CVP Cost Allocation Study
Power Benefits Methodology

Date
March 12, 2015

Purpose of Paper
The purpose of this paper is to recommend a methodology for evaluating power benefits for the Central Valley Project (CVP) Cost Allocation Study. This is an updated issue paper (original paper was dated Dec. 24, 2013) to include the overall methodology.

Background
The Bureau of Reclamation is currently undertaking a new CVP Cost Allocation Study. The last major cost allocation for the CVP was conducted in 1970, and an interim update was completed in 1975. Although new legislation and new regulatory considerations, coupled with the construction of new facilities have significantly altered project accomplishments and operations in the intervening 40 years, Reclamation was unable to update the CVP cost allocation because of the cost, complexities and controversy associated with such an effort. In 2010, however, Reclamation committed to update the CVP cost allocation in conjunction with the completion of the Folsom Safety of Dams project (anticipated in 2017) in order to better align the benefits, accomplishments and costs of the CVP with the changed operations of the CVP.

First authorized in 1935, the CVP is a multipurpose project whose individual project features and/or elements (e.g., facilities and/or divisions) have been re-authorized at key legislative junctures to be financially and operationally integrated and operated as a single project. The CVP is authorized to serve the following seven project purposes: Water Supply (irrigation, municipal and industrial (M&I) and wildlife refuges), Power, Flood Control, Recreation, Fish and Wildlife, Navigation and Water Quality. This paper focuses on the power purpose and specifically the methodology for evaluating power benefits.

Reclamation presented the proposed methodology for evaluating power benefits at public meetings on Nov. 16, 2012, and Jan. 18, 2013. A suggestion to revise the methodology was an outcome of those meetings. The *Streamlined Power Benefits* Section of this paper describes the approach taken to test the proposed change to the methodology. This decision paper documents the final power benefits methodology and focuses on the recent decision to revise the methodology to evaluate three components of power benefits through a direct application of actual and forecasted power market prices.

Power Benefits Methodology

Under the Principles and Guidelines (P&Gs), benefits are estimated from a national perspective rather than from the effects to a particular locality or regional standpoint. For power benefits, this means valuing the attributes of the CVP's hydropower accomplishments in terms of the net benefits provided to the nation through the Western Interconnection's (interconnection) Bulk Electric System, or to California's electric grid, rather than valuing the benefits as part of the preference power customers' portfolios.

Section 2.5.2 of the P&Gs provides that the "basis for evaluating the benefits from energy produced by hydroelectric powerplants is society's willingness to pay for these outputs." The section provides several alternate approaches to valuing society's willingness to pay when this approach is either not possible or cost-effective. One approach allows the use of market prices under certain conditions. The second approach is premised on estimating benefits based on the most likely alternative to be implemented in the lieu of the alternative under consideration and is commonly referred to as the alternative cost approach. The P&Gs suggest that the first approach, or market prices, represents a better approximation of society's willingness to pay than the alternative cost approach if market price is representative of marginal cost.

The market price approach requires the market price to the final consumer be based on marginal production costs rather than on average costs. The P&Gs states that "utility pricing of electricity is complex and usually based on average cost rather than marginal cost." Furthermore, "when using market price as a measure of benefits the increment in supply should ordinarily be relatively small compared to the total (i.e., little change would be expected in market price to the incremental supply)."

If the market price approach is used, current and future market prices can be simulated using production cost models, which simulate the least-cost dispatch of generation to meet electrical load in the interconnection. The PLEXOS model is a production cost model and has been extensively used by policy analysts in the power utility industry in California. Two examples where PLEXOS was used include: (1) the California Independent System Operator (CAISO) evaluated the grid reliability needs of integrating renewable generation into the electric grid using PLEXOS and (2) the California Public Utility Commission (CPUC) uses PLEXOS to determine the need for new generating resources for their biennial Long-term Procurement Plan (LTPP) process. The PLEXOS model dynamically simulates the market dispatch of generation to meet load and reserve requirements while respecting transmission constraints to estimate the price of the resource being evaluated (in this case, the CVP hydropower system). PLEXOS is particularly good at modeling hourly hydro dispatch. In the analysis, it can and will be further constrained by actual water operations and regulatory requirements to reflect how the CVP is actually physically and legally operated. In addition, PLEXOS allows future benefits to be evaluated considering load growth, market dynamics and generation additions needed to meet legislative mandates.

In the early 1980s when the Mid-Pacific Region conducted power benefit evaluations for such projects as Auburn Dam and reservoir, power benefit evaluations consisted of running a much more rudimentary production cost model than PLEXOS. The model was run in both the "with" and "without" the project conditions, and then the differences were calculated to estimate the "avoided" variable cost to the electrical grid by having the proposed project in place. The "avoided" fixed cost was based on the cost to construct the thermal powerplant, which would be constructed if the project was not built. The "with" and "without" approach assured that any change in the variable cost to produce power, which even before there was an organized market was assumed to equate to market prices, due to the absence or presence of the project was accounted for in the analysis. Typically, for the "without" project condition, a thermal plant was added to the production cost model to replace the hydro project under evaluation in order to reliably meet load. Consequently, the approach used at the time was a hybrid market price-alternative cost approach.

The above approach was the approach proposed to value power benefits for the CVP Cost Allocation Study presented at the November 2012 and January 2013 public meetings. In response, the Northern California Power Agency representative suggested that CVP energy benefits should be valued through a direct application of market rates to CVP power accomplishments rather than the suggested "with" and "without" project approach. The suggested approach, which is a market approach, was evaluated and deemed suitable, as documented in the *Streamlined Power Benefits* Section of this paper.

California's Electrical Power Markets

In 1996, the California legislature passed and the Governor signed A.B. 1890, a bill to deregulate California's electricity market. The goal was to establish open and competitive electricity markets. Consequently, in the beginning, utilities divested a significant portion of their generation and purchased resources out of the Power Exchange (PX) on a day-ahead and hour-ahead basis and from the CAISO in real-time. With the advent of the California Energy Crisis and the intervening years, California's electricity markets evolved and have been restructured to use the Locational Marginal Pricing construct. Since the PX no longer exists, the CAISO market prices for generation and ancillary services represent the marginal prices of the resources based on their market bids. In fact, since the CAISO's market power mitigation mechanisms enforces market competitiveness, the marginal prices are a better representation of marginal cost then developing cost estimates using an alternative cost approach for a specific powerplant which may have a significant degree of variability based on the time of the day and/or season.

Under California's resource adequacy mandate, three types of capacity have been defined and developed: resource standard, local and flexible. The resource adequacy mandate has been promulgated by the California Energy Commission (CEC) and enforced by the CPUC and incorporated into the bidding business practices of the CAISO. At present, the CAISO does not have a centralized market which produces a market price for the resource adequacy capacity. Short-term operational capacity which is used as ancillary services to deal with situations of unexpected shortages, e.g. unscheduled or forced outages, do not provide good measures for estimating or valuing long-term capacity. As such, when estimating capacity benefits, an alternate cost approach, instead of a market-based approach for estimating benefits is required.

Evaluation of CVP Hydropower Benefits

Following are the four components of CVP power benefits to be evaluated for the CVP Cost Allocation Study:

- Capacity
- Energy
- Ancillary Services
- Renewable Energy Credits

CAPACITY: The CEC defines capacity as "the amount of electric power for which a generating unit, generating station, or other electrical apparatus is rated either by the user or manufacturer." Whereas thermal plants can typically produce electricity at their rated capacity any time except during outage conditions, hydro powerplants depend on reservoir head and flow through the powerplant to be able to produce the rated capacity of the plant. For example, although the Shasta Powerplant has a rated capacity of 710 MW, during a typical summer day, its capacity may only be 660 MW due to reservoir head and flow conditions. This reduction in capacity is exacerbated during droughts.

Capacity is valuable because of the need for sufficient machine capability to meet the peak electrical load hour during the hottest summer day. Flexible capacity is becoming more valuable as California continues to implement its renewable mandate to provide 33 percent of generation to meet load from renewable resources (other than large hydro) by the year 2020. Because short-term capacity markets in California are not a good indicator of the long-term value of capacity, as explained above, the value of CVP capacity will be estimated using the alternative cost approach. The value of CVP capacity can be estimated from the cost to construct and operate a combination of thermal plants providing comparable capacity benefits. It is likely that the sum of the capacity of these plants would be less than the 2149 MW of CVP installed capacity since CVP capacity, especially in a dry year, is significantly less than installed capacity. The evaluation will be consistent with CAISO's Federal Energy Regulatory Commission (FERC) tariff, which currently specifies an 80 percent exceedance condition in evaluating capacity adequacy and requires a certain amount of energy support for the capacity claimed.

ENERGY: The CEC defines energy as "the capacity for doing work. Forms of energy include: thermal, mechanical, electrical and chemical. Energy may be transformed from one form into another." For hydropower, energy is in the form of electrical generation that is timed to be provided when it is most valuable, if possible. Traditionally, hydro powerplant operators have strived to maximize on-peak generation, i.e. generation provided during the peak load hours, as defined by the tariff that CAISO files with FERC; however, as renewable generation from wind and solar resources has increased, generation may now be more valuable when bid into the ancillary services markets. Estimates of such benefits, however, will be based on actual and not theoretical calculations, since benefits may be constrained by water operations, environmental regulations, contractual constraints/limitations and the governing Power Marketing Plan.

As explained in the last section, California's electricity market represents the marginal cost of energy; therefore, the value of CVP hydro generation will be determined using a market-based approach, which is described in detail in the next section and the *Streamlined Power Benefits* Section of this paper.

ANCILLARY SERVICES: The CEC defines ancillary services as "services other than scheduled energy that are required to maintain system reliability and meet Western Electricity Coordinating Council/North American Electric Reliability Corporation operating criteria. Such services include spinning, non-spinning, and replacement reserves, voltage control and black start capability." Going forward, the ancillary services of most value are those to integrate renewables into the electric grid, which are known as regulation-up and regulation-down. Hydropower is particularly valuable at providing this type of ancillary service because hydro generation can be ramped up (regulation-up) or down (regulation-down) quickly to allow the grid operator to precisely match generation to load, especially when wind and solar generation fluctuates unexpectedly. When ancillary services are bid into the market, it is common that they are not called upon. A generating entity is paid for providing ancillary service capacity into the market and then paid for the energy, if generation is actually called upon in connection with the bid. PLEXOS is capable of optimizing the value of generation between the energy and ancillary services markets on an hourly basis within the constraints of the CVP's water operations. Estimates of such benefits, however, will be based on actual and not theoretical calculations, since benefits may be constrained by water operations, environmental regulations, contractual constraints/limitations and the governing Power Marketing Plan.

California's ancillary services markets represent the opportunity cost of ancillary services; therefore, the value of ancillary services will be estimated using a market approach as described in more detail in the next section and the *Streamlined Power Benefits* Section of this paper.

RENEWABLE ENERGY CREDITS (RECs): The August 2012 CEC Renewable Portfolio Standard (RPS) Eligibility Guidebook lists four types of hydropower facilities that qualify for RPS. These types differ in size, operations and age. Two hydropower types – conduit hydropower and efficiency improvements – are not relevant to this cost allocation study. The other two hydropower types include the following:

1. Small hydropower facilities less than 30 MW

    a. Commenced commercial operation before Jan. 1, 2006, or

    b. Commenced commercial operations after Jan. 1, 2006, and does not "cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of stream flow"

2. Existing hydroelectric generation units 40 MW, or less, and operated as part of a water supply or conveyance system.

Two CVP powerplants qualify for RECs, Nimbus and Lewiston Powerplants. As is the case for electrical energy and ancillary services, there is also a market for RECs (although not an hourly one). The value of RECs will be estimated based on current and forecasted values.

Valuing CVP Power Benefits over 100 Years

When comparing the benefits and costs for all project purposes, both inputs and outputs need to reflect (and maintain) the relative relationships of prices expected to prevail over the period of analysis. To avoid speculation regarding future price relationships, Reclamation uses the prices prevailing during, or immediately preceding, the period of analysis and assumes prices will escalate at about the rate of inflation. In other words, benefits and costs for all purposes are valued at the same base year price level (2010, in this case) unless there are specific reasons to justify using a price that is different from (either higher or lower than) the existing price relationship. The next paragraph explains why the changing dynamics of California's electricity market make it imperative to value energy and ancillary service benefits at a point in time when the changing market should have stabilized, i.e. after the year 2020. Because the PLEXOS model was recently used in the 2012 LTPP process, it is convenient to select the 10-year out condition from this process to value energy and ancillary services for this "stabilized" electricity market condition. Year 2022 benefit values will be indexed to base year 2010 values. After the year 2022, electricity market prices are assumed to escalate similar to inflation.

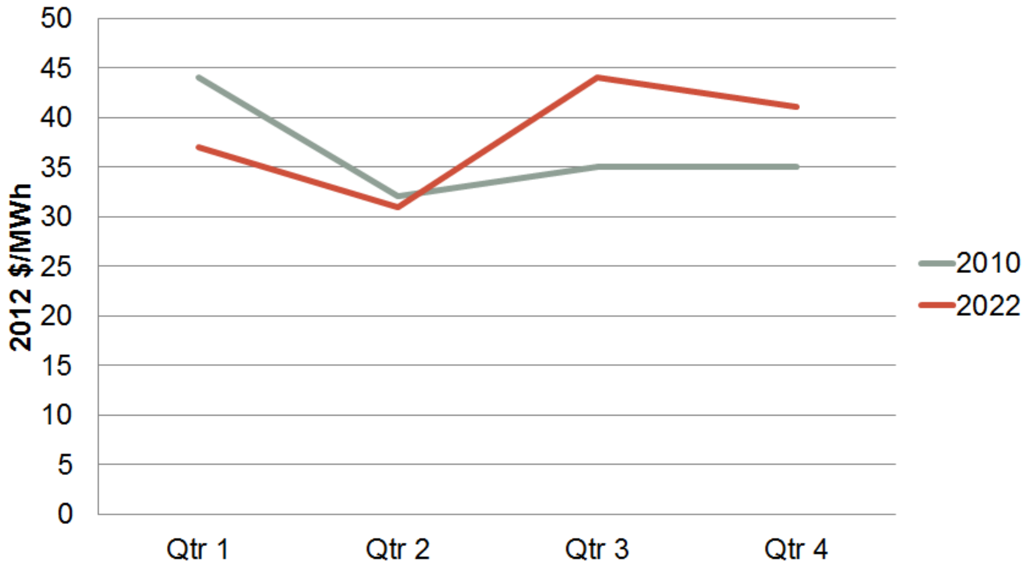
Given that California is currently implementing a 33 percent RPS and a Greenhouse Gas Emissions Reduction mandate, electricity market dynamics are undergoing a change in the price relationship currently existing for power. Implementation is expected to be complete in the year 2020. Much of the renewable generation to meet the 33 percent RPS mandate will come from non-dispatchable, intermittent resources such as wind and solar, CAISO representatives have publicly stated in a number of forums that the electricity market is undergoing a transformation to value certain attributes, such as flexible generation, more than other attributes.[1] Flexible generation can ramp up and down quickly to compensate for fluctuations in wind and solar generation to reliably meet load on a four-second-by-four-second basis. Hydropower is one of the best providers of such attributes as flexible generation (regulation-up and regulation-down), spinning reserves and other ancillary services, which are needed to allow the CAISO, or other California balancing authorities, such as the Balancing Authority of Northern California (BANC), to operate reliably to meet electrical load. BANC is a Joint Powers Authority comprised of a number of CVP preference power customers. Many CVP generation facilities, Western Area Power Administration's transmission facilities and the 500 kV California Oregon Transmission Project are among the resources located within the BANC footprint. Estimates of any spin and non-spinning reserves will be based on actual water and hydropower operations, risk management parameters, and legal/regulatory considerations, and not on theoretical capabilities.

The PLEXOS model was used to value energy and ancillary services for the year 2022. CAISO historical market prices were used for the year 2010. Following is the approach for interpolating between 2010 and 2022.

<u>ENERGY:</u> As depicted graphically below, the average annual value of actual 2010 and forecasted 2022 hourly electricity prices (in 2012 $) from the PLEXOS model over the entire year is about the same, i.e. approximately $38/MWh; however, the seasonal values are different. Because the energy benefits will not be significantly different between 2010 and 2022, a linear interpolation may be acceptable. An outstanding issue is whether and how to incorporate hydrological impacts to both CVP power accomplishments and electricity market prices into the benefit evaluation. This is an

[1] CAISO's *2012 Annual Report on Market Issues and Performance* proposed "major changes to its real-time market" including to "replace the flexible ramping constraint with a flexible ramping product." This report is found at http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf

issue for the benefit evaluations of all CVP purposes and, therefore, needs to be addressed in a consistent manner for all of the benefit evaluations.



California Base Year and Forecasted Electricity Prices

ANCILLARY SERVICES: Since we do expect a significant change in ancillary service benefit values between 2010 and 2022, interpolating benefits may require a non-linear approach. The CVP Cost Allocation Technical Team will need to confer with Reclamation's consultants to determine whether there are drivers that will influence these benefits to escalate in a non-linear fashion.

CAPACITY: Since the alternative cost rather than market price approach will be used to value capacity, no interpolation is necessary between 2010 and 2022.

RENEWABLE: The value of renewable hydro generation (from a 30 MW or less CVP hydropower feature) is the current and forecasted value of RECs. Linear interpolation is acceptable to show the escalation in these benefits since they are not a significant component of the overall CVP power benefits.

Streamlined Power Benefits

Reclamation has evaluated the NCPA suggestion that CVP energy and ancillary service benefits should be valued through a direct application of market rates to CVP energy and ancillary service accomplishments and concurs with this streamlined approach for the reasons described in the following paragraphs.

The primary reason for the Technical Team's recommendation and the Leadership Team's decision to use this streamlining approach is that the hypothesis that the CVP hydropower resource is not likely to influence California energy market prices significantly as long as the power system is resource adequate, was successfully tested. The specific hypothesis is: given that the size of the California market by the year 2020 is projected to be approximately 70,000 megawatts (MW) and that CVP capacity is 2,149 MWs or 3 percent of the overall market, when running a "with" and "without" analysis, it was deemed likely that the difference in power market prices between the two runs would not be significant. Traditionally, an important reason for doing “with” and “without” analyses is the premise that market prices will be different with the hydro project in place as compared to a without project condition; however, for a large power system where the hydro resource represents only a small fraction of the market, market prices could be assumed to be fairly similar for both the “with” and “without” project conditions.

In order to test the above hypothesis, the Leadership Team recommended that the proposed approach be validated by undertaking a proof of concept test. The PLEXOS model was used to simulate the dispatch of generation to meet load and the associated market prices for the year 2022 “with” and “without” CVP hydropower features in place as follows:

- The LTPP 2012 database was used for all PLEXOS modeling runs. This database has been well-vetted by utilities and interested stakeholder involved in the CPUC’s long-term procurement process in 2012. The CPUC uses these PLEXOS studies to inform California’s IOUs of the generation infrastructure they are to procure or construct during a 10-year out period (2022) in order to meet load in a reliable and resource adequate manner during that time frame. The IOUs are allowed to rate base these investments, which means their customers, are required to pay for them rather than their shareholders.

- A comparison of the studies run “with” and “without” the CVP shows that average monthly market prices for the year 2022 are within a percentage point of each other for all months except July, when “without” CVP prices spike at over 25 percent above the “with” CVP run. This is primarily due to a few hours when there is insufficient generation to meet load in the without CVP case and the market value is assumed to be $1000/MWh. The mean monthly difference is $1.7/MWh and the standard deviation for the 12 average monthly prices is $3.1/MWh.

- As noted above, this result points out that the system is resource inadequate without the CVP for a few hours in the month of July. Thus a third case was run. Given that the CVP power capacity valuation will use the alternate cost approach by assuming thermal capacity as the alternative to CVP hydro capacity, it is reasonable to add a like amount of thermal capacity to the PLEXOS database to replace the CVP for the energy analysis. Another reason for adding thermal capacity is California’s resource adequacy mandate, which was described above in detail. Since this is a rudimentary analysis, thermal capacity in the amount of the installed capacity was added to address the resource inadequacy problem. In retrospect, this is more capacity than the CVP provides in an 80 percent exceedance condition.

- A comparison of the studies run “with” and “without” the CVP, but with replacement thermal capacity to assure a resource adequate system, shows a much different result than the first comparison. The forecasted energy prices “without” CVP are 5 percent less than the “with” CVP prices in July and within a percentage point for all other months. The reason for the decrease in July energy prices is that the thermal resources can provide more energy in July than can CVP due to hydrological constraints. For this comparison, the mean monthly difference is $0.2/MWh and the standard deviation over the 12 months is $0.3/MWh.

Given that the difference in forecasted electricity prices for a “with” and “without” CVP analysis under a resource adequate condition when compared to the average price of electricity is on average about 0.5 percent , the proof-of-concept is deemed to be successful. The streamlined approach to evaluating CVP power benefits through the direct application of actual or forecasted electricity market prices to CVP energy and ancillary service accomplishments is deemed acceptable.

Recommendation

The Leadership Team recommends evaluating the CVP power benefits using both the alternative cost approach and the market price approach. Capacity benefits will be evaluated using the alternative cost approach. Energy, ancillary service and renewable benefits will be evaluated through a direct application of actual and forecasted power market prices.

If you have further questions, please contact Kristin White at 916-414-2425 or knwhite@usbr.gov or Brooke Miller-Levy at 916-978-5296, or bmillerlevy@usbr.gov.