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Central Valley Project Power Resources Report ("Green Book 2004")

Introduction

This report presents an update to a previous report published by the Western Area Power Administration (Western) in July 2000 entitled "Green Book, Post-2004 Power Marketing Plan, Base Resource". The purpose of the original and this revised Green Book analysis is to provide the customers and Western a basis for determining how much Base Resource power can be expected in future years under a range of possible hydrologic conditions.

This revised analysis presents the results of two separate, but related, studies. The first study focused on historic generation available from the Central Valley Project (CVP) in Water Year 2002. For this study, Western analyzed hourly historical capability and generation data. In addition to the Base Resource representation derived from this effort, this study was used to define hourly, and on-peak[1] and off-peak relationships that were used in a second study to define long-term Base Resource availability.

This latter study is similar to the original Green Book analysis in that the historical hydrology was used to look at the full range of expected hydrologic conditions and resulting project operation. The currently available, long-term hydrology consists of monthly hydrologic data from 1922 through 1994 (73 years) that has been updated to reflect current conditions. This data takes into account current land use patterns and facilities that exist on the river systems today in its determination of streamflows and inflows to reservoirs. This is the same database that is used by both the Bureau of Reclamation (Reclamation) and the California Department of Water Resources (DWR) to model the CVP and the State Water Project (SWP) for long-term planning purposes.

[1] On-peak refers to the period Monday through Saturday, 6:00 AM to 10:00 PM as defined by NERC and WECC operating guidelines. References to off-peak periods refers to the period Monday through Saturday, 10:00 PM to 6:00 AM, and all hours on Sunday & established Holidays.

In both studies, forecasts of project pumping (Project Use), the loads of Western's First Preference customers, and regulation and control area reserve requirements were taken into account in determining the availability of Base Resource capacity and energy. The long-term study identifies forecasts of monthly Base Resource energy for a range of representative water year types. From the monthly output, average daily power generation was computed and the on and off-peak relationships derived from the Water Year 2002 study were applied as rule-of-thumb estimates to determine Base Resource generation distribution.

One additional aspect of the long-term analysis is that the monthly data is presented with sub-periods in the months of April, May and August. These 3 months are split in two sub-periods that result in tables that show 15 periods of data instead of the 12 normally seen in monthly studies. Western recognizes that this may create some additional work for customers inputting data into monthly models. In making the decision to use 15 instead of 12 periods, Western felt the differences in Base Resource in the first and second halves of these months were significant enough to warrant this additional detail. The primary reason for the changes in Base Resource typically experienced in these months is the operations at the Tracy Pumping Plant and the San Luis Reservoir to accommodate changing water operations criteria. As assumed in the study, the availability of Base Resource power will typically change at some point around the middle of these months. Since the exact date of change can vary from year to year, using the mid-point of these months was considered a reasonable assumption.

The studies show that the range of Base Resource power will vary significantly depending upon hydrologic conditions for any particular year. Interestingly the monthly analysis shows that customers can expect less variation in Base Resource energy between year types in summer months than in other seasons. The largest variation in Base Resource energy will occur during the months from December through April between year types.

1. Need for Revised Green Book

Since the publication of the Green Book in July 2000, a number of important developments have changed project operations sufficient to warrant an update of the Green Book. These developments include:

- Revisions in water operations due to implementation of certain aspects of the Central Valley Project Improvement Act (CVPIA), the Federal Endangered Species Act 16 U.S.C. Sec. 1536 (a)(2), and the CALFED Record of decision which was signed by Reclamation and other federal and state agencies in August 2000.

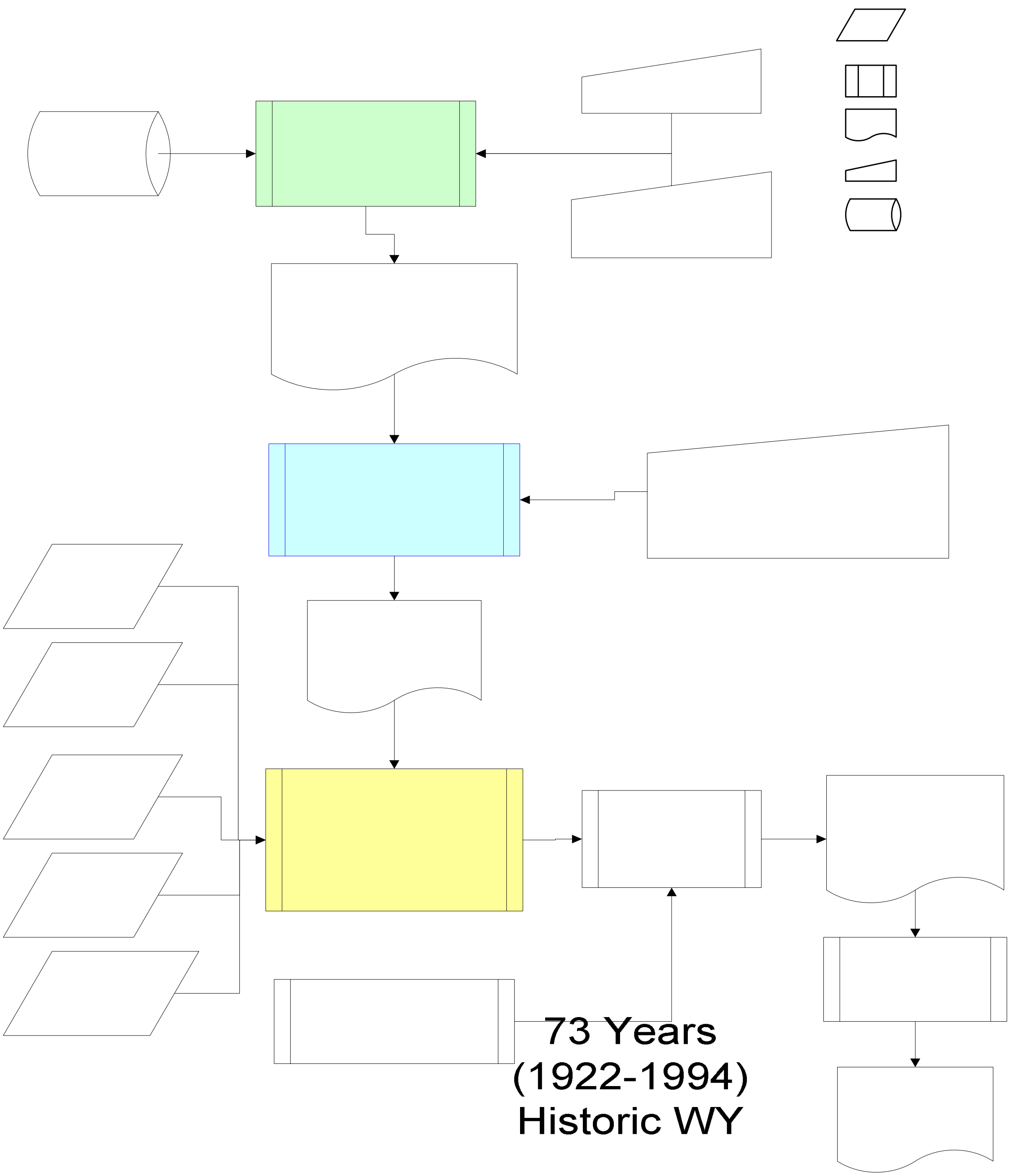
- Interim and pending decisions pursuant to the Trinity Environmental Impact Statement (EIS) affecting reservoir releases and diversions to the Sacramento River through Trinity River Division powerplants; and

- Upgrades in CVP power facilities[2].

Figure 1-1 provides an overview of the study components, modeling methods, inputs and outputs used to forecast available Base Resource.

[2] Changes to physical powerplant facilities, such as turbine runner replacements at Shasta and Folsom.

Figure 1-1 - Study Overview



2. CVP Hydro Power

The information presented in this section was extracted from Reclamation's "Long-Term Central Valley Project Operations Criteria and Plan (CVP-OCAP)", dated June 30, 2004. Applicable sections from that report have been edited as needed to provide the information deemed relevant to this report. For a more complete and detailed discussion of CVP operations, the reader can access the full OCAP at http://www.usbr.gov/mp/cvo/ocapba.html.

2.1 Background

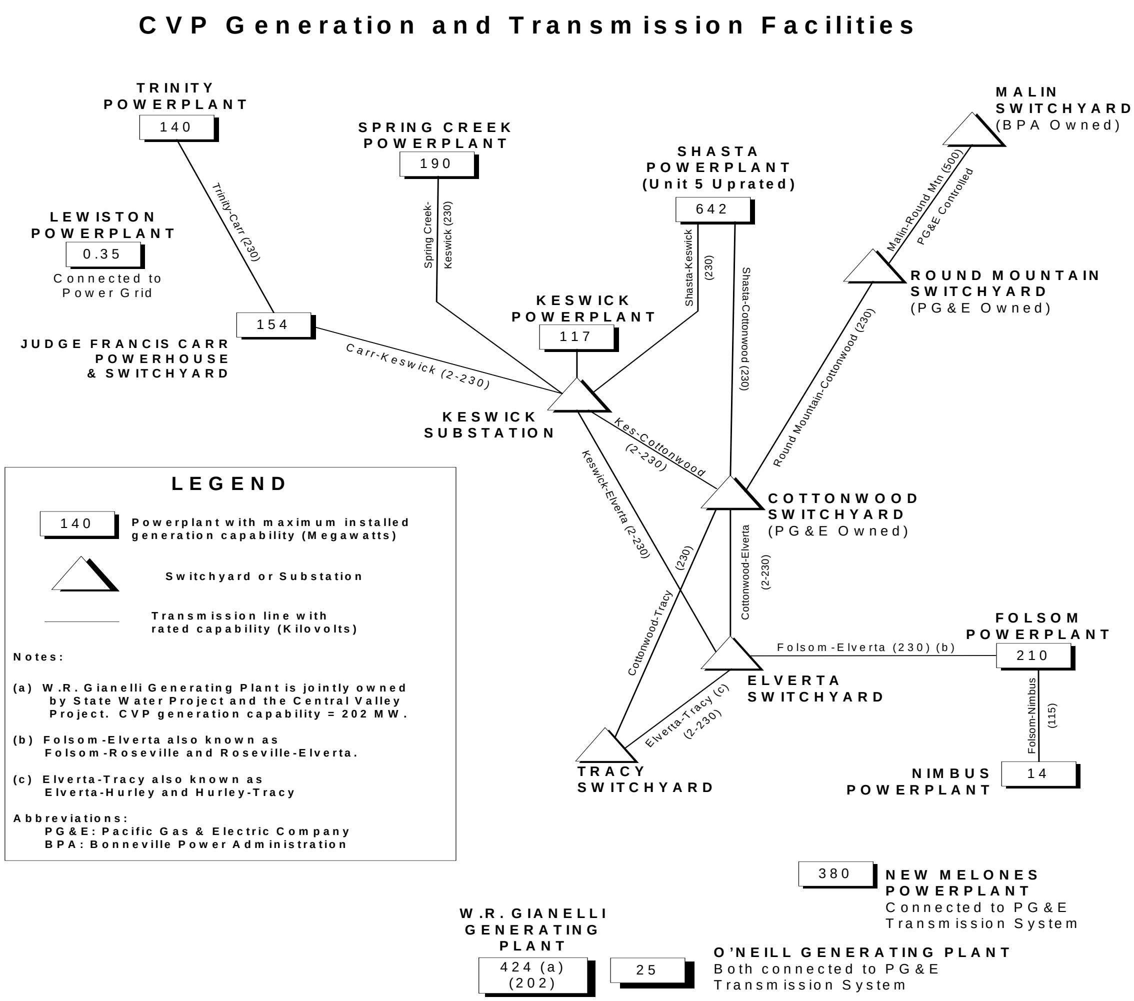
CVP power generation facilities include 11 hydroelectric powerplants with 38 generators with a total maximum generating capacity of 2,074 megawatts (MW). The CVP also includes 856 circuit miles of high-voltage transmission lines used to deliver CVP power. The transmission system is operated and maintained by Western and excess capacity is marketed under Western's Open Access Tariff.

CVP hydroelectric power is delivered to loads throughout central and northern California. Under Reclamation law, the first priority for CVP power is to meet the authorized loads of the project including irrigation pumping, municipal and industrial needs, authorized fish and wildlife purposes, and station service at CVP facilities. Approximately 25 percent to 30 percent of the CVP's power generation is typically used to support these "Project Use" needs. Western markets the remaining power to Preference Customers such as Federal agencies, military bases, municipalities, public utilities districts, irrigation and water districts, and state agencies.

In addition to providing peaking generation to the central and northern California power system, the CVP supplies many secondary benefits to the power system including VAR (magnetic or inductive power) support, regulation, spinning reserves, and black-start capabilities. A schematic of primary CVP generation and transmission facilities are shown in Figure 2-1.

For more information on the Central Valley Basin, please refer to Appendix A – Description of the Central Valley.

Figure 2-1 CVP Generation and Transmission Facilities



2.2. Reclamation Law

The body of laws applicable to CVP facilities is known as Reclamation law, including authorizing legislation for each facility. Initially, Reclamation projects were authorized under the Reclamation Act of 1902. This Act authorized projects to be developed solely for irrigation and reclamation purposes. In 1906, Reclamation law was amended to include power as a purpose of the projects if power was necessary for operation of the irrigation water supply facilities, or if power could be developed economically in conjunction with the water supply projects. The Act of 1906 allowed for lease of surplus power. Surplus power was described as power that exceeds the capacity and energy required to operate the Reclamation facilities (Project Use load). The Act of 1906 stipulated that surplus power would be leased with preference for municipal purposes.

Power supply was first authorized as a purpose for some CVP facilities in the Rivers and Harbors Act of 1937 that included the authorization for the initial CVP facilities. The Act of 1937 defined the priorities for the purposes of the CVP as: (1) navigation and flood control, (2) irrigation and municipal and industrial water supplies, and (3) power supply.

The Reclamation Project Act of 1939 modified Reclamation law for all Reclamation facilities, including the CVP. This act reconfirmed the preference clause, and included the policy that the federal government would market power to serve the public interest rather than to produce a profit.

The Trinity River Act of 1955 authorized construction of the Trinity River Division (TRD) and allocated up to 25 percent of the energy resulting from the TRD to Trinity County.

The Rivers and Harbor Act of 1962 authorized the New Melones project and authorized up to 25 percent of the energy resulting from that project to Calaveras and Tuolumne counties. Customers receiving energy under these authorizations are referred to as "First Preference" customers.

The CVPIA modified the authorizations of the CVP making fish and wildlife mitigation a higher priority than power, and power and fish and wildlife enhancement equal priorities. The CVPIA also established specific mitigation objectives and the CVPIA Restoration Fund which requires payments from CVP water and power customers to fund fish and wildlife mitigation activities.

2.3. Marketing of CVP Power

Before 1977, Reclamation operated the CVP power generation and transmission facilities and marketed the power generated by the CVP facilities. In 1977, Western was established as part of the Department of Energy. One of the functions transferred to Western was to operate, maintain, and upgrade the transmission grid that was constructed as part of the CVP. As part of its marketing functions, Western ensures that Project Use loads are met by project generation or purchases, and then markets the remaining CVP generation to Preference Power Customers or to the market.

Hydropower generation does not always occur during times of peak power needs of Project Use and Preference Power Customer loads. As originally conceived, the CVP included federally constructed thermal generation and transmission as needed to ensure that project and customer loads were met at all times. In the mid 1960s, it was determined that it would be more cost-effective to co-utilize generation and transmission facilities constructed by the Pacific Gas and Electric Company (PG&E) wherever possible to avoid duplication of facilities. In 1967, the United States Government, represented by Reclamation and PG&E signed an agreement, Contract No. 14-06-200-2948A (Contract 2948A) that provided for the sale, interchange, and transmission of electrical power between the Federal Government and PG&E. After it was established, Western assumed responsibilities for administering Contract 2948A. Under the terms of Contract 2948A, the generation of CVP hydropowerplants is integrated into PG&E’s resources, along with qualified power purchases made by Western. In return, PG&E supports firm power deliveries to Western’s Project Use and Preference Customers loads.

The CVP is operated whenever possible to optimize the use of generated power. Reclamation, Western, and PG&E work together on a daily basis to balance loads and resources and assess transmission capabilities. Daily operations are prescheduled on a day-ahead basis. Reclamation determines the required hourly stream flows and releases from CVP facilities including Keswick, Lewiston, Tulloch, and Nimbus reservoirs to meet water demands and water quality requirements. Reclamation develops a Project Use schedule and initial generation schedule to support the water release requirements and sends the information to the Western dispatch office, which coordinates with the PG&E dispatch center. All three entities confirm and, if necessary, adjust schedules as needed.

Western currently markets 1,470 MW of power to over 70 Preference customers in California which include 11 municipalities, 1 rural electric cooperative, 23 federal installations, 8 state-owned installations, 10 public utility districts, 22 water and irrigation districts and the Bay Area Rapid Transit.

Both Contract 2948A and the current marketing plan under which Western markets CVP power expire on December 31, 2004. Western, in consultation with its customers and other interested stakeholders, developed the Post-2004 Power Marketing Plan (the Marketing Plan), which will be implemented beginning January 2005. Under Contract 2948A, Western supplies customers with a fixed capacity and load-factored energy within minimum and maximum entitlement amounts.

Under the Marketing Plan, customers will receive the net power output of the project after project needs are met. This power resource is referred to as the "Base Resource." The Marketing Plan allows existing customers to receive a percentage allocation of the Base Resource based primarily on their existing Contract Rate of Delivery (CRD). The Base Resource is a fundamental component of the Marketing Plan.

Customers are generally divided into three groups for the Marketing Plan: Base Resource, Variable Resource, and Full Load Service Customers. Base Resource Customers are those customers that will only receive Base Resource power from Western. Variable Resource Customers are customers that opt for Base Resource firming service and/or supplemental power from Western in addition to their Base Resource. These first two categories of customers will receive approximately 85 percent of the Base Resource. The third category of customers, Full Load Service Customers, are customers who will have their total load met by Western through a combination of their Base Resource and additional purchases by Western on their behalf. These customers will receive approximately 15 percent of the Base Resource.

Beginning in 2005, Western expects to have up to 77 CVP Preference Power Customers, 64 existing customers and 13 new allottees. Of the existing customers, four are First Preference entities. First Preference Customers are a special class of customers who are legislatively entitled to up to 25 percent of the generation built in their counties. The two projects whose enabling legislation provided for First Preference power are New Melones, which is located in Tuolumne and Calaveras counties, and Trinity, which is located in Trinity County. First Preference power has priority over other types of preference power in the Marketing Plan.

As part of a nation-wide trend to deregulate the electric power industry, the California Independent System Operator (CAISO) began operation in 1998. Prior to the CAISO, PG&E was the Control Area Operator (CAO) for northern and central California, and under its integration contract with PG&E, Western had almost unlimited flexibility in scheduling its loads and resources. Under the CAISO, scheduling requirements for power have changed significantly. Generation schedules must now be submitted several days prior to the actual day of operation. Under newly proposed guidelines, future operations changes made during the actual day of operation can result in penalties to the generator. Since the formation of the CAISO, PG&E has served as a "Scheduling Coordinator" for the CVP, and under Contract 2948A, the CVP has not been subject to these scheduling requirements. With the expiration of Contract 2948A and the implementation of the new Marketing Plan, Western will act as Scheduling Coordinator for Project Use loads and for preference customers that request the service.

2.4. CVP Repayment

Power rates for Preference Power Customers are determined by Western. The rates must be sufficient to pay all costs assigned to the power function of the project. Power revenues pay for applicable operation and maintenance costs, interest expenses on the federal investment for construction of CVP facilities, and the investment in federal transmission facilities. Costs assigned to power also include some costs otherwise assigned to the irrigation function that are determined to be beyond the ability to pay certain CVP water contractors. In addition, pursuant to the CVP Improvement Act, Western collects monies for mitigation of environmental impacts of the CVP which are deposited in the CVPIA Restoration Fund and used for mitigation activities.

For more information on CVP repayment the reader can access Western's website at http://www.wapa.gov/sn/ and follow the links to rates information.

3. Water Year 2002 Simulation and Generation Shift Modeling

3.1. Hourly Base Resource Distribution

The ability to shape daily and hourly generation, and subsequently the CVP Base Resource, is highly dependent on the total generation amount, the source of the generation (which CVP powerplant), and the Project Use and First Preference loads that the CVP will have to meet. All of the major CVP powerplants have re-regulating reservoirs, sometimes referred to as afterbays, which allow the generation to be shaped. It is important to understand that CVP operational criteria does not provide for fluctuating of river releases for power generation. For each of the CVP powerplants, their corresponding afterbays' have unique characteristics that allow each plant to be operated in a slightly different manner. The ability to shape generation is influenced by several factors such as the available afterbay storage, rate of release from the afterbay, unregulated inflow into the afterbay, allowable rate of change of afterbay elevations, allowable ramp rates for various generating units, and possible environmental constraints such as water temperature needs. Operations and the ability to peak generation and the Base Resource will also be significantly impacted by the need for ancillary services such as requirements to meet reserve and regulation criteria.

Without knowledge of specific customer loads and resources available to customers, other than CVP generation, a final generation shape appropriate for customer portfolios cannot be determined. In lieu of trying to determine the shape customers will desire for Base Resource schedules, Western has analyzed the flexibility available from the CVP to shape generation. To examine the ability to shape CVP generation, it is helpful to look at actual operations experienced in previous years. To illustrate the possible distribution of CVP Generation between On-Peak and Off-Peak periods, Water Year (WY) 2002, October 2001 to September 2002, was used.

WY 2002 was classified as a dry year based on the Sacramento Valley 40-30-30 Water Year Index. Total CVP generation, adjusted for transmission losses, for WY 2002 was 4,221 gigawatthours (GWh). Project Use and First Preference load for WY 2002 totaled 1,422 GWh, or roughly one third of the total generation. If this generation and load combination occurred in the post-2004 period, the available Base Resource would be approximately 2,900 GWh. Based on the 73-year generation trace developed for this 2004 Green Book revision, the amount of Base Resource available is expected to exceed this amount 55 percent of the time. The monthly distribution of WY 2002 generation and load is shown in Table 3-1.

Table 3-1 – Water Year 2002 Monthly Generation and Loads

Central Valley Project Generation and Load

Generation			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Monthly Total	Off-Peak	GWh	85.7	36.4	33.4	69.1	28.5	62.0	91.7	183.6	199.8	225.4	145.6	102.8	1264.0
	On-Peak	GWh	219.2	91.1	94.8	156.2	119.1	171.0	245.1	350.5	435.8	469.3	382.6	221.9	2956.6
	Total	GWh	304.8	127.6	128.2	225.2	147.6	232.9	336.8	534.1	635.6	694.7	528.2	324.7	4220.6
Percent of Monthly Total	Off-Peak	%	28%	29%	26%	31%	19%	27%	27%	34%	31%	32%	28%	32%	30%
	On-Peak	%	72%	71%	74%	69%	81%	73%	73%	66%	69%	68%	72%	68%	70%
Percent of Water Year Total	Off-Peak	%	7%	3%	3%	5%	2%	5%	7%	15%	16%	18%	12%	8%	100%
	On-Peak	%	7%	3%	3%	5%	4%	6%	8%	12%	15%	16%	13%	8%	100%
	Total	%	7%	3%	3%	5%	3%	6%	8%	13%	15%	16%	13%	8%	100%
Daily Average	Off-Peak	GWh	2.8	1.2	1.1	2.2	1.0	2.0	3.1	5.9	6.7	7.3	4.7	3.4	3.5
	On-Peak	GWh	7.1	3.0	3.1	5.0	4.3	5.5	8.2	11.3	14.5	15.1	12.3	7.4	8.1
	Total	GWh	9.8	4.3	4.1	7.3	5.3	7.5	11.2	17.2	21.2	22.4	17.0	10.8	11.6
Standard Deviation of Daily Average	Off-Peak	GWh	3.0	1.2	1.4	2.5	1.5	2.2	3.5	5.1	6.6	6.6	4.8	3.9	4.5
	On-Peak	GWh	3.3	1.4	1.6	2.8	1.9	2.6	4.2	5.3	6.8	6.8	5.2	4.0	5.9
	Total	GWh	2.1	0.7	0.5	2.9	0.9	1.1	3.4	2.0	2.3	0.9	2.4	1.8	6.5
Combined Project Use + First Preference Load			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
Monthly Total	Off-Peak	GWh	56.4	53.3	39.6	98.9	54.8	65.3	36.2	30.3	52.2	66.5	57.4	90.1	701.1
	On-Peak	GWh	51.9	52.0	34.1	75.8	53.6	65.4	47.0	38.5	65.8	87.3	82.6	67.0	720.9
	Total	GWh	108.2	105.3	73.7	174.7	108.4	130.7	83.2	68.8	118.0	153.8	140.0	157.1	1421.9
Percent of Monthly Total	Off-Peak	%	52%	51%	54%	57%	51%	50%	44%	44%	44%	43%	41%	57%	49%
	On-Peak	%	48%	49%	46%	43%	49%	50%	56%	56%	56%	57%	59%	43%	51%
Percent of Water Year Total	Off-Peak	%	8%	8%	6%	14%	8%	9%	5%	4%	7%	9%	8%	13%	100%
	On-Peak	%	7%	7%	5%	11%	7%	9%	7%	5%	9%	12%	11%	9%	100%
	Total	%	8%	7%	5%	12%	8%	9%	6%	5%	8%	11%	10%	11%	100%
Daily Average	Off-Peak	GWh	1.8	1.8	1.3	3.2	2.0	2.1	1.2	1.0	1.7	2.1	1.9	3.0	1.9
	On-Peak	GWh	1.7	1.7	1.1	2.4	1.9	2.1	1.6	1.2	2.2	2.8	2.7	2.2	2.0
	Total	GWh	3.5	3.5	2.4	5.6	3.9	4.2	2.8	2.2	3.9	5.0	4.5	5.2	3.9
Standard Deviation of Daily Average	Off-Peak	GWh	1.3	1.2	1.2	1.7	1.4	1.2	0.6	0.5	0.9	1.2	0.9	1.2	1.3
	On-Peak	GWh	0.9	0.8	0.7	1.2	0.8	1.0	0.8	0.6	1.0	1.3	1.1	1.2	1.1
	Total	GWh	1.5	0.7	1.2	0.7	1.0	0.8	0.8	0.2	0.5	0.2	0.5	1.0	1.3
Average Daily Net Generation			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
(Based on Daily Average Generation and Load)		GWH	8.0	2.5	2.9	4.1	3.3	5.4	10.0	16.3	19.4	20.3	15.2	7.8	9.6

3.2. Generation Shaping

In recognition of the fact that the CVP was operated under Contract 2948A with PG&E in WY 2002, that year's operation may not fully demonstrate the flexibility of the CVP. However, given that WY 2002 was close to a normal hydro-year, it provides a good basis to analyze how project generation can be shaped on a daily basis and provides representative data to determine reasonable assumptions related to the relative distribution of energy between on and off-peak hours. This actual generation data inherently incorporates the required operating constraints of the CVP. The objective of this analysis was to look at daily generation levels and determine how generation could be shaped. The analysis further recognized that while WY 2002 provides a very limited sample of operations, it does provide a wide range of daily generation levels. It is important to note, however, that this is a very limited data set and does not include all possible operating constraints that may be encountered in future operations.

Hourly data based on WY 2002 was developed as part of the recent work done for Post 2004 CVP Rates. Actual hourly CVP generation and Project Use and First Preference load data is available for this period. The forward purchase that will be made to support CVP Project Use pumping and First Preference loads was also included in the analysis.

As mentioned previously, in WY 2002, the CVP was still operated under Contract 2948A with PG&E, and the historic hourly generation would not necessarily match the likely future dispatch that would be used to meet post Contract 2948A requirements. Since the first priority of the CVP is to meet Project Use and First Preference needs, and under existing operations much of the Off-Peak portion of these loads is not met by CVP resources, but by PG&E, it was recognized that some adjustment would be needed in the WY 2002 generation to reflect a more realistic operating scenario. To maximize the use of CVP generation for meeting Project Use and First Preference loads, it was assumed that generation could be shifted within the day to meet these loads. This was done by first reducing the Project Use and First Preference loads by the forward purchase being made to help meet these loads. The forward purchase was completely consumed by the WY 2002 loads. Generation was then shifted to the extent possible to meet the remaining unmet portions of these loads.

For this evaluation, individual CVP plant generation was totaled (adjusted for assumed transmission losses). It was then assumed that the minimum total system generation occurring during the day had to be maintained, and any hourly generation above this minimum could be shifted. For days when generation was insufficient to meet the loads, it was assumed supplemental energy would be acquired (possibly from an exchange account) to meet the loads. It is possible additional shifting of generation between days could have been accommodated, but that was not done for this analysis because it would have required a more detailed analysis of the water operations than was possible with the existing tools.

Once the required Project Use and First Preference loads were met, an estimate of the Base Resource (the net CVP generation after meeting the required loads) was made. It was further assumed that the generation would be most valuable during on-peak periods, and that CVP customers would get the most value from the project by maximizing the on-peak CVP generation available. To maximize the value of CVP generation, any remaining generation available after meeting required loads and maintaining daily minimums was shifted to on-peak. This was done by totaling energy available and distributing it over the hours between 6 AM and 10 PM each day in a pattern similar to the actual historical generation pattern. The hourly maximum capacity was assumed to be limited to the maximum CVP hourly system generation that occurred on the current day. It was assumed that this methodology would account for any potential outages or head-dependent capacity limits that occurred. In addition, it should be noted that since the CVP currently supplies some ancillary services to PG&E, using actual generation data means that these generation limits already include some level of ancillary services.

Figure 3-1 – "Estimated Weekly Generation and Base Resource for Week 10" covers the period December 3 through December 9 and provides an example of how the generation shifting algorithm (GenShift Model) works during a period of relatively low generation and high off-peak project loads. Again, it should be noted that generation is not shifted between days, but only within a given day. In this figure, the blue (dotted) line shows the actual WY 2002 generation with the Project Use Forward purchase added in. The red (heavy, dashed) line shows the combined Project Use and First Preference loads. The black (light, solid) line shows the shifted generation, and the green (heavy, solid) line shows generation available for the Base Resource.

Figure 3-1 – shows high off-peak loads, probably due to filling of the San Luis reservoir, in the first 4 days of the week. It is obvious that the original WY 2002 generation was not dispatched to meet CVP loads. For the first day (hours 1 through 24), the total CVP energy plus the forward purchase was insufficient to meet the loads, so there was no Base Resource energy available for that day, all available generation that was available was shifted to meet loads. In the Post 2004 period, supplemental energy from a non-CVP source would need to be acquired to meet the remaining loads for this day. In a day such as this when total load exceeds generation, it is likely the generation would be dispatched first to meet on-peak loads and that supplemental Off-Peak energy would be acquired to minimize costs. On days two through four, the shifted generation follows the loads exactly during off-peak hours, and in the on-peak period the shifted generation has the same pattern as the original generation with slightly lower values.

Figure 3-2, “Estimated Weekly Generation and Base Resource for Week 42” covers the period from July 15 through July 21. In this week, the generation exceeded the loads in all hours before any shifting was done. The generation shifting algorithm did move some generation from the off-peak period to the on-peak period by shifting some energy from the last hours of the day, by increasing the ramp rate down and then moving this energy to the on-peak period (limited to the max capacity for that day). All weeks can be viewed in the spreadsheet accompanying this report.

Figure 3-3, “Monthly Energy for Actual and Shifted Generation” shows the monthly off-peak and on-peak energy for both the actual unshifted WY 2002 generation and the shifted generation. The generation surplus to the required loads to on-peak results in an overall shifting of about 50 GWh of CVP generation from off-peak to on-peak (slightly more than 1 percent) for the entire year when both the shift to meet loads and the shift of surplus generation are accounted for. Generally, Figure 3-3 shows that during the fall and winter, generation was shifted to off-peak to meet load, and in the summer, some generation was shifted to on-peak. The shifting of the generation reduced the hours that the Project Use and First Preference load were not met by the CVP generation and the Project Use Forward Purchase from about 20 percent of the time to just 1 percent of the time. The monthly Base Resource energy based on WY 2002 conditions is shown in Figure 3-4 – “Monthly Base Resource Energy.”

Figure 3-1 – Estimated Weekly Generation and Base Resource for Week 10

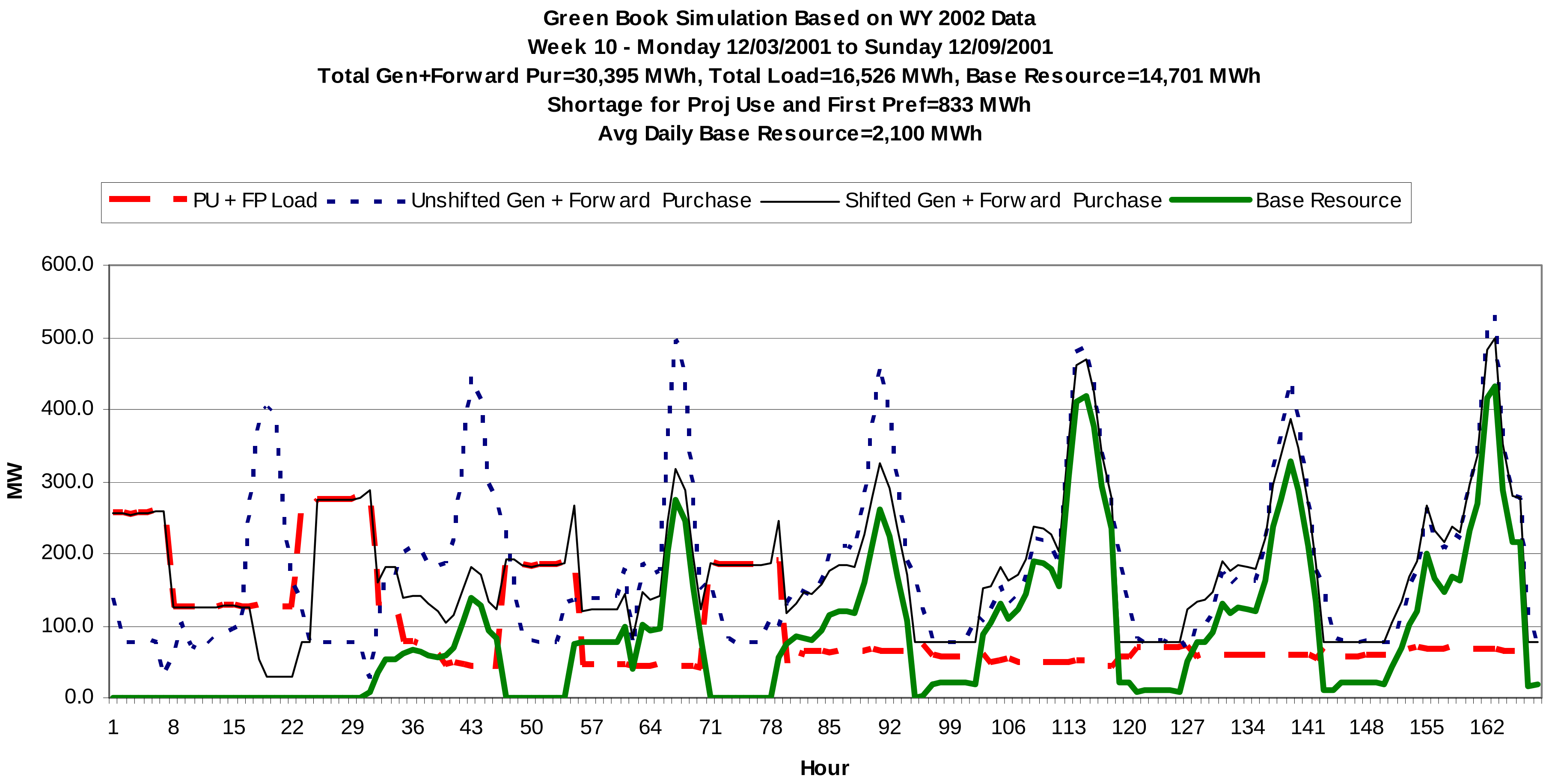


Figure 3-2 – Estimated Weekly Generation and Base Resource for Week 42

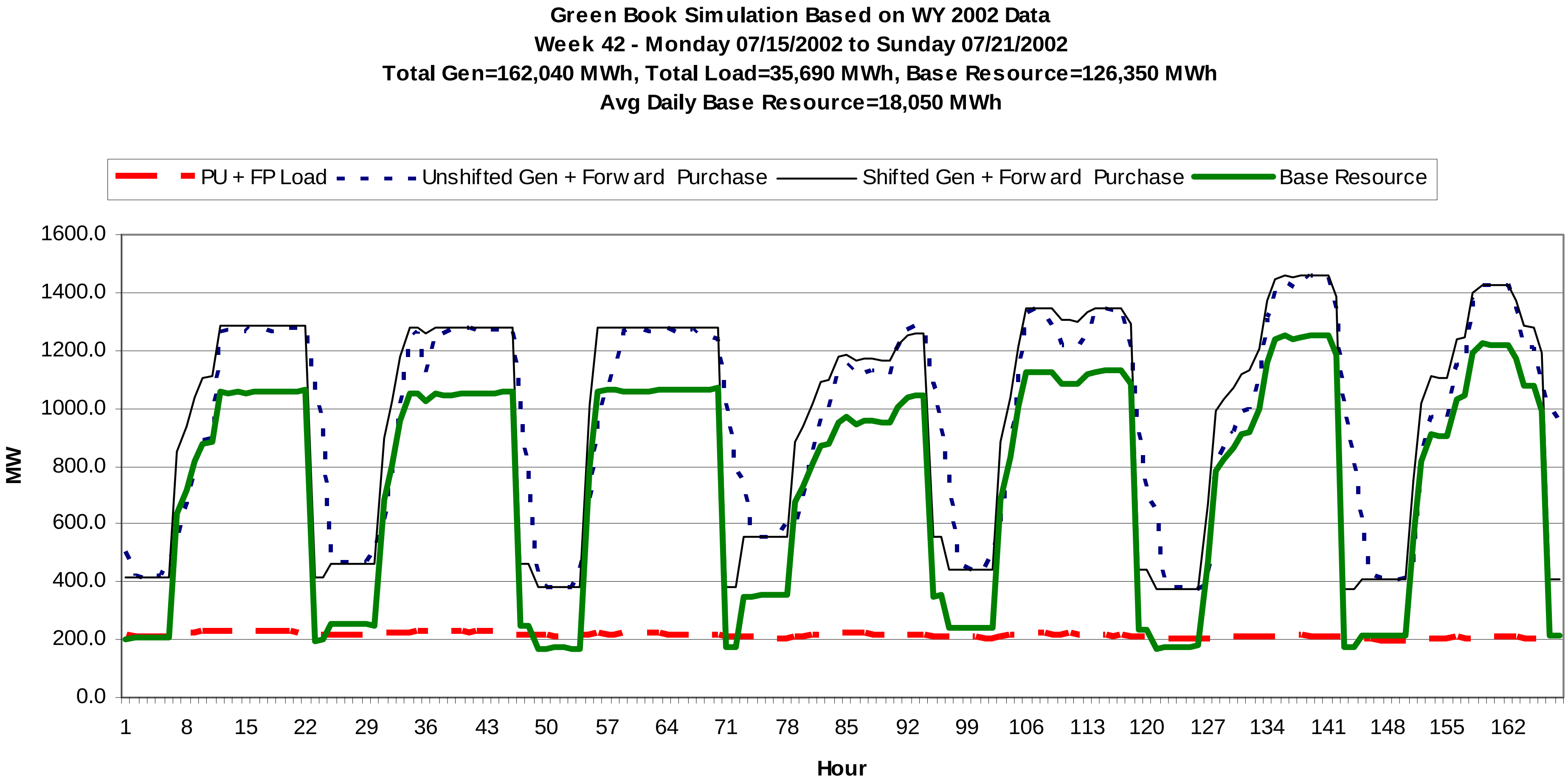
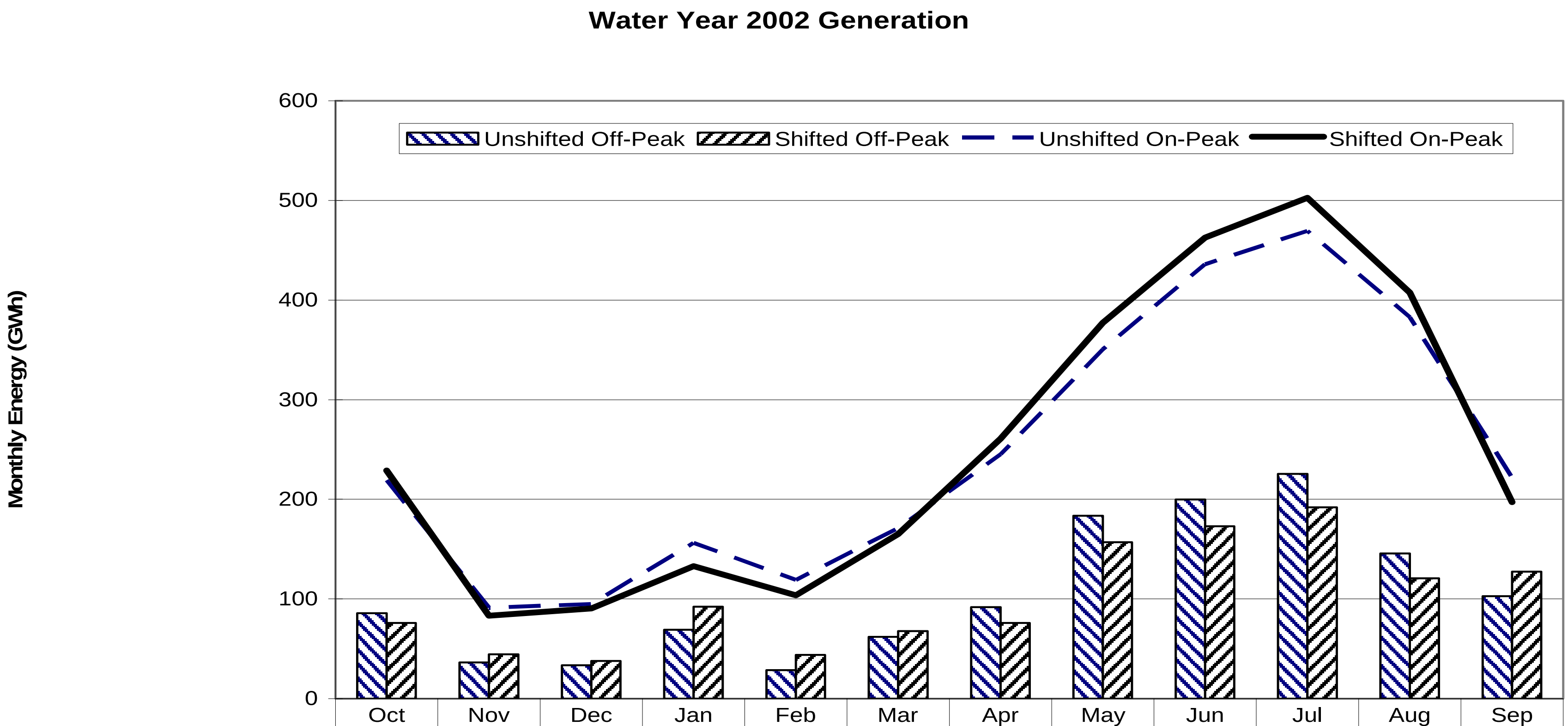


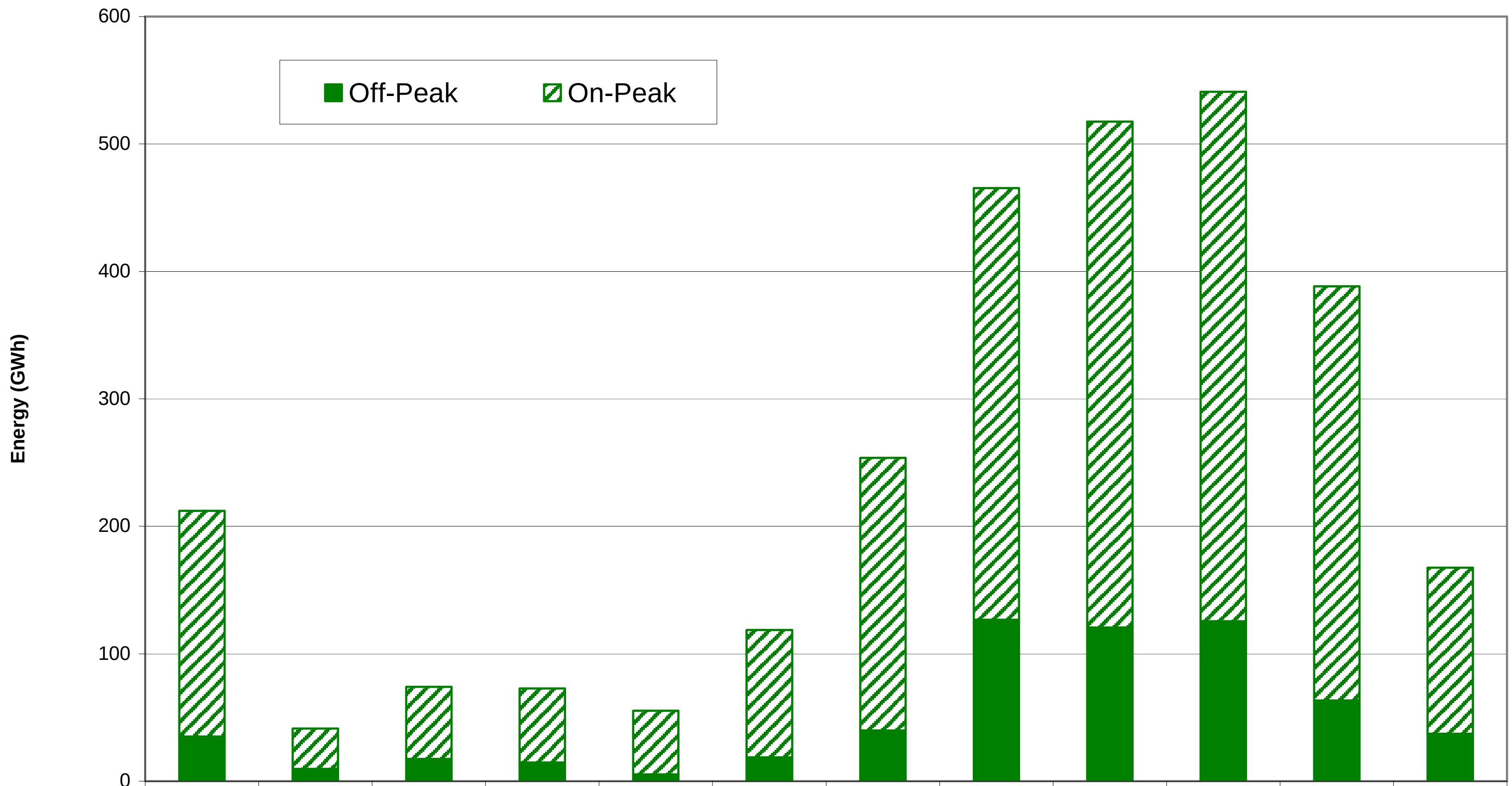
Figure 3-3 – Monthly Energy for Actual and Shifted Generation



	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Unshifted Off-Peak	86	36	33	69	28	62	92	184	200	225	146	103
Shifted Off-Peak	76	44	38	92	44	68	76	157	173	192	121	127
Unshifted On-Peak	219	91	95	156	119	171	245	351	436	469	383	222
Shifted On-Peak	229	83	90	133	104	165	261	377	463	503	407	197

Figure 3-4 - Monthly Base Resource Energy

WY 2002 Off-Peak and On-Peak Energy



	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
On-Peak	177.0	31.7	56.8	58.2	50.1	99.8	213.9	338.7	397.0	415.4	324.9	130.3
Off-Peak	35.2	9.7	17.4	14.7	5.3	18.8	39.8	126.7	120.7	125.5	63.3	37.4

Month

3.3. Base Resource Split Between On-Peak and Off-Peak

The monthly Base Resource can be divided into on- and off-peak energy based on the daily data, and the percent of energy in the on-peak period can be determined for each day and month. There are two distinct separate groupings of data sets considered in the charts and graphs below. The monthly data is first considered looking at all days, including Sundays and Holidays. The second grouping, which will be referred to as the on-peak period is limited to Monday through Saturday with Holidays excluded.

In Section 4, for long-term power system modeling, the months of April, May, and August were split into sub-periods to more accurately model the significant changes in Project Use energy pumping and San Luis generation that generally occurs in those months. Using this split-month sub-period approach, Table 3-2, “Monthly and Daily Base Resource Energy Distribution for WY 2002” shows the percent of on-peak energy that can be expected on both a monthly basis (including split months) and on a daily basis for the on-peak period only. The range of on-peak Base Resource energy on a monthly basis is between 72 percent and 90 percent. On a daily basis, for the on-peak period, the range is from 82 percent to 100 percent. It should be noted that in months where 100 percent of the Base Resource energy is shown to be available in on-peak hours, the generation needed to meet Project Use and First Preference loads in the off-peak was greater than the minimum off-peak generation required.

If the Average Daily Base Resource is grouped into ranges of similar magnitudes of generation, the average percent of on-peak generation can be estimated for each range. Since on-peak only occurs for the Monday through Saturday period, it is more useful to look at the energy distribution for the periods that only include on-peak. Figure 3-5, “Base Resource Distribution for the On-Peak Period” shows the distribution of the percent on-peak versus Daily Base Resource. There is a lot of scatter in this data, but some general trends do appear.

Table 3-3, “Percent On-Peak Generation for Monday through Saturday” shows the percent of on-peak energy for only those days that include on-peak grouped into ranges of similar amounts of Daily Base Resource energy. Overall for these days, 93 percent of the Base Resource is available in the on-peak period.

It is apparent from Table 3-2, “Monthly and Daily Base Resource Energy Distribution for WY 2002” and Table 3-3, “Percent On-Peak Generation for Monday through Saturday” that the historic distribution is not only dependent on the daily average Base Resource, but also that other factors are involved. This may be as simple as specific scheduling decisions that were made during a given day or outside factors such as high, uncontrolled natural inflows. Using Figure 3-5, “Base Resource Distribution for the On-Peak Period” with Tables 3-2 and 3-3, some assumed distributions for on-peak energy for assumed Daily Base Resource ranges can be developed. While there is a great deal of scatter in the data, the trend line for Figure 3-5 does appear to represent a reasonable upper limit of Base Resource that could be scheduled.

Table 3-4, “Assumed Daily Percent On-Peak Energy for Various Periods” shows the estimated percentage of on-peak energy for various ranges of average Daily Base Resource. These values are for the Monday through Saturday period only. The distribution for an entire week, Monday through Sunday can be estimated as follows:

% On-Peak Mon-Sun =

$$100\% - \frac{\underline{(\#\ \text{Mon-Sat Hours} * (100\%-\%\text{On-Peak Mon-Sat}) + \text{Sun Hours})}}{\text{Total Hours in Week}}$$

or

% On-Peak Mon-Sun = 100% - (144 * (100%-%On-Peak Mon-Sat) + 24) / 168

These values are also shown in Table 3-4. The Monday to Sunday values are also applicable to the total monthly energy. Weeks or Months with Holidays will have slightly lower percentages. For weeks with Holidays, the percentages can be estimated as follows:

% On-Peak Mon-Sat (Week with Holiday) =

100% - (120 * (100%-%On-Peak Mon-Sat No Holidays) + 24) / 144

% On-Peak Mon-Sun (Week with Holiday) =

100% - (120 * (100%-%On-Peak Mon-Sat No Holidays) + 48) / 168

Months with Holidays are estimated as 25 percent of the Monday to Sunday Week with Holiday value and 75 percent of the Monday to Sunday Week without Holiday value.

Table 3-2 – Monthly and Daily Base Resource Energy Distribution for WY 2002

Month	Monthly Energy (MWh) Includes All Days					Daily Energy (MWh) Monday through Saturday Only[1]			
	Off-Peak	On-Peak	Total	Daily Average	% On-Peak	Max	Min	Average	% On-Peak
Oct	35,170	177,048	212,218	6,846	83%	10,636	1,156	6,789	97%
Nov	9,722	31,709	41,431	1,381	77%	3,166	23	1,534	90%
Dec	17,401	56,769	74,169	2,393	77%	4,449	563	2,484	95%
Jan	14,741	58,152	72,893	2,351	80%	9,836	302	3,217	90%
Feb	5,309	50,062	55,371	1,978	90%	4,636	143	2,276	100%
Mar	18,796	99,816	118,613	3,826	84%	5,576	816	3,839	100%
Apr 1-14	11,343	50,038	61,381	4,384	82%	6,742	3,178	4,170	100%
Apr 15-30	28,414	163,861	192,274	12,017	85%	14,750	8,967	12,016	97%
May 1-15	58,597	150,636	209,233	13,949	72%	17,985	11,125	14,139	82%
May 16 - 31	68,057	188,061	256,118	16,007	73%	18,913	13,520	15,901	91%
Jun	120,667	396,953	517,620	17,254	77%	20,343	13,606	17,248	92%
Jul	125,509	415,430	540,939	17,450	77%	18,900	15,562	17,471	91%
Aug 1-15	38,428	174,604	213,033	14,202	82%	15,774	12,904	14,174	95%
Aug 16-31	24,921	150,249	175,170	10,948	86%	13,129	9,145	10,974	98%
Sep	37,352	130,284	167,636	5,588	78%	9,487	1,230	5,429	100%

Figure 3-5 – Base Resource Distribution for the On-Peak Period

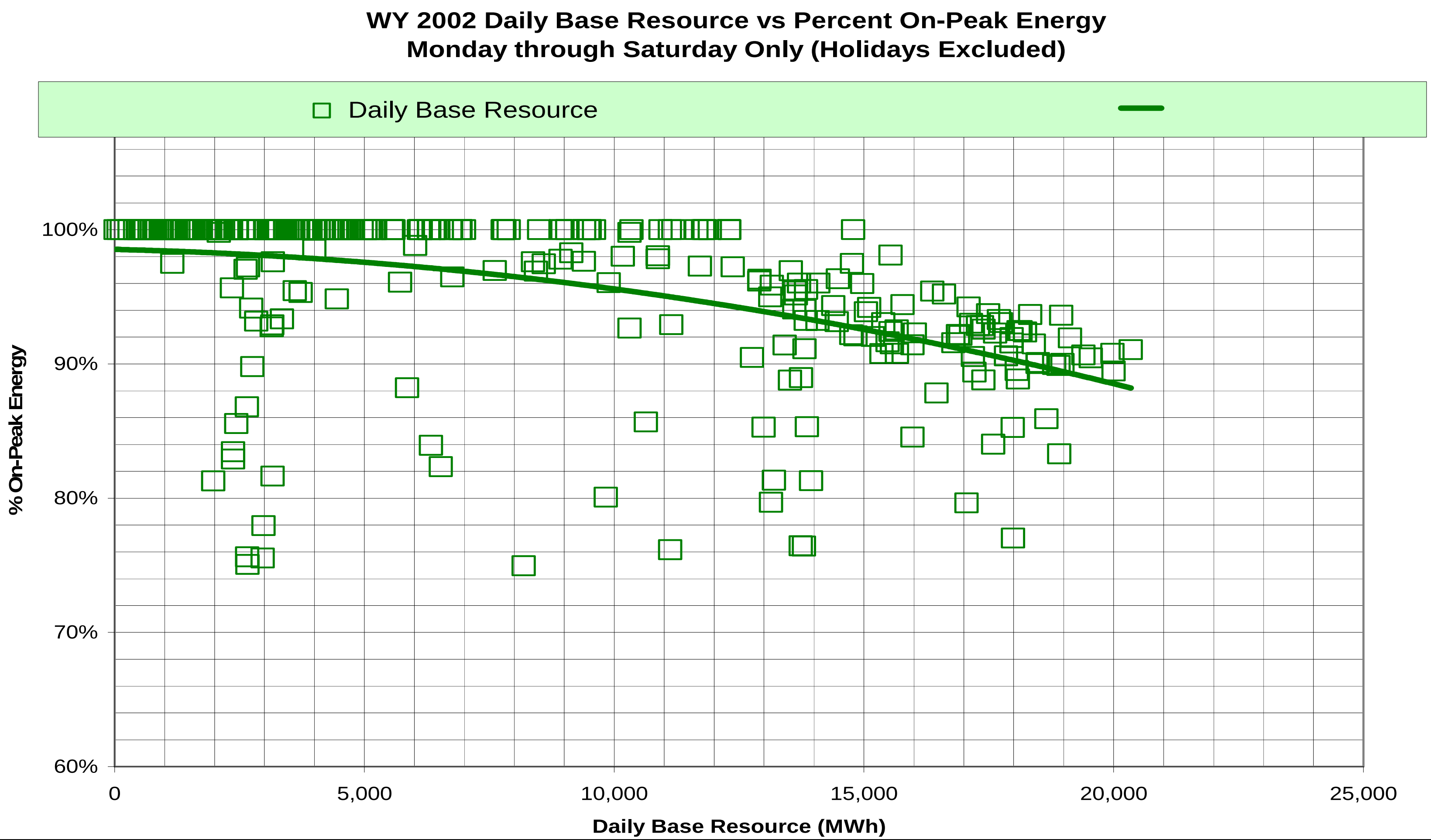


Table 3-3 – Percent On-Peak Generation for Monday through Saturday

Base Resource Estimated on WY 2002 CVP Generation and Loads

Percent of Base Resource in Heavy Load Hours (6 AM to 10 PM - Monday through Saturday)
All Sundays, Holidays, and Days with No Base Resource Excluded

Daily Base Resource Range (MWh)	Frequency		Statistics for Range (MWh)				Percent On-Peak
			Average	Minimum	Maximum	Std Dev	
	Number	%	MWh	MWh	MWh	MWh	%
1 to 500	6	2%	241	23	484	187	100%
501 to 3500	88	30%	2,046	537	3,418	869	97%
3501 to 6500	57	19%	4,727	3,517	6,419	926	99%
6501 to 9500	26	9%	8,023	6,531	9,487	987	98%
9501 to 12500	24	8%	10,990	9,515	12,377	870	96%
12501 to 15500	40	14%	14,019	12,764	15,478	769	92%
15501 to 18500	43	15%	17,188	15,537	18,485	919	91%
18501 to 21500	12	4%	19,301	18,658	20,343	550	90%
Entire Range	296	100%	8,293	23	20,343	6,137	93%

Table 3-4 – Assumed Daily Percent On-Peak Energy for Various Periods

Average Daily Base Resource (MWh)	Monday through Saturday % On-Peak		Monday through Sunday % On-Peak		Entire Month	
	Average Week	Week with Holiday	Average Week	Week with Holiday	No Holiday	With Holiday
Up to 3,000	99%	82%	85%	71%	85%	81%
Up to 6,000	98%	82%	84%	70%	84%	81%
Up to 9,000	97%	81%	83%	69%	83%	80%
Up to 12,000	96%	80%	82%	68%	82%	79%
Up to 15,000	94%	78%	80%	67%	80%	77%
Up to 18,000	92%	76%	79%	65%	79%	75%
Up to 21,000	89%	74%	76%	64%	76%	73%
Up to 24,000	86%	72%	74%	62%	74%	71%
Up to 27,000	83%	69%	71%	59%	71%	68%
Above 27,000	80%	66%	68%	57%	68%	65%

3.4. Base Resource Split Between On-Peak and Off-Peak Applied to Long-Term Modeling

Table 3-5, “Comparison of WY 2002 to Long-Term Modeling” shows the average monthly Base Resource expected in various water year types. WY 2002 was classified as “Dry” and the estimated Base Resource available based on 2002 conditions was about 7 percent greater than the average, dry year Base Resource. It can be seen that there is a large variation within months with the 2002 monthly Base Resource ranging from 42 percent to 168 percent of the average for Dry water years. This shows that even within a given water year type, there is a significant variation of distribution within months. Most of the large variations occur in the first six months of the water year, when Base Resource is relatively low, while in the second six months (April through September) higher daily amounts of Base Resource are available. Recognizing that we are dealing with a limited data set, the distributions developed from WY 2002 (Table 3-4) can be used to provide an estimate of the likely amount of on and off-peak energy that can be expected in future years.

For example, in an “Above Normal” year, based on the Long-Term Modeling, the Average Monthly Base Resource for November is 114 GWh or an average daily Base Resource of 3,790 MWh. Based on Table 3-4, for an Average Daily Base Resource between 3,000 and 6,000 MWh, for a month with a Holiday such as November, it is estimated that about 81 percent of the Base Resource would be in on-peak hours. For a week within the month, the percentage of Base Resource energy on-peak would likely range from 70 percent (Week with Holiday) to 84 percent (Week without Holiday, or Average Week). In an “Above Normal” year, based on the Long-Term Modeling, the Average Monthly Base Resource for July is 523 GWh or an average daily Base Resource of 16,887 MWh. From Table 3-4, for an Average Daily Base Resource between 15,000 and 18,000 MWh, for a month with a Holiday such as July, it is estimated that about 75 percent of the Base Resource would be in on-peak hours. For a week within the month, the percentage of Base Resource energy on-Peak would likely range from 65 percent (Week with Holiday) to 79 percent (Week without Holiday, or Average Week). Of course, these values should be considered “Ball Park” estimates. There can be significant variations within weeks and months that may reduce or increase the percent of on-peak energy.

Table 3-5 – Comparison of WY 2002 to Long-Term Modeling

Average Monthly Base Resource for Various Water Year Types (GWh)

Year Type	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	Total
All	163	104	143	163	195	207	114	174	228	214	440	524	201	201	269	3,342
Wet	207	134	319	385	372	354	148	222	279	264	481	539	220	218	412	4,555
Above Normal	163	114	96	160	307	262	104	179	250	235	452	523	202	199	265	3,511
Below Normal	172	74	83	70	139	162	97	161	230	216	427	527	193	187	223	2,963
Dry	129	99	56	43	51	98	97	152	208	194	433	529	206	214	204	2,713
Critical	121	88	61	47	50	99	106	131	147	137	385	484	168	174	160	2,356
WY 2002	212	41	74	73	55	119	61	192	209	256	518	541	213	175	168	2,908

WY 2002 Monthly Base Resource as Percent of Average for Various Water Year Types

Year Type	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	Total
All	130%	40%	52%	45%	28%	57%	54%	110%	92%	119%	118%	103%	106%	87%	62%	87%
Wet	102%	31%	23%	19%	15%	34%	41%	86%	75%	97%	108%	100%	97%	80%	41%	64%
Above Normal	130%	36%	77%	46%	18%	45%	59%	108%	84%	109%	115%	103%	106%	88%	63%	83%
Below Normal	124%	56%	90%	104%	40%	73%	63%	119%	91%	119%	121%	103%	110%	94%	75%	98%
Dry	164%	42%	134%	168%	108%	121%	63%	127%	101%	132%	119%	102%	103%	82%	82%	107%
Critical	175%	47%	121%	157%	111%	120%	58%	147%	143%	188%	135%	112%	127%	101%	105%	123%

Average Daily Base Resource for Various Water Year Types (MWh)

Year Type	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	Total
All	5,262	3,475	4,615	5,268	6,974	6,665	8,163	10,884	15,226	13,403	14,683	16,888	13,385	12,575	8,956	9,155
Wet	6,681	4,458	10,295	12,428	13,279	11,421	10,568	13,894	18,599	16,480	16,043	17,401	14,667	13,611	13,748	12,479
Above Normal	5,255	3,790	3,097	5,147	10,977	8,464	7,462	11,169	16,664	14,675	15,067	16,887	13,455	12,444	8,837	9,620
Below Normal	5,541	2,460	2,670	2,263	4,979	5,235	6,964	10,065	15,353	13,489	14,231	17,014	12,880	11,689	7,441	8,117
Dry	4,170	3,286	1,790	1,400	1,834	3,156	6,951	9,487	13,873	12,146	14,448	17,068	13,730	13,352	6,784	7,433
Critical	3,912	2,928	1,973	1,501	1,783	3,190	7,555	8,196	9,779	8,533	12,824	15,603	11,210	10,868	5,331	6,455

4. Long-Term Power System Modeling

4.1. Methods

Methods used to model long-term forecasts for CVP generation and capacity included:

- Reservoir Operations Modeling using the CALSIM II Model;
- Power generation modeling using the LongTermGen (LTGEN) model; and
- Use of generation shifting algorithm results from the WY 2002 analysis to provide relationships for on and off-peak generation levels.

4.1.1. Reservoir Operations Modeling (CALSIM II Model)

CALSIM II is a general-purpose planning simulation model developed by DWR and Reclamation for simulating the operation of California's water resources system, specifically the CVP and SWP. The simulation is performed for a 73-year period on a monthly time-step (or decision-step). The 73 years are meant to include plausible climate variability that could stress the CVP/SWP system by representing weather and the resultant hydrologic conditions that were experienced in California during the historical 1922-1994 water years. Model output reporting-years are labeled 1922 through 1994.

Typical inputs to CALSIM II represent the CVP/SWP system as a link-node network, describing the physical system (dams, reservoirs, channels, pumping plants, etc). Inputs are also provided to describe operational rules (flood-control diagrams, minimum instream flow requirements, delivery requirements, etc.) and priorities for allocating water.

Typical outputs reported from CALSIM II include, for example, end-of-month storage conditions, release amounts, flows conveyed through rivers and canals, and export volumes from the Delta. Studies using the CALSIM II model depend on assumed CVP/SWP Project operations. It was desirable that these assumptions be consistent with the current OCAP process. The OCAP studies describe different "baseline" CVP/SWP operations, varying on assumptions related to water demands (today versus future), implementation of Section 3406g (b)(2) of the CVPIA, and implementation of Environmental Water Account (EWA).

For the purposes of this Green Book update, two key assumptions were made for modeling CVP/SWP water operations:

- Project operations should be consistent with OCAP Study 3: "Today CVPIA 3406 b(2) with EWA." Study 3 assumptions are provided on Reclamation's OCAP website under "BAModelingAssumptions.doc", at http://www.usbr.gov/mp/cvo/ocap.html.
- Trinity Reservoir releases were assumed consistent with the Trinity EIS Preferred Alternative.

The combination of these assumptions for this Green Book revision resulted in a new CALSIM II study, referred to as "*Study 3a*" to denote its association with OCAP Study 3. Development of Study 3a involved changing simulation inputs to reflect changes in Trinity Reservoir release targets and adjusting the rule curves that dictate CVP and SWP Delta requirements and entitlements.

For this report, Western was aided by Reclamation's Central Valley Operations Office and the Mid-Pacific Region's Planning Division Reservoir Simulation

Branch. Results from this CALSIM II modeling effort were provided to Western in April 2004.

Further explanation of modeling assumptions and a summary of CALSIM II results is presented in Appendix B.

4.1.2. Power Generation Modeling (LongTermGen Model)

The LongTermGen model is an Excel spreadsheet designed to use CALSIM II flow operation results to compute CVP power operations, both project use and generation, that would result from the simulated water operations. The model was developed for Western and Reclamation and is currently maintained jointly by both agencies. For this analysis, the most recent version of the model (version 10) was obtained from Reclamation, which includes all current assumptions relative to CVP power operations and planning.

The LongTermGen model utilizes monthly flow and reservoir operations from a CALSIM II simulation. Since the on and off-peak power operations are on much shorter time intervals than the monthly data output from the CALSIM II model, the data from LongTermGen must be broken down into lesser time increments to analyze the power capabilities of the project. Peaking operations are also dependant on afterbay capacity and operation issues that are not included in the CALSIM II flow operation results. Because of these limitations, the LongTermGen model does not attempt to define the on and off-peak components of the CVP power generation operations.

4.2. Results

4.2.1. Power System Modeling – LongTermGen

Application of the LongTermGen model to the 73 years of monthly simulated reservoir operations resulted in simulated power production from each of the

CVP power facilities. Given the water year type classification of each of the 73 years of historic inflows, it was possible to group simulation results into water year types.

Figure 4-1 – CVP Gross Generation (Energy) at Load Center, Average All Years

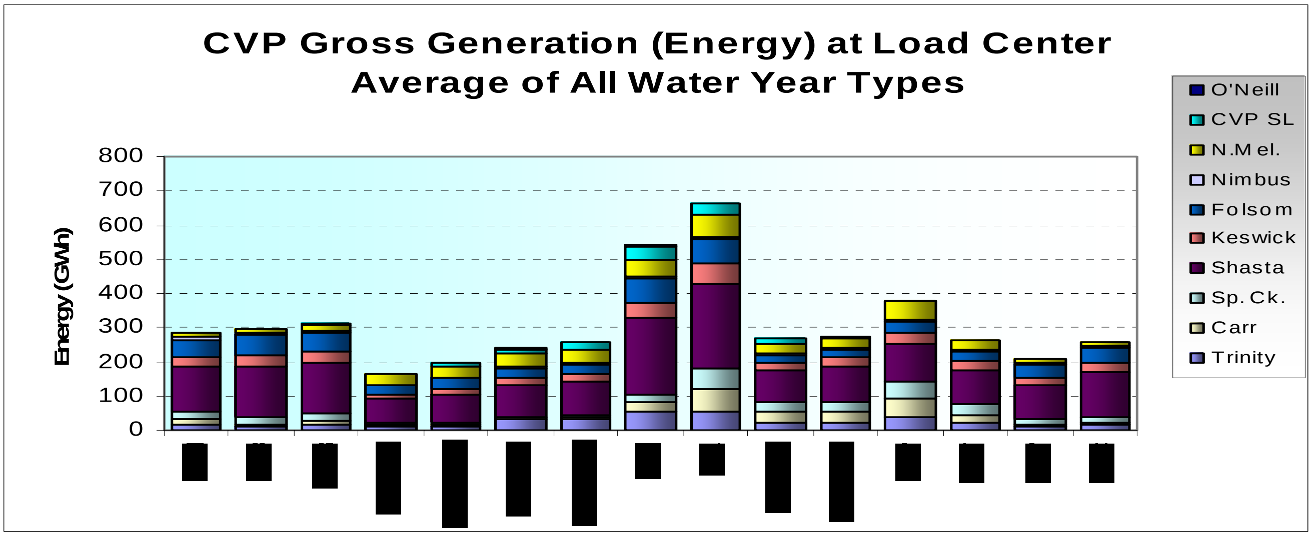
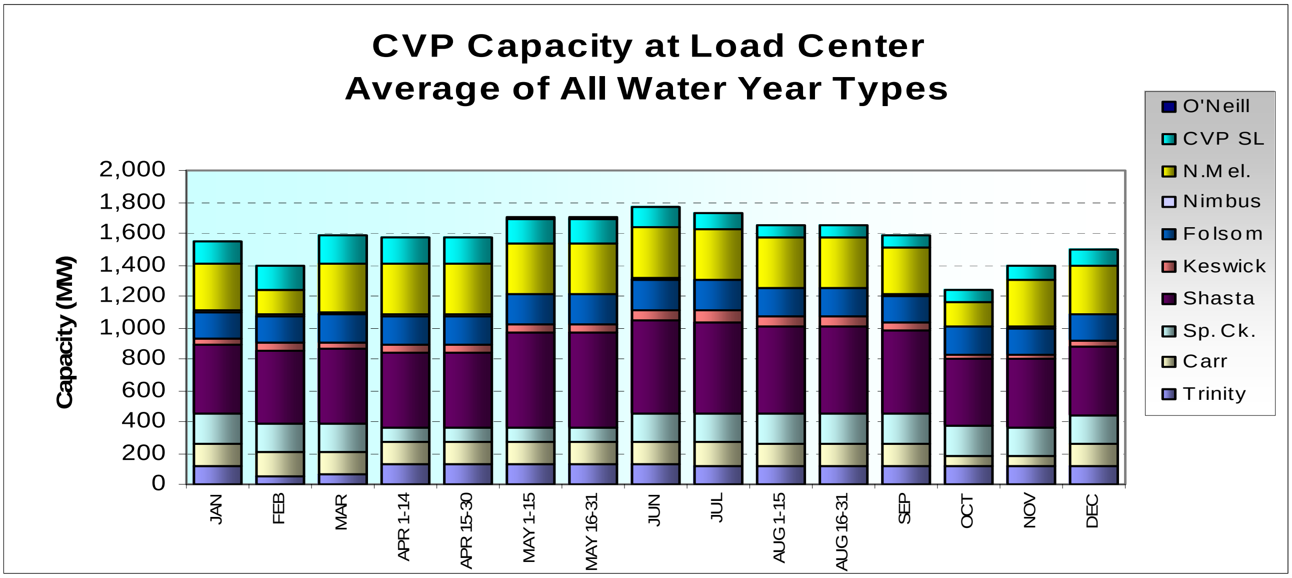


Figure 4-1 shows the computed average of all sub-period gross generation values for each of the CVP power facilities for the 15 sub-periods identified in this study. Similarly, Figure 4-2 shows the computed average of all sub-period maximum available capacity values detailed by CVP power facility.

Figure 4-2 – CVP Capacity at Load Center, Average of All Years Modeled



Similar figures for other water year types are available in supporting documentation of this study from CALSIM II and LongTermGen modeling. Also included in supporting documentation are summaries for total, on-peak and off-peak project use energy demand and capacity requirements for each project use demand source for the 15 sub-periods identified in this study. Section 6, entitled Supporting Documentation, has additional detail on sources of additional results for long-term power system modeling for the full range of water year classifications (Wet, Above Normal, Below Normal, Dry and Critical).

4.2.2. Net CVP (Base Resource) Energy and Capacity

Figure 4-3 shows the computed average of all sub-period Base Resource energy projections (CVP net generation after adjustment for Project Use and First Preference demands, reserves and losses) for the full range of water year classifications. Also shown is the on-peak and off-peak components of average annual Base Resource energy.

Figure 4-3 CVP Average Annual Base Resource (Energy)

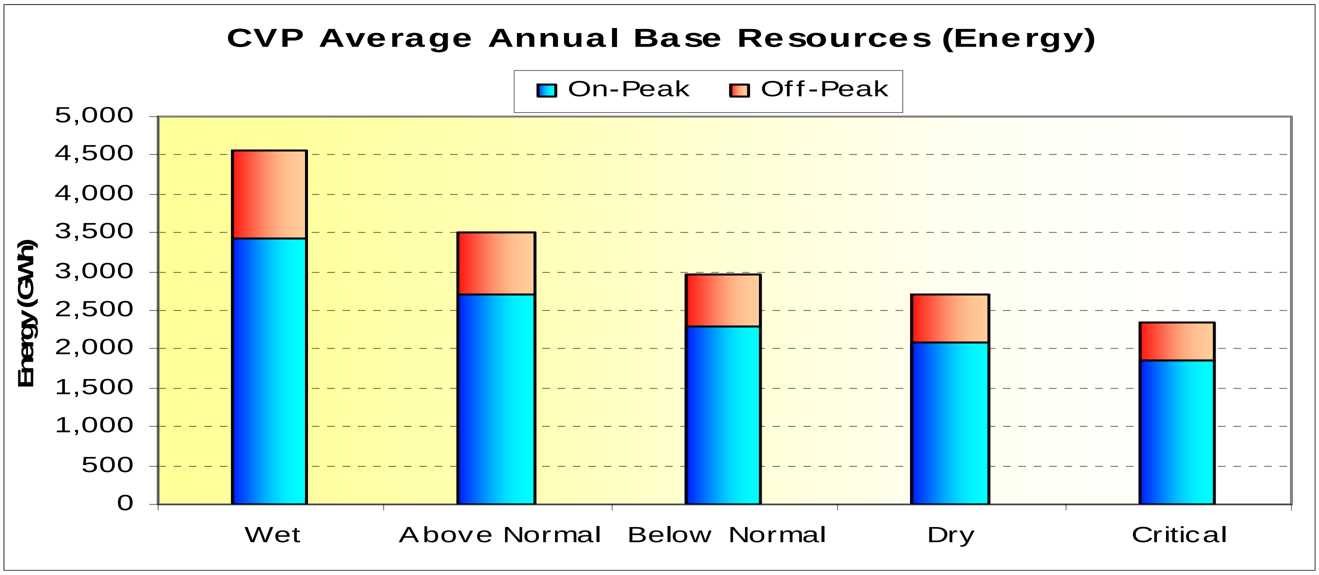


Figure 4-4 shows the computed average of all Base Resource energy projections for each 15 sub-period with on-peak and off-peak components. Similarly, Figure 4-5 shows the computed average of all Base Resource available capacity projections for each 15 sub-period.

Figure 4-4 – CVP Base Resource (Energy), Average All Years

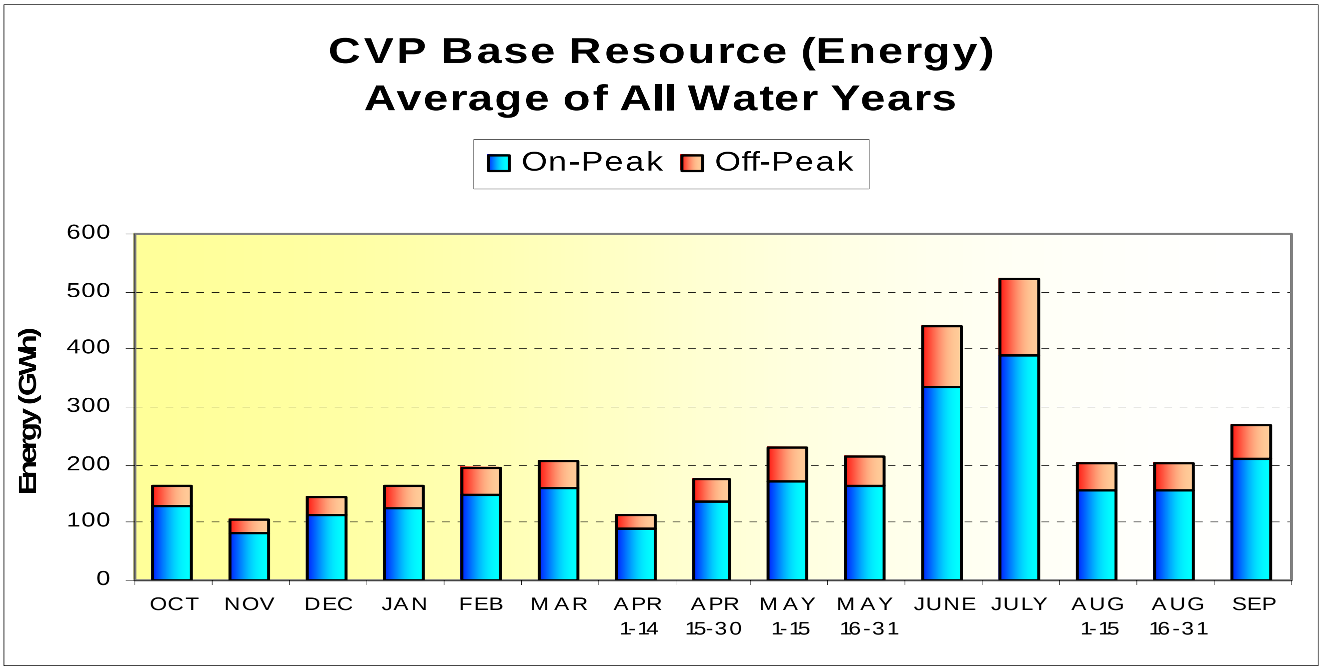
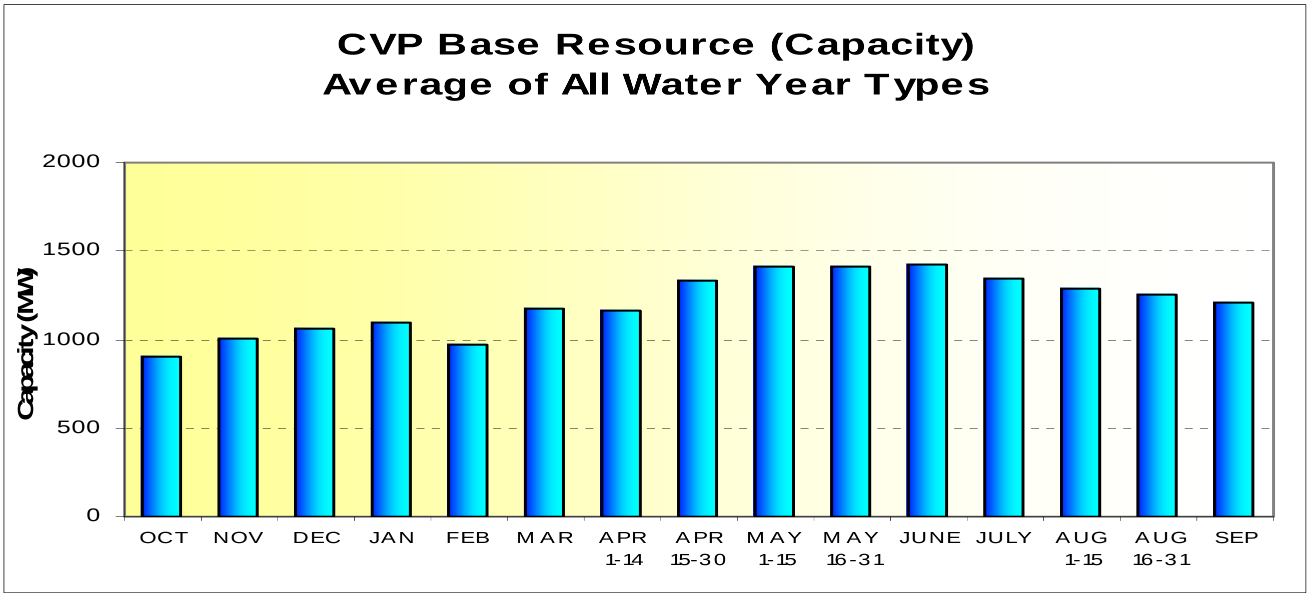


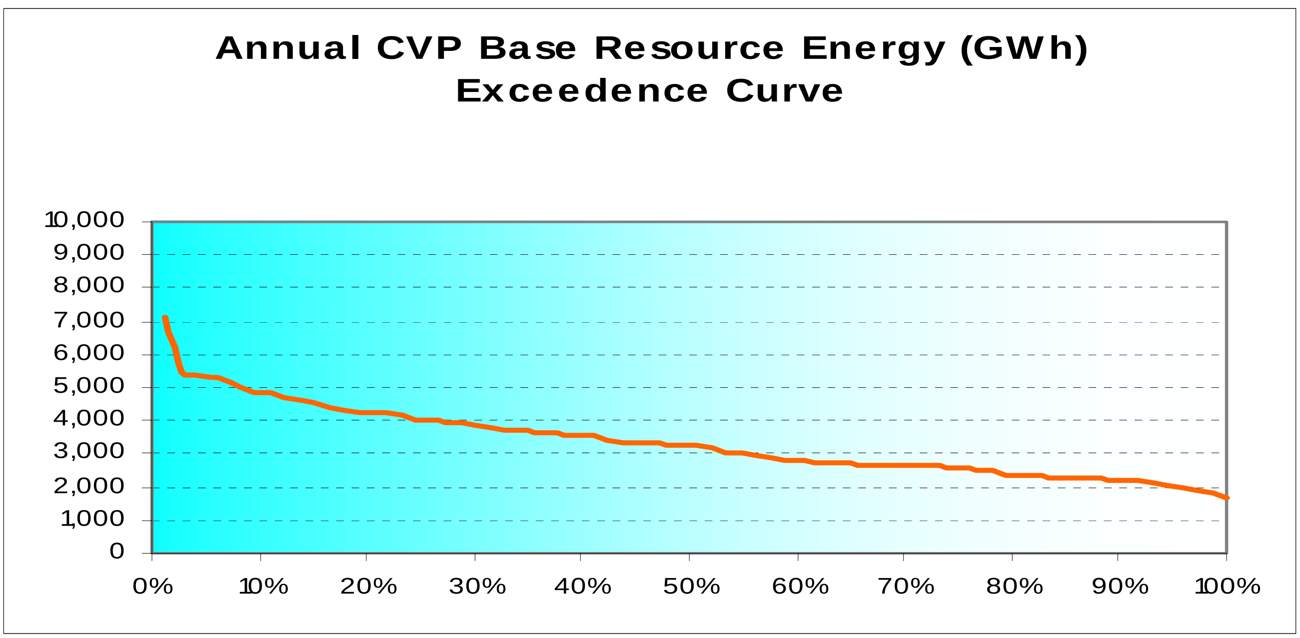
Figure 4-5 – CVP Base Resource (Capacity), Average of All Years



In addition to computed average values, a separate frequency analysis was also performed using the LongTermGen modeling results. This analysis included both determination of relative frequency of occurrence and exceedence levels of Base Resource energy and capacity for each 15 sub-period identified.

Figure 4-6 shows an exceedence curve for projected CVP Base Resource annual energy for all sub-periods. From these results, it could be concluded that CVP Base Resource annual energy could be predicted to equal or exceed 3,200 GWh less than 50 percent of the time. Similarly, CVP Base Resource annual energy could be predicted to equal or exceed 5,000 GWh less than 10 percent of the time. Exceedence curves for individual months are also available in the spreadsheets that accompany this report.

Figure 4-6 – Exceedence Curve, CVP Base Resource (Energy), Annual



Similar figures for the full range of water year classifications are available in supporting documentation of this study based on results from CALSIM II and LongTermGen modeling. Also included in this documentation are exceedence and relative frequency results for each of the 15 sub-periods. Documentation is also included for projections of both Project Use and First Preference customer energy and capacity demand, as well as computed operating reserves, that were applied to CVP gross generation and maximum capacity to quantify Base Resource energy and capacity.

Further explanation of modeling assumptions and a summary of LongTermGen results are presented in Appendix C.

4.3. Expected Base Resource for Full Range of Water Years

The following Tables 4-1 and 4-2 show the Base Resource capacity and energy that can be expected for the full range of water types. The tables also show the use of CVP generation to meet Project Use, First Preference loads and reserves, and the remaining generation available for Base Resource energy for preference customers.

See Section 6, Supporting Documentation, for more detail on sources for projected Base Resource energy and capacity for the full range of water year classifications (Wet, Above Normal, Below Normal, Dry, and Critical).

Table 4-1– CVP Capacity Available for Loads and the Base Resource

Average	MW														
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP
Base Resource	904	1,006	1,062	1,093	968	1,177	1,163	1,331	1,412	1,410	1,425	1,345	1,289	1,253	1,210
Available Capacity	1,241	1,394	1,497	1,545	1,392	1,583	1,573	1,573	1,697	1,697	1,768	1,727	1,654	1,654	1,586
Est. Op. Reserves	103	111	116	118	111	120	120	120	126	126	130	128	124	124	121
PU Purchase	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0
PU Load	260	300	339	353	336	310	265	97	137	138	184	220	209	245	227
FP Load	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
Unmet PU Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmet FP Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FP Delivery	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
PU Delivery	260	300	339	353	336	310	265	97	137	138	184	220	209	245	227

Wet	MW														
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP
Base Resource	950	1,033	1,147	1,211	1,059	1,174	1,155	1,372	1,471	1,433	1,482	1,414	1,394	1,367	1,377
Available Capacity	1,305	1,481	1,613	1,661	1,481	1,674	1,661	1,661	1,797	1,797	1,875	1,857	1,820	1,820	1,788
Est. Op. Reserves	106	115	122	124	115	125	124	124	131	131	135	134	132	132	131
PU Purchase	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0
PU Load	274	356	365	344	330	400	357	140	172	210	228	274	262	289	252
FP Load	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
Unmet PU Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmet FP Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FP Delivery	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
PU Delivery	274	356	365	344	330	400	357	140	172	210	228	274	262	289	252

Above Normal	MW														
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP
Base Resource	875	973	998	1,090	1,005	1,172	1,122	1,355	1,439	1,454	1,445	1,383	1,311	1,267	1,260
Available Capacity	1,202	1,347	1,453	1,557	1,444	1,631	1,609	1,609	1,747	1,747	1,826	1,807	1,751	1,751	1,679
Est. Op. Reserves	101	108	114	119	113	123	122	122	129	129	133	132	129	129	125
PU Purchase	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0
PU Load	252	288	361	367	348	360	341	108	156	142	219	258	279	323	265
FP Load	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
Unmet PU Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmet FP Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FP Delivery	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
PU Delivery	252	288	361	367	348	360	341	108	156	142	219	258	279	323	265

Below Normal	MW														
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP
Base Resource	909	975	1,043	1,033	941	1,202	1,169	1,347	1,426	1,441	1,429	1,356	1,275	1,207	1,194
Available Capacity	1,247	1,397	1,488	1,537	1,395	1,582	1,576	1,576	1,714	1,714	1,787	1,748	1,671	1,671	1,594
Est. Op. Reserves	103	111	116	118	111	120	120	120	127	127	131	129	125	125	121
PU Purchase	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0
PU Load	260	334	350	405	365	285	262	84	138	123	198	229	240	307	251
FP Load	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
Unmet PU Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmet FP Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FP Delivery	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
PU Delivery	260	334	350	405	365	285	262	84	138	123	198	229	240	307	251

Dry	MW														
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP
Base Resource	884	1,028	1,032	1,061	915	1,182	1,192	1,341	1,411	1,428	1,420	1,318	1,276	1,256	1,138
Available Capacity	1,229	1,384	1,470	1,509	1,353	1,559	1,558	1,558	1,677	1,677	1,740	1,683	1,586	1,586	1,499
Est. Op. Reserves	102	110	115	117	109	119	119	119	125	125	128	125	121	121	116
PU Purchase	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0
PU Load	268	268	344	351	351	282	222	73	117	100	162	205	157	177	216
FP Load	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
Unmet PU Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmet FP Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FP Delivery	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
PU Delivery	268	268	344	351	351	282	222	73	117	100	162	205	157	177	216

Critical	MW														
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP
Base Resource	864	992	1,026	1,001	877	1,150	1,163	1,210	1,268	1,275	1,310	1,216	1,120	1,089	989
Available Capacity	1,171	1,292	1,374	1,389	1,243	1,417	1,402	1,402	1,490	1,490	1,548	1,470	1,351	1,351	1,261
Est. Op. Reserves	99	106	110	111	103	112	111	111	116	116	119	115	109	109	104
PU Purchase	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0
PU Load	233	217	259	297	285	180	103	57	83	76	90	104	91	121	140
FP Load	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
Unmet PU Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmet FP Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FP Delivery	24	27	30	31	28	26	25	25	23	23	30	34	32	32	28
PU Delivery	233	217	259	297	285	180	103	57	83	76	90	104	91	121	140

Table 4-2– CVP Energy Available for Loads and the Base Resource

Average	GWh															
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	TOTAL
Base Resource	163	104	143	163	195	207	114	174	228	214	440	524	201	201	269	3342
Net Generation	260	209	256	283	298	310	164	200	260	249	542	662	267	276	380	4616
PU Purchase	17	16	17	16	16	15	0	0	0	0	0	0	0	0	0	97
PU Load	102	107	119	125	109	106	45	20	25	28	89	123	59	67	99	1224
FP Load	12	13	14	15	12	13	5	6	6	7	13	15	7	7	13	159
Unmet PU Load	0	0	2	2	1	0	0	0	0	0	0	0	0	0	0	6
Unmet FP Load	0	0	3	4	2	1	0	0	0	0	0	0	0	0	0	10
FP Delivery	12	13	11	11	10	12	5	6	6	7	13	15	7	7	13	149
PU Delivery	102	107	117	123	108	106	45	20	25	28	89	123	59	67	99	1218

Wet	GWh															
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	TOTAL
Base Resource	207	134	319	385	372	354	148	222	279	264	481	539	220	218	412	4555
Net Generation	311	259	445	505	473	489	214	257	324	312	604	710	304	310	536	6055
PU Purchase	17	16	17	16	16	15	0	0	0	0	0	0	0	0	0	97
PU Load	109	128	129	122	105	137	61	29	39	41	110	156	77	85	110	1439
FP Load	12	13	14	15	12	13	5	6	6	7	13	15	7	7	13	159
Unmet PU Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unmet FP Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FP Delivery	12	13	14	15	12	13	5	6	6	7	13	15	7	7	13	158
PU Delivery	109	128	129	122	105	137	61	29	39	41	110	156	77	85	110	1439

Above Normal	GWh															
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	TOTAL
Base Resource	163	114	96	160	307	262	104	179	250	235	452	523	202	199	265	3511
Net Generation	257	215	216	285	418	392	168	207	282	272	571	690	288	295	395	4951
PU Purchase	17	16	17	16	16	15	0	0	0	0	0	0	0	0	0	97
PU Load	99	104	127	130	115	132	58	22	26	31	106	151	79	89	117	1387
FP Load	12	13	14	15	12	13	5	6	6	7	13	15	7	7	13	159
Unmet PU Load	0	0	3	2	0	0	0	0	0	0	0	0	0	0	0	5
Unmet FP Load	0	0	4	3	0	0	0	0	0	0	0	0	0	0	0	8
FP Delivery	12	13	10	11	12	13	5	6	6	7	13	15	7	7	13	151
PU Delivery	99	104	124	128	115	132	58	22	26	31	106	151	79	89	117	1382

Below Normal	GWh															
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	TOTAL
Base Resource	172	74	83	70	139	162	97	161	230	216	427	527	193	187	223	2963
Net Generation	269	188	202	207	252	258	148	184	259	247	537	674	271	277	347	4320
PU Purchase	17	16	17	16	16	15	0	0	0	0	0	0	0	0	0	97
PU Load	102	117	125	144	117	98	45	17	23	25	97	132	71	83	111	1305
FP Load	12	13	14	15	12	13	5	6	6	7	13	15	7	7	13	159
Unmet PU Load	0	0	2	3	0	0	0	0	0	0	0	0	0	0	0	5
Unmet FP Load	0	0	3	6	1	0	0	0	0	0	0	0	0	0	0	9
FP Delivery	12	13	11	9	11	13	5	6	6	7	13	15	7	7	13	150
PU Delivery	102	117	123	140	117	98	45	17	23	25	97	132	71	83	111	1300

Dry	GWh															
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	TOTAL
Base Resource	129	99	56	43	51	98	97	152	208	194	433	529	206	214	204	2713
Net Generation	230	192	165	160	162	191	139	173	233	222	525	657	255	268	309	3880
PU Purchase	17	16	17	16	16	15	0	0	0	0	0	0	0	0	0	97
PU Load	105	96	119	126	119	95	37	15	19	21	78	113	42	47	92	1124
FP Load	12	13	14	15	12	13	5	6	6	7	13	15	7	7	13	159
Unmet PU Load	0	0	4	3	2	0	0	0	0	0	0	0	0	0	0	10
Unmet FP Load	0	0	7	7	4	0	0	0	0	0	0	0	0	0	0	18
FP Delivery	12	13	7	7	8	13	5	6	6	7	13	15	7	7	13	140
PU Delivery	105	96	115	122	116	95	37	15	19	21	78	113	42	47	92	1114

Critical	GWh															
	OCT	NOV	DEC	JAN	FEB	MAR	APR 1-14	APR 15-30	MAY 1-15	MAY 16-31	JUNE	JULY	AUG 1-15	AUG 16-31	SEP	TOTAL
Base Resource	121	88	61	47	50	99	106	131	147	137	385	484	168	174	160	2356
Net Generation	204	162	143	145	130	147	126	148	167	157	437	547	196	207	231	3147
PU Purchase	17	16	17	16	16	15	0	0	0	0	0	0	0	0	0	97
PU Load	88	76	90	105	90	55	15	11	14	14	40	48	21	25	58	749
FP Load	12	13	14	15	12	13	5	6	6	7	13	15	7	7	13	159
Unmet PU Load	0	0	4	2	4	3	0	0	0	0	0	0	0	0	0	12
Unmet FP Load	0	0	5	5	6	4	0	0	0	0	0	0	0	0	0	19
FP Delivery	12	13	9	10	6	9	5	6	6	7	13	15	7	7	13	139
PU Delivery	88	76	86	102	86	52	15	11	14	14	40	48	21	25	58	737

4.4. Application of Study Results

Based on the results from this study, it is possible to estimate the potential amount of Base Resource that could be available within defined sub-periods given a predicted water year (hydrologic) condition. For instance, if it were to be assumed that "Below Normal" condition would be likely to occur in the next period, supporting documentation in this study could be used to select this water year type to quantify the potential Base Resource energy and capacity within defined sub-periods. A CVP power customer, knowing its percentage of the Base Resource, could then determine its share of this potential Base Resource for a selected sub-period or month. Further, based on the results of analysis of simulated shifted generation, a power customer could apply on-peak percentage rules-of-thumb to estimate the amount of on-peak generation that might be available within a defined sub-period or month. Lastly, the same power customer could then use suggested rules to approximate the amount of daily generation within a future week, as well as consider potential minimum schedule requirements and ramp rate restrictions.

For illustrative purposes, assume that the CVP is forecasted to represent "Dry Year" operations, and that a representative power customer with a 5 percent Base Resource allocation is interested in forecasting a likely hourly profile of Base Resource energy and capacity for a peak day in July. From Table 3-5 from long-term modeling, the Average Monthly Base Resource for July is 529 GWh, with an Average Daily Base Resource of 17,068 MWh. From Table 3-4, for an Average Daily Base Resource "Up to 18,000 MWh", for a month with a Holiday like July roughly 75 percent of the energy could be available on-peak. From Table 4-1 for a Dry Water Year type, the average maximum Base Resource capacity in July could be equivalent to 1352 MW. From Figure 5-1, it can be assumed that the minimum capacity requirement for all customers could be roughly 200 MW in any hour in the month of July. Ramping restrictions are negligible. For our representative (5 percent) power customer, the Base Resource energy allocation would be 853 MWh for an average day, with a maximum capacity of 68 MW and a 20 MW minimum schedule requirement. Assuming that our representative customer has a July evening peak demand at HE1900 with a secondary mid-afternoon peak demand at HE1300, one possible 24-hour energy profile might be to schedule energy first to satisfy the 20 MW minimum requirement, then to distribute the remaining generation to on-peak hours to satisfy peak demands while limiting requested energy within the on-peak period to be less than 75 percent of the total Base Resource within the day.

5. Minimum Capacity Levels and Ramp Rates

5.1. Minimum Capacity Levels

The Base Resource will have some amount of flexibility for shaping the energy profile on most days. This flexibility will be defined by the hourly minimum and maximum capacity limits, ramp rates, and total daily energy limits as determined by Western for its three and two day-ahead schedules. Since the Base Resource is the net CVP generation after required Project Use and First Preference loads are met, these loads greatly influence the flexibility in CVP Base Resource. These hourly limits will be provided to Variable Resource customers both three and two days ahead of the time that Western designates to finalize Base Resource schedules. The long-term studies done for the Green Book provide maximum capacity and energy generation from the CVP on a monthly basis.

The maximum capacity levels customers can expect are presented in Section 4, Tables 4-1 and 4-2. The monthly capacity values derived from the long-term studies represent a reasonable estimate of project capacity available for Base Resource customers in the five year types discussed. The monthly figures from the long-term studies can also be used for determining daily energy amounts with some confidence, given the fairly consistent pattern of project operations under most conditions.

The two parameters not readily available from the long-term studies are the expected daily minimum capacity and ramp rates applicable under different operational scenarios. This section was included to address those two parameters. Minimum capacity levels are discussed in this sub-section and ramp rates in the following sub-section.

Figures 5-1 and 5-2 show the daily maximum and minimum generation levels and average load obligations for Project Use and First Preference customers for WY

2002 and WY 2003, respectively. The data for these graphs were derived from actual hourly generation for the periods shown. Although the project was operated under Contract 2948A in those years, for purposes of determining minimum daily capacities available from the project, these data are considered generally representative of project operations in the post-2004 period. The graphs are included in this report as a tool that can be used as guidance by customers in determining the minimum capacity limits on their hourly schedules under different operating conditions.

Minimum capacity levels will be dependent on several factors. During times of high reservoir release conditions, the flexibility associated with the Base Resource, which can be characterized as the difference in the minimum and maximum capacity limits, will be less than times of lesser release requirements. This reduction of flexibility will result from the higher base load generation level that occurs as a result of having to get more water through CVP facilities. This effect can be seen when comparing the winter months of January, February, the first week in March, and the May-through-June period in the graphs below. In Figure 5-1 (WY 2002) the minimum generation levels generally stay below 100 MW during these months. If part or all of the Project Use and First Preference loads were met by purchases or other energy exchange mechanisms, the flexibility available for Base Resource energy scheduling under these conditions would be defined by the minimum and maximum generation levels. It is evident that the minimum Base Resource capacity may be 0 MW if the above mentioned load commitments are met by available minimum CVP generation and purchases. Under this operation meeting CVP Loads with CVP gen will decrease the amount of energy available for Base Resource but may actually increase Base Resource flexibility.

In Figure 5-2 (WY 2003), the graph shows the reduction in Base Resource flexibility during a high flow period. When the months of January, February, the first week in

March, May, and June are compared to the same period in WY 2002, it is apparent that: (1) in the winter months both the maximum and minimum capacity from the project is higher, and the flexibility for shaping is somewhat reduced, and (2) in the Spring months, the maximum capacity does not seem appreciably different but the minimum can be almost as high as the maximum which would translate into little or no flexibility to shape Base Resource power under these conditions.

Another interesting feature demonstrated in Figure 5-1 (WY 2002) is that the Project Use and First Preference loads are consistently higher that minimum generation levels during Winter and Spring months. The implications during these years are that a forward purchase or an exchange arrangement to meet these loads could provide significant benefits to Base Resource customers that use Base Resource power to meet the top part of their load curve, and even with a forward purchase, there may be many days during these months when no Base Resource is available.

Figure 5-1 – WY 2002 Daily Maximum and Minimum Generation Capacity and

Average Daily Project Use and First Preference Loads

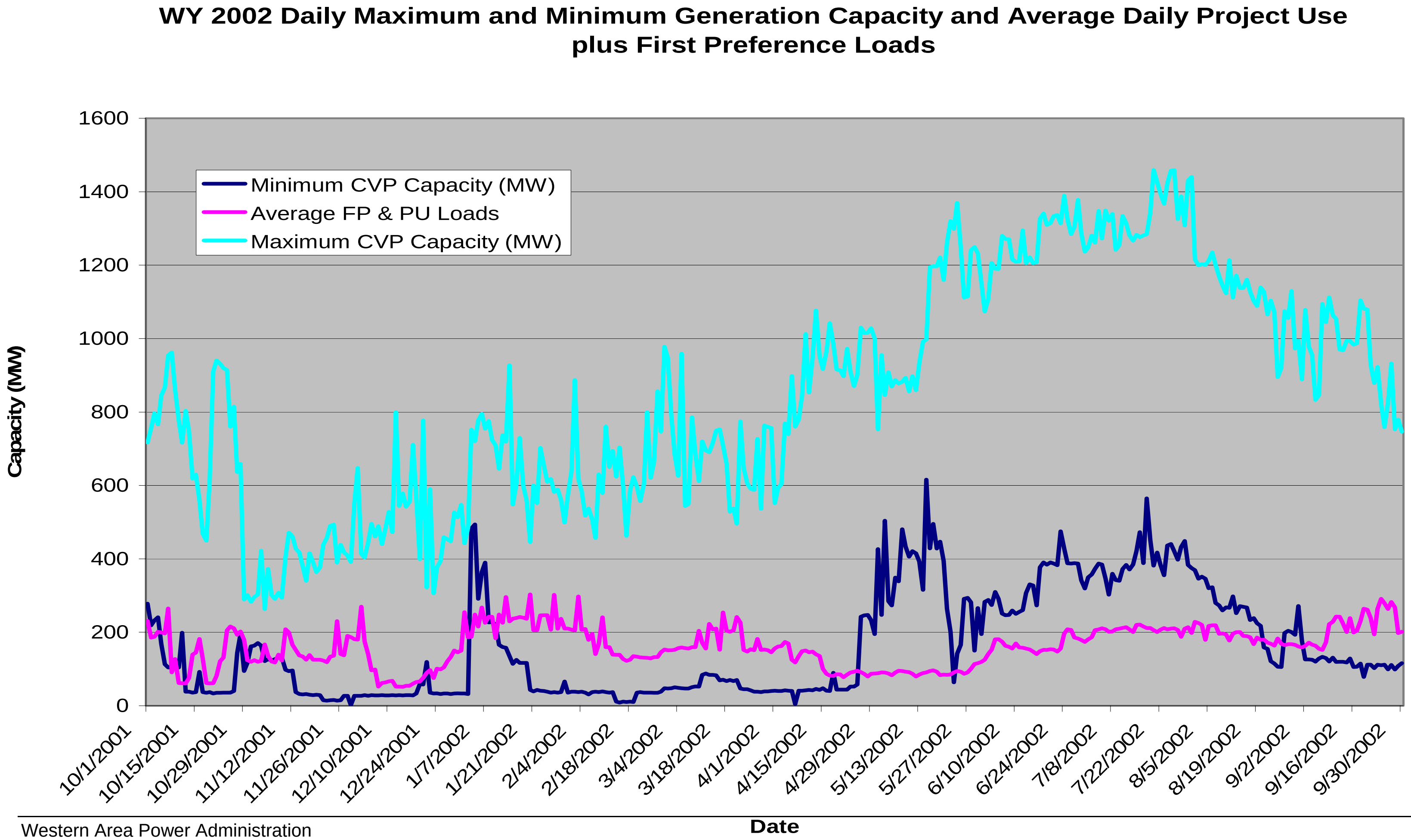
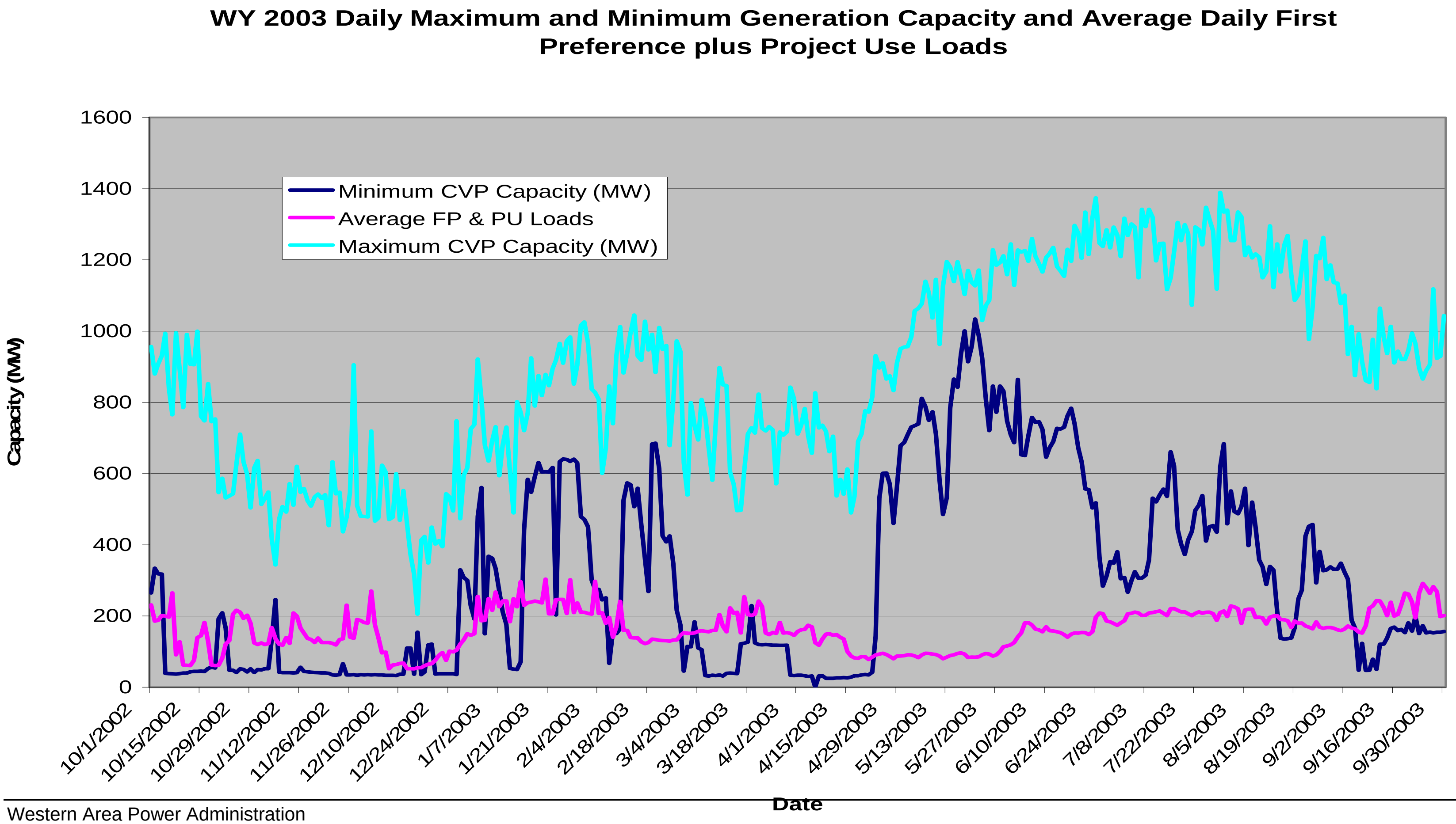


Figure 5-2 – WY 2003 Daily Maximum and Minimum Generation Capacity and Average Daily Project Use and First Preference Loads



5.2. Daily Ramping

To provide an indicator of the allowable hourly rate of change, or ramp rate, for Base Resource energy, 3 years (WY 2000-2002) of historic hourly total generation for the CVP were analyzed. Hourly changes in actual generation between adjacent hours were quantified, considering both decreasing (down ramp rate) and increasing (up ramp rate) generation changes, measured in units of MW per hour. Separate relative frequency and cumulative frequency analyses were then performed for all hours where generation changes occurred between adjacent hours. For the 3 years analyzed, no ramping occurred 64 percent of the total hours.

Figure 5-3, CVP 1-Hour Up Ramping, WY 2000-2002, suggests that 1-hour changes (increases) in generation of 100 MW per hour occurred most frequently, or 48 percent of the time when generation levels were increasing (6205 hours). Ramp rates less than or equal to 300 MW per hour occurred 95 percent of the all hours when generation was increasing.

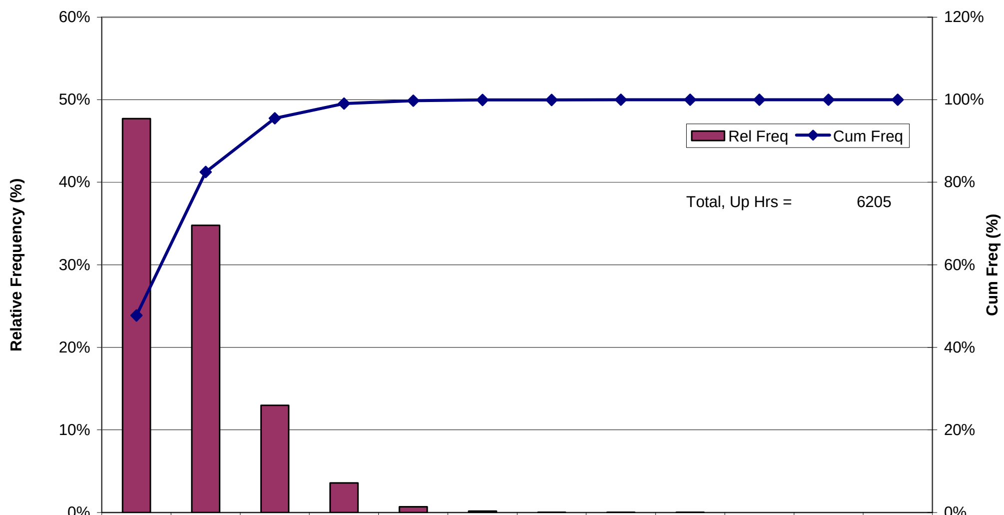
Figure 5-4, CVP 1-Hour Down Ramping, WY 2000-2002, suggests that 1-hour changes (decreases) in generation of 100 MW per hour also occurred most frequently, or 55 percent of the hours when generation levels were decreasing (3190 hours). Ramp rates less than or equal to 300 MW per hour occurred 96 percent of the all hours when generation was decreasing.

In recognition of the fact that historical operations reflected Contract 2948A operations, Western decided to investigate the capabilities of the CVP to ramp for post-2004 operations. In addition to the analysis of historical operations described above, Western held several discussions with Reclamation’s controllers. The controllers are responsible for implementing schedule changes to CVP facilities and as part of their function, they operate the project to meet hourly generation targets. Those targets have been provided by PG&E as part of Contract 2948A operations for the last several years. Beginning in 2005, Western will provide the targets based on the Base Resource needs of the preference customers. The controllers indicated, although project ramping has generally been in the 100-300 MW per hour range under PG&E schedules, in hours when PG&E asked for much higher ramps the CVP had no problem executing those schedules. In fact, in most hours the CVP is perfectly capable of ramping from minimum to maximum generation levels, or back down, in one hour. The primary operational conditions when these large ramp rates are not possible occur when limitations in the reregulating reservoirs preclude this type of operation.

Based on these conversations and the observations from historic generation, a conservative rule-of-thumb recommended for future ramp rate constraints on hourly Base Resource schedules is a 2-hour up and down ramp rate from minimum to maximum capacity per hour. A customer may choose to assume a 1-hour ramp rate with the understanding that the schedule may be modified by Western if operational conditions warrant. There will also be times when even a 2 hour ramp rate may be extended if conditions so warrant.

Figure 5-3 CVP 1-Hour Up Ramping, WY 2000-02

CVP 1-Hour Up Ramping WY 2000-02

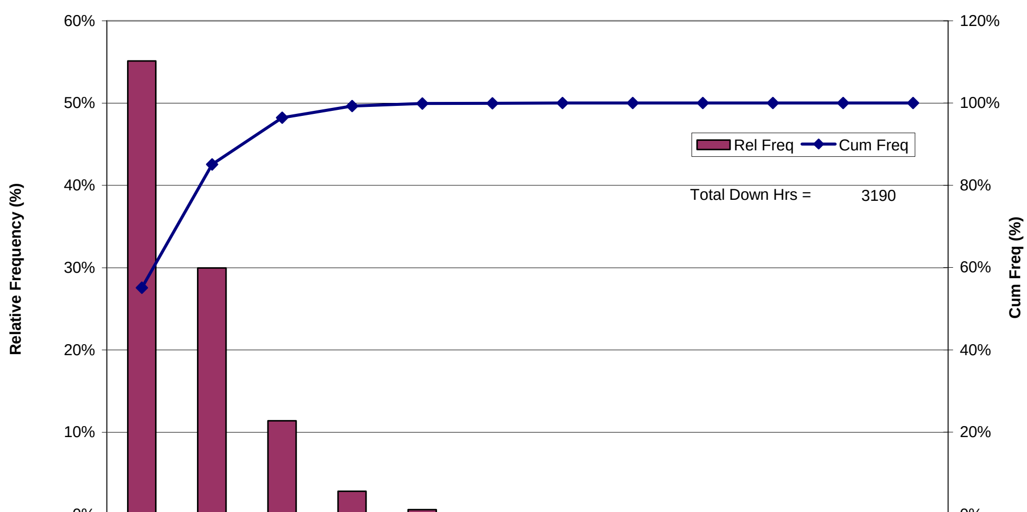


	100.000	200.000	300.000	400.000	500.000	600.000	700.000	800.000	900.000	1,000.000	1,100.000	1,200.000
Rel Freq	48%	35%	13%	4%	1%	0%	0%	0%	0%	0%	0%	0%
Cum Freq	48%	82%	95%	99%	100%	100%	100%	100%	100%	100%	100%	100%

Up Ramp (MW per Hour)

Figure 5-4 CVP 1-Hour Down Ramping, WY 2000-02

CVP 1-Hour Down Ramping WY 2000-02



	(100.000)	(200.000)	(300.000)	(400.000)	(500.000)	(600.000)	(700.000)	(800.000)	(900.000)	(1,000.000)	(1,100.000)	(1,200.000)
Rel Freq	55%	30%	11%	3%	1%	0%	0%	0%	0%	0%	0%	0%
Cum Freq	55%	85%	96%	99%	100%	100%	100%	100%	100%	100%	100%	100%

Down Ramp (MW per Hour)

6. Supporting Documentation

In addition to this report there are several Excel files that have the full range of data that was used in the development of this report. For the tables that include monthly and hourly data the spreadsheets are set up to allow customers to click on menus showing the different year types to bring up graphical representations of most of the relevant information referenced in this report. Three separate spreadsheets are provided. The first focuses on CVP generation and Project Use and First preference loads, the second focuses on Base Resource availability and some of the assumptions made to compute this resource, and the last has information relevant to WY 2002 analysis performed to develop on and off-peak relationships. For displays of LongTermGen power system modeling and simulation results for average monthly (including sub-period) gross and Base Resource energy and capacity for all water year types, please refer to Table 6-1 which lists the supporting spreadsheets.

This report, as well as all supporting spreadsheets developed for this Green Book revision, can be selectively downloaded directly from Western's Sierra Nevada Regional Office Power Marketing Web page at:
http://www.wapa.gov/sn/customers/powerMarket.asp.

For more information on any related matter to this Green Book revision, please contact Joseph Ungvari, Resource Team Lead, Sierra Nevada Regional Office, 916-353-4686, or send email to ungvari@wapa.gov.

Table 6-1 - Supporting Documentation

RESULTS	DOCUMENT	CONTENTS
Long-Term Gross CVP Power & Project Use Loads	CVP_GrossPower.xls	For selected Water Year Type (Wet, Above Normal, Below Normal, Dry, Critical) by Sub-period by Source: • CVP Gross Generation and Available Capacity at Load Center • Total, On-Peak and Off-Peak Project Use Energy and Capacity Load
Long-Term Net CVP Power (Base Resource) Adjustments for: Project Use and First Preference Loads, Losses and Reserves	CVP_BaseResource.xls	For selected Water Year Type (Wet, Above Normal, Below Normal, Dry, Critical) by Sub-period by Source: • Monthly Net CVP (Base Resource) Energy and Available Capacity, On-peak and Off-peak • Relative Frequency and Exceedence Curves, CVP Base Resource Energy and Capacity Total, On-peak, Off-peak • First Preference and Project Use Energy and Capacity • Operating Reserves
Simulation WY 2002 Generation Shift Modeling	WY2002_Analysis.xls	For all weeks simulated, includes: • Project Use and First Preference loads • Actual 2002 Generation and Project Use Forward Purchase • Shifted 2002 Generation and Forward Purchase • Base Resource

Appendix A – Description of Central Valley

<u>The Central Valley Basin of California</u>

The Central Valley Basin of California extends 500 miles in a northwest-to-southeast direction, with an average width of about 120 miles. Except for a single outlet at Carquinez Strait in the middle of the valley on the west side, mountains surround the basin. The Central Valley floor occupies about one-third of the basin, is about 400 miles in length, and averages 50 miles in width. The Cascade and Sierra Nevada ranges on the north and east rise in elevation to 14,000 feet and the Coast Range on the west to as high as 8,000 ft. Two major river systems exist in the basin: the Sacramento River system in the north and the San Joaquin in the south. The two river systems join at the Sacramento-San Joaquin Delta (the Delta) before emerging through the Carquinez Strait into the San Francisco Bay.

The climate of the Central Valley is characterized as Mediterranean, with long, warm, and dry summers that provide ideal growing conditions for a wide variety of crops under irrigation. The winters are cool and moist. Severe cold weather does not occur, but the temperatures drop below freezing occasionally in virtually all parts of the valley. Rainfall decreases from north to south, with precipitation levels much greater in the mountain ranges surrounding the valley. The average annual rainfall of the Central Valley ranges from about 5 inches in the south to 30 inches in the north. About 80 inches of precipitation, much of it in the form of snow, occurs annually at higher elevations in the northern ranges and about 35 inches occurs in the southern mountains. About 85 percent of the precipitation falls from November through April. Therefore, large variations in snowmelt runoff exist throughout the year, with larger flows occurring during winter and spring and lesser flows during the summer and fall.

Sacramento River Basin

The Sacramento River Basin includes the west drainage of the Sierra Nevada and Cascade ranges, the easterly drainage of the Coast Range, and the valley floor. The basin covers about 26,500 square miles and extends from north of Lake Shasta to Lakes Folsom and Natoma. Major tributaries to the basin include the Sacramento, Feather, Yuba, and American rivers. The Sacramento basin also receives water from the Trinity River basin through the Trinity River Division diversion works. Melting Sierra snowpack occurring in early spring and summer generates the greatest volume of runoff. In years of normal runoff, the Sacramento River Basin contributes about 70 percent of the total runoff to the Delta.

San Joaquin River Basin

The San Joaquin River Basin encompasses more than 11,000 square miles between the crest of the Sierra Nevada Range and the crest of the Coast Range and stretches to the divide between the San Joaquin and Kings rivers. Major tributaries in the basin are the San Joaquin, Merced, Tuolumne, and Stanislaus rivers. During normal runoff years, the San Joaquin contributes about 15 percent of the total runoff to the Delta. Water is imported into the San Joaquin River Basin through the Delta-Mendota Canal of the CVP and the California Aqueduct of the SWP. The CVP's primary generation facilities that are located in the basin are the New Melones Project in Calaveras and Tuolumne counties and on the west side of the San Luis Reservoir, which is pumped storage facility jointly used by Reclamation and DWR, and operated by DWR.

Major water exports are through the Friant-Kern Canal and the Hetch Hetchy Aqueduct. During the irrigation season and in January and February, much of the San Joaquin River Basin flow is made up of agricultural drainage and local surface runoff.

Sacramento-San Joaquin Delta

The Delta covers approximately 1,150 square miles at the junction of the Sacramento (north) and San Joaquin (south) rivers. The area includes about 800 square miles of agricultural lands that get their water from sloughs that traverse the Delta. Major tributaries, in addition to the Sacramento and San Joaquin rivers, are the Consumes, Mokelumne, and Calaveras rivers. The Delta was originally a vast flat marsh traversed by channels and sloughs. Land reclamation began in the 1860s with levee construction. Gradually the Delta was converted to farmland interlaced with dredged channels and levees. Water was directly exported from the Delta first in 1940 with the completion of the Contra Costa Canal (a unit of the CVP). In 1951, the Delta-Mendota Canal was completed, which receives water from the CVP's Tracy Pumping Plant, and later the Delta Cross Channel Canal was constructed near Walnut Grove to allow a more efficient transfer of water to the Tracy pumps.

Flows in the Delta are affected by a combination of river inflows, agricultural uses, diversions, and tides from the Pacific Ocean. When freshwater flows are low, flows in some of the channels change direction. The distance of upstream movement of salt water intrusion varies depending on availability of fresh water from river flows into the delta. The flows in the Delta and Delta water quality influence Reclamation's operation of the CVP. Delta outflow is highly seasonal and is characterized by high winter flows from storms and low steady flows in summer from agricultural and reservoir releases. The Sierra Nevada Region’s (SNR) Marketing Plan will have no effect on the flows to the Delta.

Trinity River Basin

The Trinity River Basin drains approximately 3,000 square miles in northwestern California before flows join with the Klamath River and drain into the Pacific Ocean. The mountainous terrain of the Trinity Basin ranges in elevation from above 9,000 It to 300 ft at the town of Weitchpec where the Trinity River joins the Klamath River.

The average runoff of the Trinity River is approximately 1,200,000 acre-ft at Lewiston and 3,800,000 acre-ft at Weitchpec. The Trinity River Basin exports water at Lewiston Reservoir to the Sacramento River Basin via the Clear Creek and Spring Creek tunnels.

Appendix B – CVP Water System Modeling – CALSIM II Model

Overview Model – California Water Simulation (CALSIM II)

The CALSIM II model is a general-purpose planning simulation model developed by DWR Reclamation for simulating the operation of California's water resources system, specifically the CVP and SWP. This simulation was performed for a 73-year period on a monthly time-step. The 73 years include most plausible climate variability that could stress the CVP/SWP system by representing weather that was experienced in California during the historical 1922-1994 water years. Model output reporting years are labeled 1922-1994.

Typical outputs reported from CALSIM II include end-of-month storage conditions, release amounts, flows conveyed through rivers and canals, export volumes from the Delta, etc. Like most simulation models, it is normally used in a comparative manner, with a baseline condition and some alternatives that are being evaluated. Output reporting is designed to show averages or trends in the simulation, not absolute system solutions during any specific month. Typical methods of output reporting include "long-term monthly averages" (i.e., averaging over the entire 1922-1994 simulation period), "year-type dependent averages" (i.e., averaging among years of the same hydrologic year-type classification according to the Sacramento 40-30-30 Index), and display of "Exceedence Plots" that show frequency and magnitude relationships on a given output variable.

Typical inputs to CALSIM II represent the CVP/SWP system as a link-node network, modeling the physical system (dams, reservoirs, channels, pumping plants, etc). Inputs are also provided to model operational rules (flood-control diagrams, minimum instream flows, requirements, delivery requirements, etc.) and priorities for allocating water. Some operations depend on rules that span months; for these operations, CALSIM II features specific rules. Embedded in this framework is the capability to route water according to user-specified priorities during any given month. This "within-month" routing decision is optimized by a linear programming (LP)/mixed integer linear programming (MILP) solver, steered by user inputs on routing weights (i.e., priorities) and physical/operational constraints.

Assumptions - Water Supply and Model Constraints

Traditionally, the CALSIM II model has been applied to support "comparative" studies, where the results from a "With Project" alternative simulation are compared to the results of a Benchmark simulation to determine the incremental effects of a project. The results from a single simulation, like that used for this Green Book revision, may not necessarily represent the exact operations for a specific month or year, but should reflect long-term trends.

Base Water Supply Study

The Green Book update depends on an assumed level of CVP/SWP reservoir operations. It is desirable to have these assumptions be consistent with those of the CVP/SWP Operations Criteria and Plan process OCAP. The OCAP studies describe different "baseline" CVP/SWP operations, varying on assumptions related to water demands (today versus future), implementation of CVPIA 3406g (b)(2), and implementation of EWA.

For the purposes of the Green Book update, Base Resource marketing in the coming years were linked to the water operation represented by OCAP Study 3, "Today CVPIA 3406 b(2) with EWA." Study 3 assumptions are provided on Reclamation's Central Valley Operations Office OCAP Web site at http://www.usbr.gov/mp/cvo/ocap.html. The Green Book Update was named "Study 3a" to denote association with OCAP Study 3.

Trinity EIS Preferred Alternative Targets

When representing Trinity Reservoir operations, release targets were replaced by those outlined of the Trinity EIS Preferred Alternative. Table B-1 below shows the difference in release targets in Study 3a.

Table B-1 – Annual Release Targets, Trinity Reservoir

Annual Trinity Release Target (TAF):	**Min**	**Max**
Existing	369	453
Trinity EIS Preferred Alternative	369	815

Water Supply Index to Demand Index

Two rule curves had to be adjusted to accommodate the new Trinity targets. The first rule-curve (the WSI-DI) serves a purpose during simulation to relate any water year's available and foreseen water supplies to a "demand index" for the coming delivery year. The second curve (the Del-Car curve) then prescribes how to split this demand index into actual deliveries and retained carryover storage that protects projects from dry conditions in the following-year.

Delivery-Carryover Curve

After adjusting the WSI-DI curves for changed Trinity Release targets, the CVP Del-Car curve was adjusted slightly in favor of more carryover storage in order to maintain the carryover "risk" values of OCAP Study 3 (i.e., frequency of years when Shasta carryover storage is less than 1900 TAF or less than 1200 TAF; frequency of years when Folsom carryover storage is less than 240 TAF or less than 300 TAF).

Appendix C – CVP Power System Modeling - LongTermGen Model

LongTermGen Model

The basic tool used in this analysis for power system modeling was a model called LongTermGen. The LongTermGen model is an Excel spreadsheet designed to use CALSIM II results and compute the resulting CVP power operations, both for Project Use and generation that would result from simulated water operations. Jointly developed by Western and Reclamation, the model is currently maintained and used by both agencies. For this analysis, the most recent version of the model (version 10) with Reclamation's latest generation curves was obtained for use in this power analysis.

The LongTermGen model takes monthly flow and reservoir operations data from a CALSIM II simulation and simulates mean monthly releases and pumping amounts using a monthly mass balance approach. While this approach is adequate for most water operations analyses, it does impose some limits on power computation. On-peak and off-peak power operations occur on much shorter time intervals than monthly, down to an hour or even lesser time-step. Peaking operations are also dependent on afterbay capacity and operations criteria that are not included in the CALSIM II flow operations results. Because of these limitations, the LongTermGen model does not attempt to define the on-peak and off-peak components of the CVP power generation operations.

There are other non-power related operational decisions that occur for time periods shorter than a month. These operational decisions can have major power implications, especially on available project capacity. In some months, generation and/or pumping facilities may be turned on for a portion of the month and off for the rest. Again, because of the use of mean monthly flow operations in CALSIM II, the flow balance is preserved so the impact on power generation or project capacity is not modeled.

For this analysis, three operational criteria were identified where the use of the mean monthly flow data from the CALSIM II water operation simulation could have significant impact on the computed power operation. These were:

- The Vernalis Adaptive Management Program;
- End of Irrigation Season Criteria; and
- Revised Trinity River Minimum Flow Requirement.

Vernalis Adaptive Management Program (VAMP)

The VAMP requirements specify that the total Delta pumping allowed for both the SWP (Banks pumping plant) and the CVP (Tracy pumping plant) is limited to 1500 cubic feet per second (cfs) plus one third of the San Joaquin River inflow to the Delta greater than 1000 cfs, during the period of April 15 to May 15. As currently implemented in CALSIM II, the Tracy pumping plant is limited to 800 cfs during this period and allowed to pump up to its maximum rate of 4600 cfs outside the period. The weighted average of these two limits is then used in a monthly mass balance approach to determine the simulated operation for the month. The final Tracy pumping values from the CALSIM II model for the month would then fall somewhere between these two extremes, with the values inside the restriction period being too high and the values outside the restriction period being too low.

This difference in Tracy pumping also results in changes in CVP San Luis operations inside and outside of the VAMP pumping restriction period. The difference could be even more dramatic as the CVP San Luis operations could switch from pumping, a Project Use, during the outside period, to a release, which results in additional generation. This implies that the power operations have a different magnitude during and outside the VAMP pumping restriction period, they could actually switch between generation and Project Use, while the monthly men values would show only generation or Project Use.

End of Irrigation Period

As the irrigation period ends, usually sometime in August, the CVP demands are significantly reduced. With reduced demands, the CVP San Luis operations may reduce releases or switch from release to fill at some point in the month. As with the VAMP period, this change in water operations could have a significant impact on power operations which is not captured by using the monthly mean flows.

Trinity Minimum Flow

The Trinity River minimum flow requirement varies on a daily basis during the April through July period. During this time the required minimum flows may exceed the flow capacity of the powerplant at the Trinity Reservoir and require that a portion of the release from the reservoir pass through the outlet works rather than the powerplant turbines. Since both CALSIM and LongTermGen use mean monthly flows for their computations, it is possible that there could be times when meeting the Trinity minimum flow requirement on a daily basis could have required release that bypassed the powerplant while the mean monthly flow was low enough that the LongTermGen model assumed that the entire release was used for generation, overestimating the energy generation for the month.

Determination of Sub-Periods

The VAMP and end-of-irrigation issues were handled by splitting each of the months of April, May, and August into two parts, or sub-periods. This results in a year being represented by 15 periods, instead of 12 months. The flow operations for each of these periods were then estimated from the CALSIM II monthly flow values.

Next, the LongTermGen model was then used to compute the power operations for each of these sub-periods by assuming that the computed period flow operations had occurred for the entire month, using the monthly LongTermGen computations to estimate the resulting power operations. These monthly power operations were then split into the appropriate sub-periods based on the ratio of the number of days in the sub-period to the number of days in the month.

The Trinity minimum flow issue was addressed by performing a daily analysis for Trinity operations for April through July of each year to estimate the amount of the monthly CALSIM flow operations, or the “effective” release that actually could have been used for power purposes. The LongTermGen model was then used to compute the Trinity power operations for those months assuming that the “effective” flow had occurred.

Trinity Minimum Flow Requirement Adjustment

The adjustments for the Trinity River Minimum Flow were performed in the Excel spreadsheet. The Trinity powerplant maximum flow capacity for each month was first obtained from the LongTermGen model of the CALSIM II results for April through June for each year. In the CALSIM II modeling, the Trinity releases always meet the mean month minimum flow requirement. There is also a local inflow component between the Trinity powerplant and the Trinity River minimum flow requirement location. As a result, Trinity releases were computed as the difference between local inflow and the Trinity River minimum flow requirement.

For this analysis, the assumption was made that the local inflow was the same each day of any given month. The daily releases were then compared to the powerplant flow capacity limit. If the release to meet the requirement was higher than the powerplant capacity, the difference was assumed to bypass the powerplant or “spill” and not be available for generation. If the release was lower than the powerplant capacity, then the difference was assumed to be available for use if releases were increased. These values where then totaled for the month to get the total release used for power generation.

Figure C-1– Daily Trinity Powerplant release to meet

Trinity River minimum flow requirements.

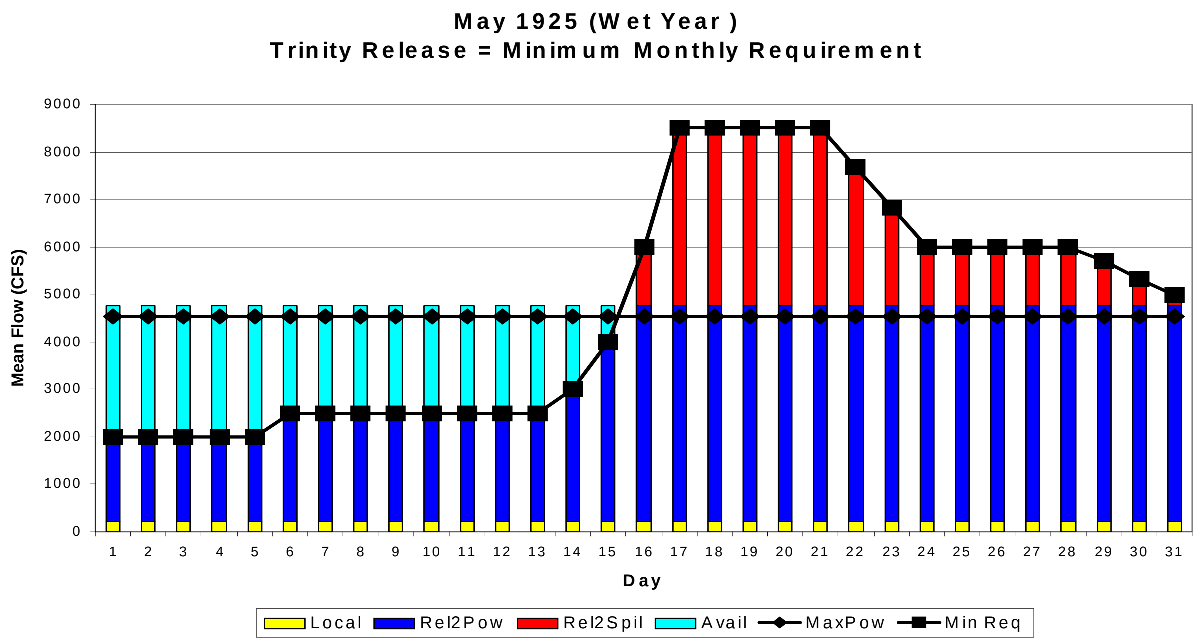


Figure C-1 illustrates this process. The black line with square markers represents the daily minimum flow requirement. The month chosen was May 1925, which happened to be a wet year. The black line with diamond markers represents the Trinity Powerplant flow capacity. The yellow bars represent the local inflow below the Trinity powerplant that cannot be used for power generation. The dark blue bars represent the flow that could be used for power generation each day of the month assuming that the Trinity release is just enough to meet the Trinity River minimum flow requirements. The red bars represent the Trinity release, required to meet the Trinity minimum flow requirements that must bypass the powerplant. The light blue bars represent the potential for additional Trinity release that could be used to generate power.

The assumption was then made that additional Trinity release, over the release required to meet the Trinity minimum flow standard, could be released on any desired day and that it would first be added to the daily release during the days when there was powerplant capacity available.

The final Trinity release used for power generation was then computed for one of three ways:

- If the Trinity release is just enough to meet the Trinity River minimum flow requirements then the release for power generation is the “effective” release.
- If the Trinity release is greater than the minimum but less than the minimum plus the “available”, then the total release for power generation is the “effective” release plus the total release minus the minimum release. This assumes that all the additional release this month could have been routed through the powerplant.
- If the Trinity release is greater than the minimum release plus the “available” flow capacity, then the total release for power generation is the “effective” release plus the “available” capacity. The assumption here was that once the powerplant is at full capacity then any additional release must bypass the powerplant.

Base Resource Computation

An additional spreadsheet was then used to compute the final Base Resource and prepare all final statistics, tables and graphics. The Base Resource for each of the periods was computed using the formulas:

Capacity:

- Base Resource =
  - Available Generation Capacity
  - Minus Estimated Operating Reserves
  - Plus Project Use Purchase
  - Minus Project Use Load
  - Minus First Preference Customer Load

Where:

- Available Generation Capacity is the computed CVP generation capacity.
- Estimated Operating Reserves is computed as 5 percent of Available Generation Capacity plus 40 MW.
- Project Use Purchase represents a power purchase contract that is assumed to be used each year. The purchase was assumed as a 50 MW off-peak purchase in Q1 and Q4 each year.
- Project Use Load is the computed CVP Project Use load.
- First Preference Customer Load was projected loads for the four First preference customers at a 2005 level. The same values were used in every year of the analysis.

Energy:

- Base Resource =
  - Gross Generation
  - Minus Transmission Losses
  - Plus Project Use Purchase
  - Minus Project Use Load
  - Minus First Preference Customer Load

Where:

- Gross Generation is the CVP system generation computed in LongTermGen model.

- Transmission Losses are computed in the LongTermGen model. The net of the gross generation minus transmission loss was used to compute the Base Resource.

- Project Use (Forward) Purchase is assumed to be used each year.

- The Project Use Load is the CVP Project Use computed in the LongTermGen model.

- First Preference Customer Load was the projected load at the 2005 level. The same values were used in every year of the analysis. The specific energy values are shown in Table C-2

Table C-2 - Project Use Purchase and First Preference Customer Loads

Period	PU Purchase		First Preference	
	Energy	Capacity	Energy	Capacity
	(GWH)	(MW)	(GWH)	(MW)
OCT	16.9	50.0	12.3	24.2
NOV	15.7	50.0	13.0	27.0
DEC	16.9	50.0	14.2	29.6
JAN	16.5	50.0	14.8	30.9
FEB	16.1	50.0	11.9	27.6
MAR	15.3	50.0	12.9	25.9
APR 1-14	0.0	0.0	5.4	24.7
APR 15-30	0.0	0.0	6.2	24.7
MAY 1-15	0.0	0.0	6.1	22.9
MAY 16-31	0.0	0.0	6.6	22.9
JUNE	0.0	0.0	12.9	29.6
JULY	0.0	0.0	15.1	34.2
AUG 1-15	0.0	0.0	6.9	32.0
AUG 16-31	0.0	0.0	7.4	32.0
SEP	0.0	0.0	13.0	28.2

The computed Base Resource energy data was then split into on-peak and off-peak portions based on the mean daily Base Resource generation and a relationship between this value and the percent of that value that could have been produced on-peak. The derivation of these values is described in Appendix C. The values used are shown in Table C-3.

Table C-3 - Mean Daily Generation Vs Percent On-Peak Generation

Mean Daily Base Resource	**Percent On-Peak**
(MWh)	**(%)**
0	81%
3000	81%
6000	80%
9000	79%
12000	77%
15000	75%
18000	73%
21000	71%
24000	68%
27000	65%
9999999	65%