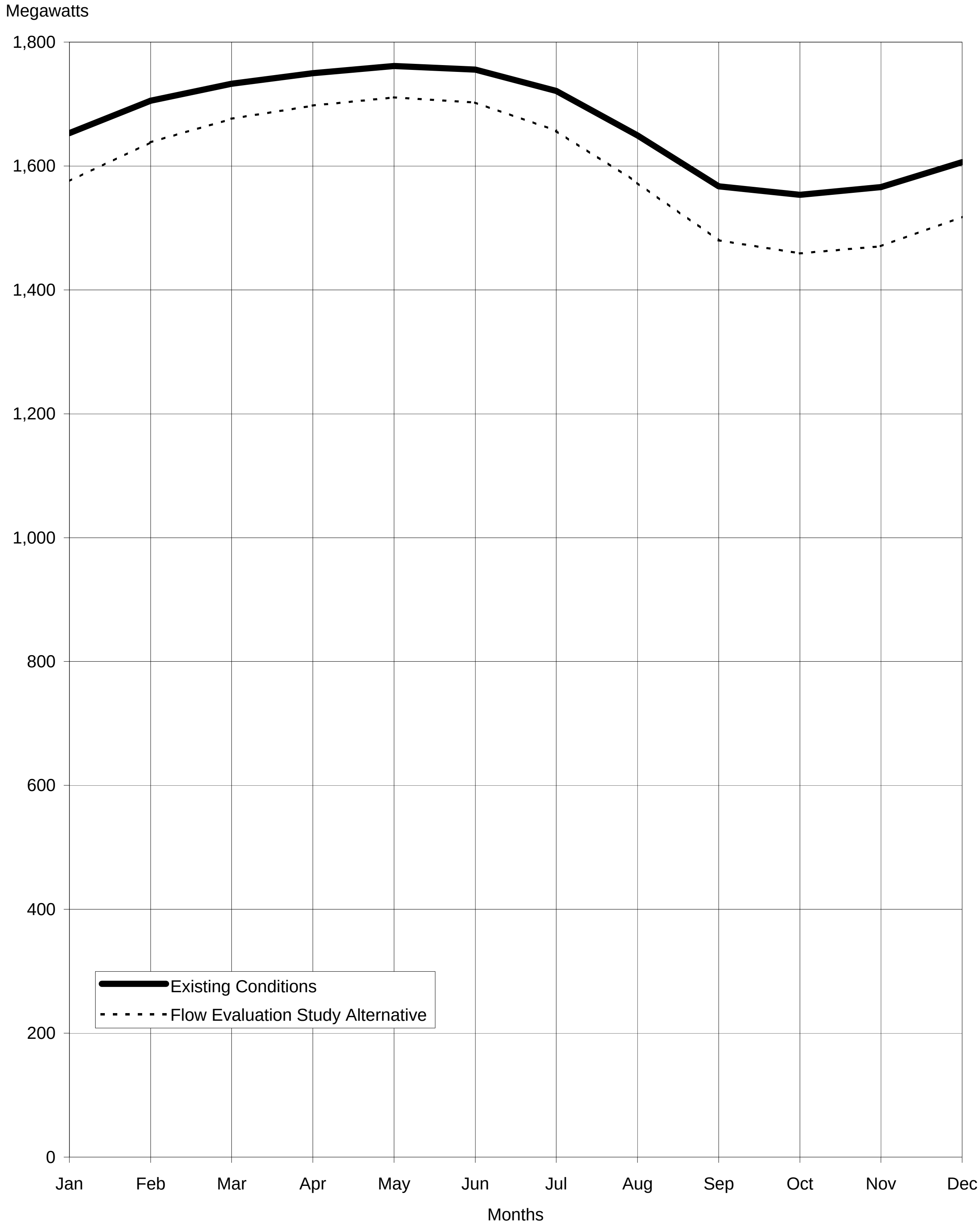

FIGURE F-21
SIMULATED AVERAGE MONTHLY AVAILABLE CAPACITY
LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640005.XLS(Wpt107.xls)

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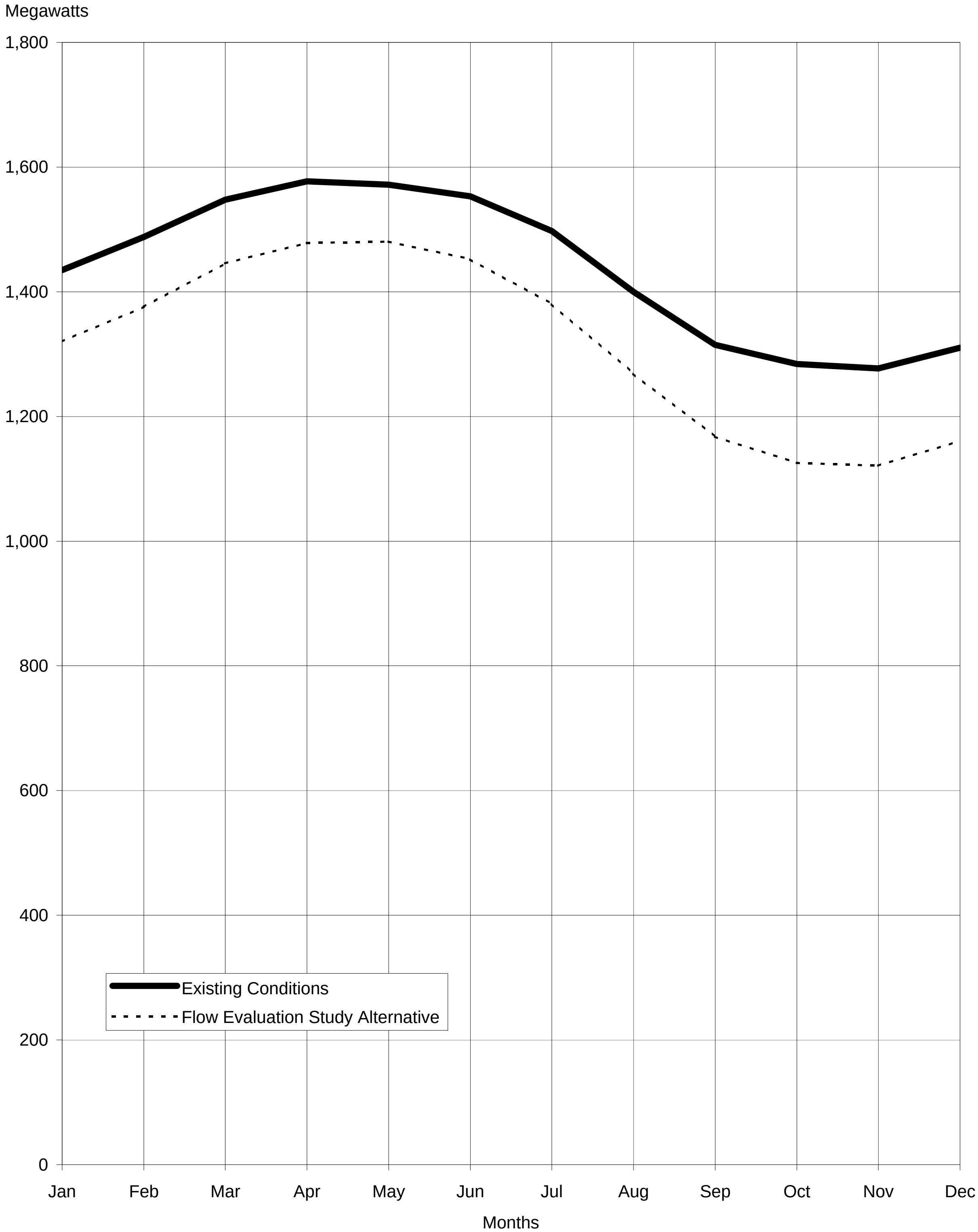

FIGURE F-22
SIMULATED AVERAGE MONTHLY AVAILABLE CAPACITY
DRY PERIOD 1928-1934

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FIGURE F-23
SIMULATED AVERAGE MONTHLY PROJECT USE ENERGY LONG-TERM AVERAGE 1922-1990

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FIGURE F-24
SIMULATED AVERAGE MONTHLY PROJECT USE ENERGY DRY PERIOD 1928-1934

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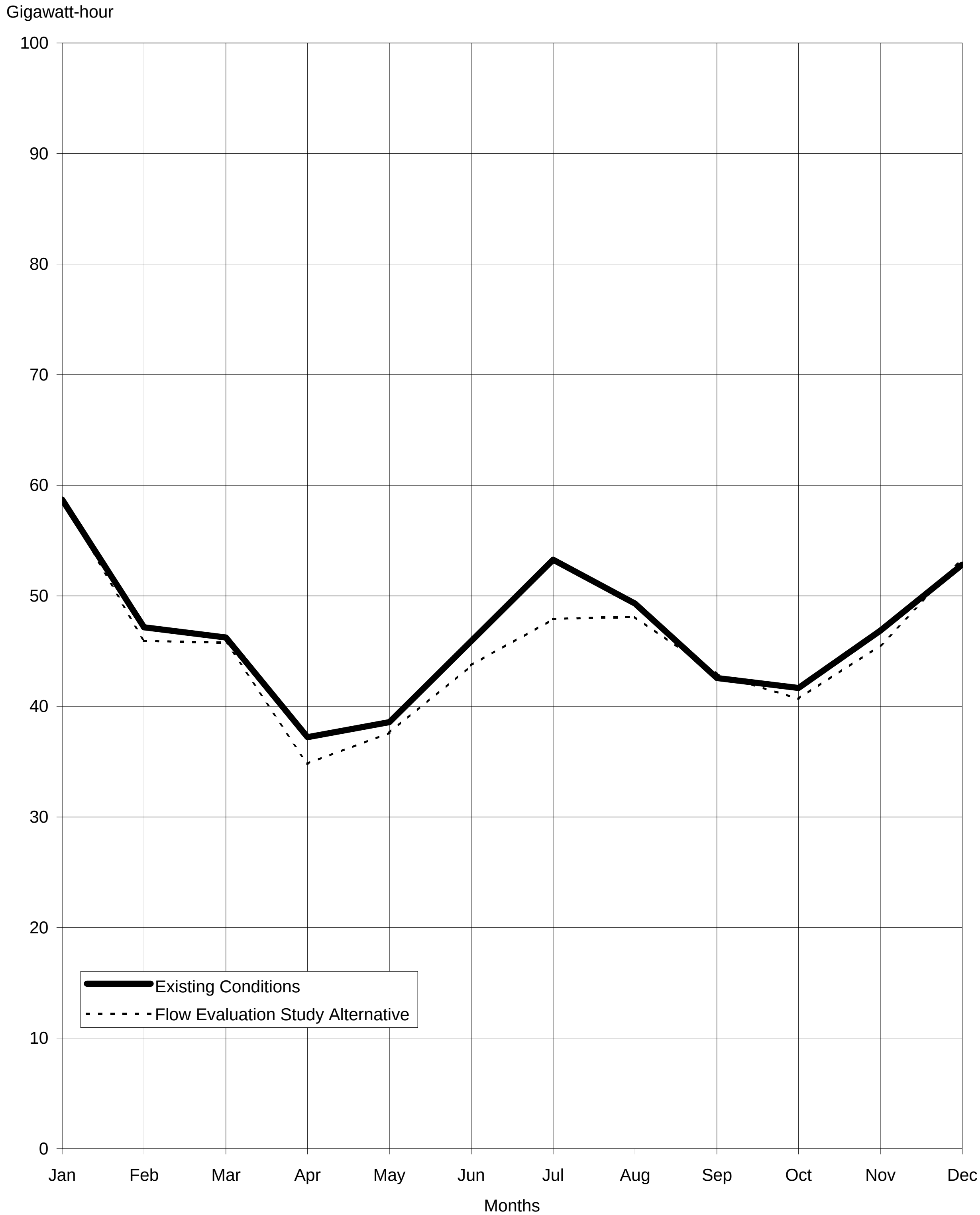

FIGURE F-25
SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE ENERGY LONG-TERM AVERAGE 1922-1990

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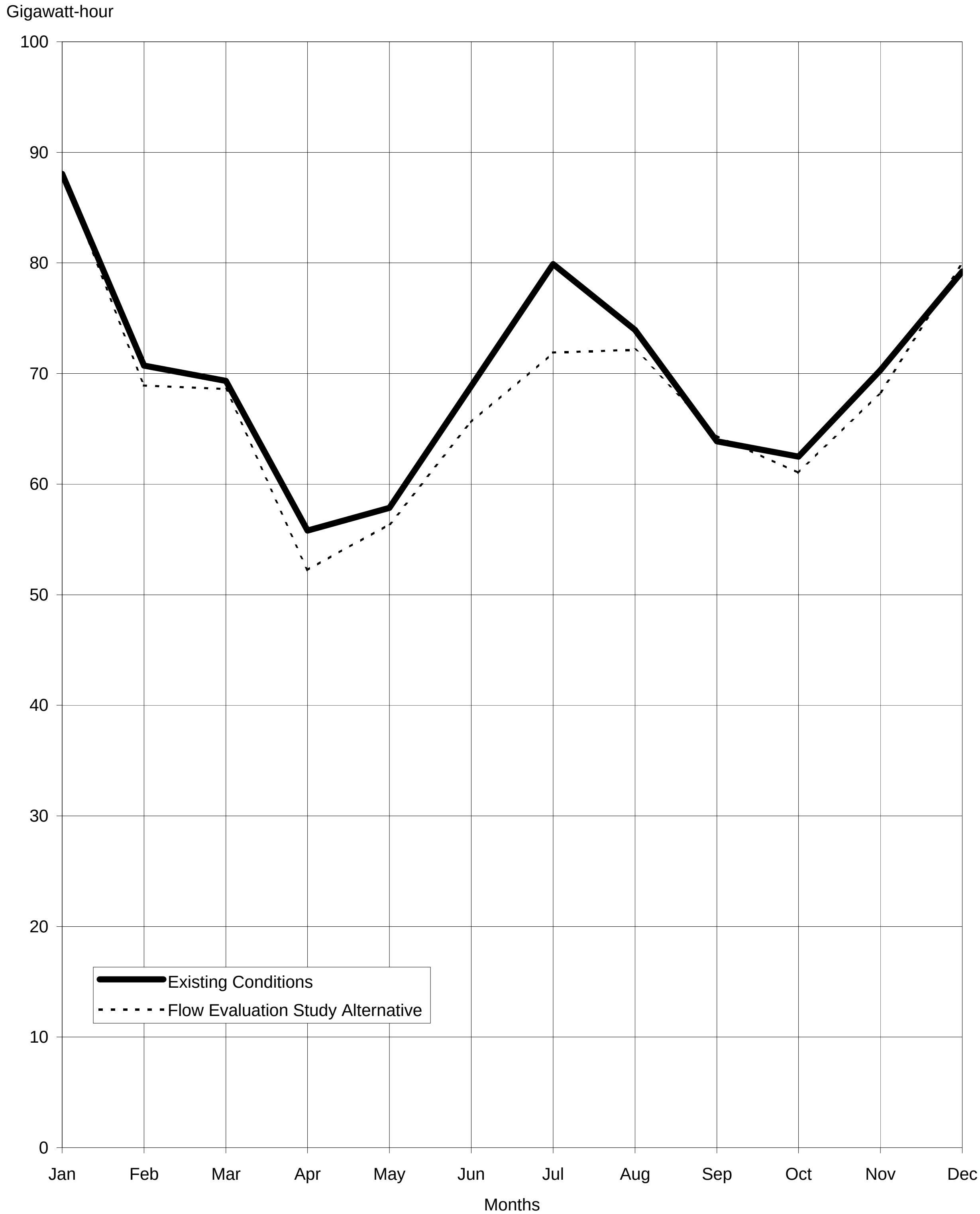

FIGURE F-26

SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE ENERGY LONG-TERM AVERAGE 1922-1990

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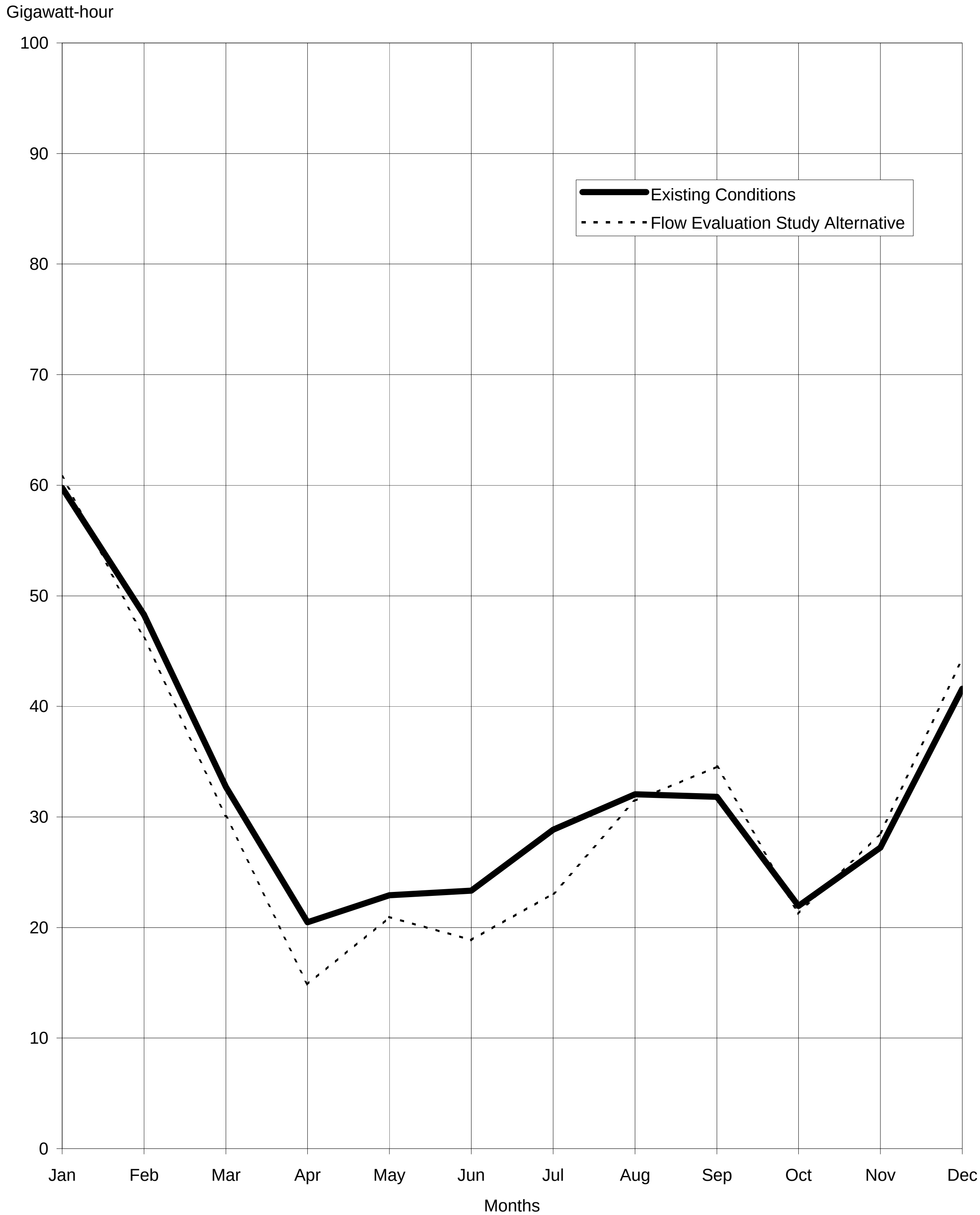

FIGURE F-27
SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE ENERGY DRY PERIOD 1928-1934

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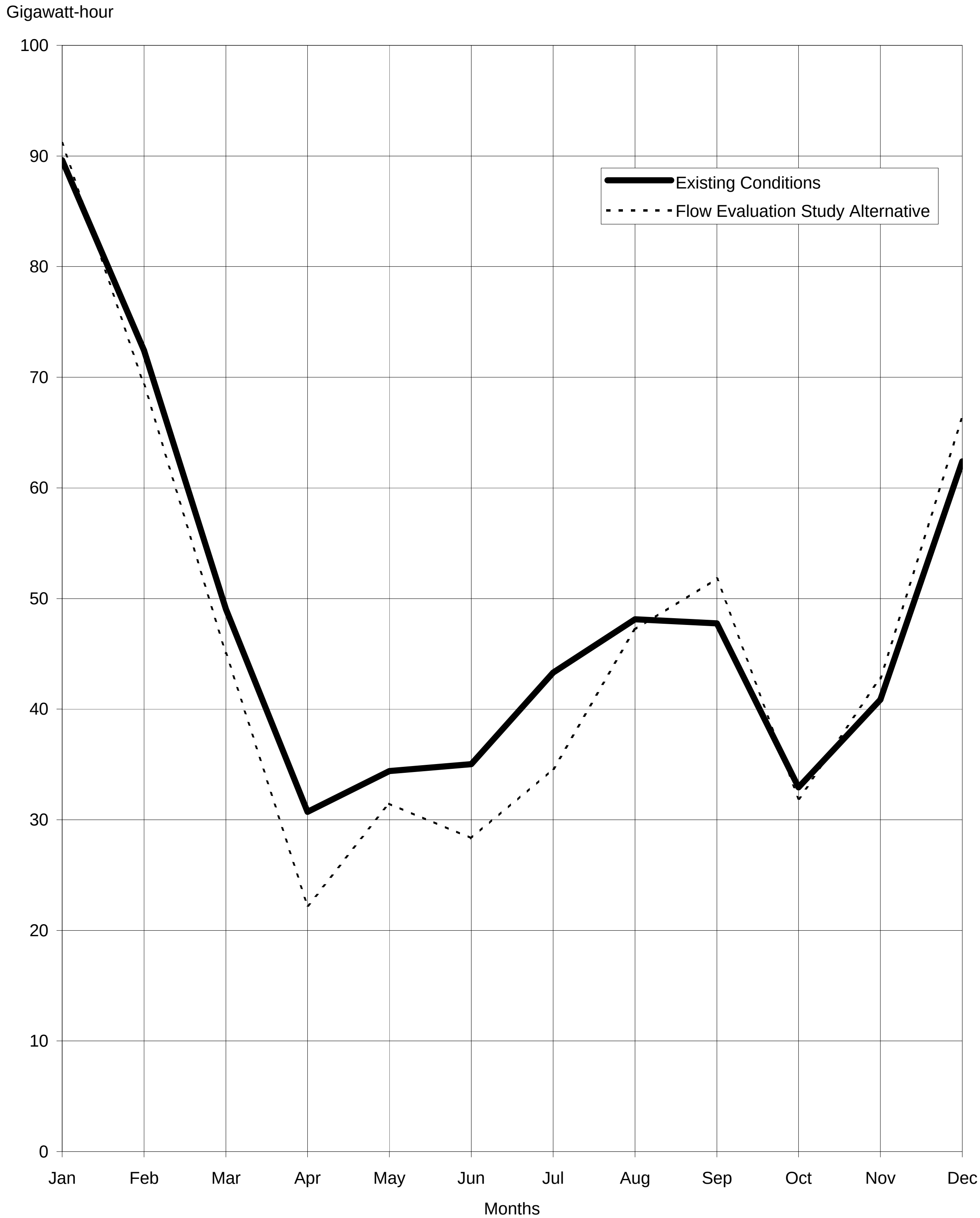

FIGURE F-28
SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE ENERGY DRY PERIOD 1928-1934

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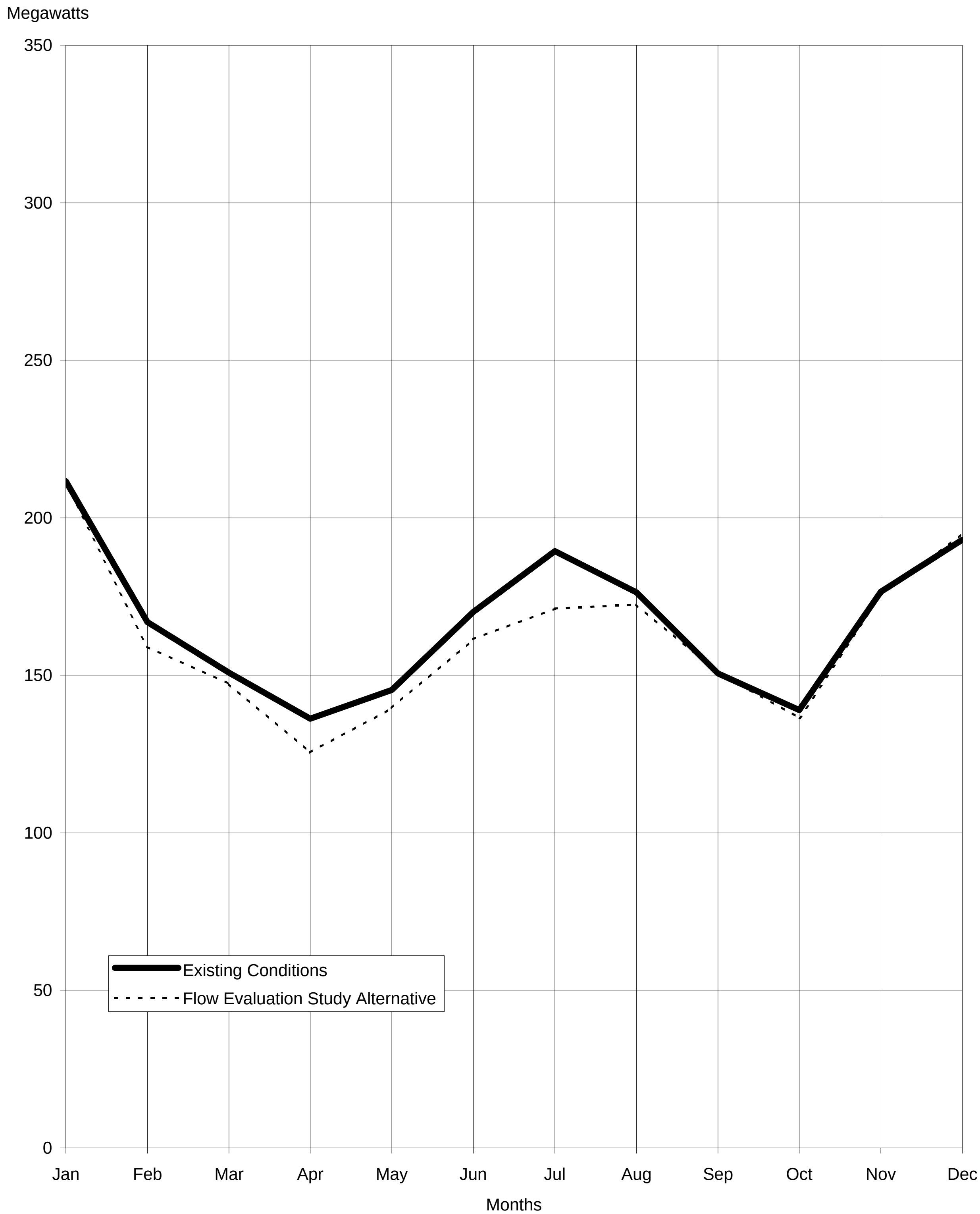

FIGURE F-29

SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE CAPACITY LONG-TERM AVERAGE 1922-1990

RDD-SFO/992640005.XLS(Wpt107.xls)

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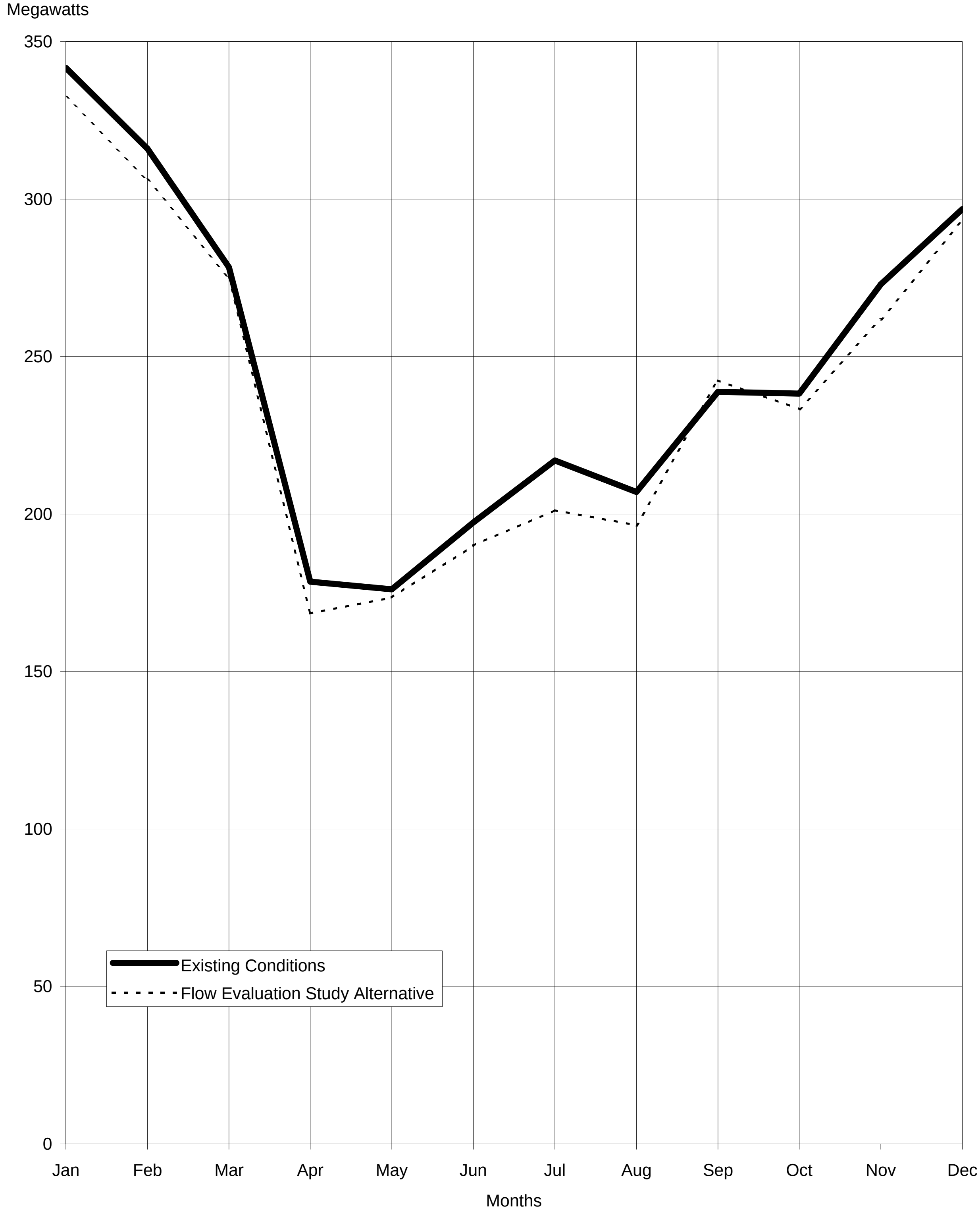

FIGURE F-30
SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE CAPACITY LONG-TERM AVERAGE 1922-1990

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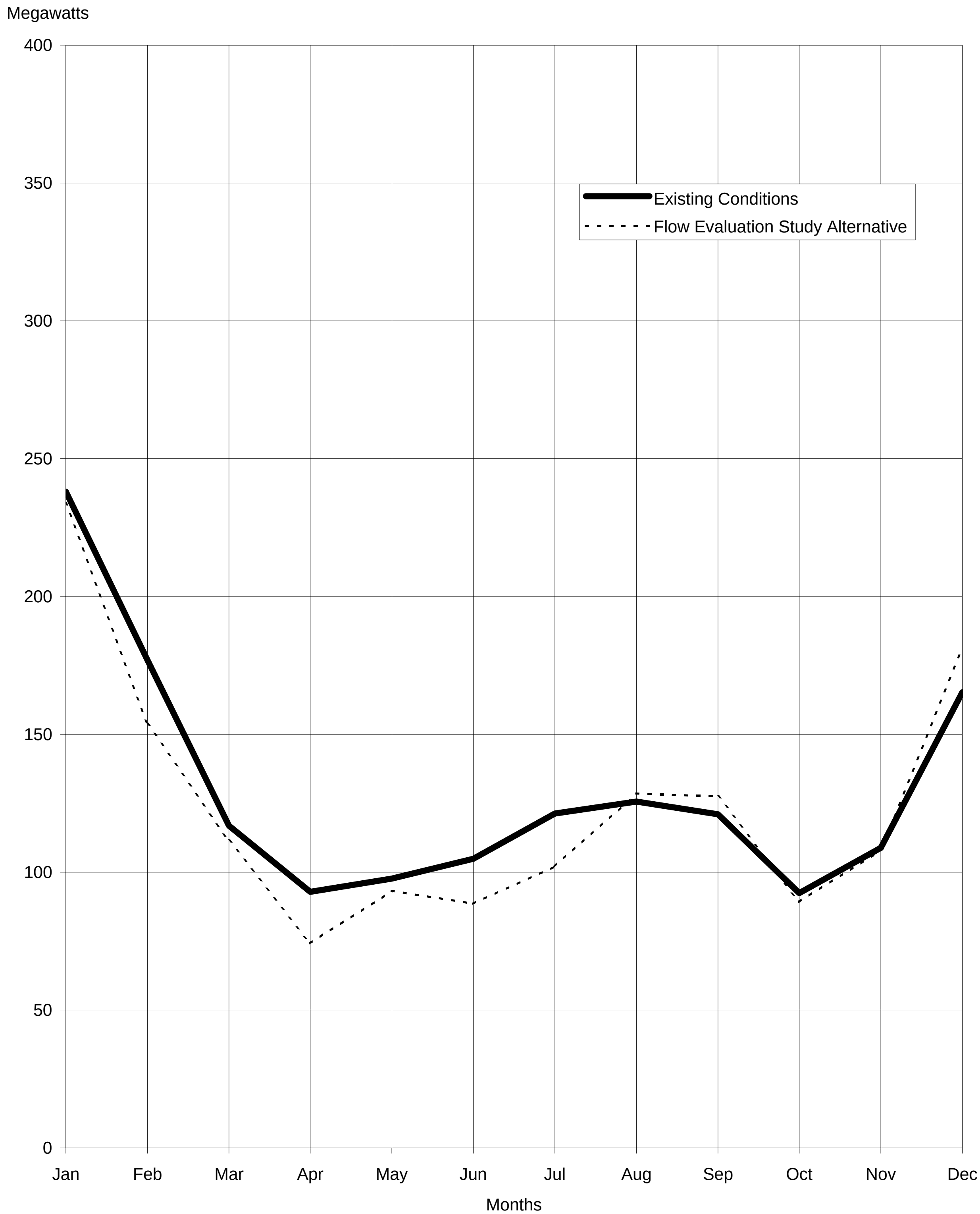

FIGURE F-31
SIMULATED AVERAGE MONTHLY ON-PEAK CVP PROJECT USE CAPACITY DRY PERIOD 1928-1934

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FIGURE F-32
SIMULATED AVERAGE MONTHLY OFF-PEAK CVP PROJECT USE CAPACITY DRY PERIOD 1928-1934

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ATTACHMENT F1

TEIS IMPACTS STUDY
(WESTERN, 1999)

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LETTER OF TRANSMITTAL

TABLE OF CONTENTS

This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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EXECUTIVE SUMMARY

An analysis of impacts associated with proposed changes in the operation of the CVP hydro generation resulting from various alternatives under study in the U.S. Fish & Wildlife Service's Trinity River Mainstem Fishery Restoration EIS/EIR (TEIS) and corresponding impacts on Western's Sierra Nevada Customer Service Region (Western) marketing program was undertaken as part of Western's participation as a cooperating agency in the TEIS process. Impacts associated with each of the TEIS alternatives relative to the No-Action case were developed and evaluated. Changes in the levels of on-peak and off-peak energy available to be marketed by Western, as well as changes in load-carrying capability, were analyzed.

Based on the "Significance Criteria" discussed herein, the maximum flow, percent inflow, and flow study alternatives all exhibited significant negative impacts. The maximum flow alternative, in particular, resulted in significant adverse economic impacts to Western's customers.

The output from the Bureau of Reclamation's project simulation model (PROSIM) indicates that there is significant variation in the long-term net (total production less Project Use) average annual energy production for each of the four alternatives when compared to the No-Action Alternative. Results for on-peak, off-peak, and total net average monthly energy production are shown graphically in **Figures 1 through 3**. **Figures 4 through 6** indicate the change in energy available for sale to Western's customers relative to the No-Action Alternative. As expected, analysis indicates that the amount of CVP energy available for sale is proportional to the amount of water diverted from the Trinity River basin to the Sacramento River. The State Permit Alternative (which has the largest amount of diversion) results in an increase in the energy and capacity with energy available for sale, whereas the Maximum Flow Alternative results in substantial decreases. The Percent Inflow and the Flow Study Alternatives lie between the two extremes, although both result in less energy and capacity available for sale than in the No-Action Alternative.

The change in load-carrying capability (capacity supported with energy net of PU load) of the CVP varies significantly between alternatives and from month to month. This is based on adverse hydrology (90% exceedance) criteria. The load-carrying capability is illustrated in **Figure 9**, and the change from the No-Action Alternative is illustrated in **Figure 10**.

The value of the CVP was developed, as outlined later in this report, and represents how the energy, capacity, and other services provided by it are valued in the marketplace relative to alternative sources of power. The net change in value based on the No-Action Alternative is illustrated in **Figures 11 through 14**. The net effect of the proposed alternatives range from an increase in the value of the CVP generation of approximately $5.9 million in the State Permit Alternative to a decrease of $26.0 million per year under the Maximum Flow Alternative. **Table 8** shows the costs (or benefits) (in 1997 dollars) associated with changes in the value of CVP generation attributable to each alternative allocated to counties and economic regions based on the CVP preference power customer Contract Rate of Deliveries (CRD) in each county and region.

OBJECTIVE

The objective of this study is to determine the change in value of CVP power generation resulting from the various alternatives in CVP operation, as set forth in the TEIS and as further described in **Appendix A**.

METHODOLOGY AND ASSUMPTIONS

Rather than attempting to estimate the total cost of the power supply requirements for the CVP preference power customers under each of the various alternatives studied, the impacts associated with each alternative were viewed from the perspective of the change in available CVP power. That is, the difference in on- and off-peak energy production as well as the difference in monthly generating capability, between the alternatives and the No-Action case was evaluated in order to estimate the impacts associated with each alternative. The basis for valuing the power is discussed below.

The Bureau of Reclamation used the PROSIM model to simulate the monthly water operation of the CVP and State Water Project (SWP) under a "No-Action" scenario and under each of the four alternative operation scenarios. The simulation was carried out for a period from 1922 through 1991. The monthly energy and capacity available from each of the CVP generators and the monthly Project Use load was determined based on these simulations. Energy, capacity and Project Use data was developed monthly for calendar years 1922 through 1991.

For each scenario, CVP energy production and associated generating capacity availability under "average" and "dry" hydrologic conditions was developed for use with the power production cost model (PROSYM) described below. Generation in an "average year" was based on a monthly average of the generation at each CVP powerplant over the 70 water years (i.e., the average January generation at Shasta was the average of the Shasta generation in each of the 70 Januarys, the average February generation was the average of the generation in each of the 70 Februarys, etc.). Average Project Use and available CVP generating capabilities at each powerplant were also calculated utilizing the same process as was used in setting the energy value (i.e., average monthly value over the 70-year period).

To determine the dry year generation and capacities, the energy generated in each month (over the 70 years) was sorted into ascending order. A month and year was then selected such that the generation in that month would be exceeded 90% of the time. This was done by month such that the generation in the dry year January would be exceeded in 90% of the Januarys, the generation in the dry year February would be exceeded in 90% of the Februarys, etc. The capacity available from each powerplant and the required Project Use were defined to be the capacity and Project Use as reported by PROSIM for each of the 90% exceedence months.

Tables 1 through 5 provide the average and dry year data from PROSIM utilized in the modeling of the No-Action case and each of the four alternatives.

In order to calculate the impact associated with each of the alternatives, it was necessary to dispatch the monthly available capacity and energy so as to determine hourly generation data. Hourly data is required to properly value energy by the time of day it is produced. Specifically, energy generated during on-peak (high load) periods has a higher value than power produced in off-peak (low load) periods. In this study, on-peak is defined as 7 a.m. to 10 p.m. Monday through Saturday, excluding holidays.

In addition, hourly data is required to determine the actual load-carrying capability of the hydro system. The monthly capacity, as reported by the PROSIM model, is a "head dependent" capacity based on the average amount of storage in each reservoir for a month. In the determination of the load-carrying capability of the system, the "head-dependent" capacity represents a maximum level of instantaneous output. However, the amount of energy generated at each powerplant (i.e., the amount of water released through each powerplant) must also be taken into account, as well as the shape of the load curve into which the hydro resource is dispatched and certain flow constraints and downstream regulation requirements. The load-carrying capability is the maximum level of sustainable energy production within a given load shape that results in minimizing the acquisition of additional capacity. Load-carrying capability may also be referred to as "capacity supported with energy."

In order to develop the hourly generation data, load curves must be developed for the Project Use load and the customer load. The preference customer load used in the analysis was the total 1994 Northern California Preference Customer load, as supplied by Western. The Project Use load

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curve was developed by reshaping the historical hourly 1995 Project Use load curve to meet the monthly on- and off-peak Project Use load estimates from the PROSIM model.

The monthly available capacity and generation at each CVP powerplant was then dispatched into a combination of the customer load and Project Use load using the PROSYM production cost model in order to create an hourly dispatch.

Currently, Western operates under a contract with PG&E referred to as 2948A. This contract provides for the integrated operation of the CVP generation with the PG&E system. The contract expires the end of 2004 and is not expected to be renewed. While the CVP has historically been operated, to the extent possible, to meet the requirements of this contract and to receive the benefits thereof, it is not expected to continue to be operated in a similar manner after contract termination in 2004. For the purposes of this study, it has been assumed that the CVP will, within the constraints (water and electrical) of the CVP, be operated to maximize its use in meeting the load requirements of the CVP preference power customers and Project Use loads.

In addition to changes resulting from the termination of 2948A, the recent restructuring of the electric utility industry will also play a significant roll in how the CVP electrical facilities are operated in the future. Industry restructuring will allow entities (including CVP preference power customers), who, at one time, are only able to access power supply from PG&E and Western with the ability to access many other energy suppliers and obtain the necessary transmission service. This universal market access has allowed many, if not all, of the CVP power customers to participate in power markets that were only available to utility customers. The results noted herein are based on modeling assumptions that all of the CVP preference power customers have equal market access.

Hourly output from the PROSYM model was used to determine the levels of on-peak and off-peak energy production from the CVP which is available for sale (i.e., net of Project Use) assuming average hydrologic conditions. The value of monthly capacity available for sale was determined based on the monthly maximum level of the net load-carrying capability (capacity supported with energy after providing for Project Use) available under adverse hydrologic conditions. In addition, the monthly capacity available without energy was also considered based on its potential value for providing reserves or other ancillary services.

DESCRIPTION OF PROSYM MODEL

The PROSYM model is an electric production cost model which performs economic dispatch of an electric system to optimize the use of the generation resources in meeting a given load curve.

PROSYM is a simulation program that models chronological electric production and is designed to be used for electric utility operating and planning studies. The program is designed to accommodate detailed hour-by-hour investigation of the operations of electric generating resources. This hour-by-hour investigation enables the simulation to closely reflect actual electric utility operation and is especially useful in studying operations at hydroelectric facilities. The program provides for upstream generation and water to be dispatched in a peaking mode, using regulating reservoirs to regulate downstream flows, thus maintaining prescribed river flows.

The PROSYM program is designed to generally dispatch hydroelectric units before any other resource type is used (e.g., fossil fuel, nuclear, etc.). This is done in recognition of hydro's very low operating costs, limited energy supply, and the way its peaking ability is generally utilized within the electric utility industry. This is accomplished through coordinated operation of the hydroelectric powerplants to levelize the residual hourly load shape that thermal and purchased resources would serve. This type of operation serves to maximize the value of the hydro resources and tends to minimize the need for additional capacity acquisition or construction.

A hydroelectric powerplant‘s minimum capacity will normally be controlled by the minimum water flow required though the powerplant. For generating units with regulating reservoirs, the size of the regulating reservoir is also modeled. In addition, the amount of water in the regulating reservoir at the beginning of each week can be specified. Given these constraints, the model will then utilize upstream hydroelectric generation to maximize its capacity in meeting load, to the extent there is storage available in the regulating reservoir and downstream releases can be maintained at their specified levels.

VALUE OF POWER

Since the analysis of the TEIS is centered on the 2020 time frame, one may expect that conditions will be representative of a general long-term balance in electrical resources and loads and that any changes in the operation of the CVP generation will be reflected in the operation of the marginal system resource. That is, an increase or decrease in the output of a CVP generator, with its relatively low operating cost, will be offset by an equal and opposite change in the output of the resource then in operation having the highest operating cost. While conditions used in the analysis are generally reflective of future conditions, the price levels used in this analysis are assumed to be expressed at 1997 levels. Due to the uncertainty involved, the level of technology involved in future generation resources, as well as their efficiencies, were assumed to remain at current 1999 levels.

Separation of capacity prices and energy prices have been eliminated within the current deregulated industry structure within California. Given that the current market structure has only been in place for about 14 months, it is difficult to clearly determine the price impact of capacity shortages on an ongoing basis. Therefore, for study purposes, we have assumed that any decrease in CVP load-carrying capacity will ultimately result in construction of new generating capacity.

Output from the CVP is predominantly peaking in nature, since the system is energy constrained during adverse water conditions. For this reason and since long-term load to resource balance was assumed, capacity from the CVP was valued based on the assumption that any change in the CVP's capacity would be offset by a corresponding change in the level of construction of combined-cycle combustion turbines. As a result of the industry restructuring, it was assumed that future capacity additions would be made by private generation companies and that very little public financing would be involved in future capacity additions. Based on these assumptions, the value of capacity was estimated to be $8.99 per kW-month (1997 dollars). **Table 6** provides details and assumptions regarding how the capacity value was estimated.

Capacity without energy (available capacity less capacity supported with energy) was also valued based on its ability to provide certain ancillary services (primarily spinning and installed reserves). The pricing history for these ancillary services in the new market environment has been very volatile, leading to substantial restructuring of these markets. Therefore, for the purposes of this study, we chose to value ancillary service capacity at 20% of the value used for the capacity supported with energy.

The value of energy produced by the CVP was estimated based on a marginal heat rate approach. To the extent the CVP output is increased or decreased in a particular time period, an opposite change will occur in the output of the marginal unit which is operating at that same time. The marginal heat rates for Northern and Southern California were reviewed. Since the Northern and Southern California prices tend to set the "Market Clearing Price," it was assumed that imports from either the Pacific Northwest or Desert Southwest would tend to be priced at or near this market clearing price. Monthly time-of-day marginal production costs for these areas were derived based on regional gas prices and adjusted to reflect transmission losses for delivery to Northern California and assumes a 1.5% transaction adder by the producer. This resulted in the alternative energy source varying monthly and by time of day (on-peak vs. off-peak). The monthly on- and off-peak values (1997 dollars) for energy used in this analysis are noted in **Table 7**, along with the associated assumptions for regional gas prices and marginal heat rates.

RESULTS

The output from PROSIM indicates that there is significant variation in the long-term net average energy production for each of the four alternatives when compared to the No-Action Alternative. Results for on-peak, off-peak, and total net average energy production are shown graphically in **Figures 1 through 3**. **Figures 4 through 6** indicate the change in their values relative to the No-Action Alternative. As expected, analysis indicates that the amount of CVP energy available for sale is proportional to the amount of water diverted from the Trinity River to the Sacramento River. The State Permit Alternative (which has the largest amount of diversion) results in an increase in the energy and capacity with energy available for sale, whereas the Maximum Flow Alternative (no diversion) results in substantial decreases. The Percent Inflow and Flow Study Alternatives lie between the two extremes, although both result in less energy and capacity available for sale than in the No-Action Alternative.

The change in load-carrying capability of the CVP varies significantly between alternatives and from month to month. This is based on adverse hydrology (90% exceedance) criteria. The load-carrying capability is illustrated in **Figure 9**, and the change from the No-Action Alternative is illustrated in **Figure 10**. This figure shows the effect of the alternatives on the dry year capacity with energy available for sale. During the critical summer months, it ranges from an increase of approximately 110 MW in the State Permit Alternative to a decrease of approximately 200 MW in the Maximum Flow Alternative. This can be compared to the Western System Coordinating Council's (WSCC), the regional forum for promoting electric service reliability, forecast (as of January 1, 1996) of 2,520 MW of planned net generation increases in WSCC's California-Southern Nevada Region from 1996 to 2005. The 200 MW represents almost 8% of this planned increase.

The net change in value of the CVP generation, based on the No-Action Alternative is illustrated in **Figures 11 through 14**. The net effect of the proposed alternatives range from an increase in CVP value of approximately $5.9 million in the State Permit Alternative to a decrease of $26.0 million per year under the Maximum Flow Alternative.

Table 8 shows the costs (or benefits) attributable to each alternative allocated to counties based on the CVP preference customer CRD in each county.

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These counties have been aggregated by economic region for use in the TEIS regional economics study.

The monthly values of energy during on- and off-peak periods, capacity, and Project Use for each alternative are tabulated in **Appendix B**. Also included is a tabulation of monthly changes from the No-Action Alternative and the associated value of changes in capacity and energy.

SIGNIFICANCE CRITERIA

The need to demonstrate the significance of impacts related to power supply on CVP customers has been addressed in this report. For the purpose of measuring whether or not a particular alternative would result in significant negative impacts on CVP customers, the following criteria was developed.

An action resulting in any one of the following impacts would be considered "significant."

- A reduction in the dry year firm load-carrying capacity (CVP hydroelectric capacity supported with CVP hydroelectric energy available for sale to preference customers of 50 MW or greater occurring during January, February, March, June, July, August, September, or December.
- A reduction of 5% or more in the annual energy available for sale to preference customers during an average year.
- A reduction of 5% or more in the energy available for sale to preference customers during any month of an average year.
- Any decrease in the value of CVP power resulting in an increase in a preference customer's average power cost by $0.50 per MWh.

In addition to the "significant" cost of power impacts noted in the following section, the proposed alternatives also result in the following "significant" negative impacts.

Alternative	CVP Capacity with Energy	CVP Average Energy
	Number of months in which there is a significant negative impact	
State Permit	0	0
Maximum Flow	5	9
Percent Inflow	1	5
Flow Study	1	7

EFFECT ON WESTERN CUSTOMERS' COST OF POWER

The analysis conducted for the Trinity EIS estimates the value of the CVP electric resources. To the extent the Project output available for sale increases

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or decreases, it will be the market that determines the value of the incremental change. Regardless of changes in Project output, Western's revenue requirements remain essentially unchanged and, therefore, Western's per unit, cost-based rates will only change to reflect the net change in Project output. To the extent that Western's rates are at or below comparable market rates, Western's customers may be expected to continue to purchase CVP power. However, to the extent CVP production is changed, a Western customer will experience a similar change in its share of CVP power, necessitating a commensurate adjustment in the other resources comprising its power supply. Presumably, in the long run, this change will be valued at prices determined in the market.

To the extent that CVP energy available for sale is decreased, Western's rates will increase and the supply of CVP energy to each customer will decrease, requiring replacement by the customer at market rates. The effect of this two-part impact (increase in Western rates and decrease in supply) on the customer may be estimated as follows. The total revenue requirement associated with each customer's share of CVP power will remain the same (note that the per unit cost will increase, but total billing should not change). However, the cost associated with the balance of the customer's power supply will increase based on market prices. Assume that a customer receives 14% of its requirement from Western, with the remaining 86% being supplied from other resources. Should the portion supplied by Western decrease to 12%, the customer will now have a resource mix with 86% priced as above, 2% priced at market, and 12% priced at a higher CVP rate (i.e., the same total CVP cost divided by less energy). This will result in an increase in the customer's average cost of power equal to the cost of replacement power times the percentage decrease in CVP power used to meet the customer's load. For example, if the CVP supply were to be reduced from 14% to 12% and the cost of replacement power was $25 per MWh, then the net change in the customer's cost of power would be 2% times 25 mills, or 0.5 mills (.02 × 25).

Based on load forecasts for the year 2004 utilized in Western's 2004 Marketing EIS, the net CVP energy available for sale in the No-Action Alternative is approximately 14% of the total energy requirements for Western's customers. Thus, by assuming that 14% of an average Western customer's load is served with CVP energy, the impact of implementing any of the TEIS alternatives may be estimated for the "average" Western customer. In addition to estimating the impact on the "average" customer, a similar analysis was conducted for a customer who received 85% of its energy requirements from Western. Currently there are a number of customers who receive substantially all of their energy requirements from Western. By estimating the effect on a customer assuming the 85% level, one can estimate the effect the alternatives will have on this group of customers.

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The cost of replacement power is reflected by the change in project value, as summarized in **Figure 14** and **Table A** below. The net effect on the "average" customer and a "high allocation" customer is also summarized in **Table A** below.

Table A
TEIS RESULTS

IMPACT ON "AVERAGE" WESTERN CUSTOMER

Alternative	Change in CVP Value $1,000	GWh for Sale	Change in CVP Energy Available for Sale GWh	% change in CVP Available Energy	Average Replacement Rate (1) $/MWh	% CVP Used in Customer Load	Change in Customer's Total Cost of Power $/MWh
No Action	N/A	3,779	N/A	N/A		14.00%	
1–State Permit	$ 5,937	3,992	212.76	5.6%	$27.91	14.79	($0.22)
2–Maximum Flow	(26,036)	2,857	(921.70)	-24.4%	28.25	10.59	0.96
3–Percent Inflow	(7,023)	3,625	(154.36)	-4.1	45.50	13.43	0.26
4–Flow Study	(5,564)	3,525	(253.57)	-6.7	21.94	13.06	0.21

IMPACT ON "HIGH ALLOCATION" WESTERN CUSTOMER

Alternative	Change in CVP Value $1,000	GWh for Sale	Change in CVP Energy Available for Sale GWh	% change in CVP Available Energy	Average Replacement Rate (1) $/MWh	% CVP Used in Customer Load	Change in Customer's Total Cost of Power $/MWh
No Action	N/A	3,779	N/A	N/A		85.00%	
1–State Permit	$ 5,937	3,992	212.76	5.6%	$27.91	89.79	($1.34)
2–Maximum Flow	(26,036)	2,857	(921.70)	-24.4%	28.25	64.27	5.86
3–Percent Inflow	(7,023)	3,625	(154.36)	-4.1	45.50	81.53	1.58
4–Flow Study	(5,564)	3,525	(253.57)	-6.7	21.94	79.30	1.25

(1) Represents the purchase of energy comparable to that lost or gained at market rates.

To the extent that the customer's cost of power is not increased it may be said that the alternative is not significant relative to the No-Action case. The relative small increase in power cost for the "average" Western customer, associated with the Percent Inflow Alternative, is not considered to be significant given the gross assumptions contained in this study work and that supporting it. However, the $0.33 per MWh and $0.98 per MWh increases noted for the Flow Study and the Maximum Flow Alternatives are considered to result in a significant negative impact to Western's preference power customers. The effects of these Alternatives is further illustrated when a customer receiving the majority of its energy requirements from Western is considered. For example, the Maximum Flow Alternative could result in almost a $5.86 per MWh increase in the customer's overall cost of energy. Such a change could be devastating to the CVP customers served by Western.

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TEIS MAIN ALTERNATIVES

NO–ACTION ALTERNATIVE (2020 LEVEL OF DEVELOPMENT)

- Compliance with D95-06.
- Provide Level 2 Refuge Supplies with existing limitations to Grassland RCD and Mendota WMA.
- Instream Trinity River flows = 340,000 ac-ft.

STATE PERMIT ALTERNATIVE (STATE NO ACTION)

- Annual instream flow releases reduced to 120,500 ac-ft.
- Habitat restoration projects not constructed or maintained.

MAXIMUM FLOW ALTERNATIVE

- Annual flow releases would vary by water year type:

  Extremely Wet .... 2,146,441 ac-ft
  Wet .... 1,505,390 ac-ft
  Normal .... 1,203,159 ac-ft
  Dry .... 886,347 ac-ft
  Critically Dry .... 462,231 ac-ft

- Peak flow of up to 30,000 cfs would occur in extremely wet years.
- No mechanical construction of restoration projects.
- Habitat maintained through flow releases.
- Trinity Dam would be modified.

PERCENT INFLOW ALTERNATIVE

- Annual flow releases are proportional to 40% of the average of the previous week's recorded Trinity Lake inflow. Historical averages are:

  Extremely Wet .... 978,464 ac-ft
  Wet .... 655,495 ac-ft
  Normal .... 443,419 ac-ft
  Dry .... 324,587 ac-ft
  Critically Dry .... 165,161 ac-ft

- Peak releases up to 11,000 cfs in extremely wet years.
- Habitat restoration through mechanical construction of 39 channel restoration projects.
- Habitat maintained through flow releases.

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FLOW STUDY ALTERNATIVE

- Annual flow releases would vary by water year type:

  Extremely Wet .... 815,228 ac-ft
  Wet .... 701,020 ac-ft
  Normal .... 635,710 ac-ft
  Dry .... 452,624 ac-ft
  Critically Dry .... 368,621 ac-ft

- Peak releases from 6,000 to 14,000 cfs in extremely wet years.
- Habitat restoration through mechanical construction of 39 channel restoration projects.
- Habitat maintained through flow releases.
- Trinity Dam may need to be modified.

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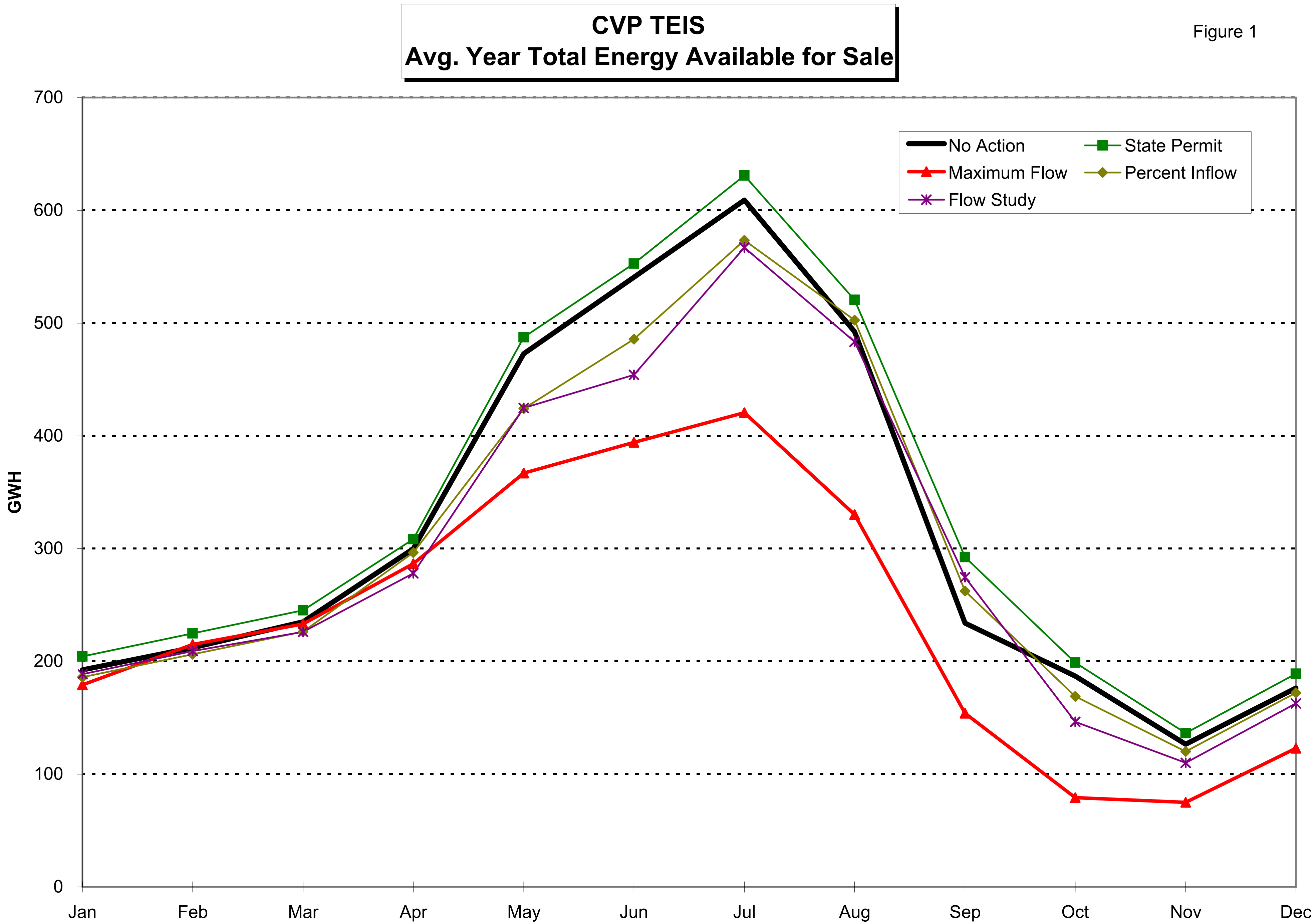
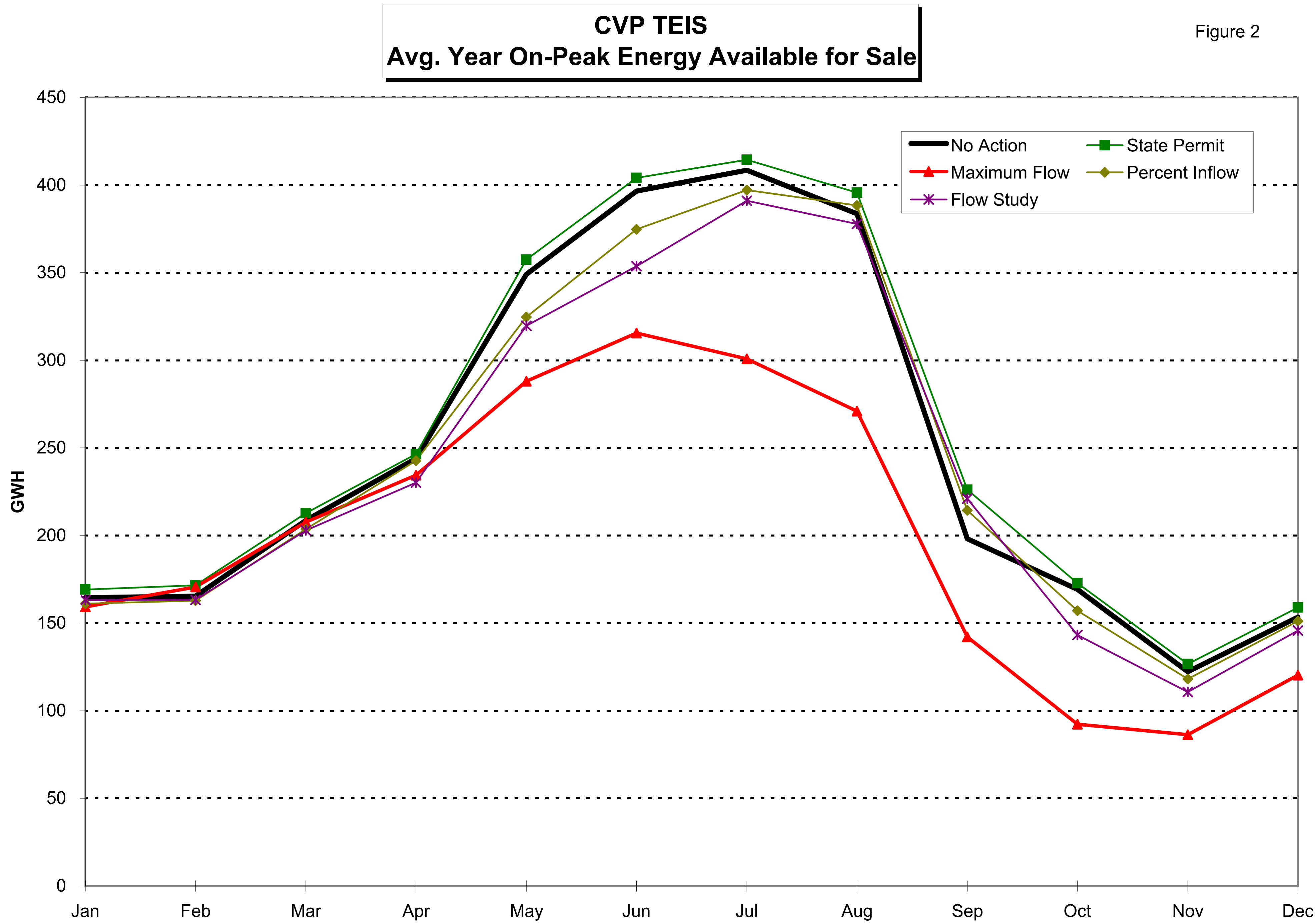
Figure 1



CVP TEIS
Avg. Year Total Energy Available for Sale
No Action
State Permit
Maximum Flow
Percent Inflow
Flow Study
GWH
700
600
500
400
300
200
100
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

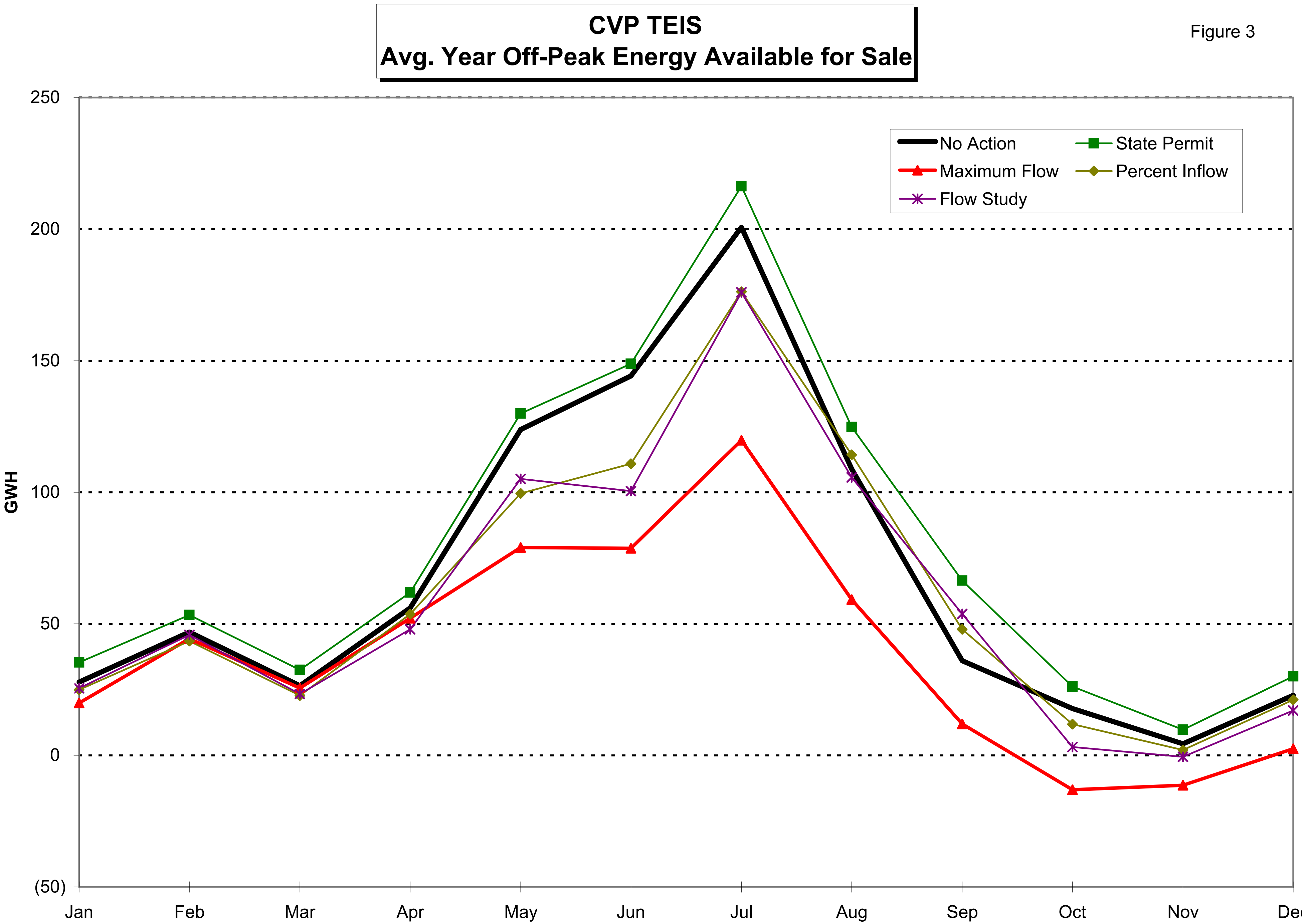
Figure 2



10/15/99

TEIS Impacts Study (Values Only).XLS

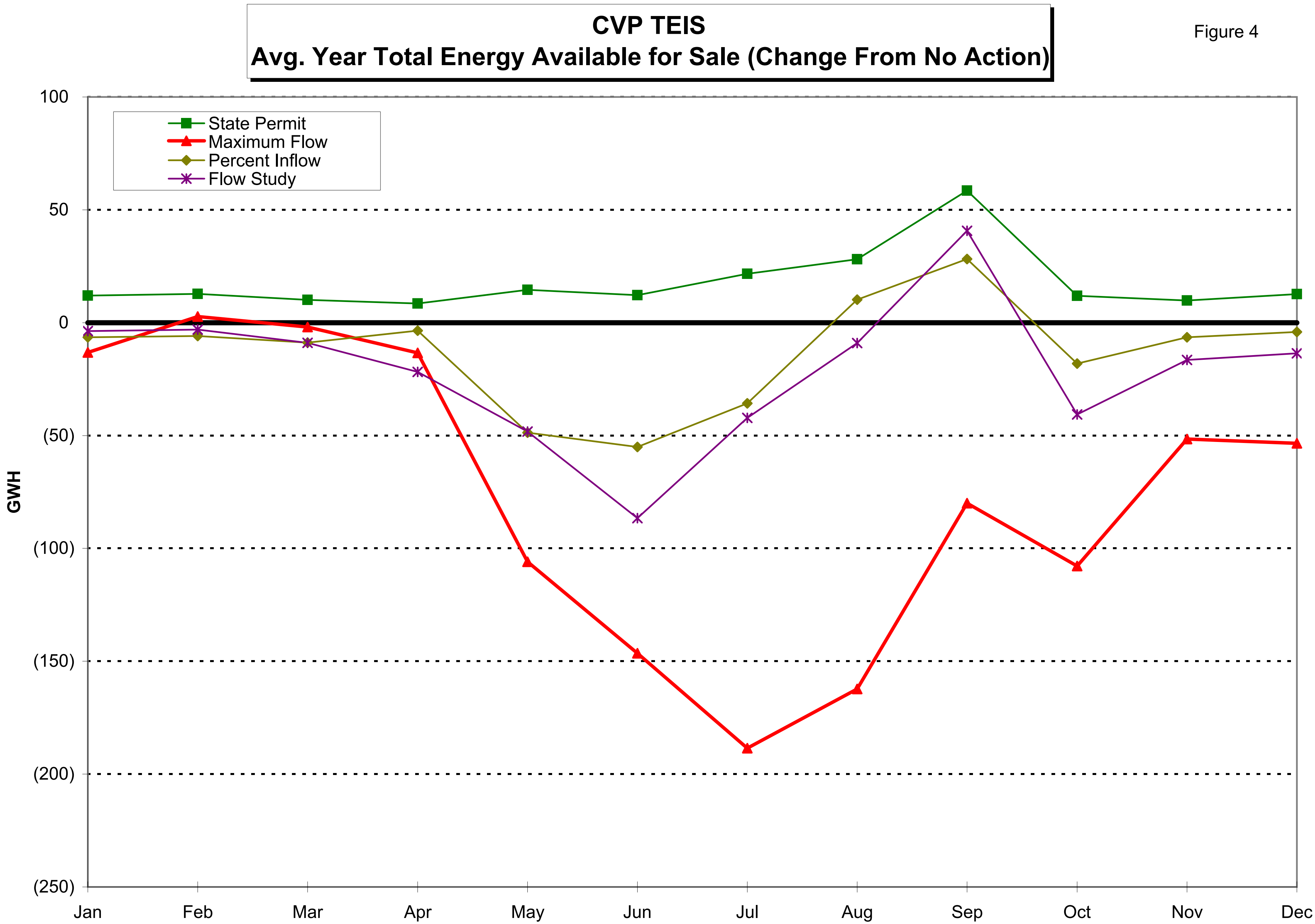
Figure 3



10/15/99

TEIS Impacts Study (Values Only).XLS

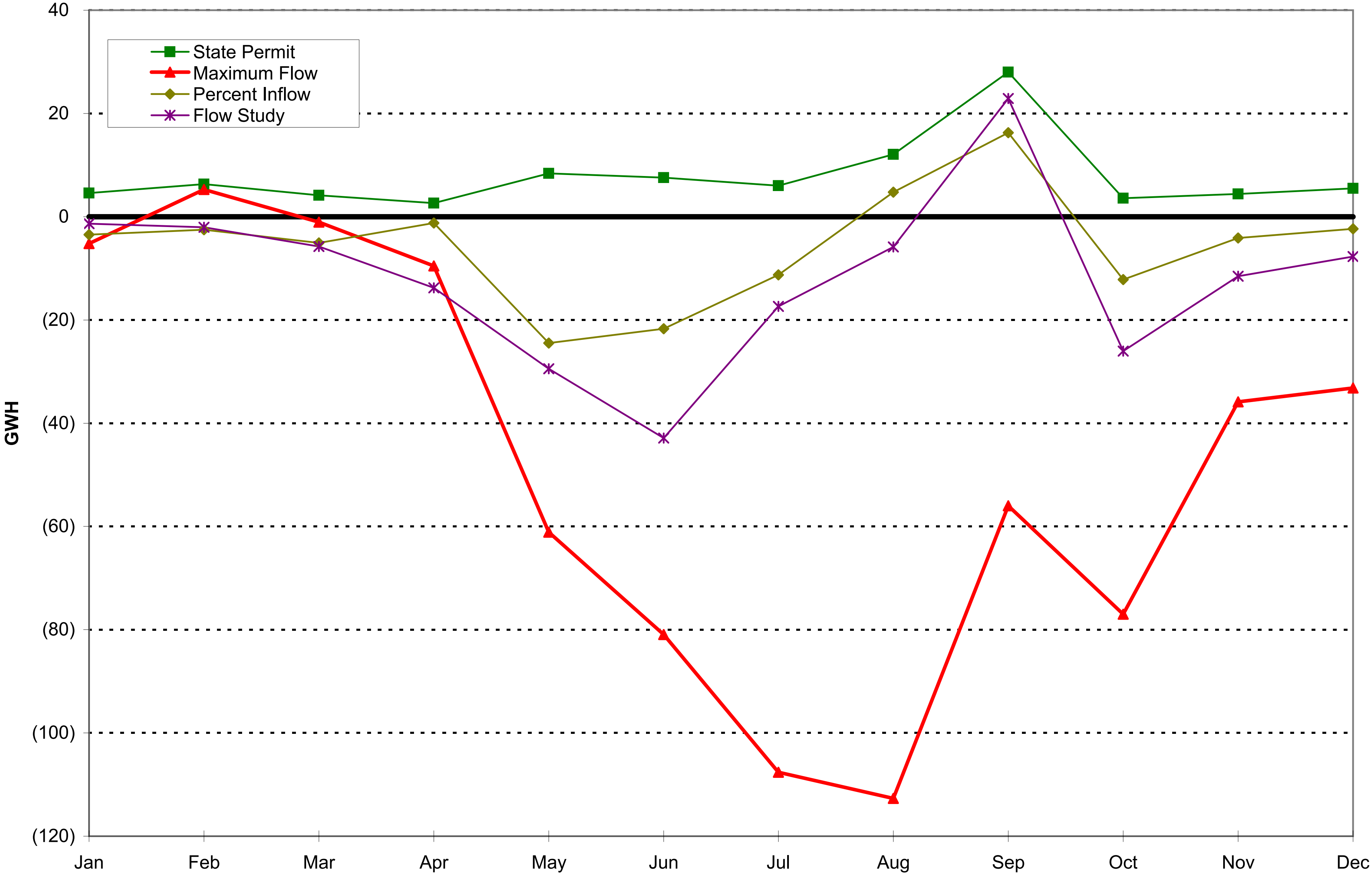
Figure 4

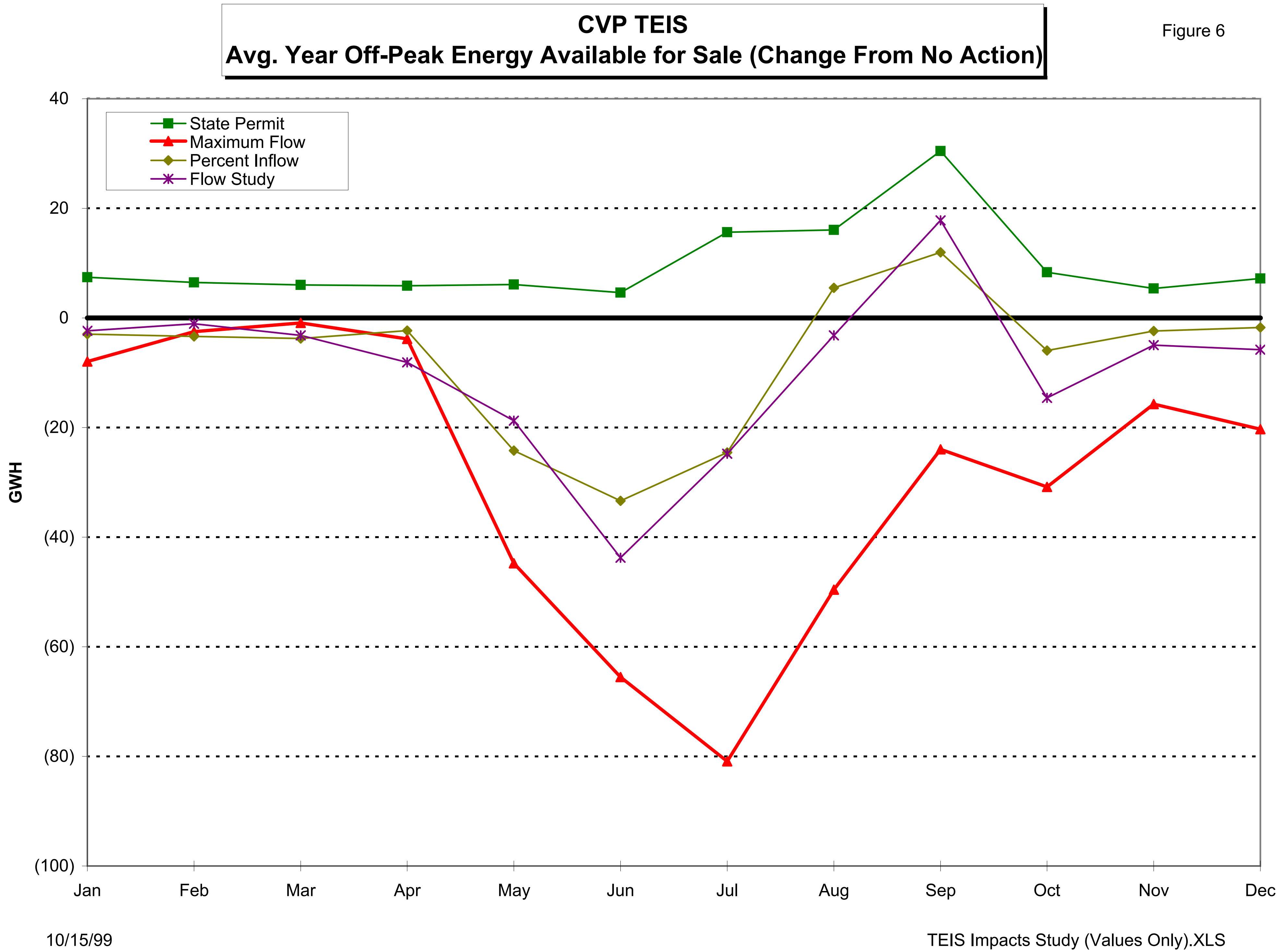


10/15/99

TEIS Impacts Study (Values Only).XLS

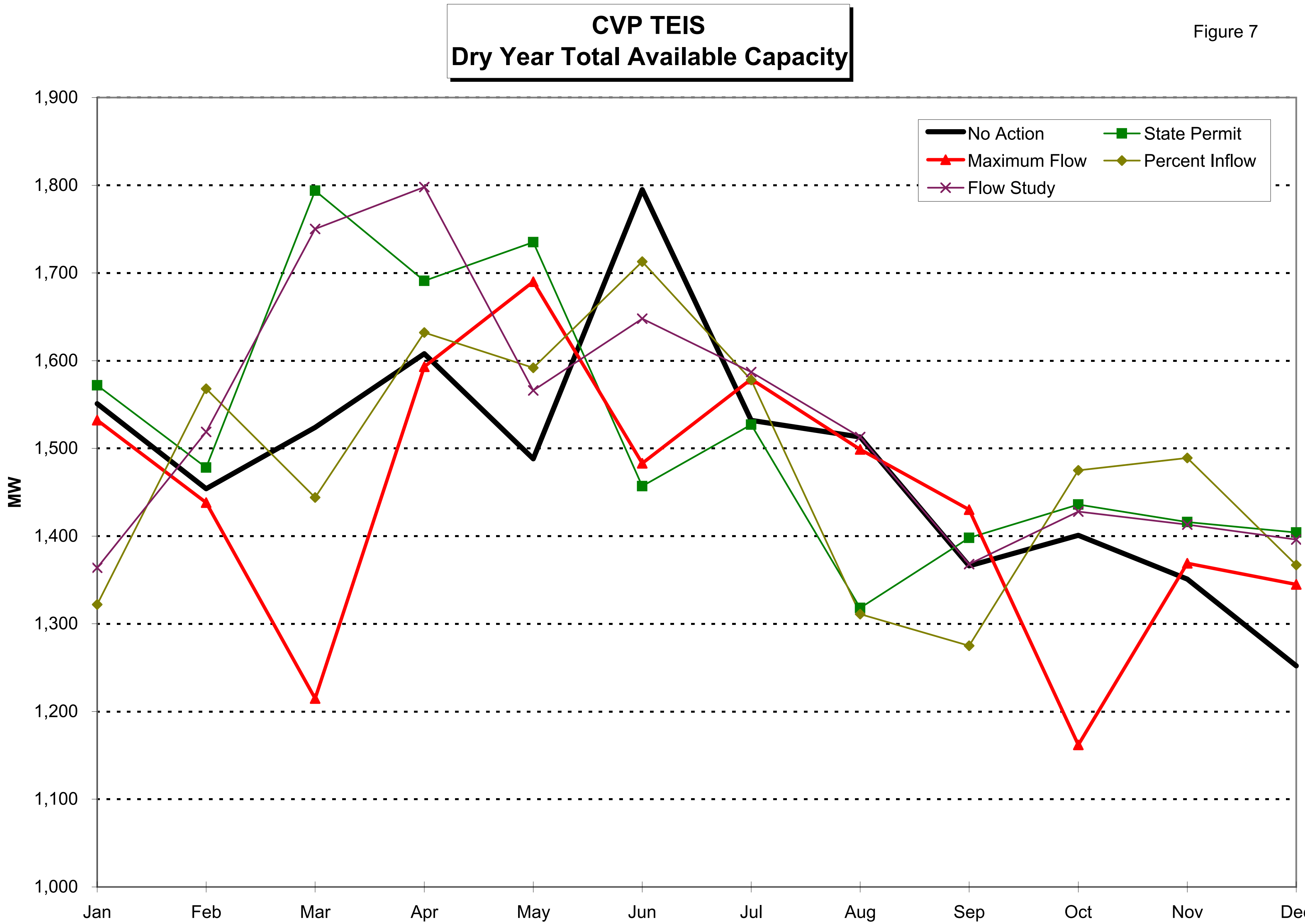
CVP TEIS
Avg. Year On-Peak Energy Available for Sale (Change From No Action)





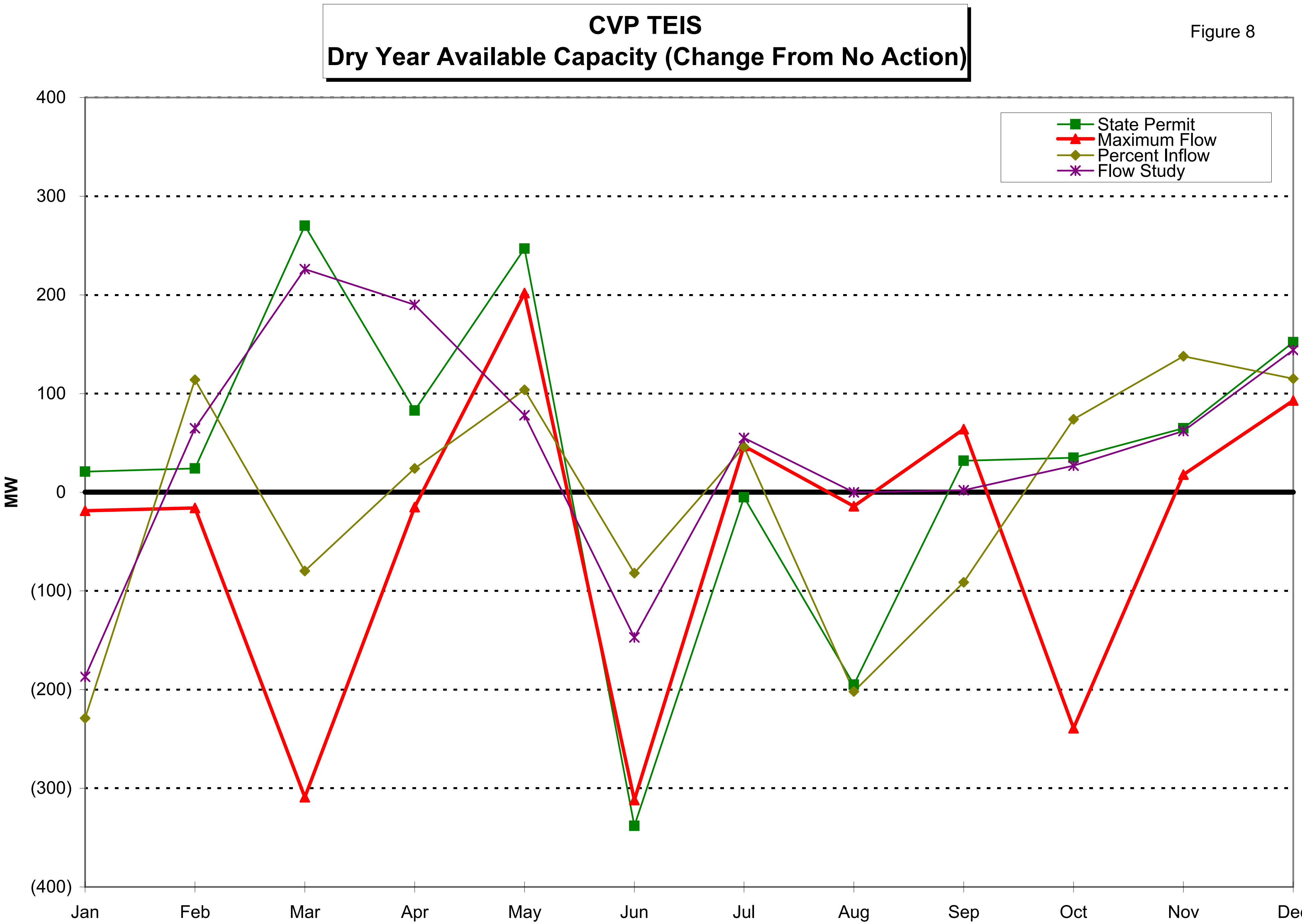
CVP TEIS
Avg. Year Off-Peak Energy Available for Sale (Change From No Action)
Figure 6
State Permit
Maximum Flow
Percent Inflow
Flow Study
GWH
40
20
0
(20)
(40)
(60)
(80)
(100)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
10/15/99
TEIS Impacts Study (Values Only).XLS

Figure 7



10/15/99

TEIS Impacts Study (Values Only).XLS



10/15/99

TEIS Impacts Study (Values Only).XLS

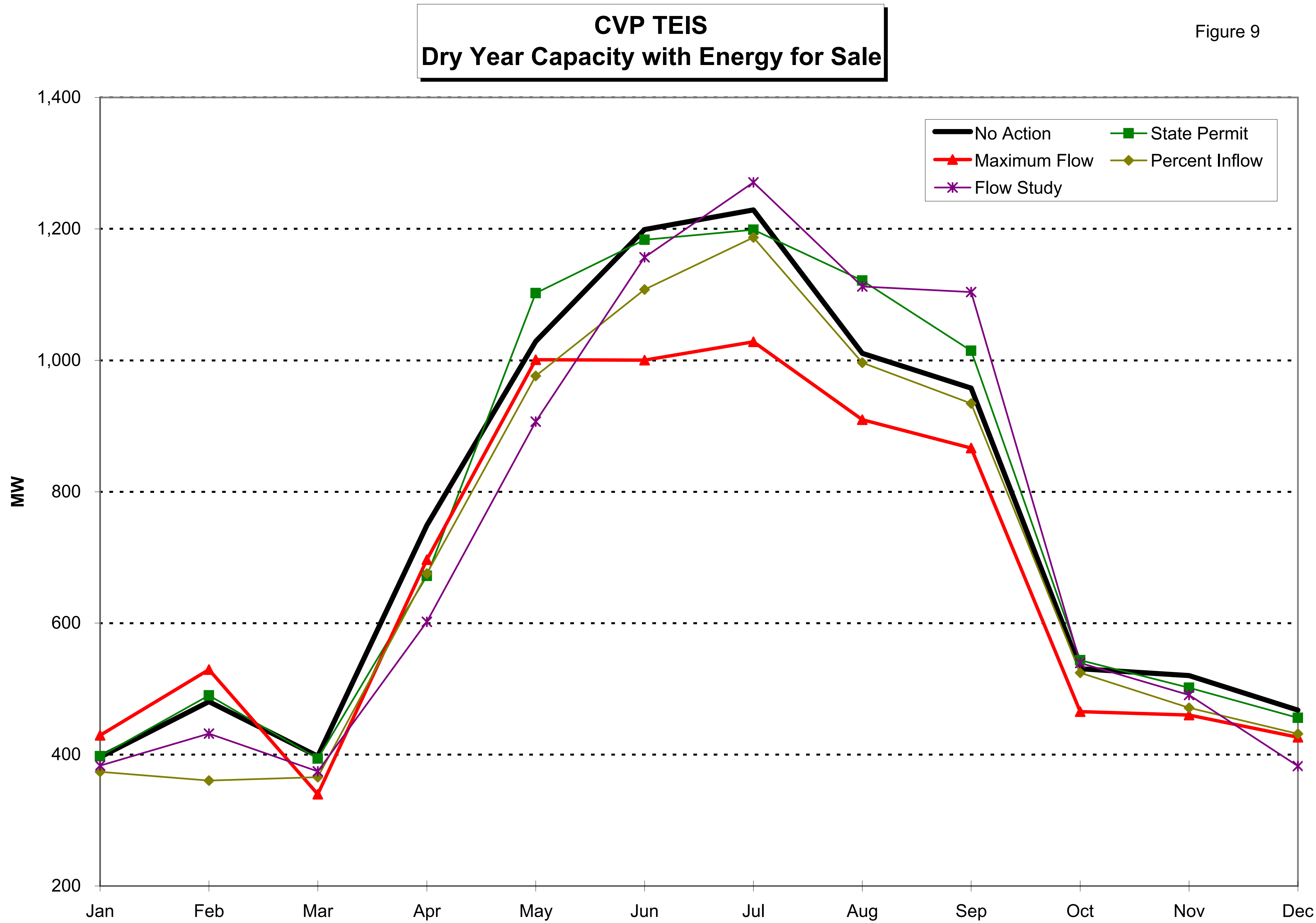
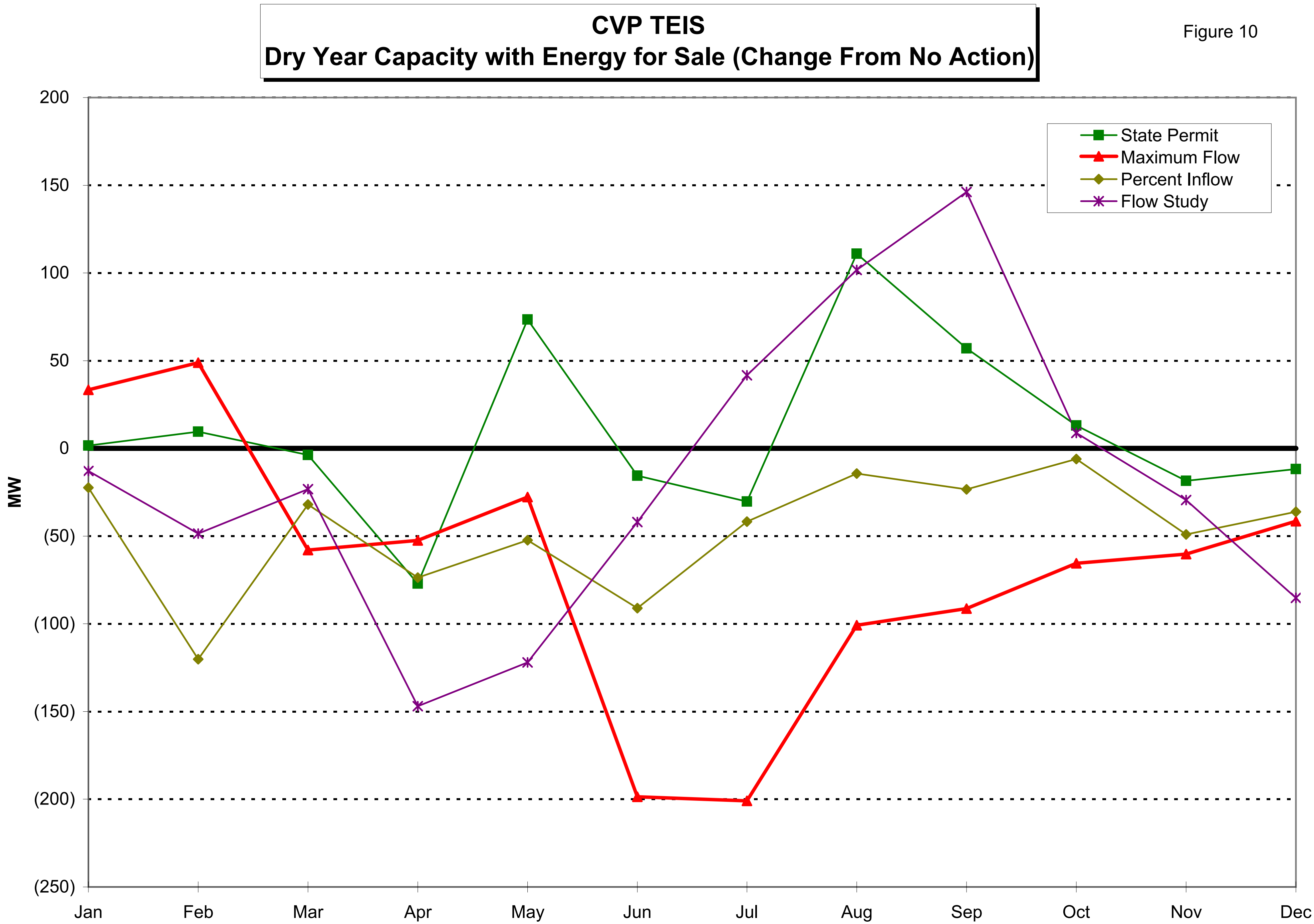

CVP TEIS
Dry Year Capacity with Energy for Sale
1,400
1,200
1,000
800
600
400
200
MW
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
No Action
State Permit
Maximum Flow
Percent Inflow
Flow Study

Figure 10



CVP TEIS
Dry Year Capacity with Energy for Sale (Change From No Action)
State Permit
Maximum Flow
Percent Inflow
Flow Study
MW
200
150
100
50
0
(50)
(100)
(150)
(200)
(250)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Figure 11

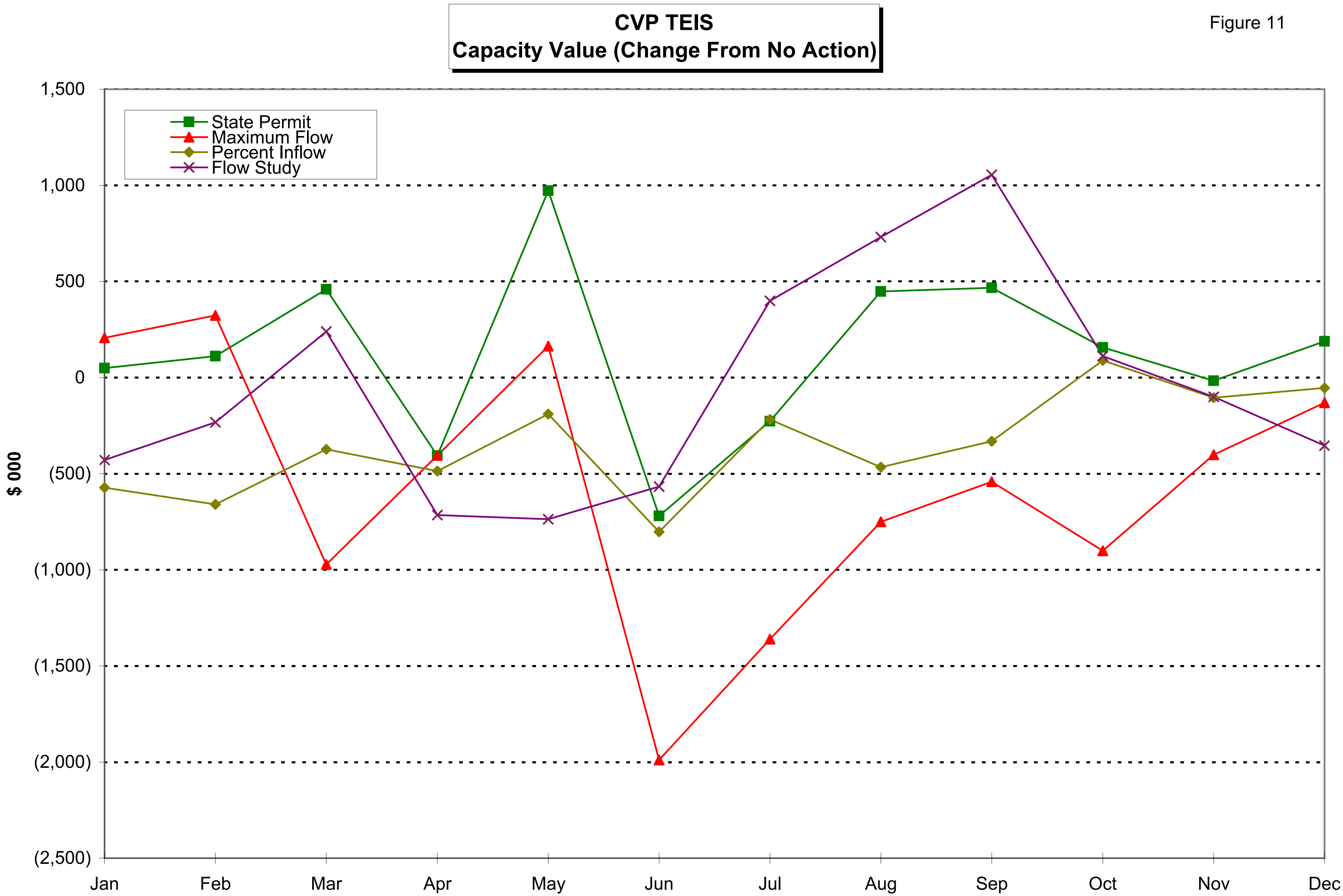

CVP TEIS
Capacity Value (Change From No Action)
State Permit
Maximum Flow
Percent Inflow
Flow Study
$ 000
1,500
1,000
500
0
(500)
(1,000)
(1,500)
(2,000)
(2,500)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Figure 12

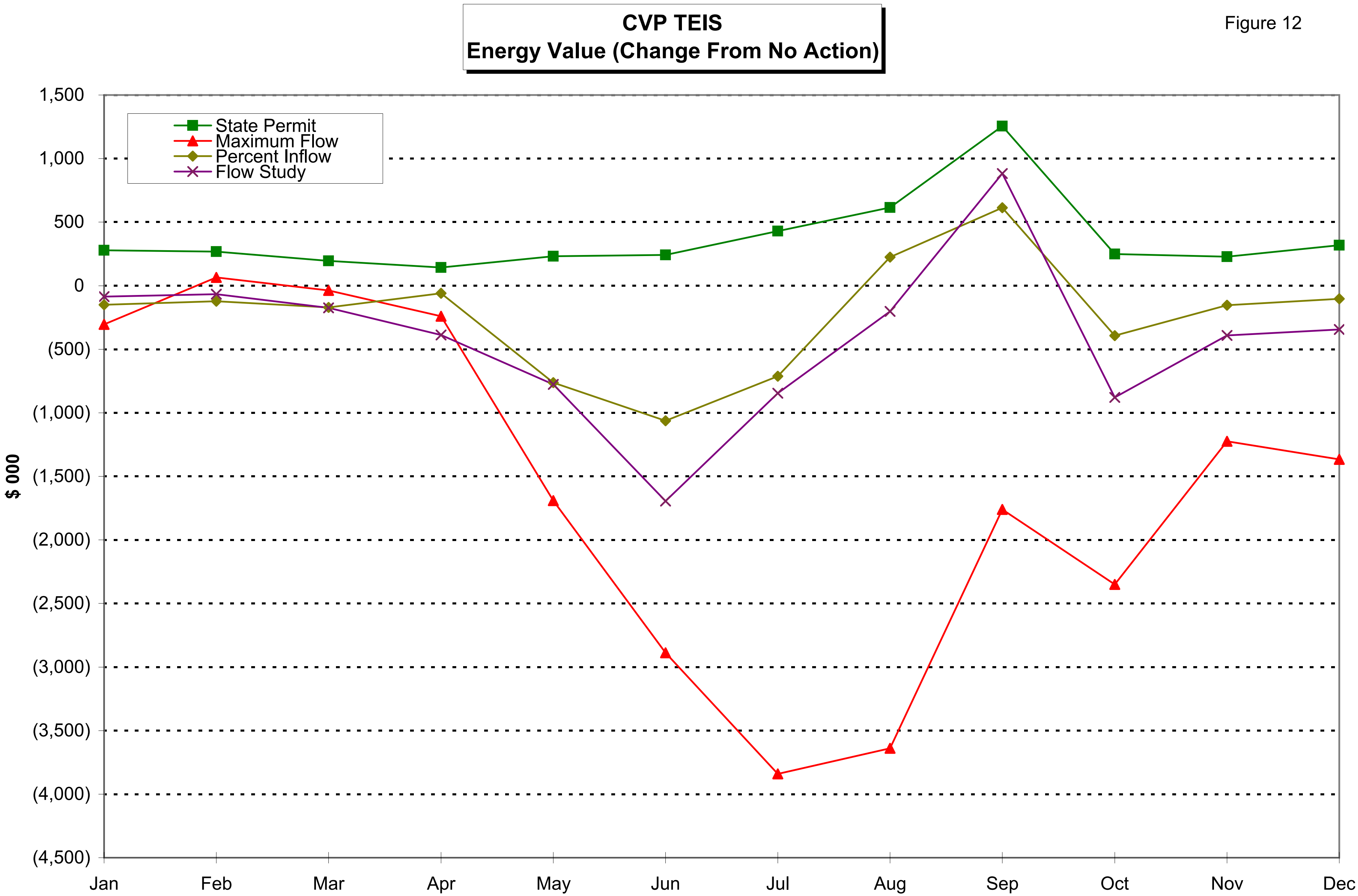
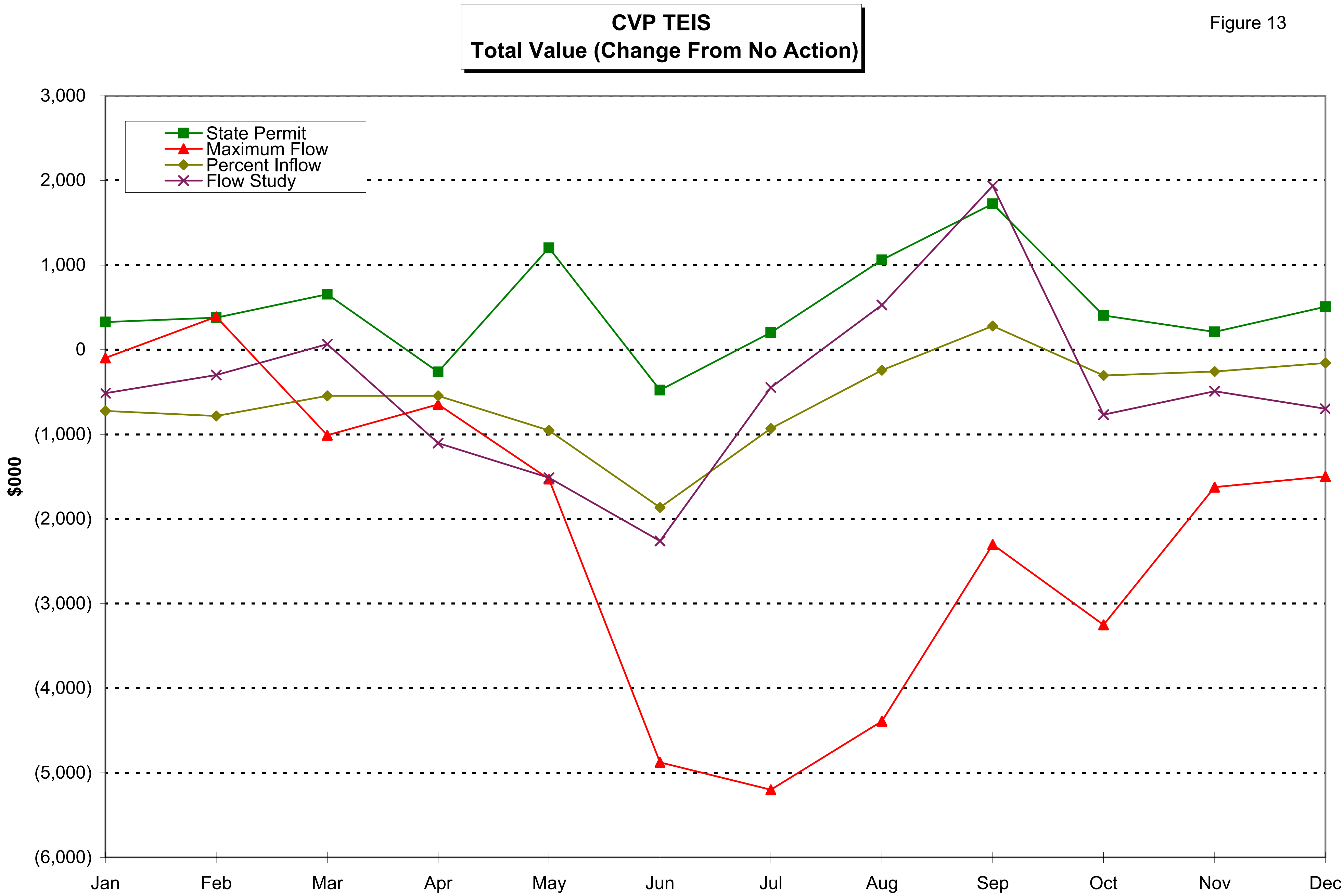
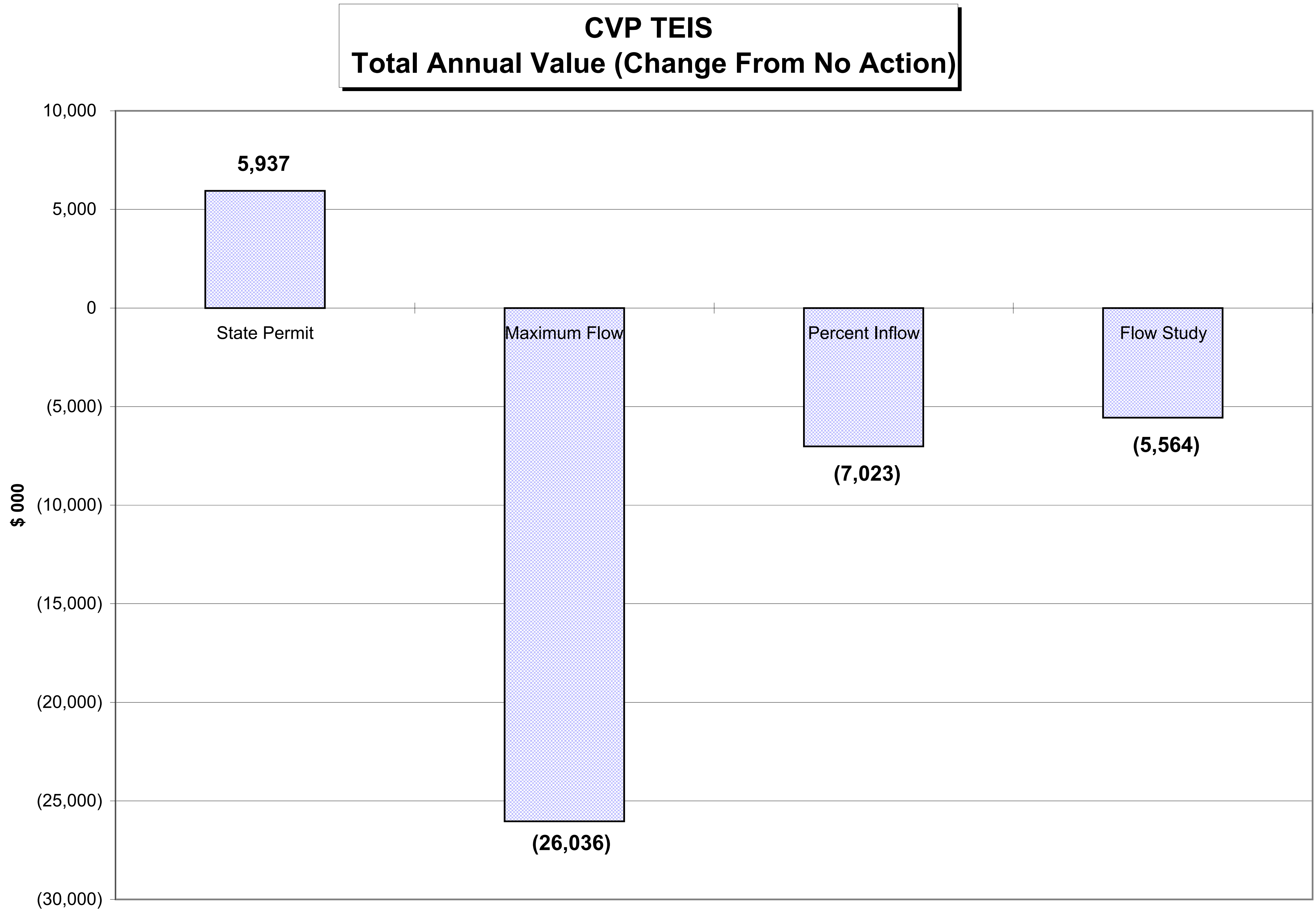

CVP TEIS
Energy Value (Change From No Action)
State Permit
Maximum Flow
Percent Inflow
Flow Study
$ 000
1,500
1,000
500
0
(500)
(1,000)
(1,500)
(2,000)
(2,500)
(3,000)
(3,500)
(4,000)
(4,500)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

Figure 13


CVP TEIS
Total Value (Change From No Action)
State Permit
Maximum Flow
Percent Inflow
Flow Study
3,000
2,000
1,000
0
(1,000)
(2,000)
(3,000)
(4,000)
(5,000)
(6,000)
$000
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec



CVP TEIS
Total Annual Value (Change From No Action)
10,000
5,000
0
(5,000)
(10,000)
(15,000)
(20,000)
(25,000)
(30,000)
$ 000
5,937
State Permit
Maximum Flow
Percent Inflow
Flow Study
(26,036)
(7,023)
(5,564)

No Action

CVP Hydro

	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total
January	1,638	1,012	996	116	223	339	1,551	565	459	35	88	123
February	1,691	1,088	1,088	117	212	330	1,454	511	493	27	83	110
March	1,723	870	870	95	254	349	1,524	537	484	31	118	148
April	1,741	1,042	987	110	280	390	1,608	773	773	46	176	222
May	1,753	1,444	1,444	182	388	569	1,488	1,167	1,057	120	289	409
June	1,750	1,582	1,489	213	442	655	1,795	1,416	1,321	140	332	471
July	1,714	1,711	1,655	281	462	742	1,532	1,489	1,272	207	341	548
August	1,637	1,531	1,513	183	433	615	1,513	1,092	1,052	115	283	398
September	1,551	1,353	1,303	101	241	342	1,366	1,021	1,021	67	168	234
October	1,534	882	882	78	210	288	1,401	589	589	36	110	145
November	1,547	790	757	75	169	244	1,351	600	559	37	97	134
December	1,588	930	930	103	207	309	1,252	534	534	34	85	119
Total	19,867	14,235	13,913	1,652	3,521	5,173	17,835	10,293	9,611	895	2,167	3,062
change from No Action	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*

Project Use

	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	Off Peak**	Max. On Peak	Coincident On Peak*	Off Peak	On Peak	Total	Off Peak**	Max. On Peak	Coincident On Peak*	Off Peak	On Peak	Total
January	335	211	62	88	59	147	313	215	63	89	59	148
February	311	165	123	71	47	118	51	51	12	13	9	22
March	271	148	148	68	45	113	163	88	86	42	28	69
April	171	129	58	54	36	90	66	60	24	17	12	29
May	175	144	75	58	39	97	70	70	28	17	12	29
June	213	169	49	69	46	114	221	184	122	72	48	120
July	222	189	102	80	53	133	115	109	43	37	25	62
August	227	175	7	74	49	123	123	106	41	39	26	65
September	244	153	108	65	43	108	153	109	63	38	26	64
October	231	137	95	60	40	101	158	108	58	41	27	69
November	269	180	85	71	47	118	182	94	39	39	26	66
December	294	192	161	80	53	133	188	96	66	42	28	70
Total	2,963	1,992	1,073	836	558	1,394	1,803	1,290	645	487	325	811
change from No Action	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*

** The capacity during the hour in which the difference between the On Peak ProsYm Capacity and On Peak Project Use Capacity is the greatest.*

*** The monthly maximum Off Peak Project Use capacity.*

No Action

Available for Sale

	Average					Dry				
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)		
			Off Peak	On Peak	Total			Off Peak	On Peak	Total
January	934	704	28	165	192	396	1,155	(54)	29	(25)
February	965	727	47	165	212	481	974	14	74	88
March	722	1,001	26	209	235	398	1,126	(11)	90	79
April	929	812	56	244	300	749	859	29	164	193
May	1,369	384	124	349	473	1,029	459	103	278	381
June	1,440	310	144	396	541	1,199	596	68	284	352
July	1,553	162	201	408	609	1,229	303	169	317	486
August	1,506	131	109	384	492	1,011	503	76	257	333
September	1,195	356	36	198	234	958	409	28	142	170
October	787	748	18	169	187	531	870	(5)	82	77
November	672	875	4	122	127	520	831	(2)	70	68
December	769	819	23	153	176	468	784	(7)	57	49
Total	12,840	7,028	816	2,963	3,779	8,966	8,869	408	1,843	2,251
change from No Action	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*

	State Permit Alt.											
	CVP Hydro											
	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total
January	1,646	1,026	1,010	123	228	351	1,572	595	595	36	89	125
February	1,699	1,102	1,102	123	218	341	1,478	518	514	28	83	111
March	1,729	898	898	103	260	363	1,794	549	480	30	118	148
April	1,747	1,048	992	118	284	401	1,691	765	765	55	168	223
May	1,760	1,459	1,459	189	397	586	1,735	1,179	1,179	112	291	402
June	1,756	1,653	1,538	221	452	672	1,457	1,229	1,229	144	335	478
July	1,722	1,663	1,658	298	469	768	1,527	1,408	1,357	229	374	603
August	1,647	1,515	1,404	199	445	644	1,318	1,221	1,221	169	327	496
September	1,562	1,372	1,306	132	270	402	1,398	1,078	1,078	89	193	281
October	1,548	869	869	86	213	299	1,436	604	604	36	114	151
November	1,559	815	765	80	174	254	1,416	630	549	40	95	135
December	1,599	862	847	110	212	322	1,404	541	536	36	86	122
Total	19,974	14,282	13,848	1,783	3,621	5,404	18,226	10,316	10,105	1,004	2,273	3,277
change from No Action	*0.5%*	*0.3%*	*-0.5%*	*7.9%*	*2.9%*	*4.5%*	*2.2%*	*0.2%*	*5.1%*	*12.2%*	*4.9%*	*7.0%*
	Project Use											
	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	Off Peak**	Max. On Peak	On Peak*	Off Peak	On Peak	Total	Off Peak**	Max. On Peak	Coincident On Peak*	Off Peak	On Peak	Total
January	333	209	62	88	59	146	307	218	197	88	59	147
February	309	163	122	70	47	116	77	71	24	15	10	24
March	282	154	154	71	47	118	183	121	86	48	32	80
April	177	134	61	56	37	93	127	118	93	42	28	70
May	178	145	79	59	39	98	172	145	77	59	39	98
June	223	175	53	72	48	120	122	93	46	36	24	60
July	225	194	146	82	55	137	184	176	158	66	44	110
August	229	177	7	74	49	123	137	127	99	46	30	76
September	245	154	112	66	44	109	154	110	63	36	24	60
October	227	137	95	60	40	100	149	105	60	41	28	69
November	270	180	85	71	47	118	198	111	47	47	31	78
December	291	192	134	80	53	133	242	95	80	47	31	79
Total	2,989	2,014	1,110	847	565	1,412	2,052	1,490	1,030	570	380	951
change from No Action	*0.9%*	*1.1%*	*3.4%*	*1.3%*	*1.3%*	*1.3%*	*13.8%*	*15.5%*	*59.7%*	*17.2%*	*17.1%*	*17.2%*

** The capacity during the hour in which the difference between the On Peak ProsYm Capacity and On Peak Project Use Capacity is the greatest.*

*** The monthly maximum Off Peak Project Use capacity.*

State Permit Alt.

Available for Sale

	Average					Dry				
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)		
			Off Peak	On Peak	Total			Off Peak	On Peak	Total
January	948	698	35	169	204	398	1,174	(52)	30	(22)
February	980	719	53	172	225	490	988	13	73	86
March	744	985	32	213	245	394	1,400	(18)	86	68
April	931	816	62	247	308	672	1,019	13	140	153
May	1,380	380	130	357	487	1,102	633	53	251	304
June	1,485	271	149	404	553	1,183	274	108	311	419
July	1,512	210	216	414	631	1,199	328	163	330	493
August	1,397	249	125	396	521	1,122	197	123	297	420
September	1,194	368	66	226	293	1,015	384	53	169	221
October	774	774	26	173	199	544	892	(5)	87	82
November	680	880	10	127	136	502	914	(7)	64	57
December	713	887	30	159	189	456	948	(11)	55	44
Total	12,738	7,237	935	3,056	3,992	9,075	9,151	434	1,893	2,327
change from No Action	*-0.8%*	*3.0%*	*14.7%*	*3.1%*	*5.6%*	*1.2%*	*3.2%*	*6.2%*	*2.7%*	*3.4%*

State Permit Alt. - No Action

	Dry		Average							
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity ($000)	Capacity w/o Energy ($000)	Energy ($000)		
			Off Peak	On Peak				Off Peak	On Peak	
January	2	19	7	5		14	35	167	111	
February	10	15	6	6		85	26	129	139	
March	(4)	274	6	4		(33)	492	114	82	
April	(77)	160	6	3		(693)	288	93	49	
May	74	174	6	8		661	312	83	149	
June	(16)	(322)	5	8		(140)	(580)	84	158	
July	(30)	25	16	6		(272)	45	301	127	
August	111	(306)	16	12		998	(550)	336	279	
September	57	(25)	30	28		512	(45)	619	637	
October	13	22	8	4		117	40	169	80	
November	(19)	83	5	4		(166)	150	120	108	
December	(12)	164	7	5		(106)	295	175	144	
Total	109	282	120	93		976	508	2,390	2,063	5,937

	Max. Flow Alt.											
	CVP Hydro											
	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total
January	1,604	982	946	107	217	325	1,532	565	486	33	86	119
February	1,663	1,072	1,072	113	216	329	1,438	545	545	31	91	122
March	1,701	838	819	92	252	343	1,215	524	492	36	119	154
April	1,718	967	967	101	267	369	1,593	707	707	52	180	232
May	1,727	1,334	1,334	129	321	450	1,690	1,039	1,039	75	243	318
June	1,716	1,381	1,266	132	351	483	1,483	1,106	1,078	88	278	367
July	1,669	1,279	1,268	178	340	518	1,579	1,146	1,068	135	265	400
August	1,588	1,172	1,091	122	312	434	1,499	929	914	71	240	311
September	1,501	1,061	1,061	70	181	252	1,430	921	921	46	129	175
October	1,478	628	628	37	126	163	1,162	538	538	28	91	119
November	1,494	666	647	53	130	183	1,369	575	488	29	74	103
December	1,540	754	754	79	171	250	1,345	511	511	29	72	101
Total	19,397	12,132	11,851	1,213	2,885	4,098	17,335	9,105	8,788	652	1,870	2,522
change from No Action	*-2.4%*	*-14.8%*	*-14.8%*	*-26.5%*	*-18.1%*	*-20.8%*	*-2.8%*	*-11.5%*	*-8.6%*	*-27.2%*	*-13.7%*	*-17.6%*

	Project Use											
	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	Off Peak**	Max. On Peak	On Peak*	Off Peak	On Peak	Total	Off Peak**	Max. On Peak	Coincident On Peak*	Off Peak	On Peak	Total
January	321	214	60	87	58	145	295	261	57	87	58	144
February	302	159	120	68	45	114	26	25	16	6	4	10
March	275	142	119	66	44	110	376	157	152	84	56	140
April	167	118	50	49	33	82	49	48	10	16	11	27
May	156	127	64	50	33	83	97	91	38	30	20	50
June	163	134	39	53	35	89	137	102	78	41	27	68
July	167	145	80	58	39	97	62	62	40	18	12	30
August	189	152	3	62	42	104	59	58	4	16	11	27
September	222	142	97	58	39	97	147	102	55	35	23	58
October	195	119	75	50	34	84	176	110	73	47	31	78
November	253	166	78	65	43	108	132	88	28	28	19	47
December	277	187	143	77	51	127	220	133	85	44	29	74
Total	2,687	1,805	928	745	496	1,241	1,776	1,237	636	452	302	754
change from No Action	*-9.3%*	*-9.4%*	*-13.5%*	*-11.0%*	*-11.0%*	*-11.0%*	*-1.5%*	*-4.1%*	*-1.4%*	*-7.0%*	*-7.0%*	*-7.0%*

** The capacity during the hour in which the difference between the On Peak ProsYm Capacity and On Peak Project Use Capacity is the greatest.*

*** The monthly maximum Off Peak Project Use capacity.*

Max. Flow Alt.

Available for Sale

	Average					Dry				
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)		
			Off Peak	On Peak	Total			Off Peak	On Peak	Total
January	886	718	20	159	179	429	1,103	(54)	29	(25)
February	952	711	44	171	215	529	909	25	87	112
March	700	1,002	26	208	233	340	875	(48)	63	14
April	917	802	52	234	287	697	897	36	169	205
May	1,270	456	79	288	367	1,001	689	45	223	269
June	1,227	489	79	316	394	1,000	483	47	251	299
July	1,188	481	120	301	421	1,028	551	116	253	370
August	1,088	500	59	271	330	910	589	54	230	284
September	964	537	12	142	154	866	564	11	106	117
October	553	924	(13)	92	79	465	697	(19)	59	40
November	569	925	(11)	86	75	460	909	0	55	56
December	611	929	3	120	123	426	919	(15)	43	28
Total	10,923	8,473	469	2,388	2,857	8,152	9,183	200	1,568	1,768
change from No Action	*-14.9%*	*20.6%*	*-42.5%*	*-19.4%*	*-24.4%*	*-9.1%*	*3.5%*	*-51.1%*	*-14.9%*	*-21.5%*

Max. Flow Alt. - No Action

	Dry		Average							
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity ($000)	Capacity w/o Energy ($000)	Energy ($000)		
			Off Peak	On Peak				Off Peak	On Peak	
January	33	(52)	(8)	(5)		300	(94)	(178)	(127)	
February	49	(65)	(2)	5		440	(117)	(50)	116	
March	(58)	(251)	(1)	(1)		(521)	(451)	(17)	(21)	
April	(53)	38	(4)	(10)		(472)	67	(61)	(179)	
May	(28)	230	(45)	(61)		(250)	413	(608)	(1,083)	
June	(199)	(113)	(66)	(81)		(1,785)	(204)	(1,194)	(1,694)	
July	(201)	248	(81)	(108)		(1,806)	446	(1,560)	(2,280)	
August	(101)	87	(50)	(113)		(906)	156	(1,037)	(2,602)	
September	(91)	155	(24)	(56)		(821)	279	(487)	(1,273)	
October	(66)	(174)	(31)	(77)		(589)	(312)	(623)	(1,727)	
November	(60)	78	(16)	(36)		(541)	140	(350)	(873)	
December	(42)	135	(20)	(33)		(373)	242	(495)	(871)	
Total	(815)	315	(347)	(575)		(7,325)	566	(6,661)	(12,615)	(26,036)

Percent Inflow Alt.

CVP Hydro

	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total	ProsIm Capacity	Maximum ProsYm Capacity	Coincident ProsYm Capacity*	Off Peak	On Peak	Total
January	1,638	1,003	980	113	220	334	1,322	566	449	35	86	121
February	1,691	1,079	1,079	115	210	325	1,568	517	478	31	82	113
March	1,722	852	852	91	250	341	1,444	561	486	34	120	154
April	1,740	998	980	107	279	386	1,632	734	716	54	183	237
May	1,751	1,423	1,423	157	363	520	1,592	1,031	1,007	101	268	370
June	1,746	1,616	1,558	179	420	599	1,713	1,395	1,168	137	314	452
July	1,710	1,711	1,610	255	449	704	1,578	1,497	1,254	183	324	507
August	1,633	1,575	1,559	187	437	624	1,311	999	999	152	307	459
September	1,550	1,343	1,343	112	257	370	1,275	1,017	1,017	81	173	254
October	1,534	838	838	72	197	268	1,475	587	587	33	108	141
November	1,546	779	744	72	165	238	1,489	632	549	38	94	132
December	1,589	922	922	101	204	305	1,367	529	529	34	81	115
Total	19,849	14,138	13,887	1,562	3,452	5,014	17,766	10,066	9,239	915	2,139	3,054
change from No Action	*-0.1%*	*-0.7%*	*-0.2%*	*-5.4%*	*-2.0%*	*-3.1%*	*-0.4%*	*-2.2%*	*-3.9%*	*2.2%*	*-1.3%*	*-0.3%*

Project Use

	Average						Dry					
	Capacity (MW)			Energy (GWH)			Capacity (MW)			Energy (GWH)		
	Off Peak**	Max. On Peak	On Peak*	Off Peak	On Peak	Total	Off Peak**	Max. On Peak	Coincident On Peak*	Off Peak	On Peak	Total
January	336	211	63	89	59	148	347	247	75	96	64	160
February	315	167	124	71	48	119	325	204	118	73	49	122
March	276	147	147	69	46	115	263	151	120	68	45	113
April	169	128	58	54	36	90	138	125	41	44	29	73
May	173	143	75	57	38	96	100	94	31	30	20	50
June	213	167	129	68	45	114	232	170	60	71	47	118
July	218	185	102	79	52	131	136	122	67	44	29	73
August	224	174	78	73	49	122	148	124	3	47	31	78
September	242	152	108	64	43	107	137	108	83	32	21	54
October	228	135	94	60	40	99	157	106	62	42	28	70
November	268	180	84	70	47	117	265	195	78	66	44	111
December	292	193	161	80	53	133	241	110	97	48	32	80
Total	2,954	1,982	1,223	834	556	1,390	2,489	1,756	835	662	441	1,104
change from No Action	*-0.3%*	*-0.5%*	*14.0%*	*-0.3%*	*-0.3%*	*-0.3%*	*38.0%*	*36.1%*	*29.5%*	*36.0%*	*36.0%*	*36.0%*

** The capacity during the hour in which the difference between the On Peak ProsYm Capacity and On Peak Project Use Capacity is the greatest.*

*** The monthly maximum Off Peak Project Use capacity.*

Percent Inflow Alt.

Available for Sale

	Average					Dry				
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)		
			Off Peak	On Peak	Total			Off Peak	On Peak	Total
January	917	721	25	161	186	374	948	(61)	22	(40)
February	955	736	43	163	206	360	1,208	(42)	33	(9)
March	705	1,017	23	204	226	366	1,079	(34)	75	41
April	922	818	54	243	296	675	957	10	154	164
May	1,348	403	100	325	424	976	616	71	248	319
June	1,429	317	111	375	486	1,108	605	67	267	334
July	1,508	202	176	397	573	1,187	391	139	295	434
August	1,481	152	114	388	503	996	315	105	276	381
September	1,235	315	48	214	262	934	341	49	151	200
October	744	790	12	157	169	525	950	(9)	80	71
November	660	887	2	118	120	471	1,018	(29)	50	21
December	761	827	21	151	172	432	936	(14)	49	34
Total	12,664	7,185	729	2,896	3,625	8,404	9,362	253	1,698	1,951
change from No Action	*-1.4%*	*2.2%*	*-10.7%*	*-2.3%*	*-4.1%*	*-6.3%*	*5.6%*	*-38.1%*	*-7.9%*	*-13.3%*

Percent Inflow Alt. - No Action

	Dry		Average							
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity ($000)	Capacity w/o Energy ($000)	Energy ($000)		
			Off Peak	On Peak				Off Peak	On Peak	
January	(22)	(207)	(3)	(3)		(201)	(371)	(67)	(84)	
February	(120)	234	(3)	(3)		(1,081)	421	(67)	(56)	
March	(32)	(48)	(4)	(5)		(288)	(86)	(71)	(100)	
April	(74)	98	(2)	(1)		(663)	176	(37)	(23)	
May	(52)	156	(24)	(24)		(471)	281	(329)	(434)	
June	(91)	9	(33)	(22)		(819)	17	(608)	(454)	
July	(42)	88	(25)	(11)		(376)	158	(473)	(238)	
August	(14)	(188)	5	5		(129)	(337)	115	109	
September	(23)	(68)	12	16		(209)	(122)	243	370	
October	(6)	80	(6)	(12)		(55)	144	(120)	(273)	
November	(49)	187	(2)	(4)		(441)	336	(53)	(100)	
December	(36)	151	(2)	(2)		(325)	272	(42)	(61)	
Total	(563)	494	(87)	(67)		(5,058)	887	(1,509)	(1,344)	(7,023)

	Flow Study Alt.											
	CVP Hydro											
	Average						**Dry**					
	Capacity (MW)			**Energy (GWH)**			**Capacity (MW)**			**Energy (GWH)**		
	ProsIm Capacity	**Maximum ProsYm Capacity**	**Coincident ProsYm Capacity***	**Off Peak**	**On Peak**	**Total**	**ProsIm Capacity**	**Maximum ProsYm Capacity**	**Coincident ProsYm Capacity***	**Off Peak**	**On Peak**	**Total**
January	1,633	1,003	981	114	222	336	1,364	561	451	32	84	117
February	1,688	1,081	1,081	115	209	324	1,519	496	494	27	81	108
March	1,720	861	861	92	249	341	1,750	544	478	30	116	147
April	1,738	978	943	100	265	365	1,798	738	738	54	166	220
May	1,749	1,398	1,398	161	357	519	1,566	973	924	91	243	334
June	1,741	1,562	1,491	166	397	563	1,648	1,251	1,158	115	299	414
July	1,701	1,671	1,587	248	439	687	1,587	1,297	1,278	162	314	476
August	1,627	1,523	1,510	178	426	604	1,513	1,147	1,144	122	309	431
September	1,543	1,350	1,228	118	264	382	1,368	1,162	1,162	89	207	296
October	1,528	800	800	64	184	248	1,428	609	609	38	115	153
November	1,538	749	719	68	156	224	1,413	576	541	35	92	128
December	1,582	844	844	97	199	296	1,396	572	549	37	83	120
Total	19,789	13,817	13,441	1,521	3,367	4,888	18,350	9,923	9,524	831	2,111	2,942
change from No Action	*-0.4%*	*-2.9%*	*-3.4%*	*-8.0%*	*-4.4%*	*-5.5%*	*2.9%*	*-3.6%*	*-0.9%*	*-7.1%*	*-2.6%*	*-3.9%*
	Project Use											
	Average						**Dry**					
	Capacity (MW)			**Energy (GWH)**			**Capacity (MW)**			**Energy (GWH)**		
	Off Peak**	**Max. On Peak**	**On Peak***	**Off Peak**	**On Peak**	**Total**	**Off Peak****	**Max. On Peak**	**Coincident On Peak***	**Off Peak**	**On Peak**	**Total**
January	332	211	62	88	59	147	312	208	68	90	60	151
February	306	159	122	69	46	115	146	92	62	31	21	52
March	275	147	147	69	46	114	224	117	104	55	37	91
April	168	126	55	52	35	87	207	152	136	67	45	112
May	174	140	76	56	38	94	48	48	17	14	9	24
June	204	162	125	66	44	109	62	62	1	13	9	22
July	202	171	96	72	48	120	63	63	7	15	10	24
August	224	172	15	72	48	120	100	93	32	33	22	55
September	243	151	110	64	43	107	151	107	58	38	25	64
October	233	137	96	61	41	102	168	107	69	46	31	77
November	262	175	81	68	46	114	239	108	50	48	32	80
December	293	195	158	80	53	133	289	250	166	82	55	136
Total	2,916	1,946	1,143	818	545	1,362	2,009	1,407	770	533	355	888
change from No Action	*-1.6%*	*-2.3%*	*6.5%*	*-2.3%*	*-2.3%*	*-2.3%*	*11.4%*	*9.1%*	*19.4%*	*9.5%*	*9.4%*	*9.5%*

** The capacity during the hour in which the difference between the On Peak ProsYm Capacity and On Peak Project Use Capacity is the greatest.*

*** The monthly maximum Off Peak Project Use capacity.*

Flow Study Alt.

Available for Sale

	Average					Dry				
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)		
			Off Peak	On Peak	Total			Off Peak	On Peak	Total
January	919	714	26	163	189	383	981	(58)	24	(34)
February	959	729	46	163	209	432	1,087	(4)	60	56
March	714	1,006	23	203	226	374	1,376	(25)	80	55
April	888	851	48	230	278	602	1,196	(14)	121	108
May	1,322	428	105	320	425	907	659	77	233	311
June	1,366	375	100	354	454	1,157	491	101	290	392
July	1,491	210	176	391	567	1,271	316	147	304	451
August	1,495	133	106	378	483	1,112	401	89	287	376
September	1,118	425	54	221	275	1,104	264	51	182	232
October	704	824	3	143	146	540	889	(8)	85	76
November	638	900	(1)	111	110	491	922	(13)	60	48
December	686	896	17	146	163	383	1,014	(45)	29	(16)
Total	12,298	7,490	703	2,822	3,525	8,754	9,596	298	1,756	2,054
change from No Action	*-4.2%*	*6.6%*	*-13.8%*	*-4.8%*	*-6.7%*	*-2.4%*	*8.2%*	*-26.9%*	*-4.7%*	*-8.7%*

Flow Study Alt. - No Action

	Dry		Average							
	ProsYm Capacity (MW)	Capacity w/o Energy (MW)	Energy (GWH)			ProsYm Capacity ($000)	Capacity w/o Energy ($000)	Energy ($000)		
			Off Peak	On Peak				Off Peak	On Peak	
January	(13)	(174)	(2)	(1)		(116)	(313)	(53)	(33)	
February	(49)	114	(1)	(2)		(437)	204	(21)	(45)	
March	(23)	249	(3)	(6)		(209)	448	(60)	(114)	
April	(147)	337	(8)	(14)		(1,322)	606	(129)	(258)	
May	(122)	200	(19)	(29)		(1,097)	360	(255)	(522)	
June	(42)	(105)	(44)	(43)		(378)	(189)	(797)	(898)	
July	42	13	(25)	(17)		375	24	(478)	(368)	
August	102	(102)	(3)	(6)		914	(183)	(66)	(136)	
September	146	(144)	18	23		1,314	(259)	362	521	
October	9	18	(15)	(26)		79	33	(295)	(584)	
November	(30)	91	(5)	(12)		(265)	165	(110)	(281)	
December	(85)	229	(6)	(8)		(766)	412	(142)	(203)	
Total	(212)	727	(113)	(141)		(1,906)	1,307	(2,044)	(2,921)	(5,564)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Capacity Cost diff. from No Action ($000)**						**Energy Cost diff. from No Action ($000)**							Total Cost diff. from No Action ($00		
2		**State Permit**	**Maximum Flow**	**Percent Inflow**	**Flow Study**			**State Permit**	**Maximum Flow**	**Percent Inflow**	**Flow Study**			**State Permit**	**Maximum Flow**	**Percent Inflow**
3	**Jan**	49	206	(573)	(429)		Jan	278	(305)	(151)	(85)		Jan	327	(99)	(724)
4	**Feb**	112	323	(660)	(233)		Feb	268	66	(123)	(66)		Feb	379	389	(783)
5	**Mar**	459	(973)	(374)	240		Mar	196	(38)	(171)	(175)		Mar	654	(1,011)	(545)
6	**Apr**	(405)	(405)	(487)	(716)		Apr	142	(240)	(59)	(387)		Apr	(263)	(645)	(546)
7	**May**	973	163	(190)	(737)		May	232	(1,691)	(763)	(777)		May	1,205	(1,528)	(953)
8	**Jun**	(720)	(1,989)	(802)	(567)		Jun	243	(2,889)	(1,062)	(1,695)		Jun	(477)	(4,878)	(1,865)
9	**Jul**	(227)	(1,361)	(218)	399		Jul	429	(3,841)	(712)	(846)		Jul	202	(5,201)	(930)
10	**Aug**	448	(750)	(466)	731		Aug	615	(3,639)	224	(202)		Aug	1,062	(4,390)	(242)
11	**Sep**	467	(542)	(332)	1,055		Sep	1,256	(1,760)	613	883		Sep	1,723	(2,301)	281
12	**Oct**	156	(901)	89	112		Oct	249	(2,350)	(393)	(879)		Oct	406	(3,251)	(304)
13	**Nov**	(16)	(401)	(105)	(101)		Nov	228	(1,223)	(153)	(391)		Nov	211	(1,624)	(258)
14	**Dec**	189	(131)	(54)	(354)		Dec	319	(1,366)	(103)	(345)		Dec	508	(1,497)	(157)
15	**Total**	**1,484**	**(6,759)**	**(4,170)**	**(599)**			**4,453**	**(19,277)**	**(2,853)**	**(4,965)**			5,937	(26,036)	(7,023)

	Q
1	))
2	**Flow Study**
3	(514)
4	(299)
5	65
6	(1,103)
7	(1,514)
8	(2,262)
9	(447)
10	529
11	1,938
12	(767)
13	(492)
14	(698)
15	(5,564)

TEIS
CVP Hydro
Capacity (MW)

	No Action Avg.					No Action Dry				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	1,638	1,012	211	934	704	1,551	565	215	396	1,155
Feb	1,691	1,088	165	965	727	1,454	511	51	481	974
Mar	1,723	870	148	722	1,001	1,524	537	88	398	1,126
Apr	1,741	1,042	129	929	812	1,608	773	60	749	859
May	1,753	1,444	144	1,369	384	1,488	1,167	70	1,029	459
Jun	1,750	1,582	169	1,440	310	1,795	1,416	184	1,199	596
Jul	1,714	1,711	189	1,553	162	1,532	1,489	109	1,229	303
Aug	1,637	1,531	175	1,506	131	1,513	1,092	106	1,011	503
Sep	1,551	1,353	153	1,195	356	1,366	1,021	109	958	409
Oct	1,534	882	137	787	748	1,401	589	108	531	870
Nov	1,547	790	180	672	875	1,351	600	94	520	831
Dec	1,588	930	192	769	819	1,252	534	96	468	784
Total	19,867	14,235	1,992	12,840	7,028	17,835	10,293	1,290	8,966	8,869
Average	1,656	1,186	166	1,070	586	1,486	858	108	747	739
Diff. from No Action	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*
	State Permit Alt. Avg.					**State Permit Alt. Dry**				
	Available	**w/ Energy**	**PU**	**w/ Energy for Sale**	**w/o Energy for Sale**	**Available**	**w/ Energy**	**PU**	**w/ Energy for Sale**	**w/o Energy for Sale**
Jan	1,646	1,026	209	948	698	1,572	595	218	398	1,174
Feb	1,699	1,102	163	980	719	1,478	518	71	490	988
Mar	1,729	898	154	744	985	1,794	549	121	394	1,400
Apr	1,747	1,048	134	931	816	1,691	765	118	672	1,019
May	1,760	1,459	145	1,380	380	1,735	1,179	145	1,102	633
Jun	1,756	1,653	175	1,485	271	1,457	1,229	93	1,183	274
Jul	1,722	1,663	194	1,512	210	1,527	1,408	176	1,199	328
Aug	1,647	1,515	177	1,397	249	1,318	1,221	127	1,122	197
Sep	1,562	1,372	154	1,194	368	1,398	1,078	110	1,015	384
Oct	1,548	869	137	774	774	1,436	604	105	544	892
Nov	1,559	815	180	680	880	1,416	630	111	502	914
Dec	1,599	862	192	713	887	1,404	541	95	456	948
Total	19,974	14,282	2,014	12,738	7,237	18,226	10,316	1,490	9,075	9,151
Average	1,665	1,190	168	1,061	603	1,519	860	124	756	763
Diff. from No Action	*0.54%*	*0.33%*	*1.10%*	*-0.79%*	*2.97%*	*2.19%*	*0.23%*	*15.50%*	*1.21%*	*3.18%*

TEIS

CVP Hydro

Capacity (MW)

	Max. Flow Alt. Avg.					Max. Flow Alt. Dry				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	1,604	982	214	886	718	1,532	565	261	429	1,103
Feb	1,663	1,072	159	952	711	1,438	545	25	529	909
Mar	1,701	838	142	700	1,002	1,215	524	157	340	875
Apr	1,718	967	118	917	802	1,593	707	48	697	897
May	1,727	1,334	127	1,270	456	1,690	1,039	91	1,001	689
Jun	1,716	1,381	134	1,227	489	1,483	1,106	102	1,000	483
Jul	1,669	1,279	145	1,188	481	1,579	1,146	62	1,028	551
Aug	1,588	1,172	152	1,088	500	1,499	929	58	910	589
Sep	1,501	1,061	142	964	537	1,430	921	102	866	564
Oct	1,478	628	119	553	924	1,162	538	110	465	697
Nov	1,494	666	166	569	925	1,369	575	88	460	909
Dec	1,540	754	187	611	929	1,345	511	133	426	919
Total	19,397	12,132	1,805	10,923	8,473	17,335	9,105	1,237	8,152	9,183
Average	1,616	1,011	150	910	706	1,445	759	103	679	765
Diff. from No Action	-2.37%	-14.77%	-9.39%	-14.92%	20.57%	-2.80%	-11.53%	-4.11%	-9.09%	3.55%

	Percent Inflow Alt. Avg.					Percent Inflow Alt. Dry				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	1,638	1,003	211	917	721	1,322	566	247	374	948
Feb	1,691	1,079	167	955	736	1,568	517	204	360	1,208
Mar	1,722	852	147	705	1,017	1,444	561	151	366	1,079
Apr	1,740	998	128	922	818	1,632	734	125	675	957
May	1,751	1,423	143	1,348	403	1,592	1,031	94	976	616
Jun	1,746	1,616	167	1,429	317	1,713	1,395	170	1,108	605
Jul	1,710	1,711	185	1,508	202	1,578	1,497	122	1,187	391
Aug	1,633	1,575	174	1,481	152	1,311	999	124	996	315
Sep	1,550	1,343	152	1,235	315	1,275	1,017	108	934	341
Oct	1,534	838	135	744	790	1,475	587	106	525	950
Nov	1,546	779	180	660	887	1,489	632	195	471	1,018
Dec	1,589	922	193	761	827	1,367	529	110	432	936
Total	19,849	14,138	1,982	12,664	7,185	17,766	10,066	1,756	8,404	9,362
Average	1,654	1,178	165	1,055	599	1,480	839	146	700	780
Diff. from No Action	-0.09%	-0.68%	-0.50%	-1.37%	2.24%	-0.39%	-2.20%	36.12%	-6.27%	5.56%

	TEIS									
	CVP Hydro									
	Capacity (MW)									
	Flow Study Alt. Avg.					Flow Study Alt. Dry				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	1,633	1,003	211	919	714	1,364	561	208	383	981
Feb	1,688	1,081	159	959	729	1,519	496	92	432	1,087
Mar	1,720	861	147	714	1,006	1,750	544	117	374	1,376
Apr	1,738	978	126	888	851	1,798	738	152	602	1,196
May	1,749	1,398	140	1,322	428	1,566	973	48	907	659
Jun	1,741	1,562	162	1,366	375	1,648	1,251	62	1,157	491
Jul	1,701	1,671	171	1,491	210	1,587	1,297	63	1,271	316
Aug	1,627	1,523	172	1,495	133	1,513	1,147	93	1,112	401
Sep	1,543	1,350	151	1,118	425	1,368	1,162	107	1,104	264
Oct	1,528	800	137	704	824	1,428	609	107	540	889
Nov	1,538	749	175	638	900	1,413	576	108	491	922
Dec	1,582	844	195	686	896	1,396	572	250	383	1,014
Total	19,789	13,817	1,946	12,298	7,490	18,350	9,923	1,407	8,754	9,596
Average	1,649	1,151	162	1,025	624	1,529	827	117	730	800
Diff. from No Action	*-0.40%*	*-2.93%*	*-2.31%*	*-4.22%*	*6.58%*	*2.89%*	*-3.59%*	*9.07%*	*-2.36%*	*8.20%*
	Revised Existing Avg.					Revised Existing Dry				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	1,653	1,032	212	946	707	1,551	578	210	414	1,137
Feb	1,705	1,104	167	983	722	1,512	525	81	470	1,042
Mar	1,733	886	151	736	997	1,539	538	108	415	1,124
Apr	1,750	1,014	136	930	820	1,629	849	103	748	881
May	1,761	1,432	145	1,358	404	1,409	1,209	32	1,199	210
Jun	1,755	1,596	170	1,418	338	1,816	1,430	187	1,235	581
Jul	1,721	1,616	189	1,457	263	1,561	1,432	212	1,271	290
Aug	1,649	1,532	176	1,507	143	1,262	1,204	73	1,147	116
Sep	1,566	1,400	151	1,129	437	1,416	952	108	887	530
Oct	1,554	869	139	771	783	1,425	607	105	546	879
Nov	1,566	830	177	667	900	1,228	566	96	542	686
Dec	1,606	858	193	699	907	1,389	567	94	473	916
Total	20,021	14,168	2,006	12,601	7,420	17,737	10,457	1,409	9,346	8,392
Average	1,668	1,181	167	1,050	618	1,478	871	117	779	699
Diff. from No Action	*0.77%*	*-0.47%*	*0.70%*	*-1.86%*	*5.58%*	*-0.55%*	*1.60%*	*9.22%*	*4.23%*	*-5.38%*

	TEIS									
	CVP Hydro									
	Capacity (MW)									
	Difference Avg. (No Action - No Action)					Difference Dry (No Action - No Action)				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-
Sep	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-	-
Diff. from No Action	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*	*0.00%*
	Difference Avg. (State Permit Alt. - No Action)					Difference Dry (State Permit Alt. - No Action)				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	9	14	(2)	14	(5)	21	29	3	2	19
Feb	8	15	(2)	16	(8)	24	8	20	10	15
Mar	7	29	6	23	(16)	270	12	33	(4)	274
Apr	5	6	5	2	3	83	(8)	58	(77)	160
May	7	15	1	11	(4)	247	12	75	74	174
Jun	6	70	6	45	(38)	(338)	(186)	(91)	(16)	(322)
Jul	7	(48)	5	(41)	49	(5)	(81)	67	(30)	25
Aug	10	(16)	2	(109)	118	(195)	129	21	111	(306)
Sep	11	18	1	(1)	13	32	57	1	57	(25)
Oct	14	(13)	-	(13)	26	35	15	(3)	13	22
Nov	13	24	-	8	5	65	30	17	(19)	83
Dec	11	(68)	-	(57)	67	152	7	(1)	(12)	164
Total	107	47	22	(102)	209	391	23	200	109	282
Average	9	4	2	(8)	17	33	2	17	9	24
Diff. from No Action	*0.54%*	*0.33%*	*1.10%*	*-0.79%*	*2.97%*	*2.19%*	*0.23%*	*15.50%*	*1.21%*	*3.18%*

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Capacity (MW)

	Difference Avg. (Max. Flow Alt. - No Action)					Difference Dry (Max. Flow Alt. - No Action)				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	(34)	(30)	3	(48)	14	(19)	(1)	46	33	(52)
Feb	(29)	(16)	(6)	(13)	(16)	(16)	35	(26)	49	(65)
Mar	(22)	(32)	(6)	(22)	0	(309)	(13)	69	(58)	(251)
Apr	(23)	(75)	(11)	(12)	(11)	(15)	(67)	(12)	(53)	38
May	(27)	(110)	(17)	(99)	72	202	(128)	21	(28)	230
Jun	(34)	(202)	(35)	(214)	180	(312)	(310)	(82)	(199)	(113)
Jul	(45)	(433)	(44)	(364)	319	47	(344)	(47)	(201)	248
Aug	(49)	(359)	(23)	(418)	369	(14)	(163)	(48)	(101)	87
Sep	(50)	(293)	(11)	(232)	181	64	(99)	(7)	(91)	155
Oct	(57)	(253)	(18)	(233)	177	(239)	(51)	2	(66)	(174)
Nov	(53)	(125)	(14)	(103)	50	18	(25)	(6)	(60)	78
Dec	(49)	(176)	(5)	(158)	110	93	(23)	37	(42)	135
Total	(471)	(2,103)	(187)	(1,916)	1,445	(500)	(1,187)	(53)	(815)	315
Average	(39)	(175)	(16)	(160)	120	(42)	(99)	(4)	(68)	26
Diff. from No Action	*-2.37%*	*-14.77%*	*-9.39%*	*-14.92%*	*20.57%*	*-2.80%*	*-11.53%*	*-4.11%*	*-9.09%*	*3.55%*

	Difference Avg. (Percent Inflow Alt. - No Action)					Difference Dry (Percent Inflow Alt. - No Action)				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	-	(9)	-	(17)	17	(229)	1	32	(22)	(207)
Feb	(0)	(9)	2	(10)	10	114	6	153	(120)	234
Mar	(1)	(17)	(1)	(16)	16	(80)	25	63	(32)	(48)
Apr	(1)	(43)	(1)	(7)	6	24	(39)	65	(74)	98
May	(3)	(21)	(1)	(21)	19	104	(136)	24	(52)	156
Jun	(4)	34	(2)	(12)	7	(82)	(21)	(14)	(91)	9
Jul	(5)	(1)	(4)	(45)	40	46	8	13	(42)	88
Aug	(4)	44	(1)	(25)	21	(202)	(93)	18	(14)	(188)
Sep	(1)	(11)	(1)	40	(41)	(91)	(3)	(1)	(23)	(68)
Oct	(1)	(44)	(2)	(43)	43	74	(2)	(2)	(6)	80
Nov	(0)	(12)	-	(12)	12	138	32	101	(49)	187
Dec	0	(8)	1	(8)	8	115	(5)	14	(36)	151
Total	(19)	(97)	(10)	(176)	157	(69)	(227)	466	(563)	494
Average	(2)	(8)	(1)	(15)	13	(6)	(19)	39	(47)	41
Diff. from No Action	*-0.09%*	*-0.68%*	*-0.50%*	*-1.37%*	*2.24%*	*-0.39%*	*-2.20%*	*36.12%*	*-6.27%*	*5.56%*

	TEIS									
	CVP Hydro									
	Capacity (MW)									
	Difference Avg. (Flow Study Alt. - No Action)					Difference Dry (Flow Study Alt. - No Action)				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	(5)	(10)	-	(15)	10	(187)	(5)	(7)	(13)	(174)
Feb	(3)	(6)	(6)	(5)	2	65	(15)	41	(49)	114
Mar	(3)	(8)	(1)	(7)	5	226	7	29	(23)	249
Apr	(3)	(64)	(3)	(41)	38	190	(35)	92	(147)	337
May	(4)	(46)	(4)	(47)	43	78	(194)	(22)	(122)	200
Jun	(9)	(21)	(7)	(75)	66	(147)	(165)	(122)	(42)	(105)
Jul	(13)	(41)	(18)	(62)	49	55	(192)	(46)	42	13
Aug	(10)	(8)	(3)	(11)	2	(0)	55	(13)	102	(102)
Sep	(8)	(4)	(2)	(78)	70	2	141	(2)	146	(144)
Oct	(7)	(82)	-	(83)	76	27	20	(1)	9	18
Nov	(8)	(41)	(5)	(33)	25	62	(25)	14	(30)	91
Dec	(7)	(86)	3	(83)	76	144	38	154	(85)	229
Total	(79)	(417)	(46)	(541)	462	515	(370)	117	(212)	727
Average	(7)	(35)	(4)	(45)	39	43	(31)	10	(18)	61
Diff. from No Action	*-0.40%*	*-2.93%*	*-2.31%*	*-4.22%*	*6.58%*	*2.89%*	*-3.59%*	*9.07%*	*-2.36%*	*8.20%*

	Difference Avg. (Revised Existing - No Action)					Difference Dry (Revised Existing - No Action)				
	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale	Available	w/ Energy	PU	w/ Energy for Sale	w/o Energy for Sale
Jan	15	20	1	12	3	0	13	(5)	18	(18)
Feb	14	16	2	18	(4)	58	15	30	(10)	68
Mar	10	17	3	15	(4)	15	2	20	17	(2)
Apr	9	(28)	7	2	7	21	76	43	(1)	22
May	8	(12)	1	(11)	19	(79)	42	(38)	170	(249)
Jun	5	14	1	(23)	28	21	15	3	36	(15)
Jul	7	(95)	-	(95)	102	29	(57)	103	42	(13)
Aug	12	1	1	1	12	(251)	112	(33)	136	(387)
Sep	15	46	(2)	(66)	81	50	(69)	(1)	(71)	121
Oct	20	(13)	2	(16)	35	24	18	(3)	15	9
Nov	20	40	(3)	(5)	25	(123)	(34)	2	22	(145)
Dec	18	(72)	1	(70)	88	137	34	(2)	5	132
Total	153	(67)	14	(239)	392	(98)	165	119	379	(477)
Average	13	(6)	1	(20)	33	(8)	14	10	32	(40)
Diff. from No Action	*0.77%*	*-0.47%*	*0.70%*	*-1.86%*	*5.58%*	*-0.55%*	*1.60%*	*9.22%*	*4.23%*	*-5.38%*

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Energy (GWH)

	No Action Avg.									No Action Dry								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	116	223	339	88	59	147	28	165	192	35	88	123	89	59	148	(54)	29	(25)
Feb	117	212	330	71	47	118	47	165	212	27	83	110	13	9	22	14	74	88
Mar	95	254	349	68	45	113	26	209	235	31	118	148	42	28	69	(11)	90	79
Apr	110	280	390	54	36	90	56	244	300	46	176	222	17	12	29	29	164	193
May	182	388	569	58	39	97	124	349	473	120	289	409	17	12	29	103	278	381
Jun	213	442	655	69	46	114	144	396	541	140	332	471	72	48	120	68	284	352
Jul	281	462	742	80	53	133	201	408	609	207	341	548	37	25	62	169	317	486
Aug	183	433	615	74	49	123	109	384	492	115	283	398	39	26	65	76	257	333
Sep	101	241	342	65	43	108	36	198	234	67	168	234	38	26	64	28	142	170
Oct	78	210	288	60	40	101	18	169	187	36	110	145	41	27	69	(5)	82	77
Nov	75	169	244	71	47	118	4	122	127	37	97	134	39	26	66	(2)	70	68
Dec	103	207	309	80	53	133	23	153	176	34	85	119	42	28	70	(7)	57	49
Total	1,652	3,521	5,173	836	558	1,394	816	2,963	3,779	895	2,167	3,062	487	325	811	408	1,843	2,251
			0.0%			0.0%			0.0%			0.0%			0.0%			0.0%

	State Permit Alt. Avg.									State Permit Alt. Dry								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	123	228	351	88	59	146	35	169	204	36	89	125	88	59	147	(52)	30	(22)
Feb	123	218	341	70	47	116	53	172	225	28	83	111	15	10	24	13	73	86
Mar	103	260	363	71	47	118	32	213	245	30	118	148	48	32	80	(18)	86	68
Apr	118	284	401	56	37	93	62	247	308	55	168	223	42	28	70	13	140	153
May	189	397	586	59	39	98	130	357	487	112	291	402	59	39	98	53	251	304
Jun	221	452	672	72	48	120	149	404	553	144	335	478	36	24	60	108	311	419
Jul	298	469	768	82	55	137	216	414	631	229	374	603	66	44	110	163	330	493
Aug	199	445	644	74	49	123	125	396	521	169	327	496	46	30	76	123	297	420
Sep	132	270	402	66	44	109	66	226	293	89	193	281	36	24	60	53	169	221
Oct	86	213	299	60	40	100	26	173	199	36	114	151	41	28	69	(5)	87	82
Nov	80	174	254	71	47	118	10	127	136	40	95	135	47	31	78	(7)	64	57
Dec	110	212	322	80	53	133	30	159	189	36	86	122	47	31	79	(11)	55	44
Total	1,783	3,621	5,404	847	565	1,412	935	3,056	3,992	1,004	2,273	3,277	570	380	951	434	1,893	2,327
			4.5%			1.3%			5.6%			7.0%			17.2%			3.4%

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CVP Hydro

Energy (GWH)

	Max. Flow Alt. Avg.									Max. Flow Alt. Dry								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	107	217	325	87	58	145	20	159	179	33	86	119	87	58	144	(54)	29	(25)
Feb	113	216	329	68	45	114	44	171	215	31	91	122	6	4	10	25	87	112
Mar	92	252	343	66	44	110	26	208	233	36	119	154	84	56	140	(48)	63	14
Apr	101	267	369	49	33	82	52	234	287	52	180	232	16	11	27	36	169	205
May	129	321	450	50	33	83	79	288	367	75	243	318	30	20	50	45	223	269
Jun	132	351	483	53	35	89	79	316	394	88	278	367	41	27	68	47	251	299
Jul	178	340	518	58	39	97	120	301	421	135	265	400	18	12	30	116	253	370
Aug	122	312	434	62	42	104	59	271	330	71	240	311	16	11	27	54	230	284
Sep	70	181	252	58	39	97	12	142	154	46	129	175	35	23	58	11	106	117
Oct	37	126	163	50	34	84	(13)	92	79	28	91	119	47	31	78	(19)	59	40
Nov	53	130	183	65	43	108	(11)	86	75	29	74	103	28	19	47	0	55	56
Dec	79	171	250	77	51	127	3	120	123	29	72	101	44	29	74	(15)	43	28
Total	1,213	2,885	4,098	745	496	1,241	469	2,388	2,857	652	1,870	2,522	452	302	754	200	1,568	1,768
			-20.8%			-11.0%			-24.4%			-17.6%			-7.0%			-21.5%

	Percent Inflow Alt. Avg.									Percent Inflow Alt. Dry								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	113	220	334	89	59	148	25	161	186	35	86	121	96	64	160	(61)	22	(40)
Feb	115	210	325	71	48	119	43	163	206	31	82	113	73	49	122	(42)	33	(9)
Mar	91	250	341	69	46	115	23	204	226	34	120	154	68	45	113	(34)	75	41
Apr	107	279	386	54	36	90	54	243	296	54	183	237	44	29	73	10	154	164
May	157	363	520	57	38	96	100	325	424	101	268	370	30	20	50	71	248	319
Jun	179	420	599	68	45	114	111	375	486	137	314	452	71	47	118	67	267	334
Jul	255	449	704	79	52	131	176	397	573	183	324	507	44	29	73	139	295	434
Aug	187	437	624	73	49	122	114	388	503	152	307	459	47	31	78	105	276	381
Sep	112	257	370	64	43	107	48	214	262	81	173	254	32	21	54	49	151	200
Oct	72	197	268	60	40	99	12	157	169	33	108	141	42	28	70	(9)	80	71
Nov	72	165	238	70	47	117	2	118	120	38	94	132	66	44	111	(29)	50	21
Dec	101	204	305	80	53	133	21	151	172	34	81	115	48	32	80	(14)	49	34
Total	1,562	3,452	5,014	834	556	1,390	729	2,896	3,625	915	2,139	3,054	662	441	1,104	253	1,698	1,951
			-3.1%			-0.3%			-4.1%			-0.3%			36.0%			-13.3%

	TEIS																	
	CVP Hydro																	
	Energy (GWH)																	
	Flow Study Alt. Avg.									**Flow Study Alt. Dry**								
	Available Off Peak	**Available On Peak**	**Total Available**	**PU Off Peak**	**PU On Peak**	**Total PU**	**Available Off Peak for Sale**	**Available On Peak for Sale**	**Total Available for Sale**	**Available Off Peak**	**Available On Peak**	**Total Available**	**PU Off Peak**	**PU On Peak**	**Total PU**	**Available Off Peak for Sale**	**Available On Peak for Sale**	**Total Available for Sale**
Jan	114	222	336	88	59	147	26	163	189	32	84	117	90	60	151	(58)	24	(34)
Feb	115	209	324	69	46	115	46	163	209	27	81	108	31	21	52	(4)	60	56
Mar	92	249	341	69	46	114	23	203	226	30	116	147	55	37	91	(25)	80	55
Apr	100	265	365	52	35	87	48	230	278	54	166	220	67	45	112	(14)	121	108
May	161	357	519	56	38	94	105	320	425	91	243	334	14	9	24	77	233	311
Jun	166	397	563	66	44	109	100	354	454	115	299	414	13	9	22	101	290	392
Jul	248	439	687	72	48	120	176	391	567	162	314	476	15	10	24	147	304	451
Aug	178	426	604	72	48	120	106	378	483	122	309	431	33	22	55	89	287	376
Sep	118	264	382	64	43	107	54	221	275	89	207	296	38	25	64	51	182	232
Oct	64	184	248	61	41	102	3	143	146	38	115	153	46	31	77	(8)	85	76
Nov	68	156	224	68	46	114	(1)	111	110	35	92	128	48	32	80	(13)	60	48
Dec	97	199	296	80	53	133	17	146	163	37	83	120	82	55	136	(45)	29	(16)
Total	1,521	3,367	4,888	818	545	1,362	703	2,822	3,525	831	2,111	2,942	533	355	888	298	1,756	2,054
			-5.5%			-2.3%			-6.7%			-3.9%			9.5%			-8.7%
	Revised Existing Avg.									**Revised Existing Dry**								
	Available Off Peak	**Available On Peak**	**Total Available**	**PU Off Peak**	**PU On Peak**	**Total PU**	**Available Off Peak for Sale**	**Available On Peak for Sale**	**Total Available for Sale**	**Available Off Peak**	**Available On Peak**	**Total Available**	**PU Off Peak**	**PU On Peak**	**Total PU**	**Available Off Peak for Sale**	**Available On Peak for Sale**	**Total Available for Sale**
Jan	122	226	348	88	59	147	34	168	201	36	91	127	85	57	143	(49)	34	(15)
Feb	123	217	340	70	47	117	52	170	222	29	88	116	23	16	39	5	72	77
Mar	100	256	356	69	46	115	31	210	240	31	120	151	39	26	66	(8)	93	85
Apr	117	285	401	56	37	93	61	247	309	53	181	234	44	30	74	9	151	160
May	184	386	570	58	38	96	127	347	474	145	269	414	11	7	18	134	262	396
Jun	210	439	649	68	46	114	142	393	535	134	329	462	78	52	131	55	276	332
Jul	285	456	742	80	53	133	206	403	609	208	347	555	88	59	147	120	288	408
Aug	186	428	614	73	49	122	113	379	491	116	289	404	22	15	36	94	274	368
Sep	105	237	342	64	42	106	42	194	236	66	168	234	41	27	68	25	141	166
Oct	86	211	298	62	42	104	24	170	194	37	117	154	42	28	70	(4)	89	85
Nov	78	170	248	70	47	117	8	123	131	36	95	131	32	22	54	3	73	77
Dec	107	207	314	79	53	132	27	155	182	37	89	126	46	31	77	(9)	58	49
Total	1,703	3,517	5,220	837	558	1,396	866	2,959	3,825	927	2,181	3,109	552	370	922	376	1,811	2,187

TEIS

CVP Hydro

	Energy (GWH)									Energy (GWH)								
	Difference Avg. (No Action - No Action)									Difference Dry (No Action - No Action)								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Difference Avg. (State Permit Alt. - No Action)									Difference Dry (State Permit Alt. - No Action)								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	7	4	11	(1)	(0)	(1)	7	5	12	1	1	2	(1)	(0)	(1)	2	1	3
Feb	6	6	12	(1)	(1)	(1)	6	6	13	1	0	1	2	1	3	(1)	(1)	(2)
Mar	9	6	14	3	2	4	6	4	10	(1)	0	(0)	6	4	11	(7)	(4)	(11)
Apr	8	4	12	2	1	3	6	3	8	9	(7)	2	25	17	41	(16)	(24)	(40)
May	7	9	16	1	1	2	6	8	15	(8)	1	(7)	42	28	69	(50)	(26)	(76)
Jun	8	10	18	3	2	5	5	8	12	4	3	7	(36)	(24)	(60)	40	27	67
Jul	18	7	25	2	1	4	16	6	22	23	33	56	29	19	48	(6)	13	7
Aug	16	12	29	0	0	1	16	12	28	54	45	98	7	4	11	47	40	87
Sep	31	29	60	1	1	1	30	28	58	22	25	47	(2)	(2)	(4)	24	27	51
Oct	8	4	12	(0)	(0)	(0)	8	4	12	0	5	5	0	0	0	0	5	5
Nov	5	4	10	-	-	-	5	4	10	2	(1)	1	7	5	12	(5)	(6)	(11)
Dec	8	6	13	0	0	0	7	5	13	2	1	3	6	4	9	(4)	(2)	(6)
Total	130	100	231	11	7	18	120	93	213	109	106	215	84	56	139	25	51	76
			4.5%			1.3%			5.6%			7.0%			17.2%			3.4%

TEIS
CVP Hydro

	Energy (GWH)									Energy (GWH)								
	Difference Avg. (Max. Flow Alt. - No Action)									Difference Dry (Max. Flow Alt. - No Action)								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	(9)	(6)	(15)	(1)	(1)	(2)	(8)	(5)	(13)	(2)	(2)	(4)	(2)	(1)	(4)	0	(0)	0
Feb	(5)	4	(1)	(2)	(2)	(4)	(2)	5	3	4	8	13	(7)	(5)	(12)	11	13	24
Mar	(3)	(2)	(5)	(2)	(1)	(3)	(1)	(1)	(2)	5	1	6	42	28	71	(37)	(27)	(65)
Apr	(8)	(13)	(21)	(5)	(3)	(8)	(4)	(10)	(13)	6	4	10	(1)	(1)	(1)	7	5	12
May	(53)	(67)	(120)	(8)	(6)	(14)	(45)	(61)	(106)	(45)	(46)	(91)	13	8	21	(58)	(54)	(112)
Jun	(81)	(91)	(172)	(15)	(10)	(26)	(66)	(81)	(146)	(51)	(53)	(105)	(31)	(21)	(52)	(21)	(33)	(53)
Jul	(102)	(122)	(224)	(22)	(14)	(36)	(81)	(108)	(189)	(72)	(76)	(148)	(19)	(13)	(32)	(53)	(63)	(116)
Aug	(61)	(120)	(181)	(11)	(8)	(19)	(50)	(113)	(162)	(45)	(42)	(87)	(23)	(15)	(38)	(22)	(27)	(49)
Sep	(30)	(60)	(90)	(6)	(4)	(10)	(24)	(56)	(80)	(21)	(39)	(59)	(4)	(3)	(6)	(17)	(36)	(53)
Oct	(41)	(84)	(124)	(10)	(7)	(16)	(31)	(77)	(108)	(8)	(19)	(27)	6	4	10	(14)	(23)	(37)
Nov	(22)	(40)	(62)	(6)	(4)	(10)	(16)	(36)	(52)	(9)	(22)	(31)	(11)	(7)	(18)	2	(15)	(12)
Dec	(24)	(36)	(59)	(3)	(2)	(6)	(20)	(33)	(53)	(6)	(12)	(18)	2	2	4	(8)	(14)	(22)
Total	(439)	(636)	(1,075)	(92)	(61)	(153)	(347)	(575)	(922)	(243)	(297)	(540)	(34)	(23)	(57)	(209)	(274)	(483)
			-20.8%			-11.0%			-24.4%			-17.6%			-7.0%			-21.5%

	Difference Avg. (Percent Inflow Alt. - No Action)									Difference Dry (Percent Inflow Alt. - No Action)								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	(3)	(3)	(6)	0	0	1	(3)	(3)	(6)	(0)	(2)	(2)	7	5	12	(7)	(7)	(14)
Feb	(3)	(2)	(5)	1	0	1	(3)	(3)	(6)	4	(1)	4	60	40	100	(56)	(41)	(97)
Mar	(3)	(5)	(8)	1	1	1	(4)	(5)	(9)	4	3	6	26	18	44	(23)	(15)	(38)
Apr	(2)	(1)	(4)	(0)	(0)	(0)	(2)	(1)	(4)	8	7	15	27	18	45	(19)	(10)	(29)
May	(25)	(25)	(50)	(1)	(0)	(1)	(24)	(24)	(49)	(19)	(21)	(40)	13	8	21	(32)	(30)	(61)
Jun	(34)	(22)	(56)	(0)	(0)	(0)	(33)	(22)	(55)	(2)	(17)	(20)	(1)	(1)	(2)	(1)	(17)	(18)
Jul	(26)	(12)	(38)	(1)	(1)	(2)	(25)	(11)	(36)	(23)	(17)	(41)	7	5	12	(30)	(22)	(52)
Aug	5	4	9	(1)	(0)	(1)	5	5	10	37	24	61	8	5	13	29	19	48
Sep	12	16	28	(0)	(0)	(1)	12	16	28	15	5	20	(6)	(4)	(10)	21	10	30
Oct	(7)	(13)	(19)	(1)	(0)	(1)	(6)	(12)	(18)	(3)	(2)	(5)	1	1	2	(4)	(2)	(6)
Nov	(3)	(4)	(7)	(0)	(0)	(1)	(2)	(4)	(6)	0	(2)	(2)	27	18	45	(27)	(21)	(47)
Dec	(2)	(2)	(4)	(0)	(0)	(0)	(2)	(2)	(4)	(0)	(4)	(4)	6	4	11	(7)	(8)	(15)
Total	(90)	(69)	(159)	(3)	(2)	(4)	(87)	(67)	(154)	20	(28)	(8)	175	117	292	(156)	(145)	(300)
			-3.1%			-0.3%			-4.1%			-0.3%			36.0%			-13.3%

TEIS
CVP Hydro

	Energy (GWH)									Energy (GWH)								
	Difference Avg. (Flow Study Alt. - No Action)									Difference Dry (Flow Study Alt. - No Action)								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	(2)	(1)	(4)	(0)	(0)	(0)	(2)	(1)	(4)	(3)	(4)	(6)	1	1	3	(4)	(5)	(9)
Feb	(3)	(3)	(6)	(2)	(1)	(3)	(1)	(2)	(3)	(0)	(2)	(2)	18	12	30	(18)	(14)	(32)
Mar	(3)	(5)	(8)	1	0	1	(3)	(6)	(9)	(1)	(1)	(2)	13	9	22	(14)	(10)	(24)
Apr	(10)	(15)	(25)	(2)	(1)	(3)	(8)	(14)	(22)	8	(10)	(2)	50	33	83	(43)	(43)	(85)
May	(20)	(31)	(51)	(2)	(1)	(3)	(19)	(29)	(48)	(29)	(46)	(75)	(3)	(2)	(5)	(26)	(44)	(70)
Jun	(47)	(45)	(92)	(3)	(2)	(5)	(44)	(43)	(87)	(25)	(32)	(57)	(58)	(39)	(97)	33	7	40
Jul	(33)	(23)	(56)	(8)	(5)	(13)	(25)	(17)	(42)	(45)	(28)	(72)	(23)	(15)	(37)	(22)	(13)	(35)
Aug	(5)	(7)	(11)	(1)	(1)	(2)	(3)	(6)	(9)	7	26	33	(6)	(4)	(10)	13	30	43
Sep	18	23	40	(0)	(0)	(1)	18	23	41	22	40	62	(0)	(0)	(0)	22	40	62
Oct	(14)	(26)	(40)	1	0	1	(15)	(26)	(41)	2	6	7	5	3	8	(3)	3	(1)
Nov	(7)	(13)	(20)	(2)	(2)	(4)	(5)	(12)	(16)	(2)	(4)	(6)	9	6	14	(11)	(10)	(20)
Dec	(6)	(8)	(13)	0	0	0	(6)	(8)	(14)	2	(1)	1	40	27	67	(38)	(28)	(66)
Total	(132)	(154)	(285)	(19)	(13)	(32)	(113)	(141)	(254)	(64)	(56)	(120)	46	31	77	(110)	(87)	(197)
			-5.5%			-2.3%			-6.7%			-3.9%			9.5%			-8.7%

	Difference Avg. (Revised Existing - No Action)									Difference Dry (Revised Existing - No Action)								
	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale	Available Off Peak	Available On Peak	Total Available	PU Off Peak	PU On Peak	Total PU	Available Off Peak for Sale	Available On Peak for Sale	Total Available for Sale
Jan	6	3	8	(0)	(0)	(0)	6	3	9	1	3	4	(4)	(2)	(6)	5	5	10
Feb	5	5	10	(0)	(0)	(0)	5	5	10	2	5	7	10	7	17	(8)	(2)	(11)
Mar	6	1	7	1	1	2	4	1	5	0	2	2	(2)	(1)	(3)	3	3	6
Apr	7	5	12	2	1	3	5	4	9	7	5	12	27	18	45	(20)	(13)	(33)
May	2	(2)	0	(0)	(0)	(1)	3	(2)	1	24	(20)	4	(7)	(4)	(11)	31	(16)	15
Jun	(2)	(3)	(6)	(0)	0	(0)	(2)	(3)	(5)	(6)	(3)	(9)	6	4	11	(13)	(7)	(20)
Jul	5	(6)	(1)	0	(0)	(0)	5	(5)	(1)	2	6	7	51	34	85	(49)	(29)	(78)
Aug	3	(5)	(2)	(1)	(0)	(1)	4	(5)	(1)	0	6	6	(17)	(11)	(29)	17	17	35
Sep	5	(4)	0	(1)	(1)	(2)	6	(4)	2	(1)	0	(1)	3	2	4	(4)	(1)	(5)
Oct	8	2	10	2	1	3	6	0	7	2	8	9	1	0	1	1	7	8
Nov	3	1	3	(1)	(0)	(1)	3	1	4	(1)	(2)	(3)	(7)	(5)	(11)	5	3	8
Dec	4	1	4	(0)	(1)	(1)	4	1	5	3	4	7	4	3	7	(1)	1	(0)
Total	51	(4)	47	1	1	2	50	(4)	46	32	14	47	65	46	111	(33)	(32)	(64)
			0.9%			0.1%			1.2%			1.5%			13.7%			-2.9%

Table A

IMPACT ON "AVERAGE" WESTERN CUSTOMER							
Alternative	Change in CVP value $1,000	GWH for Sale	Change in CVP Energy Available for Sale GWH	% change in CVP Available Energy	Average Replacement Rate (1) $/MWH	% CVP used in Customer load	Change in Customers Total Cost of Power $/MWH
No Action	N/A	3521	N/A	N/A		14.00%	
State Permit	$ 7,101	3686	165	4.7%	$ 43.04	14.66%	$ (0.28)
Maximum Flow	$ (24,608)	2660	-861	-24.5%	$ 28.58	10.58%	$ 0.98
Percent Inflow	$ (1,911)	3372	-149	-4.2%	$ 12.83	13.41%	$ 0.08
Flow Study	$ (8,395)	3263	-258	-7.3%	$ 32.54	12.97%	$ 0.33
IMPACT ON "HIGH ALLOCATION" WESTERN CUSTOMER							
Alternative	Change in CVP value $1,000	GWH for Sale	Change in CVP Energy Available for Sale GWH	% change in CVP Available Energy	Average Replacement Rate (1) $/MWH	% CVP used in Customer load	Change in Customers Total Cost of Power $/MWH
No Action	N/A	3521	N/A	N/A		85.00%	
State Permit	$ 7,101	3686	165	4.7%	$ 43.04	88.98%	$ (1.71)
Maximum Flow	$ (24,608)	2660	-861	-24.5%	$ 28.58	64.21%	$ 5.94
Percent Inflow	$ (1,911)	3372	-149	-4.2%	$ 12.83	81.40%	$ 0.46
Flow Study	$ (8,395)	3263	-258	-7.3%	$ 32.54	78.77%	$ 2.03
(1) Represents the purchase of energy comparable to that lost or gained at market rates							

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Table A							
TEIS Results							
IMPACT ON "AVERAGE" WESTERN CUSTOMER							
Alternative	Change in CVP value $1,000	GWH for Sale	Change in CVP Energy Available for Sale GWH	% change in CVP Available Energy	Average Replacement Rate (1) $/MWH	% CVP used in Customer load	Change in Customers Total Cost of Power $/MWH
No Action	N/A	3,779	N/A	N/A		14.00%	
1	$ 5,937	3,992	212.76	5.6%	$ 27.91	14.79%	$ (0.22)
2	$ (26,036)	2,857	(921.70)	-24.4%	$ 28.25	10.59%	$ 0.96
3	$ (7,023)	3,625	(154.36)	-4.1%	$ 45.50	13.43%	$ 0.26
4	$ (5,564)	3,525	(253.57)	-6.7%	$ 21.94	13.06%	$ 0.21
IMPACT ON "HIGH ALLOCATION" WESTERN CUSTOMER							
Alternative	Change in CVP value $1,000	GWH for Sale	Change in CVP Energy Available for Sale GWH	% change in CVP Available Energy	Average Replacement Rate (1) $/MWH	% CVP used in Customer load	Change in Customers Total Cost of Power $/MWH
No Action	N/A	3,779	N/A	N/A		85.00%	
1	$ 5,937	3,992	212.76	5.6%	$ 27.91	89.79%	$ (1.34)
2	$ (26,036)	2,857	(921.70)	-24.4%	$ 28.25	64.27%	$ 5.86
3	$ (7,023)	3,625	(154.36)	-4.1%	$ 45.50	81.53%	$ 1.58
4	$ (5,564)	3,525	(253.57)	-6.7%	$ 21.94	79.30%	$ 1.25
(1) Represents the purchase of energy comparable to that lost or gained at market rates							