Attachment 1.IA to
Amended and Restated Boulder Canyon Project
Implementation Agreement (Restated Agreement)
Agreement No. 95-PAO-10616 (Western)
Agreement No. 5-CU-30-P1128 (Reclamation)

ATTACHMENT 1.IA

COMMITTEE REPRESENTATIVES

COORDINATING COMMITTEE REPRESENTATIVES

PRIMARY	ALTERNATES
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AUGUSTINE BAND OF CAHUILLA INDIANS	
BISHOP PAIUTE TRIBE	
CABAZON BAND OF MISSION INDIANS	
CALIFORNIA DEPT. OF WATER RESOURCES	

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LAS VEGAS PAIUTE TRIBE

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MORONGO BAND OF MISSION INDIANS

PRIMARY

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PASCUA YAQUI TRIBE

PECHANGA BAND OF LUISENO MISSION INDIANS

SALT RIVER PIMA-MARICOPA INDIAN COMMUNITY

SAN DIEGO COUNTY WATER AUTHORITY

SAN LUIS REY RIVER INDIAN WATER AUTHORITY

SAN MANUEL BAND OF MISSION INDIANS

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<u>PASCUA YAQUI TRIBE</u>	
<u>PECHANGA BAND OF LUISENO MISSION INDIANS</u>	
<u>SALT RIVER PIMA-MARICOPA INDIAN COMMUNITY</u>	
<u>SAN DIEGO COUNTY WATER AUTHORITY</u>	
<u>SAN LUIS REY RIVER INDIAN WATER AUTHORITY</u>	
<u>SAN MANUEL BAND OF MISSION INDIANS</u>	

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PASCUA YAQUI TRIBE	
PECHANGA BAND OF LUISENO MISSION INDIANS	
SALT RIVER PIMA-MARICOPA INDIAN COMMUNITY	
SAN DIEGO COUNTY WATER AUTHORITY	
SAN LUIS REY RIVER INDIAN WATER AUTHORITY	
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ATTACHMENT 2.IA

LOWER COLORADO RIVER MULTI-SPECIES CONSERVATION PROGRAM

ATTACHMENT 2.IA

LOWER COLORADO RIVER MULTI-SPECIES CONSERVATION PROGRAM

1. In accordance with section 11 of the Contracts and subsection 2(d)(2)(E) of the Hoover Power Allocation Act of 2011, each Contractor's proportionate share of its State's respective contribution to the cost of the MSCP is determined in accordance with each State's applicable funding agreement. The funding agreement applicable to Contractors located in Arizona is the Trust Indenture and Joint Payment Agreement. The funding agreement applicable to Contractors located in California is the First Amended California Joint Payment Agreement for the Lower Colorado River Multi-Species Conservation Program. The funding agreement applicable to Contractors located in Nevada is the First Amended Agreement to Share the Costs of Implementation of the Lower Colorado River Multi-Species Conservation Program Among the Colorado River Commission of Nevada and Electric Service Contractors.
2. Each Schedule A and Schedule B Contractor is a party to its respective State's funding agreement. Each Schedule A and Schedule B Contractor has paid, and shall continue to be required to pay, its respective MSCP cost share contribution in the amounts and in the manner specified by its respective State funding agreement. Reclamation will not issue bills for collection to Schedule A or Schedule B Contractors, under this Restated Agreement.
3. As provided in section 13 of the Restated Agreement, Reclamation will issue quarterly bills for collection to Schedule D Contractors in California and the Tribal Contractors in Arizona and Nevada, and these Schedule D Contractors shall make payment to Reclamation. Although these Schedule D Contractors are not expected to become parties to any of the State funding agreements, the amount of each of these Schedule D Contractor's proportionate share of the MSCP funding schedule billed by Reclamation will be determined in accordance with the applicable State funding agreement. This provision does not apply to non-tribal entities that received Schedule D allocations from Western and are offered contracts through APA and CRC.

4. On an annual basis, the entity responsible under each State funding agreement for determining the proportionate MSCP cost share payment due from each Contractor located in that State shall determine the amount payable by each Contractor in accordance with the terms of the State funding agreement, and shall provide written notice to Reclamation and to each of the Contractors located in that State indicating the amount payable. Reclamation will issue bills to the Schedule D Contractors in California and the Tribal Contractors in Arizona and Nevada for collection based on this notice.
5. The proportionate share of the MSCP cost share contribution is based on the cost share allocations specified in MSCP program documents, specifically including Section 8 of the MSCP Funding and Management Agreement and Table 7-1 of the MSCP Habitat Conservation Plan, stated in 2003 dollars. In accordance with the MSCP program documents, the amount of the cost share contribution is adjusted annually for inflation.
6. The tables below identify the respective cost share contributions for each Schedule D Contractor in California and the Tribal Contractors in Arizona and Nevada as of October 1, 2017, as determined under the applicable State funding agreements.
7. Should a Schedule D Contractor's Allocation be reduced or increased, as described in section 16 of the Contract, the Contractor's funding obligation will be reduced or increased, accordingly, as of the effective date of the reallocation. The State MSCP cost-share formulas are based on the capacity and energy of all BCP and Parker-Davis Project power users within the state, so adjustments may be made to cost-share amounts if the energy and capacity of the power users are adjusted.

MSCP COST SHARE

Schedule D Tribal Contractors – Arizona Allocation

Quarterly Payment Due:

<u>$119,000 x IA$^{(1)}$ x Tribal %</u>

Tribal %

Fort McDowell Yavapai Nation	.0806 %
Gila River Indian Community	.7154 %
Hualapai Indian Tribe	.0909 %
Kaibab Band of Paiute Indians	.0296 %
Navajo Tribal Utility Authority	.7154 %
Pascua Yaqui Tribe	.1042 %
Salt River Pima-Maricopa Indian Community	.7154 %
Tohono O'odham Nation	.6460 %
Tonto Apache Tribe	.0596 %

Schedule D Contractors – California Allocation

Quarterly Payment Due:

<u>California Required Payment (2003 dollars) x 20% x IA$^{(1)}$ x Contractor %</u>

Tribal %

Agua Caliente Band of Cahuilla Indians	.1077 %
Augustine Band of Cahuilla Indians	.0356 %
Bishop Paiute Tribe	.0283 %
Cabazon Band of Mission Indians	.0746 %
Chemehuevi Indian Tribe	.1039 %
Morongo Band of Mission Indians	.0817 %
Pechanga Band of Luiseno Mission Indians	.1487 %
San Luis Rey River Indian Water Authority	.2230 %
San Manuel Band of Mission Indians	.1899 %
Timbisha Shoshone Tribe	.0089 %
Torres Martinez Desert Cahuilla Indians	.1234 %
Twenty-Nine Palms Band of Mission Indians	.0982 %
Viejas Band of Kumeyaay Indians	.1032 %

Non-Tribal %

Anza Electric Cooperative, Inc.	.1186%
California Department of Water Resources	.2230%
City of Cerritos	.2230%
City of Corona	.2221%
City of Rancho Cucamonga	.2230%
City of Victorville	.1951%

Schedule D Tribal Contractors – Nevada Allocation

Quarterly Payment Due:

<u>$469,635 x IA[(1)] x Tribal %</u>

Tribal %

Las Vegas Paiute Tribe	.1265 %

[(1)] IA = Inflation Adjustment means for any Program Year the inflation adjustment factor calculated for that Program Year pursuant to Section 8.1.1 of the Funding and Management Agreement.

ATTACHMENT 3.IA

WORKING CAPITAL CALCULATION

ATTACHMENT 3.IA

WORKING CAPITAL CALCULATION

1. The annual Working Capital will be collected by the process described in section 15.4 of the Restated Agreement.
2. By February 1st of each year after Fiscal Year 2017, Reclamation shall prepare a Projected Dam Fund Balance Analysis.
   - 2.1. The Projected Dam Fund Balance Analysis shall be based upon the most recent approved final BCP Ten Year Operating Plan prepared in accordance with section 8 of the Restated Agreement.
   - 2.2. The analysis reflects the monthly cash in-flows to the Colorado River Dam Fund by Annual Revenue Requirement and out year projected revenue by the established categories.
   - 2.3. The analysis reflects the monthly obligations to the Colorado River Dam Fund by established categories.
   - 2.4. The analysis reflects the balance of unobligated funds in the Colorado River Dam Fund on the last day of each month.
3. The Working Capital methodology may be changed to meet changing needs of the project. Each year following Fiscal Year 2019, the change in the amount of Working Capital, to be accumulated through or credited against the Annual Revenue Requirement during the upcoming Fiscal Year, shall be determined by Reclamation. The Working Capital amount will be positively or negatively adjusted to ensure the balance of the unobligated funds in the Colorado River Dam Fund on the last day of each month in the upcoming Fiscal Year is zero (0) or a positive amount.
4. Reclamation shall mitigate, to the extent possible, any increases in the Working Capital amount. Based upon any adjustments to the Annual Revenue Requirement, Reclamation shall prepare a revised Projected Dam Fund Balance Analysis. The Projected Dam Fund Balance Analysis shall be emailed to the

E&OC Representatives within two (2) weeks after submission of the most recent final BCP Ten Year Operating Plan.

5. The Projected Dam Fund Balance Analysis shall be reviewed and discussed at the third Fiscal Year regularly scheduled E&OC meeting. If necessary, as determined by the E&OC, a subcommittee of the E&OC will be established to further meet, review and analyze the Monthly Obligated Funds Flow Analysis with Reclamation.

6. Upon approval of the Projected Dam Fund Balance Analysis by the E&OC, Reclamation shall notify Western of any necessary changes in the amount of the Working Capital to be accumulated through or credited against the Annual Revenue Requirement during the upcoming Fiscal Year.

Example Calculation:

BOULDER CANYON PROJECT

Projected Dam Fund Balance Using Incremental Obligation Funding
Fiscal Year 2018
<u>BASED ON FY2016 FINAL TEN YEAR PLAN</u>

	REVENUE						OBLIGATIONS									
Month	Beginning Balance	Net Power	Water	WAPA-Other	Visitor Services	TOTAL REVENUE	Operation Maintenance A&GE	EOM	Visitor Services	Replacements	Payment of States	Principal Payment	Interest Payment	Transfers to WAPA	TOTAL OBLIGATIONS	ENDING BALANCE
October '17	0		44,167		887,345	931,512	2,688,291	63,000	446,578	875,000	-	-	-	656,583	4,729,452	(3,797,940)
November '17	(3,797,940)		44,167		797,518	841,685	4,397,046	62,000	652,857	1,009,000	-	-	-	656,583	6,777,486	(9,733,742)
December '17	(9,733,742)	4,084,523	44,167	120,833	870,364	5,119,887	4,120,475	182,000	977,359	1,009,000	-	-	-	656,583	6,945,417	(11,559,272)
January '18	(11,559,272)	4,843,390	44,167	120,833	832,728	5,841,118	2,489,438	386,000	405,455	1,009,000	-	538,000	-	656,583	5,484,476	(11,202,630)
February '18	(11,202,630)	4,800,683	44,167	120,833	781,768	5,747,451	3,857,891	385,000	570,997	1,282,000	-	-	-	656,583	6,752,471	(12,207,650)
March '18	(12,207,650)	5,201,470	44,167	120,833	1,103,502	6,469,972	4,483,848	203,000	1,088,717	1,707,000	-	-	-	656,583	8,139,148	(13,876,826)
April '18	(13,876,826)	5,244,177	44,167	120,833	1,185,350	6,594,527	3,776,006	200,000	557,498	990,000	-	-	-	656,583	6,180,087	(13,462,387)
May '18	(13,462,387)	6,141,020	44,167	120,833	1,001,504	7,307,524	3,785,152	200,000	658,457	585,000	600,000	-	-	656,583	6,485,192	(12,640,055)
June '18	(12,640,055)	6,683,068	44,167	120,833	1,171,768	8,019,836	3,985,896	813,000	899,914	586,000	-	-	434,000	656,583	7,375,393	(11,995,612)
July '18	(11,995,612)	6,380,835	44,167	120,833	1,315,719	7,861,554	3,572,092	813,000	630,029	425,000	-	-	-	656,583	6,096,704	(10,230,763)
August '18	(10,230,763)	6,052,321	44,167	120,833	1,137,336	7,354,657	3,900,146	813,000	676,034	422,000	-	-	-	656,583	6,467,763	(9,343,869)
September '18	(9,343,869)	6,029,325	44,167	120,833	915,099	7,109,424	3,995,721	813,000	1,069,106	-	-	-	-	656,583	6,534,410	(8,768,855)
October '18	(8,768,855)	5,362,442		120,833		5,483,275									0	(9,285,580)
November '18	(3,285,580)	4,879,526		120,833		5,000,360									0	1,714,780
Total		65,702,780	530,000	1,450,000	12,000,000	79,682,780	45,052,000	4,933,000	8,633,000	9,899,000	600,000	538,000	434,000	7,879,000	77,968,000	

Lowest Monthly Balance projected Fiscal Year 2018	$13,876,826
FY 2018 Lowest Monthly Balance rounded to the nearest million	$14,000,000
Plus an additional $1,000,000 increase to ensure solvency	<u>$ 1,000,000</u>
Total Working Capital Fund Reserve	$15,000,000

ATTACHMENT 4.IA

MULTI-PROJECT WRITTEN PROCEDURES

PROCEDURES FOR MULTI-PROJECTS COSTS

Multi-project Costs (MPC) are the costs of those facilities which are paid for through the appropriation process by one Project, but provide benefits to other Projects.

Projects identified in the MPC allocation process:

AC Intertie Project

Boulder Canyon Project

Central Arizona Project

Colorado River Basin Salinity Control Project

Colorado River Front Work and Levee System

Colorado River Storage Power System

Parker-Davis Project

Facilities identified in the MPC allocation process that benefit other Projects:

Items 1. Phoenix Service Center and Mead Service Center.

Item 2. SCADA System

<u>Items 1, Phoenix Service Center and Mead Service Center:</u>

The factor for distribution of costs for the Phoenix Service Center and the Mead Service Center was based on the methodology used for the Desert Southwest Regional Office's distribution of General Western Allocations (GWA). This distributes building costs in the same percentage as the direct hours charged against the Projects. The procedure for developing the distribution of General Western Allocations (GWA) is:

a) Determine direct labor hours (DLH) from the General Ledger 451 report (O&M) from the previous year. Insert them in the second column of the table below.

b) Divide these hours by a productive staff hour figure that accounts for loss of productive staff hours related to sick leave, annual leave, training, and other uses. The current figure for staff hours in 1,750. The 1,750 number was based on a 5-year average of previous actual data. The resultant figure is shown in the third column of the table below.

c) Determine the percentage figure of the total for each project in the fourth column of the table below. This percentage figure is then used to allocate the MPC to each project.

d) Current year data is provided in Appendix D.

Sample Showing FY 1994 Distribution for Service Centers MPCs

Project	Direct Labor Hours	# of FTE	Percentage
AC Intertie Project	14,966.00	8.57	7.02%
Boulder Canyon Project	23,772.80	13.58	11.12%
Central Arizona Project	14,269.70	8.15	6.67%
Colorado River Basin Salinity Control Project	958.40	0.55	0.45%
Colorado River Front Work and Levee System	945.00	0.54	.044%
Colorado River Storage Project	14,144.00	8.08	6.62%

Parker-Davis Project	144,670.23	82.67	67.68%
Total	213,756.13	122.14	100.00%

Item 2, SCADA:

a) The factor for each Project is based on the total distribution of data point count requirements currently allocated and in service. The calculations are based on documented current point count utilization requirements for the SCADA as determined by Operations as of April 1994. The number of points will be reviewed annually.

b) The percentages for the point factor are calculated by dividing the number of the individual project points by the total number of points. The total SCADA point count used in the current analysis is included in Appendix C.

c) The following table displays an example of calculating the point factor percentage for each project based on the number of total points to each individuals project points, based on current point allocations.

d) Current year data is provided in Appendix C.

Distribution Showing FY 1994 SCADA costs in MPCs

Project	# of Points	Percentage
AC Intertie Project	1,441	16.50%
Boulder Canyon Project	733	8.39%
Central Arizona Project	479	5.48%
Colorado River Basin Salinity Control Project	50	.57%
Colorado River Front Work and Levee System	0	0%
Colorado River Storage Project	474	5.43%
Parker-Davis Project	5,558	63.63%
Total	8,735	100.005

Elements of costs related to Items 1 and 2 are:

1. Historic and Future Investments Costs (both Additions and Replacements)

2. Interest Expense

Procedures for compiling the Multi-projects Costs.

1. Identify Investments, include both Plant-In-Service and Construction Work-In-Progress (CWIP) for historic years and appropriate future years. The Investments in the current study were identified by a Desert Southwest Regional Office MPC Process Improvement Team and documented in their final report.

   While reviewing the data under the Phoenix Service Center in Western's FY 1994 Results of Operations Plant-In-Service (Schedule 1), $7,351,068 is related to the old SCADA system. Western has determined that the old SCADA system should be fully funded by the Parker-Davis Project. Based on this information, Western proposed that the costs for the old SCADA system should not be included in the Multiproject Cost allocation process. All other cost booked to the SCADA system accounts are related to the new SCADA system and should be included in the Multiproject cost allocation process.

The SCADA costs from the Engineering & Construction Ten-Year Plan were evaluated further to determine which portion of the costs were Replacements and which portion of the costs were Additions. A tabulation and analysis was compiled by Operations and is included in Appendix C.

2. Gather the current year Plant in Service data from Western's Results of Operations (ROOS), Schedule 1, General Ledger 10100/10610. The data for the current tables in Appendix A are marked on page 15 of GL 10100 and page 29 of GL 10610 of the Parker Davis ROOS for the Phoenix Service Center; page 2 of the Intertie ROOS for GL 10100 for the Mead Service Center; and page 4 of the Intertie ROOS for GL 10610 for the Mead Service Center. This data is then directly input into a spreadsheet which is shown in Appendix D titled "Multiproject Cost Allocations").

3. Gather the budgeted annual investment cost for the current year and the first five (5) future years. This information for the Phoenix O&M Stage 02 and for the SCADA as shown in Appendix B, is obtained from the 1995 Final Engineering and Construction Ten-Year Plan, Section B, page A1, items 6 and 7; and from GL 10710, Schedule 2, pages 9 and 10 in Appendix A. Add the Construction Work in Progress amounts from GL 10710 for all the work order totals shown on pages 9 and 10 plus the current year IDC to the Phoenix Service Center costs.

4, The SCADA costs in Appendix C are taken from the data from the paragraph above and allocated into Replacements and Additions.

5. Allocated the historical and future cost by the allocation factors.

6. The procedure for determining the interest rate is documented in the DOE Order RA 6120.2.11, Change 1, Dated October 1, 1983. A paraphrase of Paragraphs 11.a and b of the Order is that the interest rate used for computing interest during construction (IDC) and interest on the unpaid balance of the costs of Federal power facilities is the "yield rate" which is determined by the Secretary of the Treasure as of October 1 of the preceding fiscal year. The yield rate is the average yield during the preceding fiscal year on interest-bearing marketable securities of the United States, which, at the time of the computation, have terms of 15 years or more remaining to maturity. In the year, construction costs are charged to a FERC plant accounts 301 and 350 or above, the Treasury interest rate for that year is the interest rate is assigned to the life of the investment.

7. To determine service lives of investments, look up the unit of property in the current edition of the book entitled "Replacements Units Service Lives Factors" as jointly published by the U.S. Department of Energy, Western Power Administration, and the U.S. Department of Interior, Bureau of Reclamation, dated May 1989.

Set up project-specific amortization tables for each facility. A sample amortization table is included in Appendix D with references to where the input data comes from. The amortization tables begin with Page 2 of the same spreadsheet titled "Allocations". The amortization tables for each project consist of:

a) an amortized amount from steps (2), (3), and (4) above.

b) the Project allocated costs as determined in (5) above.

c) an interest rate

d) a Service Life

9. The Rates Division will update the power repayment study for each project so that the future revenue distribution will reflect the current percentages for the Multiproject Costs. For those Projects with annual appropriations or annual funds advancement, the recovery of costs will be handled annually by accounting adjustments to Operating Expenses as a separate "Rental/Lease" payment entry.

a) The Boulder Canyon Project rates are determined each year. The rate process allows the addition of MPC.

b) Parker-Davis Project, Pacific Northwest-Pacific Southwest Intertie Project and the Colorado River Storage Project have multi-year rate processes. The rate process will allow the addition of the MPC.

c) The Central Arizona Project Contracts will allow the addition of MPC.

d) Western and the Bureau of Reclamation have a "Master and Operating Agreement" which covers the operation and maintenance of joint use facilities as well as facilities transferred to Western. This agreement included the Colorado River Basin Salinity Control Project and Colorado River Front Work and Levee System. The MPC is covered as associated funding requirements under these Projects.

10. The Rates Team Lead will initiate a memo to the Financial Manager for request of the appropriate accounting entries to each project accounts for the specific current year costs and specific current year offsets to the costs prior to September 15 of each Fiscal Year.

11. The timelines for updating Appendices and repayment tables are as follows:

Requests financial data (Rates Team Lead)	September
Updates Appendix A data (Rates)	January
Prepares final PRS (Rates)	December
Updates Service Center hour distribution table (Rates)	December
Updates SCADA points table (Appendix C) (Operations)	December
Updates Ten-Year Engineering Plan (Maintenance)	October
Updated Amortization Tables (Appendix D) (Rates)	January
Distributes to E&OC	February

MULTI PROJECT BENEFITS

PROCEDURES

BCP MULTI PROJECT BENEFITS

OVERVIEW

Purpose: Provide a written summary of the process for determining, calculating, and allocating the Multiproject benefits of exchange energy through resource integration of Western Area Lower Colorado (WALC) federal projects, inclusive of internal energy exchanges among the Boulder Canyon Project participants, and among the Parker-Davis Project participants.

Resource Integration Definition: The process of mutually agreeing to a statically scheduled firm monthly exchange of energy among individual participants of the Boulder Canyon Project and among the Parker-Davis Project customers is Resource Integration. All monthly energy exchanges must zero balance at the completion of each fiscal year. The energy exchanged is a firm commitment by all participants and is received within each contractor's available contract capacity entitlement. Additional capacity to deliver or receive energy is not a component of the integration process.

Resource Integration Criteria: The primary points of concern to Western, as the resource manager, when planning and implementing the integration process are Equity, Risk Management, Operational feasibility, and serving Customer requests consistent with sound business practice. A more focused description of the criteria elements follows:

> **Equity**: Each participant and project, within the requested compatible monthly energy exchange profiles, realized an energy diversity benefit on a fiscal year basis similar in value to other participating contractors and projects. If a contractor's requested monthly exchange profile is not compatible with the integrated offering of other participants, energy exchanges for the individual contractor will not be possible. The individual participants value the energy diversity benefits. When requested, Western will provide an estimate of benefit based on the spot market replacement of energy.

Risk: Western Area Lower Colorado (WALC), in agreeing to exchange firm blocks of monthly energy between federal projects, gauges and accepts a degree of uncertainty in resource and load availability, which could cause detrimental operational effects throughout the fiscal year. Each contractor agrees to accept the possible detrimental effects that altered monthly energy target may have on their individual resource availability profiles.

Operational Feasibility: WALC, in conformance with all active contractual obligations, considers resource impacting elements such as planned unit outages, levels of monthly projected generation from Hoover, Parker and Davis planned capacity restrictions and Lower Colorado river release restrictions, in preparation of monthly energy exchanges used in the Resource Integration program.

Customer Requests: Each contractor requests exchange energy to achieve improved load and resource matching and thus reduce the cost of operation. WALC attempts to provide the desired exchange energy within EQUITY, RISK, and OPERATIONAL FEASIBILITY criteria. At times, the individual customer monthly energy exchange requests cannot be met within all criteria or does not contain adequate diversity to permit energy exchanges. The customer making such an energy exchange will be excluded from the Resource Integration Program. The customer energy exchange requests are considered first among the contractors and then between the WALC federal projects. WALC responds to each requesting participants with their level of Resource Integration participation prior to June 1 of each calendar year.

Resource Integration Conflicting Requests: Circumstances in which Resource Integration participants request similar exchanges on certain months, that cannot both be served, will be individually considered when an adjustment in the particular month's exchange energy is made. Due to each customer's varying monthly requests a pro-rata reduction in exchanges between the individual customers is usually not operationally feasible and are reviewed individually. The thorough review results in a monthly exchange profile reduced to coincide with other requests over the 12 months of the target fiscal year.

<u>Guidelines</u>: These guidelines are used for determining the monthly exchange of energy for the Boulder Canyon Project and Parker-Davis Project follow.

<u>PARKER DAVIS PROJECT</u>: The primary elements which derive the projected resources and loads used in developing the PDP project Resource Integration energy exchanges are as follows:

a) Generation –

The monthly load profile is indexed according to the Bureau of Reclamation 2 year most probable water supply study and loss of interchanges received from other entities.

b) External –

The allocated load, using the baseline 1988 exhibits, as a reference is indexed to totalize monthly firm allocated load. This is also referred to as external load.

c) MWD Parker Dam Energy Entitlement –

Based on Parker monthly estimated releases, MWD received ½ of the projected generation. These indexed values will act as additional firm Parker-Davis project load.

d) Internal –

Historical load profiles serve as the monthly WALC Control area internal kWh value and act as the third component of Parker-Davis project load.

e) Surplus/Deficiency in Generation –

To compute Parker-Davis surplus or deficiency in generation and provide a parameter for monthly energy exchange the following computation serves as a guideline which may be adjusted as required. Generation (a) – External Load (b) – MWD Load (c) – Internal Load – (d) = Parker-Davis Generation Surplus/Deficiency.

f) Parker-Davis Monthly exchange generation –

On a monthly basis the surplus or deficiency in generation is evaluated as to the maximum quantity available, but not necessarily to be exchanged between projects.

g) Proposed Parker-Davis monthly Exchanged energy –

The computation for Parker-Davis project monthly exchanged energy is developed from each individual customer's proposed exchange requests. Each customer's separate request is listed using the following formula for proposed exchanges: Firm Allocation – Proposed Customer Allocation = Parker-Davis proposed Exchange, indexed by month. If the individual requested monthly exchanges do not comply with the Resource Integration criteria, then an adjustment on the pertinent month(s) is performed.

h) Parker-Davis Capacity –

To assure ample capacity is available for total Parker-Davis load and reserve requirements, a computation including consideration of planned unit outages is performed.

i) P-DP Customer notification –

P-DP customers interested in Resource Integration are formally notified by Western of the level of Integration possible for the subject fiscal year. P-DP customers rejecting Western integration plan may notify WALC's Power Scheduling Office by fax with a formal follow up letter to the Area Manager.

BOULDER CANYON PROJECT:

a) Generation –
The Hoover Master Schedule's preliminary monthly energy target pertaining to the subject fiscal year is the baseline resource reference for BCP resource integration planning purposes. A preliminary Master Schedule based on the latest BOR's 24 Month Most Probably Water Supply Study is distributed to the BCP contractors by December 15.

b) Individual exchange analysis –

Each customer's requested monthly exchange profile is provided to WALC by January 15th and is subtracted from the preliminary Master Schedule to ascertain each customer's energy exchange request. Individual Boulder Canyon participants energy exchange is assessed in two Stages. Stage 1 consists of 2 phases. Phase 1 conducted by WALC, is the total exchange analysis among all interested BCP contractor's requesting exchange. Phase 2 is the "individual" exchange analysis performed between BCP participants desiring energy exchanges on a one on one basis. Stage 2 is the Project exchange between Parker-Davis and Boulder Canyon Project. Exchange energy between Projects must meet the same Equity criteria as for individual participants. Ample diversity must be evident between Projects to permit a zero balanced energy exchange condition for each fiscal year.

c) Project exchange analysis –

The totalized Boulder Canyon Project proposed monthly exchange quantity, in Stage 2, is used to compare maximum monthly quantities offered by the Parker-Davis project. This comparison of the projects exchange quantities is the occasion in which the Resource Integration criteria is applied to determine the level of monthly exchange by each project.

d) BCP Master Schedule Redraft –

Following adjustment of the customers requested exchange to a practical level in Stage 2, a redraft of the Master Schedule, containing the proposed energy exchanges, is distributed to the customers. Following BCP customer acceptance of the proposed energy exchange a draft of the Master Schedule is generated and distributed to the BCP customers. A minimum two week customer comment period is provided before the Actual Master Schedule is created.

f) Actual Master Schedule –

This document is created and distributed, in accordance with the contract, to all Boulder Canyon Contractors and includes Resource Integration energy exchange by June 1 of each year. Distribution of the Actual Master Schedule marks the completion of Resource Integration planning and is the date of formal acceptance by the Contractors.

SUMMARY OF ANNUAL RESOURCE INTEGRATION PROCESS AND REVIEW

The following is a narrative of the Resource Integration information presented at the June 9, 1995 Multiproject cost/benefit Meeting. It represents the annual process and review performed by the operations group.

HOOVER STG1 – VS - STG2 EXCHANGE: This graphical presentation compares Multiproject cost/benefit levels of available and accepted energy exchanges in Stage 1 as compared with Stage 2.

HOOVER ENERGY INTERCHANGE ACCOUNTING (Stage 1 and Stage 2 Summed): Information shown here is a listing of the final energy exchanged between all BCP participants on a monthly basis. The process as described in the Guidelines Section of stage 1 (phase 1 and phase 1) coincides with the creation of these values. All monthly exchange data listed in this summary are a component of the Hoover Master Schedule for the coming fiscal year.

DEPICTION OF ENERGY EXCHANGE FOR THE FISCAL YEAR: The information graphically and numerically shown here indicated the monthly exchange profile by project. The limitations to exchange are described in the Overview and Guidelines Sections. Complete and equitable exchanges that zero balance and that provide a degree of equity among the participants are shown here.

HOOVER STAGE 1&2 RESOURCE INTEGRATION EVALUATION & REVENUE COSTS:

This sheet is an example of the type of analysis available when requested for reviewing the replacement cost of energy exchanged as part of Stage 1 and Stage 2. Zero integration which was planned for in Stage 2, results in all Hoover Exchange Benefit to reflect only that which has to occur in Accepted Stage 1 value.

The sheet's purpose is to estimate the value of benefit the BCP contractors receive directly from energy exchanges.

Each Contractor may choose to assess this exchange value differently and may have a differing benefit weighting process for assessing value than are used by western.

REVENUE ANALYSIS OF ENERGY EXCHANGES:

This sheet is an example of the type of analysis available, when requested for reviewing the stage 2 saving estimates. These are based on energy replacement and a weighted average of energy market prices over a period of time. Since there were no energy exchanges between BCP and P-DP for the fiscal year there was a zero net loss and a zero net gain between the two projects. The Parker-Davis Project exercised other exchange and purchase alternatives external to WALC projects.

PARKER-DAVIS CAPACITY FORECAST:

This summary has three sections (A, B, & C) that reflect the forecasted Parker-Davis Capacity availability and surplus capacity above reserve requirements. The data indicates that P-DP has the capacity available to meet its spinning reserve obligations.

HOOVER CAPACITY BALANCE:

The Hoover Capacity Balance sheet numerically and graphically depicts the capacity support provided amongst Hoover and Parker Davis as part of WALC Control Area resources. The information shows the level of capacity transfers made in the FY 94 fiscal year as a result of fungible resources being integrated into Control Area Operations. The Outcome in indicative of current operating practices which result in loading units at the most efficient point possible in response to the varying capacity schedules requested on a "Real Time" basis at Hoover.

CONCLUSION: The primary resource evaluation reference is the BOR 24 Month Study for P-DP and BCP. The historical internal load estimates and contractual firm loads serve as load references for P-DP Resource Integration analysis. A series of correspondences between Western and the Contractors in which Western provides the projected monthly generation estimates and receives energy exchange requests occurs between December 1st and January 15th each fiscal year. Following an analysis by Western a response indicating the level energy exchange possible is distributed to the Contractors. The Contractors reply to Western accepting or rejecting the exchange offered. Western then formally notifies the customers, by

June 1st, either through individual documents or through a Master Schedule of the finalized energy exchanges for the subject fiscal year. These guidelines may require modification to adjust to fluctuating hydro resource availability forecast or changing conditions in evaluating individual project exchanges or in analyzing individual customer exchange requests.

Western Area Power Administration

FY96

HOOVER ENERGY INTERCHANGE ACCOUNTING
STAGES 1 & 2 SUMMED (MWh)

Contractor	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
LADWP SCHED ENTITY													
LADWP	700	-2664	2000	-709	125	0	0	0	175	175	198	0	0
BURBANK	-100	-350	-250	-400	200	0	0	0	200	300	400	0	0
GLENDALE	0	0	0	0	0	0	0	0	0	0	0	0	0
PASADENA	0	0	0	0	0	0	0	0	0	0	0	0	0
LADWP TOTAL	600	-3014	1750	-1109	325	0	0	0	375	475	598	0	0
SCE SCHED ENTITY													
SCE	0	0	0	0	0	0	0	0	0	0	0	0	0
MWD	-690	8154	-1830	1230	-84	0	0	0	-2042	-2308	-2430	0	0
ANAHEIM	0	0	0	0	0	0	0	0	0	0	0	0	0
AZUSA	0	0	0	0	0	0	0	0	0	0	0	0	0
BANNING	0	0	0	0	0	0	0	0	0	0	0	0	0
COLTON	0	0	0	0	0	0	0	0	0	0	0	0	0
RIVERSIDE	20	20	20	20	18	0	0	0	-138	20	20	0	0
SCE TOTAL	-670	8174	-1810	1250	-66	0	0	0	-2180	-2288	-2410	0	0
VERNON SCHED ENTITY													
VERNON	70	-22	60	-141	-259	0	0	0	92	100	100	0	0
SRP SCHED ENTITY													
APA	0	-5138	0	0	0	0	0	0	1713	1713	1712	0	0
NPC SCHED ENTITY													
CRC	0	0	0	0	0	0	0	0	0	0	0	0	0
BOULDER CITY	0	0	0	0	0	0	0	0	0	0	0	0	0
NPC TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
HOOVER TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0

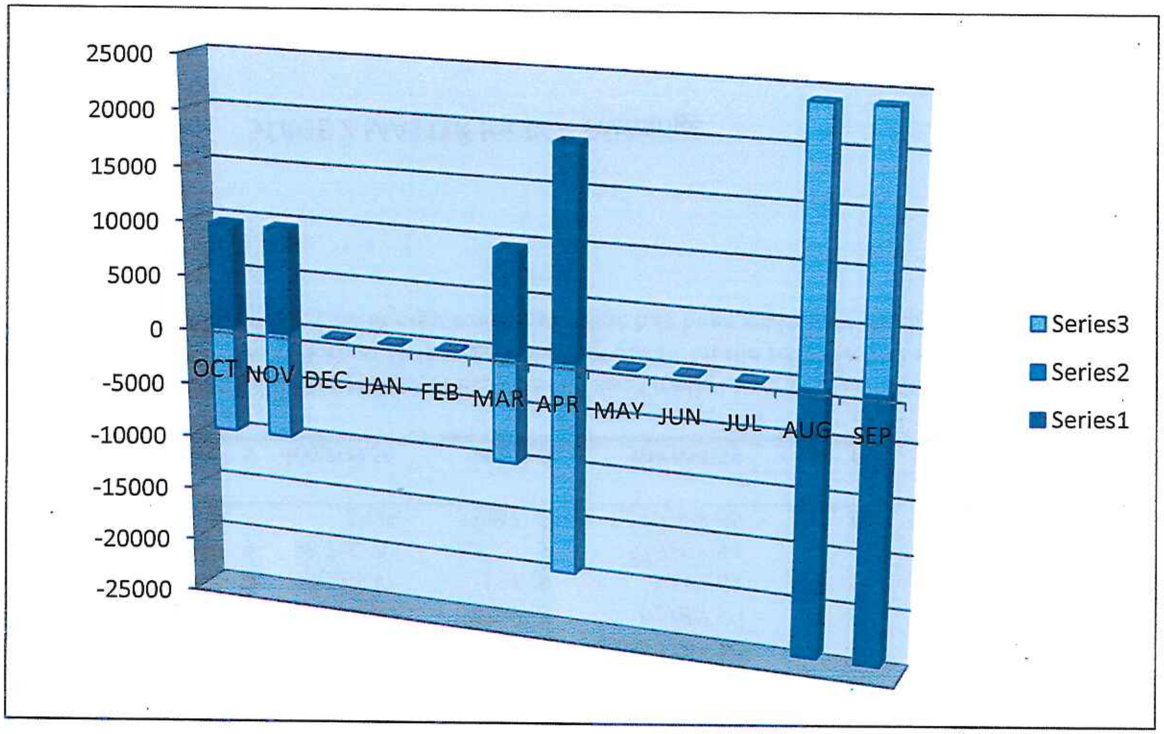
STAGE 2 MASTER for BCP Exchange

Western Area Power Administration

FY96

DEPICTION OF ENERGY EXCHANGE FOR THE FISCAL YEAR

	PDP	HVR	ALT
OCT	9600	0	-9600
NOV	9600	0	-9600
DEC	0	0	
JAN	0	0	
FEB	0	0	
MAR	9600	0	-9600
APR	19200	0	-19200
MAY	0	0	
JUN	0	0	
JUL	0	0	
AUG	-24000	0	24000
SEP	-24000	0	24000



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WESTERN AREA POWER ADMINISTRATION

HOOVER STAGE 1 & 2 RESOURCE INTEGRATION COST EVALUATION AND REVENUE COSTS

FY 96

Stage 2

		STG 1	STG1	STG 1	STG 1	STG 2	STG 2	STG 2	STG 2	STG 6	TOTAL
		REQUEST EXCH W/HVR	REQUEST VALUE $/MWH	Accepted EXCH W/HVR	Accepted VALUE $/MWH	Accepted EXCH W/LCA	REQUEST VALUE $/MWH	Accepted EXCH W/LCA	Accepted VALUE $/MWH	AVERAGE $$/MWH	HOOVER EXCH BENEFIT
OCT	95	50669	$ 960,408.06	790	$ 14,965.23	49909	$ 945,442.82	0	$0.00	18.94	$ 14,965.23
NOV	95	-34814	$ (672,722.53)	8174	$ 157,948.93	-42988	$ (830,671.45)	0	$0.00	19.32	$ 157,948.93
DEC	95	-314	$ (6,353.27)	2080	$ 42,085.33	-2394	$ (48,438.60)	0	$0.00	20.23	$ 42,085.33
JAN	96	66786	$ 1,313,012.76	1250	$ 24,575.00	65536	$ 1,288,437.76	0	$0.00	19.66	$ 24,575.00
FEB	96	67778	$ 1,225,200.31	343	$ 6,200.30	67435	$ 1,219,000.02	0	$0.00	18.08	$ 6,200.30
MAR	96	-45008	$ (856,802.29)	0	$0.00	-45008	$ (856,802.29)	0	$0.00	19.04	$0.00
APR	96	-93442	$ (1,884,413.67)	0	$0.00	-93442	$ (1,884,413.67)	0	$0.00	20.17	$0.00
MAY	96	-76258	$ (1,415,094.29)	0	$0.00	-76258	$ (1,415,094.39)	0	$0.00	18.56	$0.00
JUN	96	4930	$ 111,270.10	2180	$ 49,202.60	2750	$ 62,067.50	0	$0.00	22.57	$ 49,202.60
JUL	96	2467	$ 56,782.12	2308	$ 53,122.47	159	$ 3,659.65	0	$0.00	23.02	$ 53,122.47
AUG	96	24659	$ 595,679.24	2430	$ 58,700.70	22229	$ 536,978.54	0	$0.00	24.16	$ 58,700.70
SEP	96	57687	$ 1,379,488.46	0	$0.00	57687	$ 1,379,488.46	0	$0.00	23.91	$0.00
TOTAL		25140	$ 806,455.01	19555	$ 406,800.56	5615	$ 399,654.35	0	$0.00		$ 406,800.56

EXPLANATION: All cost evaluations are based on historical average sales prices of spot market energy. The Coumn entitled "Total Hoover Exch Value" is the savings to BCP exchange participants. Total Hoover Exchange benefit is based on the premise that each participant is benefitting in the exchange process when receiving energy when needed. This energy exchange value has been multiplied by the monthly historical average to produce an extimate of value.

STAGE 2 MASTER for BCP Exchange

WESTERN AREA POWER ADMINISTRATION

REVENUE ALALYSIS OF ENERGY EXCHANGES

FY96	STAGE 2 ENERGY EXCHANGE ONLY						
	MWh EXCH PDP*	$$$ VALUE PDP	MWh EXCH HVR	$$$ VALUE HVR	MWh EXCH Alt. Source	$$$ VALUE Alt. Source	ENERGY Exchange PRICE
MONTH							
OCT	9600	($181,856.00)	0	$0.00	-9600	$181,856.00	$18.94
NOV	9600	($185,504.00)	0	$0.00	-9600	$185,504.00	$19.32
DEC	0	$0.00	0	$0.00	0	$0.00	$20.23
JAN	0	$0.00	0	$0.00	0	$0.00	$19.66
FEB	0	$0.00	0	$0.00	0	$0.00	$18.08
MAR	9600	($182,752.00)	0	$0.00	-9600	$182,752.00	$19.04
APR	19200	($387,200.00)	0	$0.00	-19200	$387,200.00	$20.17
MAY	0	$0.00	0	$0.00	0	$0.00	$18.56
JUN	0	$0.00	0	$0.00	0	$0.00	$22.57
JUL	0	$0.00	0	$0.00	0	$0.00	$23.02
AUG	-24000	$579,760.00	0	$0.00	24000	($579,760.00)	$24.16
SEP	-24000	$573,920.00	0	$0.00	24000	($573,920.00)	$23.91
TOT	0	$ 216,368.00	0	$0.00	0	($216,368.00)	$20.64

The anticipated savings estimates above are based on energy replacement and spot sale pricing. The Parker-Davis Project realized an approximate Net Loss of zero and a Net Gain of zero Revenue as there was no energy exhanges between BCP and P-DP for the Fiscal Year.

The Parker-Davis Project and Boulder Canyon Project realized an avoided cost of $216,368.00, through monthly energy exchanges.

The exchange energy price is based on a monthly composite spot energy index avereaged over the last 3 years. The polarity used in this spreadsheet is: +=Surplus energy, -=Deficiency of energy

FY96

PARKER-DAVIS CAPACITY FORECAST

AREA - A

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
			B x C			E x F		D + G + H					J + K + L + M	I - N
MONTH	DAVIS UNIT RATING	OUTAGE Reduction %	DAVIS Reserve Capacity	PARKER UNIT RATING	OUTAGE Reducton %	PARKER Reserve Capacity	HDG Reserve Capacity	TOTAL RESERVE Capacity	MWD Load Capacity	Allocated Firm Load Capacity	Spinning Reserve Obligation	WALC Internal Capacity	TOTAL Peak Load Capacity	Capacity Above Obligation
OCT	270	80%	216	108	75%	81	14	311	41	184	24	25	274	38
NOV	270	80%	216	108	75%	81	14	311	41	184	24	25	274	38
DEC	270	80%	216	108	75%	81	14	311	41	184	24	25	274	38
JAN	270	75%	203	108	75%	81	14	298	41	184	24	25	274	24
FEB	270	72%	194	108	100%	108	14	316	54	184	24	25	287	29
MAR	270	95%	257	108	100%	108	14	379	54	244	24	25	347	32
APR	270	100%	270	108	100%	108	14	392	54	244	24	35	357	35
MAY	270	100%	270	108	100%	108	14	392	54	244	24	40	362	30
JUNE	270	100%	270	108	100%	108	14	392	54	244	24	40	362	30
JUL	270	100%	270	108	100%	108	14	392	54	244	24	45	367	25
AUG	270	100%	270	108	100%	108	14	392	54	244	24	45	367	25
SEP	270	100%	270	108	100%	108	14	392	54	244	24	45	367	25

AREA -B

Forecasted Spinning Above Reserves

(PRIOR to reduction for Spinning Obligation

A	B	C	D
MONTH	FY-96 FORECAST Available Capacity for LOAD	FY94 ACTUAL LOAD reported to IPP	Spinning Available Above Reserve Obligation
OCT	311	203	108
NOV	311	209	102
DEC	311	257	54
JAN	298	239	59
FEB	316	249	67
MAR	379	283	96
APR	392	292	100
MAY	392	266	126
JUN	392	293	99
JUL	392	279	113
AUG	392	314	78
SEP	392	348	44

AREA -C

Forecasted Spinning for FY96 using FY94 Actual Load

(AFTER reduction for Spinning Obligation)

E	F	G	H	I	J
			F -G		H - I
MONTH	FY-96 FORECAS Available Capacity for LOAD	FY94 ACTUAL LOAD reported to IPP	Spinning Available BEFORE Reserve Obligation	Sprinning Reserve Obligation	Spinning Available AFTER Reserve Obligation
OCT	311	203	108	24	84
NOV	311	209	102	24	78
DEC	311	257	54	24	30
JAN	298	239	59	24	35
FEB	316	249	67	24	43
MAR	379	283	96	24	72
APR	392	292	100	24	76
MAY	392	266	126	24	102
JUN	392	293	99	24	75
JUL	392	279	113	24	89
AUG	392	314	78	24	54
SEP	392	348	44	24	20

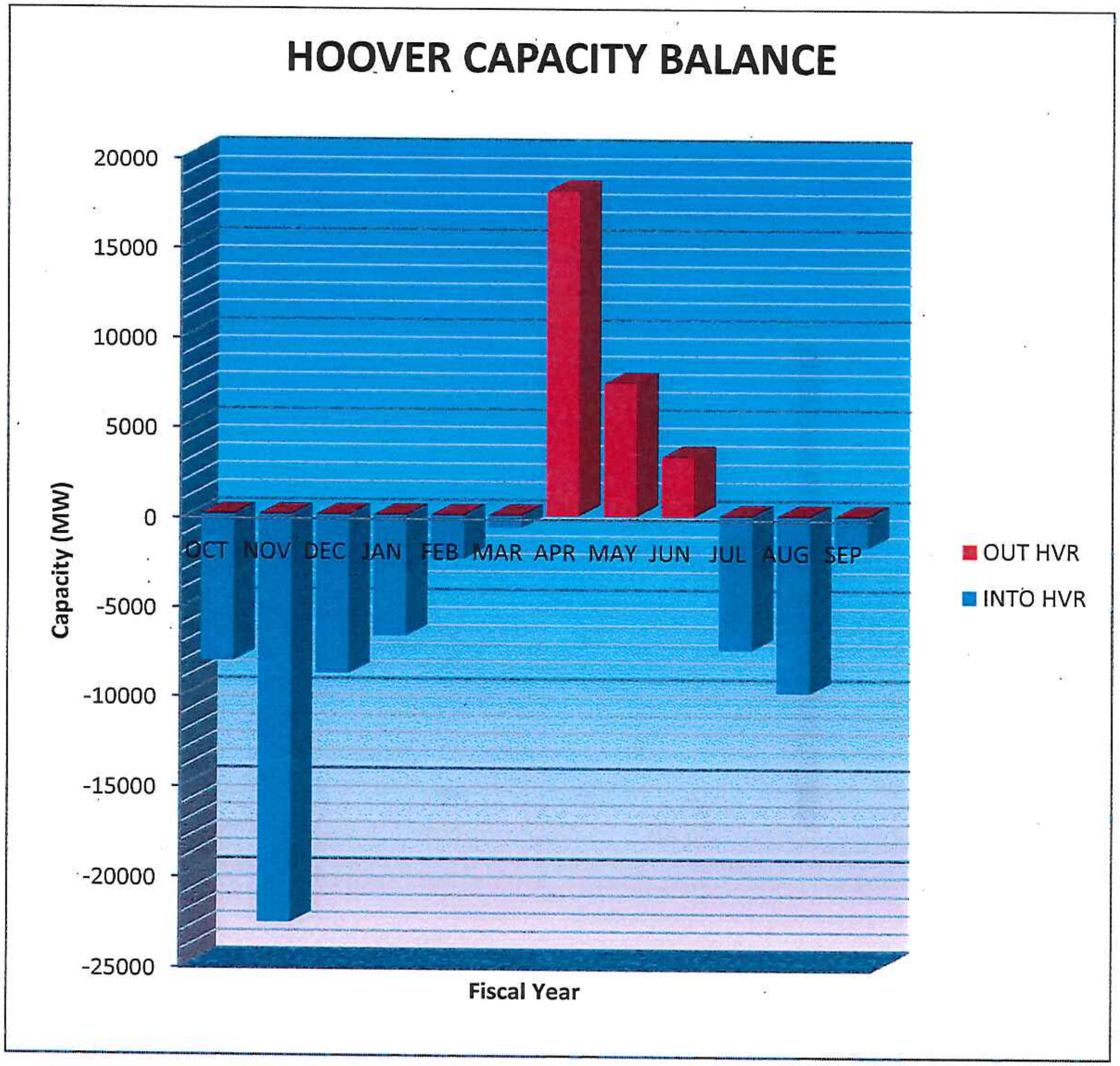
EXPLANATION:

AREA A - The Projected Parker-Davis (PDP) Generation Capacity less Projected Load and Spinning Reserve Obligation. This Area indicates PDP's ability to cover the WALC Spinning Reserve Oblication.

AREA B - The Projected PDP Generation Capacity (before spinning resefve reductions) less the Actual Peak Load for the prior fiscal year. This Area indicates that sufficient spinning capacity is available above using actual data. Negative values, if apparent, are covered through IPP purchases or interchanges. One must remember the numbers used for load are Peak values and are therefore the extreme in analyzing reserve capacity.

AREA C - The Projected PDP Generation Capacity less Actual Load and less the spinning obligation to indicate probable surplus PDP capacity.

HOOVER CAPACITY (MW) BALANCE		
	FY94 CAPACITY Into HVR	FY94 CAPACITY Out HVR
OCT	-8136	0
NOV	-22681	0
DEC	-8841	0
JAN	-6720	0
FEB	-2406	0
MAR	-669	0
APR	0	18031
MAY	0	7322
JUN	0	3235
JUL	-7437	0
AUG	-9887	0
SEP	-1713	0
TOTAL	-68490	28588



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APPENDIX A

WESTERN'S RESULTS OF OPERATIONS

(ROOS)

APPENDIX B

DESERT SOUTHWEST

ENGINEERING & CONSTRUCTION

TEN-YEAR PLAN

APPENDIX C

ANALYSIS OF SCADA SYSTEM

APPENDIX D

COST ALLOCATION TABLE

AND

AMORTIZATION TABLES

ATTACHMENT 5.IA

CONTINGENT CAPACITY, FIRM ENERGY,

AND BCP PERCENTAGES

ATTACHMENT 5.IA

CONTINGENT CAPACITY, FIRM ENERGY, AND BCP PERCENTAGES

The following table is meant to identify the Contractors' percentage entitlements to Contingent Capacity and Firm Energy pursuant to the Contracts. Contingent Capacity and Firm Energy are given equal weight in calculating the Contractor BCP percentages. When used in a formula in this Restated Agreement, numbers expressed as a percent (i.e. 10.2345%) shall be interpreted to be the decimal equivalent (i.e. 0.102345). The percentages below shall be updated by September 30, 2017, to reflect the final percentages including the allocation of Schedule D power.

Schedule A, B and D BCP Percentages	% of Contingent Capacity	% of Firm Energy	% of BCP [(1)]
Schedule A and B Percentages			
Arizona:			
Arizona Power Authority	18.3572%	18.0051%	18.1811%
Nevada:			
Colorado River Commission	18.3572%	22.2021%	20.2797%
U.S. (Boulder City)	0.9739%	1.6788%	1.3263%
California:			
Anaheim	1.9477%	1.0912%	1.5195%
Azusa	0.1947%	0.1049%	0.1498%
Banning	0.0974%	0.0420%	0.0697%
Burbank	0.9800%	0.5582%	0.7691%
Colton	0.1461%	0.0839%	0.1150%
Glendale	0.9739%	1.5080%	1.2409%
Los Angeles	23.9022%	14.6517%	19.2770%
Metropolitan Water District of Southern California	12.0515%	27.1123%	19.5819%
Pasadena	0.9738%	1.2948%	1.1343%
Riverside	1.4608%	0.8184%	1.1396%
Southern California Edison Company	13.5123%	5.2609%	9.3866%
Vernon	1.0713%	0.5876%	0.8294%
Total Schedule A and B	**95.0000%**	**95.0000%**	**95.0000%**

	% of Contingent Capacity	% of Firm Energy	% of BCP [1]
Schedule D Percentage			
Arizona:			
Arizona Power Authority (APA)	**1.4028%**	**1.4028%**	**1.4028%**
Arizona Tribes:			
Fort McDowell Yavapai Nation	0.0163%	0.0163%	0.0163%
Gila River Indian Community	0.1446%	0.1447%	0.1447%
Hualapai Indian Tribe	0.0184%	0.0184%	0.0184%
Kaibab Band of Paiute Indians	0.0060%	0.0060%	0.0060%
Navajo Tribal Utility Authority	0.1446%	0.1447%	0.1447%
Pascua Yaqui Tribe	0.0211%	0.0211%	0.0211%
Salt River Pima-Maricopa Indian Community	0.1446%	0.1447%	0.1447%
Tohono O'odham Nation	0.1306%	0.1306%	0.1306%
Tonto Apache Tribe	0.0121%	0.0121%	0.0121%
	0.6383%	**0.6385%**	**0.6384%**
Schedule D Percentages			
Nevada:			
Colorado River Commission (CRC)	**1.0610%**	**1.0609%**	**1.0609%**
Nevada Tribes:			
Las Vegas Paiute Tribe	0.0332%	0.0332%	0.0332%
Schedule D Percentage			
California:			
Agua Caliente Band of Cahuilla Indians	0.0699%	0.0699%	0.0699%
Anza Electric Cooperative, Inc.	0.0770%	0.0769%	0.0769%
Augustine Band of Cahuilla Indians	0.0231%	0.0231%	0.0231%
Bishop Paiute Tribe	0.0183%	0.0183%	0.0183%
Cabazon Band of Mission Indians	0.0484%	0.0484%	0.0484%
California Department of Water Resources	0.1446%	0.1447%	0.1447%
Chemehuevi Indian Tribe	0.0674%	0.0674%	0.0674%
City of Cerritos	0.1446%	0.1446%	0.1446%
City of Corona	0.1441%	0.1440%	0.1440%
City of Rancho Cucamonga	0.1446%	0.1446%	0.1446%
City of Victorville	0.1266%	0.1265%	0.1266%
Imperial Irrigation District	0.1446%	0.1447%	0.1447%
Morongo Band of Mission Indians	0.0529%	0.0530%	0.0529%

Schedule D Percentage (continued) California:	% of Contingent Capacity	% of Firm Energy	% of BCP [1]
Pechanga Band of Luiseno Mission Indians	0.0964%	0.0965%	0.0964%
San Diego County Water Authority	0.0781%	0.0780%	0.0781%
San Luis Rey River Indian Water Authority	0.1446%	0.1447%	0.1447%
San Manuel Band of Mission Indians	0.1231%	0.1232%	0.1232%
Timbisha Shoshone Tribe	0.0057%	0.0057%	0.0057%
Torres Martinez Desert Cahuilla Indians	0.0800%	0.0800%	0.0800%
Twenty-Nine Palms Band of Mission Indians	0.0636%	0.0637%	0.0637%
Viejas Band of Kumeyaay Indians	0.0669%	0.0669%	0.0669%
	1.8647%	**1.8648%**	**1.8647%**
Total Schedule D	**5.0000%**	**5.0000%**	**5.0000%**

[1] The % of BCP equals the sum of the percent of Contingent Capacity plus the percent of Firm Energy divided by two.

Attachment 6.IA to
Amended and Restated Boulder Canyon Project
Implementation Agreement (Restated Agreement)
Agreement No. 95-PAO-10616 (Western)
Agreement No. 5-CU-30-P1128 (Reclamation)

ATTACHMENT 6.IA

APPENDIX G OF THE 1995 IMPLEMENTATION AGREEMENT

APPENDIX G
CONTINGENT CAPACITY, FIRM ENERGY, AND PROJECT PERCENTAGES

For ease of understanding this Agreement and reference, the following table is meant to duplicate the Contractor's percentage entitlement to Contingent Capacity and Firm Energy pursuant to the Contracts. Contingent Capacity and Firm Energy are given equal weight in calculating the Contractor's Project percentage. When used in a formula in this Agreement, numbers expressed as a percent (i.e. 10.2345%) shall be interpreted to be the decimal equivalent (i.e. 0.102345).

	% of Contingent Capacity	% of Firm Energy	% of Project (1)
Arizona:			
Arizona Power Authority	19.3234%	18.9527%	19.1381%
Nevada:			
Colorado River Commission	19.3234%	23.3706%	21.3470%
U. S. (Boulder City)	1.0251%	1.7672%	1.3961%
California:			
Anaheim	2.0503%	1.1487%	1.5995%
Azusa	0.2050%	0.1104%	0.1577%
Banning	0.1025%	0.0442%	0.0733%
Burbank	1.0315%	0.5876%	0.8096%
Colton	0.1538%	0.0884%	0.1211%
Glendale	1.0251%	1.5874%	1.3063%
Los Angeles	25.1602%	15.4229%	20.2915%
Metropolitan Water District	12.6858%	28.5393%	20.6125%
Pasadena	1.0251%	1.3629%	1.1940%
Riverside	1.5377%	0.8615%	1.1996%
Southern California Edison	14.2235%	5.5377%	9.8806%
Vernon	1.1276%	0.6185%	0.8731%

(1) The % of Project equals the sum of the percent of Contingent Capacity plus the percent of Firm Energy divided by two.

Attachment 7.IA to
Amended and Restated Boulder Canyon Project
Implementation Agreement (Restated Agreement)
Agreement No. 95-PAO-10616 (Western)
Agreement No. 5-CU-30-P1128 (Reclamation)

ATTACHMENT 7.IA

TABLE 7 FROM CALCULATIONS FOR

REPAYABLE CAPITAL INVESTMENTS (REPAYABLE ADVANCES) FROM

THE 1995 IMPLEMENTATION AGREEMENT

Table # 7

CALCULATION OF REPAYABLE CAPITAL INVESTMENTS

(1)	(2)	(3)	(4)	(5)
Fiscal Year	Annual Replacement Amount to be Amortized $	Sum of Annual Principal Payments Recovered Based on Amortization of Replacement Amount $	Repayable Advance Amount Cols (2 - 3) $	Cumulative Repayable Advances $
Historical Expense:				
1989	1,744,871	1,959	1,742,912	1,742,912
1990	3,347,645	6,434	3,341,211	5,084,123
1991	2,240,603	10,015	2,230,588	7,314,711
1992	174,377	11,163	163,214	7,477,925
1993	2,708,728	17,090	2,691,638	10,169,563
1994	5,851,590	32,355	5,819,235	15,988,798
1995	5,832,686	48,110	5,784,576	21,773,374
1996	4,101,862	59,998	4,041,864	25,815,238
1997	21,460,909	119,743	21,341,166	47,156,405
1998	4,068,478	139,000	3,929,478	51,085,883
1999	2,799,682	158,826	2,640,854	53,726,737
2000	7,651,285	198,973	7,452,312	61,179,050
2001	3,290,264	223,406	3,066,858	64,245,907
2002	2,473,225	248,709	2,224,516	66,470,423
2003	3,153,914	278,834	2,875,080	69,345,503
2004	2,569,674	310,862	2,258,812	71,604,315
2005	2,639,725	344,197	2,295,528	73,899,843
2006	4,335,357	390,864	3,944,493	77,844,336
2007	3,318,829	433,385	2,885,444	80,729,780
2008	5,760,722	490,638	5,270,084	85,999,864
2009	6,908,500	561,286	6,347,214	92,347,078
2010	6,140,371	637,351	5,503,020	97,850,098
2011	6,283,219	716,769	5,566,450	103,416,548
2012	5,179,890	794,764	4,385,126	107,801,674
2013	6,449,341	900,218	5,549,123	113,350,797
2014	10,724,514	1,048,384	9,676,130	123,026,928
2015	7,320,125	1,165,716	6,154,409	129,181,337
Subtotal	$138,530,386	$9,349,045		$129,181,337
2016	7,424,438	1,289,496	6,134,942	135,316,278
2017	11,101,440	1,448,395	9,653,045	144,969,323
2018	0	1,526,568	(1,526,568)	143,442,756
2019	0	1,609,432	(1,609,432)	141,833,324
2020	0	1,697,295	(1,697,295)	140,136,029
2021	0	1,790,484	(1,790,484)	138,345,544
2022	0	1,889,352	(1,889,352)	136,456,192
2023	0	1,994,272	(1,994,272)	134,461,921
2024	0	2,105,645	(2,105,645)	132,356,276
2025	0	2,223,902	(2,223,902)	130,132,374
2026	0	2,349,503	(2,349,503)	127,782,870
2027	0	2,482,944	(2,482,944)	125,299,926
2028	0	2,634,386	(2,634,386)	122,665,540
2029	0	2,785,970	(2,785,970)	119,879,570
2030	0	2,947,170	(2,947,170)	116,932,400
2031	0	3,118,634	(3,118,634)	113,813,766
2032	0	3,301,069	(3,301,069)	110,512,697
2033	0	3,495,224	(3,495,224)	107,017,472
2034	0	3,701,914	(3,701,914)	103,315,558

Table # 7

CALCULATION OF REPAYABLE CAPITAL INVESTMENTS

(1)	(2)	(3)	(4)	(5)
Fiscal Year	Annual Replacement Amount to be Amortized	Sum of Annual Principal Payments Recovered Based on Amortization of Replacement Amount	Repayable Advance Amount Cols (2 - 3)	Cumulative Repayable Advances
	$	$	$	$
2035	0	3,921,999	(3,921,999)	99,393,560
2036	0	4,156,410	(4,156,410)	95,237,150
2037	0	4,406,150	(4,406,150)	90,831,000
2038	0	4,685,875	(4,685,875)	86,145,124
2039	0	4,505,760	(4,505,760)	81,639,364
2040	0	4,767,517	(4,767,517)	76,871,847
2041	0	4,846,127	(4,846,127)	72,025,719
2042	0	5,108,748	(5,108,748)	66,916,972
2043	0	5,184,030	(5,184,030)	61,732,942
2044	0	5,048,113	(5,048,113)	56,684,829
2045	0	4,893,768	(4,893,768)	51,791,061
2046	0	4,840,158	(4,840,158)	46,950,903
2047	0	3,567,615	(3,567,615)	43,383,288
2048	0	3,445,256	(3,445,256)	39,938,032
2049	0	2,955,346	(2,955,346)	36,982,685
2050	0	3,081,479	(3,081,479)	33,901,206
2051	0	2,996,955	(2,996,955)	30,904,251
2052	0	2,972,362	(2,972,362)	27,931,889
2053	0	2,907,199	(2,907,199)	25,024,690
2054	0	2,885,209	(2,885,209)	22,139,481
2055	0	2,851,835	(2,851,835)	19,287,646
2056	0	2,739,056	(2,739,056)	16,548,590
2057	0	2,665,985	(2,665,985)	13,882,605
2058	0	2,457,149	(2,457,149)	11,425,456
2059	0	2,197,001	(2,197,001)	9,228,455
2060	0	1,988,376	(1,988,376)	7,240,079
2061	0	1,757,947	(1,757,947)	5,482,132
2062	0	1,575,267	(1,575,267)	3,906,865
2063	0	1,375,363	(1,375,363)	2,531,502
2064	0	1,003,463	(1,003,463)	1,528,039
2065	0	732,318	(732,318)	795,721
2066	0	447,520	(447,520)	348,201
2067	0	0	0	348,201
Subtotal	**$157,056,264**	**$156,708,063**		**$348,201**

Notes:

Col. (1) This column provides the beginning year for amortization of the replacement expense

Col. (2) Provides, from Table #4, the replacement expense that is to be amortized.

Col. (3) Total annual principal amount, from Table #6, which would have been paid by the Contractors each year had appropriations been available to fund the replacement cost.

Col. (4) Displays the difference between the annual replacement expense to be amortized, shown in column (2), and the principal payments shown in column (3). The difference represents an amount funded by the Contractors that is in excess of the amount that would have been paid by the Contractors if replacement were funded by appropriations and amortized.

Col. (5) This is the reimbursement due to the present Hoover Power Contractors by the Post-2017 Contractors having a payment obligation as set out in Section 6.4, of the Boulder Canyon Project Implementation Agreement.

ATTACHMENT 8.IA

CALCULATIONS FOR REPLACEMENTS AND REPAYABLE CAPITAL INVESTMENTS FROM THE 2016 RESTATED AGREEMENT

TABLE #1

SUMMARY OF BOULDER CANYON PROJECT REPLACEMENTS

ITEM NO.	DESCRIPTION	AMORT. CLASS	FY 2018 $	FY 2019 $	FY 2020 $	FY 2021 $	FY 2022 $	FY 2023 $	FY 2024 $	FY 2025 $	FY 2026 $
1	Drum Gate Control Valve	Annual		115,000	620,000						
2	Generator Coolers	Annual	481,000	504,000	528,000	579,000	581,000	610,000	639,000	670,000	702,000
3	Stainless Steel Wicket Gates	Annual	510,000								
4	Drum Gate Repair & Components	Annual	1,850,000	2,547,000	2,674,000	2,703,000	1,435,000				
5	A2, A4, A7, PRV Modernization	Annual	801,000								
6	Flow Meter	Annual	870,000	177,000	177,000	177,000					
7	Hoover 16.5 KV Generator Breaker	Annual	5,250,000	1,350,000							
8	Elevator Motor and Controller	Annual	1,340,000	1,290,000	920,000						
9	Wastewater Treatment Facility	Annual		170,000	2,900,000						
10	Hoover-Mead Consolidation	Multi-yr	800,000	1,000,000	400,000						
11	Jet Flow Gates - Install/Design	Multi-yr	100,000	70,000							
12	Station/Domestic Water Systems	Multi-yr		900,000	400,000	150,000					
TOTAL REPLACEMENTS COST REPAYABLE TO U.S. TREASURY			**$12,002,000**	**$8,123,000**	**$8,619,000**	**$3,609,000**	**$2,016,000**	**$610,000**	**$639,000**	**$670,000**	**$702,000**

* This table compiles all replacements from the Final Ten Year Operating Plan and identifies them as an Annual or Multi-Year Replacement.
* Annual Replacement: Replacement items placed into service in the same year expenditures are made.
* Multi-Year Replacement: Replacement items <u>not</u> placed into service in the year expenditures are made.

TABLE #2

CALCULATION OF INTEREST DURING CONSTRUCTION (IDC) FOR REPLACEMENTS NOT PLACED IN SERVICE IN THE FISCAL YEAR EXPENDITURE IS MADE

BEGINNING IN FY 2018 MULTI-YEAR REPLACEMENTS W/IDC

(1) Fiscal Year	(2) Item No.	(3) Replacement Description	(4) Replacement Expenditure	(5) 96% of Replacement Expenditure	(6) Current Interest Rate	(7) Annual IDC	(8) End of Period Expenditure	(9) Multi-Year Total For Amortization
2018	10	Hoover-Mead Cons	800,000	768,000	3.375%	12,960	780,960	
2019	10		1,000,000	960,000	3.375%	42,557	1,783,517	
2020	10		400,000	384,000	3.375%	66,674	2,234,191	
			2,200,000	2,112,000		122,191	2,234,191	
2021	10	Amort Start Year						$2,234,191

BEGINNING IN FY 2018 MULTI-YEAR REPLACEMENTS W/IDC

(1) Fiscal Year	(2) Item No.	(3) Replacement Description	(4) Replacement Expenditure	(5) 96% of Replacement Expenditure	(6) Current Interest Rate	(7) Annual IDC	(8) End of Period Expenditure	(9) Multi-Year Total For Amortization
2018	11	Jet Flow Gates	100,000	96,000	3.375%	1,620	97,620	
2019	11		70,000	67,200	3.375%	4,429	169,249	
			170,000	163,200		6,049	169,249	
2020	11	Amort Start Year						$169,249

TABLE #2

CALCULATION OF INTEREST DURING CONSTRUCTION (IDC) FOR REPLACEMENTS NOT PLACED IN SERVICE IN THE FISCAL YEAR EXPENDITURE IS MADE

BEGINNING IN FY 2019 MULTI-YEAR REPLACEMENTS W/ID

(1) Fiscal Year	(2) Item No.	(3) Replacement Description	(4) Replacement Expenditure	(5) 96% of Replacement Expenditure	(6) Current Interest Rate	(7) Annual IDC	(8) End of Period Expenditure	(9) Multi-Year Total For Amortization
2020	12		400,000	384,000	3.500%	37,489	1,300,609	
2021	12		150,000	144,000	3.500%	48,041	1,492,650	
			1,450,000	1,392,000		100,650	1,492,650	
2022	12	Amort Start Year						$1,492,650

* This table is linked to Table #1 and calculates IDC on each Multi-Year Replacement.

(1) Beginning and final year for each multi-year replacement, as well as, the year amortization of the replacement expense will begin.

(2) Item Number of the multi-year replacement.

(3) Description of the multi-year replacement activity.

(4) Actual cost of each multi-year replacement.

(5) 96% of the Replacement Expenditure as specified in section 20.3.2 of the Restated Agreement.

(6) Current interest rate for each fiscal year, as determined in accordance with repayable interest rates as provided by the Department of the Interior.

(7) Interest During Construction calculation based on a twelve month period. IDC is the product of column (5) and (6) multiplied by half an annual interest period plus the product of the previous year's amount, if any, in column (8) and (6).

(8) Accumulation of the sum of columns (5) and (7).

(9) Total amount, inclusive of IDC, that is to be amortized. The amount and fiscal year are inputted to Table #4.

TABLE #3

REPLACEMENTS PLACED IN SERVICE IN THE SAME FISCAL YEAR EXPENDITURE IS MADE

FY 2018 ANNUAL REPLACEMENTS W/O IDC					
(1)	(2)	(3)	(4)	(5)	(6)
Fiscal Year	Item No.	Replacement Description	Annual Replacement Cost	96% of Annual Replacement Cost	Cumulative Annual Total For Amortization
2018	2	Generator Coolers	481,000	461,760	461,760
2018	3	Stainless Steel Wicket Gates	510,000	489,600	951,360
2018	4	Drum Gate Repair & Components	1,850,000	1,776,000	2,727,360
2018	5	A2, A4, A7, PRV Modernization	801,000	768,960	3,496,320
2018	6	Flow Meter	870,000	835,200	4,331,520
2018	7	Hoover 16.5 KV Generator Breaker	5,250,000	5,040,000	9,371,520
2018	8	Elevator Motor and Controller	1,340,000	1,286,400	10,657,920
2019		Annual Amort Start Year Total			$10,657,920

FY 2019 ANNUAL REPLACEMENTS W/O IDC					
(1)	(2)	(3)	(4)	(5)	(6)
Fiscal Year	Item No.	Replacement Description	Annual Replacement Cost	96% of Annual Replacement Cost	Cumulative Annual Total For Amortization
2019	1	Drum Gate Control Valve	115,000	110,400	110,400
2019	2	Generator Coolers	504,000	483,840	594,240
2019	4	Drum Gate Repair & Components	2,547,000	2,445,120	3,039,360
2019	6	Flow Meter	177,000	169,920	3,209,280
2019	7	Hoover 16.5 KV Generator Breaker	1,350,000	1,296,000	4,505,280
2019	8	Elevator Motor and Controller	1,290,000	1,238,400	5,743,680
2019	9	Wastewater Treatment Facility	170,000	163,200	5,906,880
2020		Annual Amort Start Year Total			$5,906,880

* This table is linked to Table #1 and calculates 96% on each Annual Replacement.

(1) Fiscal year of each annual replacement, as well as, the year amortization of the replacement expense will begin.
(2) Item Number of the annual replacement.
(3) Description of the annual replacement.
(4) Actual cost of each annual replacement.
(5) 96% of the Replacement Expenditure as specified in section 20.3.2 of the Restated Agreement.
(6) Accumulation of the sum of column (5). The amount and fiscal year are inputted to Table #4.

TABLE #4
SUMMARY OF AMORTIZATION AMOUNTS

(1) Amortization Start Year	(2) Multi-Year Replacement Total	(3) Annual Replacement Total	(4) Replacement Capital Investments (Total Amount to be Amortized)	(5) Interest Rate
2018	0	0	0	3.375%
2019	0	10,657,920	10,657,920	3.500%
2020	169,249	5,906,880	6,076,129	3.375%
2021	2,234,191	7,506,240	9,740,431	3.125%
2022	1,492,650	3,320,640	4,813,290	3.000%
2023	0	1,935,360	1,935,360	3.000%
2024	0	585,600	585,600	3.000%
2025	0	613,440	613,440	3.000%
2026	0	643,200	643,200	3.000%
Total	**$3,896,090**	**$31,169,280**	**$35,065,370**	

* This table is linked to Table #2 and Table #3 and compiles the total amortization dollars for both Multi-Year and Annual Replacements.

(1) Start year for amortization of replacement expenditures.
(2) Multi-Year Replacement expenditures to be amortized, from Table #2, column (9).
(3) Annual Replacement expenditures to be amortized, from Table #3, column (6).
(4) Sum of columns (2) and (3). The amount is inputted in Table #5.
(5) Current interest rate for each fiscal year, as determined in accordance with repayable interest rates as provided by the Department of the Interior.

TABLE #5
AMORTIZATION TABLES FOR
REPLACEMENT CAPITAL INVESTMENTS

FY 2019

Amount to be Amortized	$10,657,920
Yearly Interest	3.500%
Amortization Period	50 Years
Principal & Interest Payment	$454,387

(1) Fiscal Year	(2) BOP Remaining Principal $	(3) Payments P&I $	(4) Payments Interest $	(5) Payments Principal $	(6) EOP Remaining Principal $
2019	10,657,920	454,387	373,0	81,359	10,576,561
2020	10,576,561	454,387	370,1	84,207	10,492,353
2021	10,492,353	454,387	367,2	87,154	10,405,199
2022	10,405,199	454,387	364,1	90,205	10,314,994
2023	10,314,994	454,387	361,0	93,362	10,221,633
2024	10,221,633	454,387	357,7	96,630	10,125,003
2025	10,125,003	454,387	354,3	100,012	10,024,992
2026	10,024,992	454,387	350,8	103,512	9,921,480
2027	9,921,480	454,387	347,2	107,135	9,814,345
2028	9,814,345	454,387	343,5	110,885	9,703,460
2029	9,703,460	454,387	339,6	114,766	9,588,695
2030	9,588,695	454,387	335,6	118,782	9,469,912
2031	9,469,912	454,387	331,4	122,940	9,346,972
2032	9,346,972	454,387	327,1	127,243	9,219,730
2033	9,219,730	454,387	322,6	131,696	9,088,034
2034	9,088,034	454,387	318,0	136,305	8,951,728
2035	8,951,728	454,387	313,3	141,076	8,810,652
2036	8,810,652	454,387	308,3	146,014	8,664,638
2037	8,664,638	454,387	303,2	151,124	8,513,514
2038	8,513,514	454,387	297,9	156,414	8,357,100
2039	8,357,100	454,387	292,4	161,888	8,195,212
2040	8,195,212	454,387	286,8	167,554	8,027,658
2041	8,027,658	454,387	280,9	173,419	7,854,239
2042	7,854,239	454,387	274,8	179,488	7,674,751
2043	7,674,751	454,387	268,6	185,770	7,488,980
2044	7,488,980	454,387	262,1	192,272	7,296,708
2045	7,296,708	454,387	255,3	199,002	7,097,706
2046	7,097,706	454,387	248,4	205,967	6,891,739
2047	6,891,739	454,387	241,2	213,176	6,678,563
2048	6,678,563	454,387	233,7	220,637	6,457,927
2049	6,457,927	454,387	226,0	228,359	6,229,567
2050	6,229,567	454,387	218,0	236,352	5,993,216
2051	5,993,216	454,387	209,7	244,624	5,748,591
2052	5,748,591	454,387	201,2	253,186	5,495,405
2053	5,495,405	454,387	192,3	262,047	5,233,358
2054	5,233,358	454,387	183,1	271,219	4,962,139
2055	4,962,139	454,387	173,6	280,712	4,681,427
2056	4,681,427	454,387	163,8	290,537	4,390,890
2057	4,390,890	454,387	153,6	300,706	4,090,185
2058	4,090,185	454,387	143,1	311,230	3,778,955
2059	3,778,955	454,387	132,2	322,123	3,456,831
2060	3,456,831	454,387	120,9	333,398	3,123,434
2061	3,123,434	454,387	109,3	345,066	2,778,367
2062	2,778,367	454,387	97,2	357,144	2,421,223
2063	2,421,223	454,387	84,7	369,644	2,051,580
2064	2,051,580	454,387	71,8	382,581	1,668,998
2065	1,668,998	454,387	58,4	395,972	1,273,026
2066	1,273,026	454,387	44,5	409,831	863,196
2067	863,196	454,387	30,2	424,175	439,021
2068	439,021	454,387	15,3	439,021	0
2069	0	0	0	0	0
Total		**$22,719,333**	**$12,061,413**	**$10,657,920**	

TABLE #5
AMORTIZATION TABLES FOR
REPLACEMENT CAPITAL INVESTMENTS

FY 2020

Amount to be Amortized	$6,076,1293
Yearly Interest	375%
Amortization Period	50 Years
Principal & Interest Payment	$253,236

(1) Fiscal Year	(2) BOP Remaining Principal $	(3) Payments P&I $	(4) Payments Interest $	(5) Payments Principal $	(6) EOP Remaining Principal $
2019	0	0	0	0	0
2020	6,076,129	253,236	205,069	48,167	6,027,962
2021	6,027,962	253,236	203,444	49,793	5,978,169
2022	5,978,169	253,236	201,763	51,473	5,926,696
2023	5,926,696	253,236	200,026	53,210	5,873,486
2024	5,873,486	253,236	198,230	55,006	5,818,479
2025	5,818,479	253,236	196,374	56,863	5,761,617
2026	5,761,617	253,236	194,455	58,782	5,702,835
2027	5,702,835	253,236	192,471	60,766	5,642,069
2028	5,642,069	253,236	190,420	62,817	5,579,253
2029	5,579,253	253,236	188,300	64,937	5,514,316
2030	5,514,316	253,236	186,108	67,128	5,447,188
2031	5,447,188	253,236	183,843	69,394	5,377,794
2032	5,377,794	253,236	181,501	71,736	5,306,058
2033	5,306,058	253,236	179,079	74,157	5,231,901
2034	5,231,901	253,236	176,577	76,660	5,155,241
2035	5,155,241	253,236	173,989	79,247	5,075,994
2036	5,075,994	253,236	171,315	81,922	4,994,073
2037	4,994,073	253,236	168,550	84,686	4,909,386
2038	4,909,386	253,236	165,692	87,545	4,821,842
2039	4,821,842	253,236	162,737	90,499	4,731,343
2040	4,731,343	253,236	159,683	93,554	4,637,789
2041	4,637,789	253,236	156,525	96,711	4,541,078
2042	4,541,078	253,236	153,261	99,975	4,441,103
2043	4,441,103	253,236	149,887	103,349	4,337,754
2044	4,337,754	253,236	146,399	106,837	4,230,916
2045	4,230,916	253,236	142,793	110,443	4,120,474
2046	4,120,474	253,236	139,066	114,170	4,006,303
2047	4,006,303	253,236	135,213	118,024	3,888,279
2048	3,888,279	253,236	131,229	122,007	3,766,272
2049	3,766,272	253,236	127,112	126,125	3,640,148
2050	3,640,148	253,236	122,855	130,381	3,509,766
2051	3,509,766	253,236	118,455	134,782	3,374,985
2052	3,374,985	253,236	113,906	139,331	3,235,654
2053	3,235,654	253,236	109,203	144,033	3,091,621
2054	3,091,621	253,236	104,342	148,894	2,942,727
2055	2,942,727	253,236	99,317	153,919	2,788,807
2056	2,788,807	253,236	94,122	159,114	2,629,693
2057	2,629,693	253,236	88,752	164,484	2,465,209
2058	2,465,209	253,236	83,201	170,036	2,295,173
2059	2,295,173	253,236	77,462	175,774	2,119,399
2060	2,119,399	253,236	71,530	181,707	1,937,692
2061	1,937,692	253,236	65,397	187,839	1,749,853
2062	1,749,853	253,236	59,058	194,179	1,555,674
2063	1,555,674	253,236	52,504	200,732	1,354,942
2064	1,354,942	253,236	45,729	207,507	1,147,435
2065	1,147,435	253,236	38,726	214,510	932,924
2066	932,924	253,236	31,486	221,750	711,174
2067	711,174	253,236	24,002	229,234	481,940
2068	481,940	253,236	16,265	236,971	244,969
2069	244,969	253,236	8,268	244,969	0
Total		**$12,661,820**	**$6,585,691**	**$6,076,129**	

* This table is linked to Table #4 and calculates the Amortization Tables (Principal & Interest) for each fiscalyear.

TABLE #6

PRINCIPAL PAYMENTS REQUIRED IF REPLACEMENT CAPITAL INVESTMENTS WERE FUNDED BY APPROPRIATIONS

(1)	(2)	(3)
Fiscal Year	Sum of Annual Principal Payments from Amortization Tables $	Cumulative Principal Payments $
Historical Expense:		
2019	81,359	81,359
2020	132,374	213,734
Subtotal	**$213,734**	**$213,734**
Budgeted Expense:		
2021	136,947	350,681
2022	141,678	492,358
2023	146,572	638,931
2024	151,636	790,566
2025	156,874	947,441
2026	162,294	1,109,735

* This table is linked to Table #5 and sums the Annual and Cumulative Principal Payments.

(1) Fiscal Year of Principal Payments.

(2) Total annual principal which would have been paid each fiscal year by the Contractors, representing the capital recovered annually by the United States if all replacements had been funded by appropriations.

(3) Accumulation of the sum of column (2).

TABLE #7

CALCULATION OF REPAYABLE CAPITAL INVESTMENT AMOUNTS

(1)	(2)	(3)	(4)	(5)
Fiscal Year	Annual Replacement Capital Investments to be Amortized $	Sum of Annual Principal Payments Recovered Based on Amortization Replacement Capital Investment Amount $	Repayable Capital Investment Amount $	Cumulative Repayable Capital Investment $
Historical Expense:				
2019	10,657,920	81,359	10,576,561	10,576,561
2020	6,076,129	132,374	5,943,755	16,520,315
Subtotal	**$16,734,049**	**$213,734**	**$16,520,315**	**$16,520,315**
Budgeted Expense:				
2021	9,740,431	136,947	9,603,484	26,123,799
2022	4,813,290	141,678	4,671,612	30,795,412
2023	1,935,360	146,572	1,788,788	32,584,199
2024	585,600	151,636	433,964	33,018,164
2025	613,440	156,874	456,566	33,474,729
2026	643,200	162,294	480,906	33,955,635

* This table is linked to Table #4 and Table #6 and sums the total Repayable Capital Investments.

(1) Fiscal Year of Repayable Capital Investments.

(2) Replacement expense that is to be amortized; from Table #4, column (4).

(3) Total annual principal amount which would have been paid each fiscal year by the Contractors, if all replacements had been funded by appropriations; from Table #6, column (2).

(4) Difference between columns (2) and (3) representing the annual Repayable Capital Investments.

(5) Accumulation of the sum of column (4) representing the total Repayable Capital Investments.

ATTACHMENT 9.IA

BOULDER CANYON PROJECT TEN YEAR OPERATING PLAN

ATTACHMENT 9.IA

BCP TEN YEAR OPERATING PLAN

1. **BCP TEN YEAR OPERATING PLAN:** The plan will be organized into a report containing the following sections and information unless Reclamation and Western, in coordination with the E&OC, agree otherwise.

2. **BUREAU OF RECLAMATION:** This section of the report will contain information applicable to Reclamation.

SECTION 1 – INTRODUCTION AND HIGHLIGHTS

This section contains a narrative summary of Reclamation's BCP Ten Year Operating Plan with supporting tables, charts, and graphs, as appropriate.

SECTION 2 – ORGANIZATION CHART

This section contains Reclamation's organization chart with staffing projections.

SECTION 3 – BUDGET SUMMARY

This section contains an overall picture of Reclamation and Western's proposed budget and revenues.

SECTION 4 – OPERATION, MAINTENANCE, AND A&GE BUDGET SUMMARY

This section provides information regarding Reclamation's planned operation and maintenance program, including administrative and general costs. This section will include: Reclamation's projected budget for the current Fiscal Year and for the next nine (9) Fiscal Years; staffing projections; overhead costs; BCP ten year maintenance outage schedule; and justification for any projected increase.

SECTION 5 – EXTRAORDINARY MAINTENANCE, REPLACEMENTS, ADDITIONS, AND BETTERMENTS BUDGET SUMMARY

This section provides information regarding Reclamation's planned extraordinary maintenance, replacements, additions, and betterments for the current Fiscal Year and for the next nine (9) Fiscal Years. The first five (5) years of data will be provided based on specific replacement programs. The second five (5) years of data will be provided on the basis of strategic planning processes with known items costing $750,000 or more specifically identified. The program summaries provide information describing the substantial costs, schedule, and goals of the program for the ten year planning period. A program report provides the following information for each item in the plan:

a) Description of the item.
b) Estimated Cost of the item.
c) Schedule for the item.
d) Justification for the item. Examples of justifications could be as follows: test reports; data analysis; maintenance costs and repair frequency; criteria and assumptions used to identify the need; probability of equipment failure without action in the time period shown; cost and resulting impact from failure of action; cost/benefit analysis; emergencies; changes in laws and regulations; unavailability of spare parts; and any other pertinent information or analysis.

SECTION 6 - VISITOR SERVICES BUDGET SUMMARY

This section provides information regarding: the planned visitor facility program for the current Fiscal Year and for the next nine (9) Fiscal Years; staffing projections related to visitor services; projections of the operation and maintenance costs for visitor services; and justification for any projected increase. This section of the report provides projections of any capital expenditures to be made in support of visitor services and provides supporting justification for any projected expenditure. This section of the report provides projections of revenues to be received from visitor services.

SECTION 7 - HISTORIC DATA

This section contains tables, graphs, charts, and narrative discussions, as appropriate, regarding historic operating statistics for the BCP for the most recently completed five (5) Fiscal Years for the following categories:

A. Staffing Levels

B. Operation and Maintenance:

(a) Reclamation Operation Line Items and Costs

(b) Reclamation Maintenance Line Items and Costs

C. Administrative and General:

(a) Reclamation Administrative and General Costs

D. Extraordinary Maintenance:

(a) Reclamation Extraordinary Maintenance Line Items and Costs

E. Replacements, Additions and Betterments:

(a) Reclamation Replacement Line Items and Costs

(b) Reclamation Additions and Betterments Line Items and Costs

F. Visitor Services

(a) Visitor Levels

(b) Visitor Service Revenues

(c) Visitor Facilities Operation and Maintenance Line Items and Costs

(d) Visitor Facilities Replacements, Additions and Betterments Costs

G. Generation:

(a) Hydrology

(b) Generation Output

(c) Generating Unit Availability Factors

(d) Outage Schedules and Causes

(e) Plant Efficiency Factors

SECTION 8 - BUDGET EXPENDITURES

This section contains Reclamation's most recently completed Fiscal Year Fund Utilization Report.

SECTION 9 - HYDROLOGY AND GENERATION PROJECTIONS

This section contains projections of generation output, outflow from Lake Mead and Lake Mead elevation for the current Fiscal Year and for the next nine (9) Fiscal Years. It also contains supporting information identifying the methodology and assumptions used to develop the projections.

SECTION 10 – APPENDIX A: TRC REPORT AND RESPONSES

This section contains the TRC Recommendations Report submitted to the E&OC by the Contractors and the associated responses from Reclamation and Western.

3. **WESTERN AREA POWER ADMINISTRATION:** This section will contain information applicable to Western.

SECTION 11 – INTRODUCTIONAND HIGHLIGHTS

This section contains a narrative summary of Western's BCP Ten Year Operating Plan with supporting tables, charts, and graphs, as appropriate.

SECTION 12 – ORGANIZATION CHART

This section contains Western's organization chart with staffing projections.

SECTION 13 – OPERATIONS, MAINTENANCE, & REPLACEMENTS

This section provides information regarding Western's planned operation and maintenance program, facility expenses and system wide expenses. This section will include Western's projected budget for the current Fiscal Year and for the next nine (9) Fiscal Years overhead costs; and justification for any projected increase.

This section also provides information regarding Western's planned retirements, replacements, additions, and Mead Common Facilities projects for the current Fiscal Year and for the next nine (9) Fiscal Years. Specific projects will be included in years that have already been determined. The remaining data will be provided on the basis of strategic planning processes to identify projected amounts for projects to be determined at a later date

SECTION 14 - HISTORIC DATA

This section contains tables, graphs, charts, and narrative discussions, as appropriate, regarding historic operating statistics for the most recently completed five (5) Fiscal Years for the following categories:

A. Staffing Levels

B. Operation and Maintenance:

(a) Western Operation Line Items and Costs

(b) Western Maintenance Line Items and Costs

(c) Western Extraordinary Maintenance Line Items and Costs

C. Administrative and General:

(a) Western Administrative and General Costs

(b) General Western Allocation Costs

D. Retirements, Replacements, and Additions:

(a) Western Replacement Line Items and Costs

(b) Western Retirement and Addition Line Items and Costs

E. Multi-Project Allocations

(a) Multi-Project Expenses distributed to the BCP by other Western projects

(b) Multi-Project Revenues Received by the BCP from other Western projects

F. Generation:

(a) Revenues from Sale of Electric Power

SECTION 15 - BUDGET EXPENDITURES

This section contains Western's most recently completed Fiscal Year Budget Execution Report.

SECTION 16 - MULTI-PROJECT PROGRAM

This section provides information regarding the planned Multi-Project Program for the current Fiscal Year and for the next nine (9) Fiscal Years; projections of multi-project costs to be paid to other Western projects and supporting documentation identifying the methodology and assumptions used to derive those projections; and projection of multi-project revenues to be received from other Western projects and supporting documentation identifying the methodology and assumptions used to derive those projections.

SECTION 17 - PRELIMINARY POWER REPAYMENT STUDY

This section contains a preliminary PRS projecting BCP rates utilizing the projected costs, revenues, and power sales contained in the previous sections of the BCP Ten Year Operating Plan and supporting work papers including investment repayment calculations, and interest during construction calculations.

SECTION 18 – REPLACEMENT CALCULATION

This section contains the previous year's calculation of repayable replacement amounts for the BCP.

4. BCP TEN YEAR OPERATING PLAN DEVELOPMENT:

4.1 Reclamation and Western will meet with the TRC, in September of each year, unless otherwise agreed to by the TRC Representatives, to present and discuss the Preliminary BCP Ten Year Operating Plan. The Preliminary BCP Ten Year

Operating Plan shall be mailed, or sent by means agreed to by the Representatives, to the E&OC ten (10) working days prior to the scheduled meeting.

4.2 The Contractor Representatives of the TRC shall prepare a report of recommendations for the E&OC on the Preliminary BCP Ten Year Operating Plan prior to the E&OC meeting that follows the TRC meeting. Reclamation and Western will provide responses to and consideration of the recommendations of the TRC for the inclusion and development of the Final BCP Ten Year Operating Plan.

4.3 The E&OC shall prepare and submit final comments to Reclamation and Western regarding the Preliminary BCP Ten Year Operating Plan within three (3) working days following the E&OC meeting.

4.4 Reclamation and Western shall prepare and submit a draft "Section 10: Appendix A: TRC Report and Responses" to the E&OC including responses to the recommendations and comments in paragraph 4.3 by December 1 of each year.

4.5 The E&OC, Reclamation and Western shall work together to finalize the Appendix A and address any other comments prior to finalizing the Final BCP Ten Year Operating Plan.

4.6 Reclamation and Western shall prepare and submit to the E&OC the Final BCP Ten Year Operating Plan by February 1st of each year.

4.7 The E&OC shall review the Final BCP Ten Year Operating Plan. Each E&OC Representative will be provided an opportunity to identify, in writing, concerns with the Final BCP Ten Year Operating Plan within fifteen (15) days of receipt.

4.8 Reclamation and Western shall respond in writing within thirty (30) days to any concerns expressed by any E&OC Representative regarding the Final BCP Ten Year Operating Plan.

ATTACHMENT 10.IA

BOULDER CANYON PROJECT ELECTRIC SERVICE CONTRACTORS

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BOULDER CANYON PROJECT ELECTRIC SERVICE CONTRACTORS

Agua Caliente Band of Cahuilla Indians
Anza Electric Cooperative, Inc.
Arizona Power Authority
Augustine Band of Cahuilla Indians
Bishop Paiute Tribe
Cabazon Band of Mission Indians
California Department of Water Resources
Chemehuevi Indian Tribe
City of Anaheim, California
City of Azusa, California
City of Banning, California
City of Burbank, California
City of Cerritos, California
City of Colton, California
City of Corona, California
City of Glendale, California
City of Los Angeles, California
City of Pasadena, California
City of Rancho Cucamonga, California
City of Riverside, California
City of Vernon, California
City of Victorville, California
Colorado River Commission of Nevada
Fort McDowell Yavapai Nation
Gila River Indian Community
Hualapai Indian Tribe
Imperial Irrigation District
Kaibab Band of Paiute Indians
Las Vegas Paiute Tribe
Metropolitan Water District of Southern California
Morongo Band of Mission Indians
Navajo Tribal Utility Authority
Pascua Yaqui Tribe
Pechanga Band of Luiseno Mission Indians
Salt River Pima-Maricopa Indian Community
San Diego County Water Authority
San Luis Rey River Indian Water Authority
San Manuel Band of Mission Indians
Southern California Edison Company
Timbisha Shoshone Tribe
Tohono O'odham Nation
Tonto Apache Tribe
Torres Martinez Desert Cahuilla Indians
Twenty-Nine Palms Band of Mission Indians
United States, for Boulder City
Viejas Band of Kumeyaay Indians