Final

Attachment 1
Payment Capacity of Hydropower Beneficiaries

Cost Allocation Appendix

Shasta Lake Water Resources Investigation

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Abbreviations and Acronyms

Cal ISO	California Independent System Operator
CRD	contract rate of delivery
CVP	Central Valley Project
CVPIA	Central Valley Project Improvement Act
Delta	Sacramento-San Joaquin Delta
DMC	Delta-Mendota Canal
DOE	Department of Energy
MW	megawatts
MWh	megawatt-hour
NCPA	Northern California Power Agency
NP-15	North Path-15
OM&R	operation, maintenance, and replacement
PRR	power revenue requirement
RPS	Renewable Portfolio Standard
SMUD	Sacramento Municipal Utility District
WAPA	Western Area Power Administration

Payment Capacity of Hydropower Beneficiaries

Payment capacity for hydropower beneficiaries is ultimately based on the cost of Central Valley Project (CVP) power in relation to power market rates in the region. In 2012, Reclamation, in coordination with the Western Area Power Administration (WAPA), conducted analyses to identify potential risks related to the effective recovery of the Federal investment in the CVP. This attachment summarizes results of these analyses related to historical and anticipated future cost competitiveness of CVP power, which were used to support payment capacity evaluations for hydropower beneficiaries presented in Chapter 6, "Recommended Plan and Implementation Requirements," of the Final Feasibility Report. The following sections provide background on CVP hydropower use and rate setting, and summarize the CVP power rate projections estimated for three potential future hydrology and power generation scenarios analyzed by Reclamation in coordination with WAPA. As described below, historically, power market rates have exceeded CVP power costs on a long-term average annual basis, and it is expected that CVP power will remain an attractive component of power contractors' electricity generation portfolios in the future.

Background

CVP generated hydropower is first used to meet CVP operation needs or loads. CVP power loads primarily consist of energy demands to pump CVP water from the Sacramento-San Joaquin Delta (Delta) into the Delta-Mendota Canal (DMC) and the Contra Costa Canal, and from the DMC into the San Luis Reservoir. Future demands will include pumping from the Sacramento River into the Tehama-Colusa Canal and pumping water from the DMC into the California Aqueduct via an intertie. Any power in excess of CVP project use is offered for commercial sale. The Department of Energy (DOE) Organization Act of 1977 transferred the power marketing functions from Reclamation, including the construction and OM&R of transmission lines, to WAPA. WAPA markets the excess power and collects construction and operation, maintenance, and replacement (OM&R) costs, as well as Central Valley Project Improvement Act (CVPIA) Restoration Fund charges from the CVP power contractors.

Power Contracts and Rates

Power beyond the needs of the CVP is marketed by WAPA, Sierra Nevada Region. Since the inception of the power marketing plan in 2004, the Sierra Nevada Region has marketed approximately 3,100 gigawatt-hours of power annually from over 2,100 megawatts (MW) of CVP hydropower generation. WAPA also owns and maintains power lines which transmit power from Federal dams to power customers.

Power Marketing Plan

Under the power marketing plan, CVP power contractors no longer pay for power on a per-unit basis (i.e., dollars per megawatt per hour). Instead, power contractors repay costs allocated to power based on their assigned percentage share of the hydropower output of the project. Under the previous marketing plan, contractors received a contract rate of delivery (CRD). The percentage resulting from that process was carried over for each contractor into the new marketing plan. Similar to water repayment contracts, annual repayment amounts are based on revenue requirements to recover OM&R, construction costs, and the interest on investment. Revenue requirements are independent of the amount of power which may be delivered.

Revenue Requirement

WAPA calculates an annual power revenue requirement to recover OM&R, construction costs, and interest on the investment. The annual power revenue requirement (PRR) is estimated over five years. For the fiscal years 2011 to 2015, the forecasted annual power revenue requirements are shown in Table 1.

WAPA does not ordinarily change the rate unless significant increases to the forecasted annual revenue requirement occurred, or are expected to occur. However, WAPA has the flexibility to revise the estimated annual PRR before the start of each fiscal year based on updated forecasts of revenues and expenses in order to collect sufficient repayment revenue.

Table 1. Annual Power Revenue Requirements (As of October 1, 2010)

Fiscal Year	Estimated Annual Power Revenue Requirements ($ millions)
2011	$75.8
2012	$76.4
2013	$76.4
2014	$78.1
2015	$79.0

Source: WAPA, March 2011

In determining the appropriate annual PRR, Reclamation allocates CVP costs, which include WAPA's transmission costs. WAPA incorporates these costs into the PRR along with requirements for other services and products provided by WAPA. Each power customer is then assigned its percentage share of the annual PRR.

WAPA closely monitors the relationship between revenues and expenses during the year. At the mid-point of the Federal fiscal year, (April 1st), WAPA analyzes actual revenues and forecasted expenses to determine if the current rate of collections will effectively recover the annual expenses and costs faster or slower than planned.

WAPA reconciles actual and estimated revenue requirements within the fiscal year, and shortfalls or excesses are accounted for in the next year's PRR. As of the end of fiscal year 2009, approximately 75 percent of the CVP construction costs allocated to power had been repaid.

In addition to CVP construction costs allocated to power for repayment, CVP power contractors are also obligated to repay construction costs and mitigation charges for agricultural water contractors receiving relief through the Ability to Pay program. As of September 30, 2010, the power contractors' aid to irrigation contractors was estimated at over $43 million. To date, WAPA has not included these costs in the PRR.

Power Cost & Revenue Trends

Historically, power market rates have exceeded CVP hydropower costs on an annual basis. Recently, the margin between the net costs of CVP power versus the market rate has decreased as indicated in Table 2. CVP costs may not always be less than market rates for multiple reasons. In reviewing the data and comparing the cost of Federal power to market prices averaged over all hours of the year at North Path-15 (NP-15), a delivery designation point and energy trading hub for the California Independent System Operator (Cal ISO), it is important to note that the CVP is often times constrained by environmental operating criteria. As a result, the opportunities to optimally peak the resource, or to generate hydropower when it is the most valuable, may be constrained by water operation restrictions. This reduces the value of CVP power on average.

Historically, Reclamation has qualified over 40 CVP irrigation districts for relief, which amounts to approximately $40 million in construction costs and $36 million in mitigation and restoration charges, for fiscal years 1993 through 2009.

Preliminary results of current studies indicate that improved irrigation practices, higher crop yields and increased product value due to global influences, are resulting in many districts having a greater ability to pay for their construction costs and mitigation charges and thus reduced relief. If preliminary results hold, more costs will be borne by irrigation districts and fewer costs redirected to power contractors.

Table 2. Ratio of Mitigation and Restoration Charges to Total Power Costs

Fiscal Year	Base Rate For Power ($/MWh)	Additional Restoration Charge ($/MWh)	Percent of Restoration Charges to Total Costs for Power	Total Cost of CVP Power[1] ($/MWh)	Power Market Rates (NP-15)[2] ($/MWh)
2002	$23.83	$3.28	12.1%	$27.11	$26.03
2003	$24.63	$2.02	7.6%	$26.65	$42.24
2004	$24.73	$.60	2.4%	$25.33	$45.39
2005	$13.18	$6.78	33.9%	$19.96	$56.17
2006	$8.71	$3.23	27.1%	$11.94	$60.70
2007	$20.19	$2.02	9.1%	$22.21	$56.81
2008	$28.50	$11.04	27.9%	$39.54	$73.88
2009	$29.89	$15.65	34.3%	$45.54	$36.81
2010	$31.76	$5.29	14.3%	$37.05	$38.19
2011	$21.24	$7.77	26.8%	$29.01	$39.09

Source: WAPA SNR Rates Department, March 2011
Notes:
[1] Does not include any additional aid to irrigation costs
[2] Power market rates are estimated at North Path-15, a delivery point and energy trading hub for Cal ISO
[3] Reflects projected new rate for the next 5-year marketing plan period.
Key:
CVP = Central Valley Project
Cal ISO = California Independent System Operator
NP-15 = North Path-15
MWh = megawatt-hour

Power Rate Projections

Recovery of the Federal investment assigned to the power contractors for repayment may be impacted if prices paid for CVP power significantly exceed market power rates over an extended period of time. CVP power contractors, especially municipal utilities such as Sacramento Municipal Utility District (SMUD), develop electricity generation portfolios to reliably meet their load obligations in a cost-effective manner consistent with local, State and Federal mandates such as the Renewable Portfolio Standards (RPS).

Utility generation portfolios generally include resources owned by the utility, long-term power purchases, and short-term market purchases. If the cost of an individual resource, such as CVP power, either exceeds the alternative cost of producing electricity, such as through the construction of a new resource or making purchases through long or short-term contracts, then it is possible the utility might opt out of their CVP power purchase contract. However, a utility would carefully consider the long-term risks before making such a decision.

CVP power customers value CVP power differently depending on such factors as their status as balancing authority operators, the fit of CVP power with their remaining resource mix, and the manner in which power is transmitted to the utility.

For example, SMUD, as a balancing authority operator, can access CVP power from its Elverta Substation, which generally is under loaded. Despite the need to pre-schedule CVP power two days in advance, CVP power provides SMUD with flexibility in scheduling other resources in its generation portfolio because transmission congestion is almost never a factor impacting their use of CVP power. In addition, WAPA has provided SMUD with 60 MW in ancillary services (Department of Energy Conservation regulation) from the CVP.

As another example, CVP power, on average, meets more than 30 percent of the Northern California Power Agency (NCPA) member communities’ energy needs. Because many NCPA members are connected to the grid via the Cal ISO transmission system, CVP power is exchanged with Cal ISO in order to serve these member communities. Consequently, the CVP power is valued at the composite Cal ISO market rate weighted by the percentage of power produced on-and off-peak.

In deciding whether CVP power is a good value in their resource portfolios, CVP power customers also consider adverse circumstances, such as periods of extended drought, when the price of alternative generation resources, such as natural gas-fired power plants, generally goes up because of higher natural gas prices, scarcity of air emission credits, etc.

Long-Term Drivers

Many CVP power customers also consider the long-term drivers of electricity prices. California has two mandates that are likely to result in significant increases to the market price of electricity:

1. Senate Bill X1-2, signed by Governor Brown in April 2011, mandates that both publicly-owned and investor-owned utilities adopt RPS goals of 20 percent of retails sales from renewable resources by the end of 2013, 25 percent by the end of 2016, and 33 percent by the end of 2020.

2. On May 4, 2010, the State Water Resources Control Board adopted the “Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling” to establish technology-based standards which implement Federal Clean Water Act section 316(b) and reduce the harmful effects associated with cooling water intake structures on marine and estuarine life. The policy standards include retiring or modifying power plants which use ocean water to cool plant systems, then return the water to the ocean at higher-than-normal temperatures.

Hydropower Price Competitiveness

Two separate approaches were used to compare the relative price competitiveness of CVP hydropower. The first approach used alternative cost of power during the time of peak load that a utility might ordinarily use to meet its power needs. Typically, a production cost model is used to determine the value in $/MWh of an existing resource, such as CVP hydropower, by comparing the cost to meet load with and without the resource. In lieu of running a production cost model, the forecasted NP-15 summer peak price was used as a surrogate for the alternative cost of power.

The second approach took into consideration that CVP hydropower is a take or pay, around the clock product. As such, CVP power costs were compared to a forecast of composite market prices weighted on an average seasonal basis. Although power customers repay their proportionate share of the Federal investment on an annual revenue requirements basis, it is possible to calculate on an average annualized basis, the average per unit cost and to compare that cost against forecasted market-based power rates to determine overall cost competitiveness.

While forecasting CVP and market-based energy prices on a long-term basis is difficult due to the high degree of uncertainty associated with energy markets, it is still possible to undertake a cost comparison analysis showing the relative cost competitiveness of CVP hydropower resources against the two forecasts of energy prices described above and the three hydrologic scenarios used for the water rate projections. The power rate analysis was developed as follows:

1. The output from the CalSim II study of current CVP operations and 81 years of hydrologic data used for the water rate projections were processed through a power generation module that estimated CVP generation, project-use energy consumption, and losses to define the net amount of power available for marketing in each year of the three scenarios.

2. WAPA’s estimated power revenue requirements for fiscal years 2012 through 2015 were used for the first four years and then escalated for each of the three scenarios using a rate of three percent.

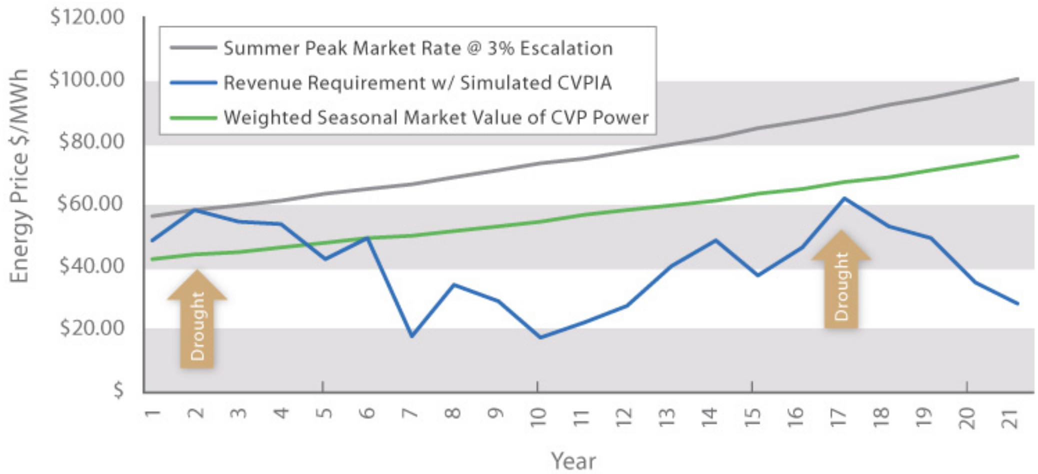
3. CVPIA mitigation and restoration charges were estimated for each year for both irrigation and municipal and industrial users. These annual estimates were then subtracted from the total annual mitigation and restoration requirements to determine the net mitigation and restoration collections required from the preference power customers to achieve a $30 million annual collection.

4. An energy price was calculated for each year based on the sum of the revenue requirement and estimated mitigation and restoration collection amount divided by the annual production of the water year types. Aid to irrigation was assumed to be zero beyond 2015.

5. Finally, the derived CVP energy cost is compared to the alternative cost of power, a forecasted market rate provided by WAPA for forecasted NP-15[1] prices (on-peak and off-peak) equating to the latest pricing forecast from IVG Energy.

This forecast of market prices ignores energy price swings common in wet and dry years, as well as the comparative advantages or disadvantages that specific power resources have during those times. As described previously, renewable energy mandates are anticipated to apply upward pressure on the rates, likely in excess of the three percent annual escalation assumed.

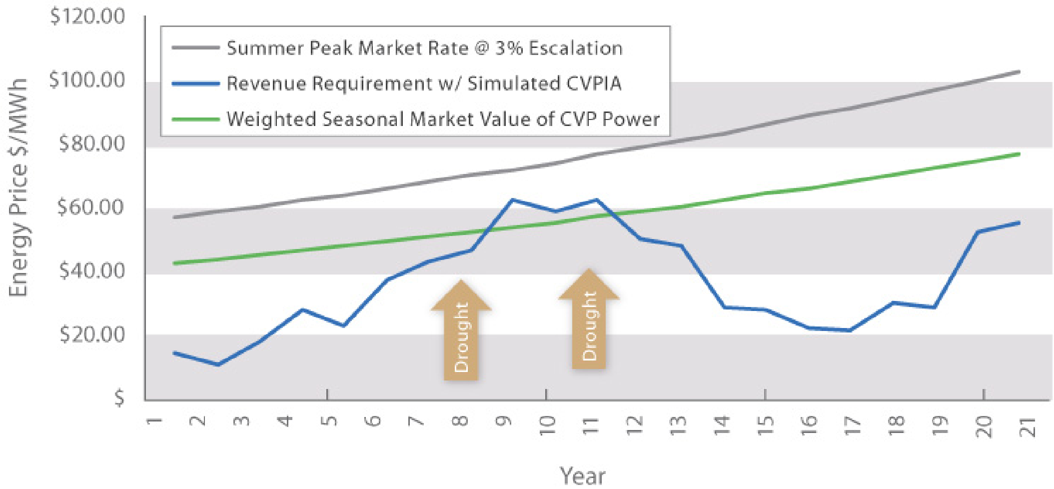
The subject comparisons are shown in Figures 1 through 3.



Source: Reclamation MP Region, April 2011, WAPA and IVG Energy, May 2011

Figure 1. Summary of CVP Power Rate Projections – Scenario 1: 1932 to 1952 Hydrology

[1] North of Midway to Los Banos Transmission path, which refers to the electricity market prices of most relevance to CVP preference power customers.



Source: Reclamation MP Region, April 2011, WAPA and IVG Energy, May 2011

Figure 2. Summary of CVP Power Rate Projections – Scenario 2: 1982 to 2002 Hydrology

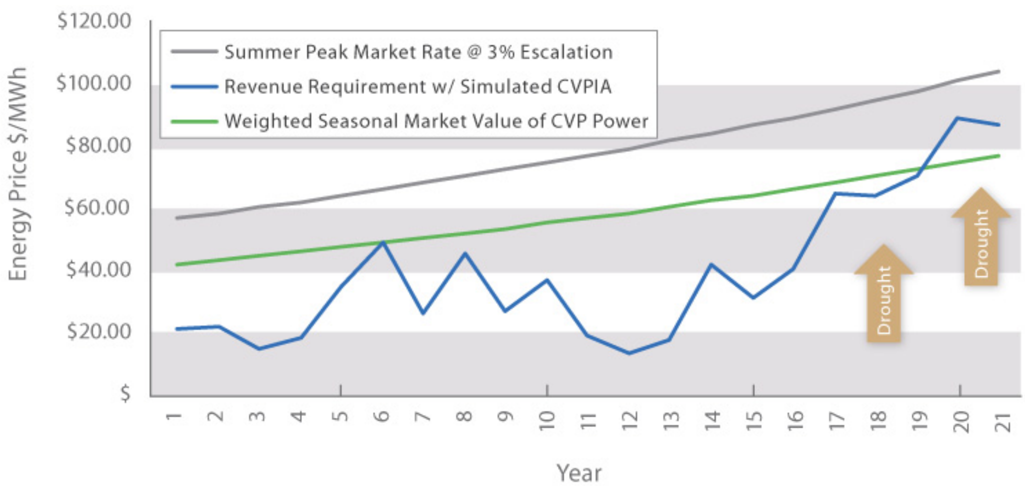


Figure 3. Summary of CVP Power Rate Projections – Scenario 3: 1972 to 1992 Hydrology

Market Response to Power Rate Projections

Based on the power rate projections estimated for the three hydrology and power generation scenarios, it does not appear that CVP energy costs will exceed alternative costs of power for a prolonged period of time under current operating conditions, and CVP energy costs will remain competitive and be less expensive than market energy prices. However, should operating conditions significantly change, it is possible that the relative price competitiveness of the CVP hydropower product will be impacted. As a result, the possibility of CVP power customers opting out of their contracts with WAPA in the near term appears low. Reclamation and WAPA will need to continue monitoring the price of CVP hydropower in relationship to its reliability and the cost of alternative sources.