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Revised Methodology for Sub-Allocating Existing and New Power Costs to Water and Power Contractors

Issue:

The Pacific Gas and Electric contract 2948A terminates at the end of 2004 or sooner due to circumstances beyond our control. The paradigm under which the existing Cost Sub-Allocation Methodology was developed will change. When this happens, Reclamation will assume the operation of the project for which there is no methodology. A methodology must be developed to allocate existing and new costs in a manner that reflects the new operating paradigm.

Background:

Reclamation and Western Area Power Administration (Western) have been operating the project under Contract 2948A with Pacific Gas and Electric (PG&E). This contract will terminate at some point in the indeterminable future but no later than December 2004. Contract 2948A governs the interconnection of PG&E's and Western's transmission systems, Western's use of PG&E's transmission and distribution system, and the integration of PG&E's and Reclamation's loads and resources. The contract provides for coordinated use and dispatch of the Central Valley Project (CVP) power resources with PG&E's resource portfolio to meet the Federal load that is supported under the contract. There are also transmission obligations by PG&E to deliver CVP power to preference customers not directly connected to the Western transmission system.

Prior to 1993, Project Use load in the Mid Pacific Region were served by PG&E under a monthly and annual energy accounting defined in 2948A. The government developed monthly and annual schedules of power consumption. These schedules provided the estimate of energy and peak hourly capacity that the government expected to be consumed in its operation of the project. The schedules also provided an estimate of the monthly generation and maximum available capacity at CVP powerplants. The contract provided that PG&E would provide the imbalance energy (during the off-peak hours) provided that the energy was scheduled back to PG&E during the on-peak hours within the calendar year. Subsequent to a settlement agreement between PG&E and Western in 1993, the support of the imbalance was assumed by Western utilizing Western's purchase of non-CVP generated power. Western indicated that the costs for this effort would be absorbed by Western's power marketing function for the duration of integration contract.

Under the integration contract PG&E is responsible for the firm electric service of loads designated as Project Use by Reclamation that exceed 100 kW of demand for three consecutive months. The charges for that service are limited to wheeling charges and transmission losses.

Due to deregulation in California, PG&E has indicated it is burdened unfairly with the service arrangement and will seek relief from providing anything other than power delivery service. On March 28, 2001, PG&E filed a petition (under Section 205 of the Federal Power Act) with the Federal Energy Regulatory (FERC) to increase the rates and is proposing to change the methodology for calculating the energy rate established under the contract; this changes the fundamental terms and conditions of the contract. PG&E proposes numerous changes to the contract's terms, conditions, rates and charges. On May 25, 2001, FERC issued a tentative decision accepting PG&E's 205 filing (subject to refund) beginning on October 28, 2001.

The deregulation of the power market in California transferred the control area operation responsibility from PG&E and other investor owned utilities to a new state corporation called the California Independent System Operator (CAISO). The CAISO performs its function under tariffs submitted to and approved by the Federal Energy Regulatory Commission (FERC). These tariffs define a market structure that accounts for power consumption and generation on a 10 minute time period for each hour of the day and each day of the year. The CAISO must be notified of the power consumption requirement for every load in the state at least two hours prior to the time the power is consumed. Any power not prearranged forces the CAISO to make purchases to ensure that the power can be consumed without impact to other power providers and loads. All power consumption is monitored by power meters that CAISO monitors. The CAISO reviews the actual power consumption and the prearranged power schedule and bills the load or generator for any differences in 10-minute increments of every hour of every day. The difference is referred to as energy imbalance. The cost to the CAISO for the energy imbalance is based on the market rate for power.

When the integration contract with PG&E is terminated, service to the project features need to be renegotiated. The power marketing function of CVP deals with surplus power and not applicable to project-use loads. The O&M of the CVP transmission facilities was transferred to Western. The Federal transmission facilities were constructed to transmit CVP generation and to ensure the widespread efficient use of federal generation. By that, Western is obligated to reserve sufficient transmission capacity to serve loads directly connected to the federal transmission system. The requirement for the connection is not considered an O&M function of the transmission line, and therefore the arrangement for the interconnection remains with Reclamation. Reclamation would retain the statutory requirement to ensure service to facilities under its administration i.e. Project Use Loads.

Reclamation, in corporation with interested power, water, and wildlife stakeholders, has studied a number of alternatives for operating the CVP to maximize power production while meeting downstream water user needs post 2948A. Included in these alternatives were the use of load following and maximum peaking power production alternatives. The analysis and evaluation showed an increased benefit for the project under the maximum peaking alternative. Reclamation has recommended that the maximum peaking power production alternative be implemented. Under this scenario, Western would purchase all the energy requirements for project-use needs while requesting that Reclamation operate the CVP to maximize the power output value of the CVP. The water users will remain whole, but will share in the costs of scheduling the power and for power costs above the output resource capabilities of the CVP.

The costs for the purchases may need to be made by Reclamation. Up to December 2000, Western has reduced the number of power purchase contracts it can use to meet its power marketing obligations. In addition, Western has received authorization from Congress to use receipts from power sales contracts to make purchases. The money Western collects is principally based upon the rate Western charges for firm power sales to its long-term firm-power contractors (preference power users) and from sales of transmission capacity. The concept was effective when Western's rate was just below the market rate for power. Currently, Western's rate is more than 5 times below the market rate, which means Western could only purchase1/5th of a kW for each kW it sold. Currently, Western does not have sufficient authorization to support the combination of marketing obligations and purchases for pumping loads. Reclamation would seek appropriations to make the purchases to support the pumping operation.

It has long been recognized that there is insufficient generation in every hour to support full project deliveries. Reclamation would need to seek arrangements with additional sources of power to firm up the power plant generation in support of project deliveries. Reclamation could make arrangements involving the exchange of power for the more efficient operation of the project.   Without the arrangements, Reclamation would be forced to either make water releases strictly for power production to meet the electrical demand of its pumping facilities; or, only as a last resort, curtail pumping.

Reclamation's Position:
An interagency team consisting of representatives from Western Area Power Administration, Reclamation, and customers will be appointed to develop a revised methodology for allocating the new power operation and maintenance costs associated with project use energy to the water function and preference power customers post 2948A. (See attached proposed chart)

After integrating public comments on the methodology, submit it to Reclamation and Western management for approval and implementation.

Enter into a revised interagency agreement which describes the functional activities of each agency and areas of overlap and coordination.

Stakeholders' Position:
There is cause for great concern for CVP water users and power customers when 2948A terminates, as the cost to purchase power from alternative sources, could severely impact the project-use energy costs that are passed on to the CVP water users and preference power customers.

Stakeholders want to ensure:

- that the CVP is operated in such as manner as to ensure that the CVP water users and preference power customers are afforded project use energy (PUE) and preference power at the lowest possible rates.
- the availability of adequate project-use power during all hydrologic conditions.
- that stakeholder meetings are held to identify interests, issues, pertinent variables, work products, including model development and possible alternative solutions.

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Addendum to Reclamation's Issue Paper – Additional Issues raised by the Financial Affairs Committee dated 7-19-01

Objective: To ensure that the CVP is operated in such as manner as to ensure that the CVP water users and preference power customers are afforded project use energy (PUE) and preference power at the lowest possible rates.

Interests:

- Operation of the CVP in a post Contract 2948A scenario.
- Equitable distribution of the power-function costs.
- Having adequate Project-Use Power Available during all hydrologic conditions.
- Support Western in its counter-filings to PG&E's 205 filing on Contract 2948A.
- Working with Western and Reclamation to put in place a bridging plan should Contract 2948A be terminated prior to December 31, 2004.

Considerations:

- Post-2004 Operational scenarios.
  - Load-following.
  - Max generation.
  - Flexibility in water delivery schedules: daily, weekly, and monthly.
  - Meeting Project Use requirements.
  - Providing flexibility to CVP operations to maximize power benefits.
- Cost allocation impacts under operational post-2004 scenarios.
  - Fair allocation of costs.
  - Allocation of costs between Project Use and Preference Power.
  - Costs include O&M, capital repayment, interest, transmission, and purchase power.
- Issues related too the maintenance of Contract 2948A.
  - Support Western in its efforts to maintain existing contract terms.
  - Support Western to keep purchase power costs as low as possible.
  - Support Western's Motion to Reject PG&E 205 filing.
  - Alternatively, support Western's request for a five-month delay by FERC.
  - FERC may reject, or may accept subject to refund.
- Post 2004 Implementation Issues.
  - Reclamation's role.
  - Western's role.
  - Project-Use loads.
  - Preference Power Customers.
- Bridging or Interim Contract.
  - Implementation.
  - Project Use loads.
  - Preference Power Customer Loads.
  - Supporting Energy Requirements.
- Other financial issues.
  - Ability to pay by water users and impact on Preference Power.
  - Periodic review of costs allocated to Project Use and Preference Power.

Background: Western Area Power Administration's (Western) integration contract (Contract 2948A) with Pacific Gas and Electric (PG&E) terminates at the end of 2004. Contract 2948A governs the interconnection of PG&E's and Western's transmission systems, Western's use of PG&E's transmission and distribution system, and the integration of PG&E's and Western's loads and resources. The contract provides for coordinated use and dispatch of the Central Valley Project (CVP) power resources with PG&E's resource portfolio to meet the Western load that is supported under the contract, as well as PG&E loads. Additionally, CVP generation that is surplus to Western's load is banked by PG&E in Energy Account #2 (EA2), at the then current PG&E thermal energy production cost. When Western's load, including Project-use loads, exceeds CVP generation and other resources available to Western, PG&E sells support energy to Western at its then current thermal production cost, less a 15% credit discount that was paid in advance by Western at the time energy was deposited into EA2. There are also transmission obligations by PG&E to deliver CVP power to preference customers not directly connected to the Western transmission system.

Because the contract will not be renewed after it terminates at the end of 2004, Reclamation, in corporation with interested power, water, and wildlife stakeholders has studied a number of alternatives for operating the CVP to maximize power production while meeting downstream water user needs in the post-2004 period. Included in these alternatives were the use of load following and maximum peaking power production alternatives. Reclamation has recommended that the maximum peaking power production alternative be implemented; under this scenario, Western would purchase all the energy requirements for project-use needs while requesting that Reclamation operate the CVP to maximize the power output value of the CVP. The water-users would remain whole under either scenario, but would share in the costs of scheduling the power and for power costs above the output resource capabilities of the CVP.

PG&E filed a petition (under Section 205 of the Federal Power Act) with the Federal Energy Regulatory (FERC) to increase the rates it charges Western when it provides load support power to the CVP in accordance with terms of its integration contract. PG&E proposes numerous changes to the contract's terms, conditions, rates and charges.

In their 205 filing, PG&E is proposing to change the methodology for calculating the energy rate established under the contract; this changes the fundamental terms and conditions of the contract. PG&E appears to be using the restructuring of the electric industry as an excuse to unilaterally change and materially alter the terms and conditions of contract. PG&E has received benefits from Contract 2948A for over thirty-four years, but had chosen not to hedge its obligations under Contract 2948A when it divested 72% of its fossil fuel-fired generation a few years ago. Now, when the market rates have substantially increased, PG&E is seeking to change the contract to increase revenues from energy sales that it makes to Western under Contract 2948A.

To further complicate matters, PG&E recently filed for bankruptcy. The uncertainty surrounding PG&E and its contract with Western is cause for great concern for CVP water users and power customers, as the cost to purchase power from alternative sources, should PG&E not deliver under its current contract, could severely impact the project-use energy costs that are passed on to the CVP water users and Preference Power Customers.

More recently, several Western Preference Power Customers (Respondents) requested bifurcation of the 205 proceedings requesting that FERC first hear only the issues surrounding PG&E's right to file under 205 as respondents contend that PG&E seeks to change the rate "methodology" (formula) and not just the associated "rate" (data input). Respondents contend the rate formula is not subject to change by unilateral action and PG&E's attempt to set rates other than in conformity with the formula and to change the underlying terms of the amended contract violates the Mobile-Sierra rule.[1]

PG&E contends they have 205 rights under the original contract; respondents contend that the 1992 Letter Agreement amending the original agreement prevails and that therein it sets forth that the "methodology" cannot be unilaterally changed; thus, PG&E has no right to change the rate methodology--only to apply new data to the rate formula.

PG&E would also seek to change other "terms" of the contract such as closing deposits to Energy Account 2, eliminating PG&E's obligation to sell capacity to Western, changing Western's obligation to support firm load with energy from a monthly to an hourly basis, and affording itself new Section 205 rights by amending Article 32 of the original contract. If viewed by the ALJ as an attempt to change the "terms" of the contract, this would not be allowed nor would extrinsic evidence to prove the otherwise intent of the parties be allowed.

If the bifurcated proceeding is not determined in favor of Western and the Respondents in final prior to October 28th, increased rates will go into effect October 28, 2001 until such time as the initial opinion issued by the ALJ is confirmed by the FERC. A Motion for Summary Disposition (equivalent to a "civil" Motion for Summary Judgment) is currently pending with FERC; PG&E has cross-filed a similar motion. A Motion for Summary Disposition is essentially a request by the parties for the judge to review the case as presented thus far on the record and where there is no outcome determinative question of fact the judge is requested to render a decision on the issues of law. If the ALJ believes there remains a significant issue of fact, not law, Respondent's Motion will be defeated and a hearing will proceed. Interpretation of the contract is a question of law that can be decided by the ALJ; it is not a question of fact that would require a hearing. Absence procedural intervention hearing is set for August 17, 2001.

[1] Under Mobile Sierra doctrine such an action might be permissible if health, safety or other major public policy issues were as stake. Pacific Gas and Electric might also have such rights if forced to do so under CPUC or other regulatory edict. Pacific Gas and Electric points to AB 1890 as a "government action" that required divestiture of the thermal assets thereby trigger its right to 205 filing. Respondents counter that divesture was voluntary therefore 205 is not triggered. Further, Pacific Gas and Electric stated in the bankruptcy filing that the divestiture was voluntary. Even if this were the case, Pacific Gas and Electric performed the contract for two years after divestiture thus evidencing ability to abide by the contract is spite of the alleged government action. Roughly stated, Pacific Gas and Electric need only cover 2000 MW of supply to Western. They have Diablo Canyon plus other remaining thermal units sufficient to cover the contract. Even if this Pacific Gas and Electric generation was not available, arguably the 2948a and 1992 Letter Agreements do not require Pacific Gas and Electric to provide the thermal energy from their own generation; therefore, they could buy it elsewhere and still remain within the confines of the contract.

Schedule:
Mar 28, 2001: PG&E filed a 205 filing under contract 2948A with FERC that sought to:

- Seek pass through costs for the following ISO costs:
    - Reliability Services.
    - Grid Management Charges.
    - Scheduling Coordinator Charges.
- Replace the EA2 rate of thermo production cost methodology.

April 02, 2001: Western filed a motion w/ FERC requesting rejection of PG&E's filing.
April 06, 2001: PG&E filed for Chapter 11 Bankruptcy (Reorganization).

- PG&E may request for early termination of 2948A.
- Goal of Western is to keep 2948A in place and preserve 2948A rate calculation methodologies (e.g. thermal production costs).

May 25, 2001: FERC issued a tentative decision accepting PG&E's 205 filing (subject to refund) beginning on October 28, 2001.
July 16, 2001: Western Customer Meeting to proceed with determining the Power cost associated with the scenario of the PG&E contract being terminated in order for them to proceed with their budget requests for FY 2002.
Aug 16, 2001: Oral arguments on the sole issue of whether PG&E has the right to file unilaterally to change transmission and energy rate methodology.
Aug 17, 2001: Hearing based on oral arguments.

- The judge should then have a decision on the issue within 30 days. If the ruling is in Western's favor, the hearing/trial schedule is suspended.
- Assuming the judge's initial decision is in Western's favor, FERC may, within 10 days, suspend the effective date for the PG&E filed rates.
- FERC will probably not make a decision on the entire 205 filing until early in Spring 2002.

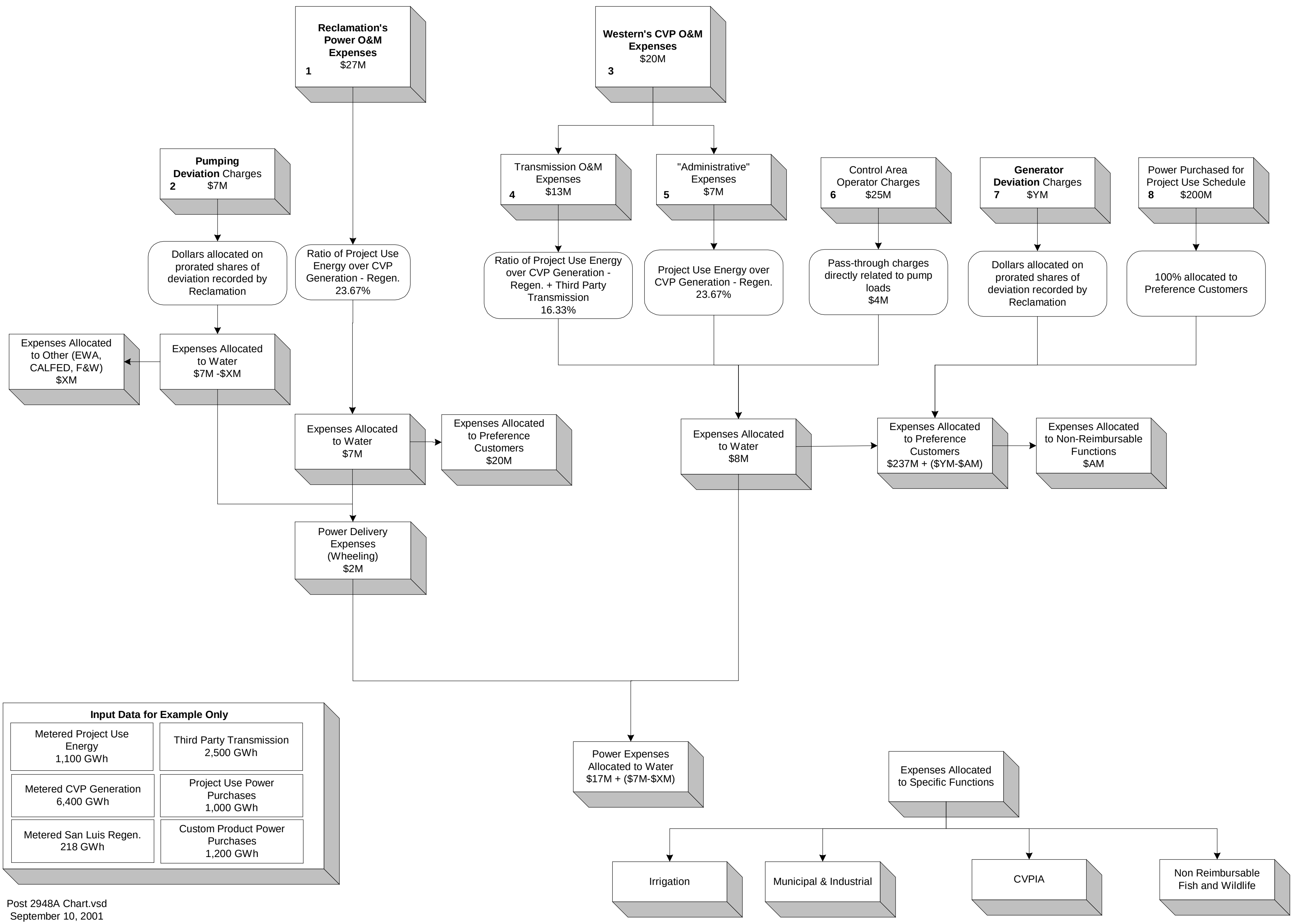
Goals (USBR and WAPA):

- The PG&E filing with FERC will be denied, the contract remains in place through the bankruptcy proceedings, and therefore the current contractual obligations of 2948A will remain in effect until Dec. 2004. At that time, Western's new 2005 marketing plan would be put into place.

Process:

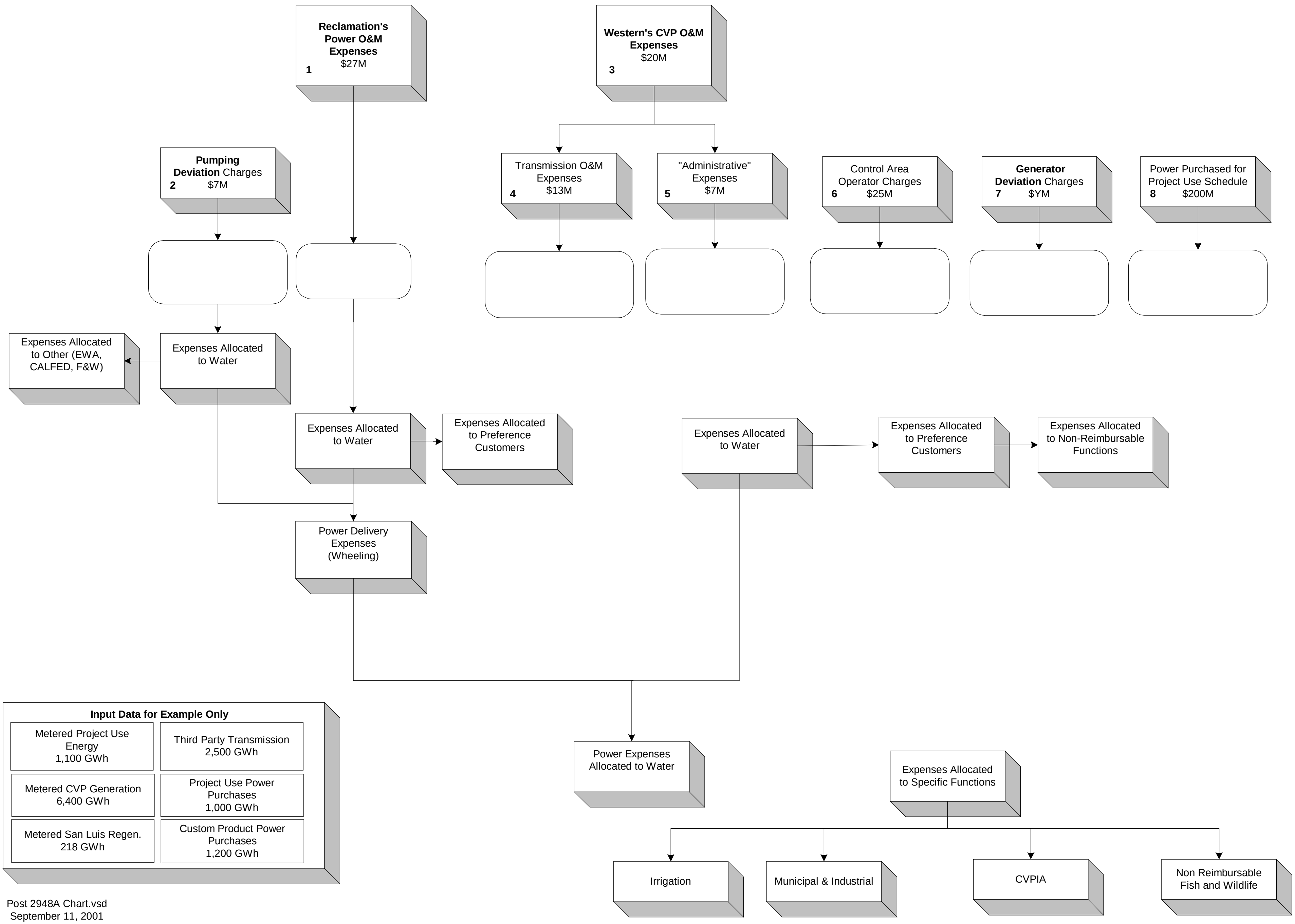
- Series of working meetings to identify interests, issues, pertinent variables, work products, including model development and possible alternative solutions; Reclamation, Western and interested stakeholders to participate. Western will provide periodic estimated rate impacts from the PG&E filing, as the October date approaches for the purchase power rates under 2948A to be put in place, subject to refunds.
- Chase Hurley & Ed Roman to provide monthly updates to FAC membership and other interested parties.

CVP Project Use O&M Cost Sub Allocation Chart Using Estimated Data for Post 2948A Condition Possible Solution



Post 2948A Chart.vsd
September 10, 2001

CVP Project Use O&M Cost Sub Allocation Chart Using Estimated Data for Post 2948A Condition



Post 2948A Chart.vsd
September 11, 2001

Chart Definitions

1. Reclamation's Power O&M Expenses
    - Hydraulic Power Generation
    - Transmission Expense
    - Administrative and General Expense
    - Carriage System
    - Water Marketing
    - Wheeling Expense
    - Amortization of San Luis and New Melones Transmission
    - PG&E Pass Through Costs

2. Pumping Deviation Charges
    - ISO charges associated with changes to the day-ahead schedules of the energy consumption of the loads.

3. Western's CVP O&M Expenses
    - Comprised of Transmission O&M Expenses (4) and Administrative Expenses (5) below

4. Transmission O&M Expenses
    - Transmission expenses operation
        - San Luis Switchyard O&M expenses
        - Dos Amigos PP Switchyard O&M expenses
    - Transmission expenses maintenance

5. Administrative Expenses
    - Power users accounting and collecting expenses
    - Conservation and renewable energy expenses
    - Power marketing and general power resources planning expenses
    - General Western allocation
    - Administrative and General expenses
    - Movable property depreciation
    - Non-operating expenses – accrual of annual leave

6. Control Area Operator Charges
    - Spinning Reserve
    - Non-spinning Reserve
    - AGC Regulation
    - Replacement Reserve
    - Regulation Up
    - Regulation Down
    - Ancillary Service Rational Buyer Adjustment
    - RMR Preemption of Spinning Reserve
    - RMR Preemption of Non-spinning Reserve
    - RMR Preemption of Replacement Reserve
    - RMR Preemption of Regulation Up
    - RMR Preemption of Regulation Down
    - Distribution of Preempted Spinning Reserve
    - Distribution of Preempted Non-spinning Reserve

- Distribution of Preempted Replacement
- Distribution of Preempted Regulation Up
- Distribution of Preempted Regulation Down
- Unscheduled RMR Energy
- Intra-zonal Congestion Incs/Decs Settlement/Charge/Refund (DA Grid Operations Charge)
- Inter-zonal Congestion Settlement/Refund/Debit
- Monthly Grid Management Charge
- Control Area Services Grid Management Charge
- Interzonal Scheduling Grid Management Charge
- Market Operations Grid Management Charge
- Emissions cost Recovery
- Start-Up Cost Recovery
- Wheeling Out/Wheeling Through
- High Voltage Access Charge/Revenue
- High/Low Voltage Wheeling Charge/Refund/Revenue
- Neutrality Adjustments
- Black Start Capacity/Energy
- Long Term Voltage Support
- Supplemental Reactive Energy
- Rounding Adjustment
- A/S Energy and Supplemental Energy
- Instructed Energy/Excess Cost for Instructed Energy
- Generation/Load/Import/Export Deviation
- Unaccounted for Energy
- Uninstructed Energy
- Allocation of Excess Cost for Instructed Energy
- Insufficient Energy in Response to ISO Instructions
- Reduction in Available Capacity Due to Uninstructed Deviation
- No Pay Charge – Spinning Reserve/Non-spinning Reserve/Replacement Reserve
- No Pay Provision Market Refund
- Generation/Load/Import Deviation from Instructed Energy

Retired or marked for retirement
Future charge types

7. Generator Deviation Charges
   - ISO charges associated with changes made to generation after the day-ahead schedules are submitted, i.e., forced outages, environmental constraints, etc.

8. Power Purchased for Project Use Schedule
   - Power purchased to meet project use load requirements