THE FINANCIAL IMPACTS OF THE LOW SUMMER STEADY FLOW EXPERIMENT AT GLEN CANYON DAM

S. Clayton Palmer
Clark Burbidge
Heather Patno

WESTERN AREA POWER ADMINISTRATION

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ABSTRACT

The operation of Glen Canyon Dam was altered during the summer of 2000 to provide flows to aid in the study and recovery of native endangered fish in the Colorado River below the Glen Canyon Dam. The testing of these flows was called for in the Fish and Wildlife Service's 1995 Biological Opinion on the operation of Glen Canyon Dam as part of the Endangered Species Act process. The Biological Opinion called for such a test during a summer when hydrological conditions would have dictated low releases from the dam because of the water supply. This change in operation modified the timing of electrical generation at the power plant at the dam. This paper describes the methods used for simulating the operation of Glen Canyon Dam during the low summer steady flow test and what operations would have been without the test. This paper also examines methods for estimating the financial cost of this change in operation and it calculates the cost.

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I. PURPOSE OF THE LSSF

The science plan for WY 2000 low-steady summer flows was primarily designed to provide data concerning patterns of response by biological resources to summer season low-steady flows. Four areas of emphasis are included in this plan: (1) physical variables, (2) biotic habitat, (3) primary productivity, and (4) fish response. Other areas of study were addressed: effects on Lake Powell water quality that ultimately can affect the downstream resources of concern, the opportunity to advance understanding of sediment storage and sediment budgeting, and the financial and power system impacts of such a test.

Ecosystem Studies

The main projects were focused in scope and integrated across the four areas of emphasis identified above. Integration and the potential to detect a response necessitate a concentrated effort within a relatively small geographic area, primarily from Glen Canyon Dam to Phantom Ranch. The focused scope will result in data collection that can help direct efforts under possible future steady flow years. For example, patterns seen under this scenario may be tested in other areas of the river corridor in future steady flow years or may be used in future monitoring programs for resources. Patterns may be applicable across many sites or may be site specific. Resulting research involving processes and interactions can be identified and refined in this manner.

Much of the data collected during this test of low summer steady flows (LSSF) can be viewed as a "baseline" against which possible future summer seasons dominated by low flows (fluctuating or steady) can be compared. The actual pattern of water release for this test is illustrated Figure I.1. In subsequent low-volume water years, different treatments (e.g., flow regimes) may be used. Thinking about the WY 2000 test of low summer steady flows in the context of a multi-year study design is consistent with the Biological Opinion on the Operation of Glen Canyon Dam [Service, 1994], which called for the development of a program of experimental flow regimes in low volume years and the recommendations of the report on endangered fish flows [Valdez, et. al., 1999].

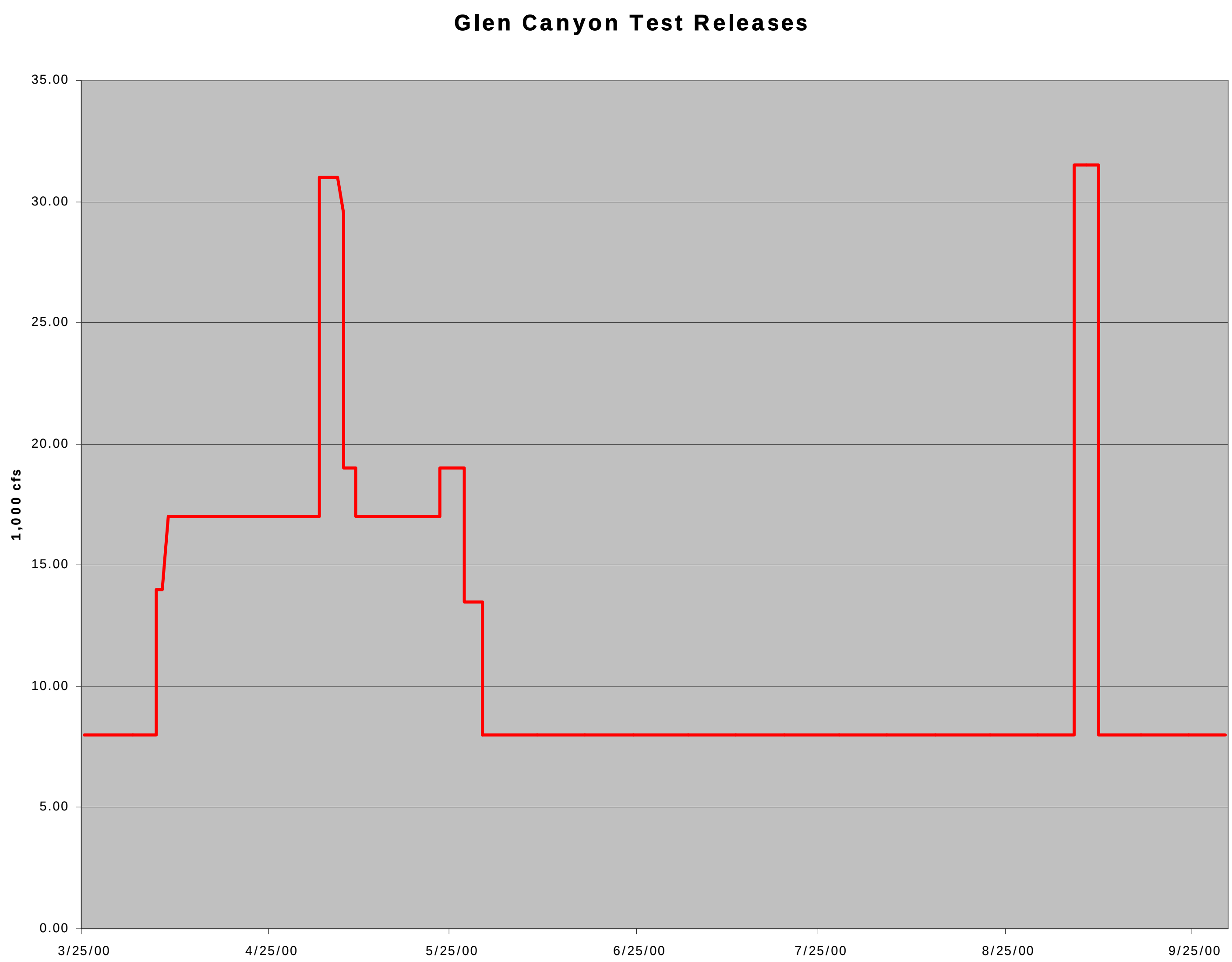

FIGURE I.1 Low Summer Steady Flow Pattern of Release

This plan was designed to address the assumptions implicit in the Fish and Wildlife Service's concept of seasonally adjusted steady flows intended to benefit native fish. They were:

1. Steady flows (i.e., 8,000 cfs) will provide consistently available low-velocity near shoreline habitats.

2. Water temperature will increase during summer steady flows both longitudinally and in and along near shoreline habitats, and 8,000 cfs flows provide greater warming than higher discharges.

3. Productivity (primary and secondary) is enhanced by steady flows and food availability is sufficient to compensate for the increased energetic demands of younger, faster growing fish.

4. Steady flows stabilize habitats used and will benefit young fish survivorship.

5. Hydrology that simulates the seasonal patterns of the natural hydrograph benefits native fish more than non-native fish.

6. Predator-prey and competitive interactions between non-native and native fish will not offset the positive effects on native fish derived from the increased availability of suitable habitat for rearing.

7. Impounding tributary mouths, primarily the LCR, retains larvae and immediate post-larvae allowing them sufficient growth to survive when they enter the mainstem in the summer and find increased suitable habitat.

8. A spike flow of 33,000 cfs for 4 days in spring will create suitable habitat and displace non-native fish, and a spike flow of 33,000 cfs for 4 days in fall will disadvantage non-native fish relative to native fish.

Purpose of this Financial Study

The purpose of this report is to describe and explain the methods used by the authors to estimate the financial impact of the LSSF study on Western and its electrical service customers, to illustrate the change in Glen Canyon operations, and to describe power system impacts of the LSSF. In addition, the *Grand Canyon Protection Act of 1992* requires Western to calculate the cost of test flows at Glen Canyon Dam. These costs are "nonreimbursable" to the U.S. Treasury. The model and the methods used in this study were used to analyze the financial effect of the implementation of a Biological Opinion on the operation of Flaming Gorge. The result of the Flaming Gorge study was used to justify the cost-sharing arrangements included in Public Law 106-392 [Palmer, 1999].[1]

II. THE GLEN CANYON DAM AND ITS HISTORICAL OPERATION

The Glen Canyon Dam and Power Plant

Glen Canyon Dam is part of the Colorado River Storage Project (CRSP), authorized by Congress in 1956 as part of the CRSP Act. Construction of the dam was completed in 1963. Glen Canyon Dam has a power plant with eight generators. The combined capacity is 1,296 megawatts. Its electrical power generation is connected to an electrical transmission grid, which is tied to the other CRSP power plants and to other private and publicly owned power plants. The power plant has a maximum release capacity of approximately 33,200 cubic feet per second (cfs). The dam has river outlet works and two spillways, which can be used to release water.

Historic Operations of Glen Canyon Dam

Water released out of Glen Canyon Dam is intended to meet the purposes of the CRSP Act of 1956 and the Colorado River Basin Act of 1968. Briefly, Reclamation sets monthly and annual release volumes, in consultation with the Colorado River Basin states, to meet water delivery and storage requirements and for purposes consistent with laws and statutes collectively known as "The Law of the River." Western schedules hourly releases in conformance with the monthly water volumes and to meet contractual

[1] RIP long-term funding legislation.

obligations for the delivery of electrical power. From 1963 to 1990, power plant operations were constrained by a minimum flow of 1,000 cfs during the winter months and 3,000 cfs during the summer white water rafting season. Hourly operations above these minimum values were set in order to meet contractual requirements for power delivery and maximize the firm electrical power available. In 1990, test flows were conducted at Glen Canyon Dam. These were followed in 1991 by Interim Flows. These significantly constrained power operations at Glen Canyon Dam and were continued while an Environmental Impact Statement (EIS) was prepared on the operation of Glen Canyon Dam. In 1996, the Secretary of the Interior signed the Record of Decision (ROD). The operational limits of the ROD are: maximum power release is 25,000 cfs; minimum release is 5,000 cfs from 7:00 p.m. until 7:00 a.m., and 8,000 cfs from 7:00 a.m. to 7:00 p.m. Daily changes in water releases are limited to 5,000, 6,000, or 8,000 cfs depending on the monthly release volume[2]. Hourly down ramping restrictions are 1,500 cfs/hr and hourly up ramping restrictions are 4,000 cfs/hr.

In addition, the ROD allows for a continuation of operations to keep the Federal power system reliable and specifies an “emergency exception criteria” by which the ROD constraints can be superceded for power system emergencies. Among the power requirements are Area Load Control and Spinning Reserves. Area load control requirements are set at 40 MW (≅1,000 cfs). Spinning reserve requirements are at 52 MW[3].

[2] Months with releases less than 600,000 AF are limited to 5,000 cfs daily fluctuation. Months with releases greater than 600,000 AF but less than 800,000 AF are limited to 6,000 cfs daily fluctuation. Months with water releases over 800,000 AF are limited to 8,000 cfs daily fluctuation.
[3] Area load control and spinning reserve requirements affect the maximum and minimum generation values. See footnotes 14 and 15.

1995 Biological Opinion

In accordance with the *Endangered Species Act*, the U.S. Fish and Wildlife Service submitted a Biological Opinion to the Bureau of Reclamation in connection with Glen Canyon Dam Operations. The Biological Opinion stated that the historical operation of Glen Canyon Dam was jeopardizing the continued existence of endangered and other native fish species. It described a Reasonable and Prudent Alternative (RPA) to the current operation of the dam. It also described a number of conservation measures not specifically related to the operation of the dam.

Among the RPA requirements, a program of experimental flows to include high steady flows in the spring and low steady flows in summer and fall during low water years was called for. The LSSF of WY 2000 was the first experiment conducted within this not yet defined program of experimental flows.

III. FINANCIAL VS. ECONOMIC STUDIES

While the distinction is often a subtle one, the difference between financial and economic analysis is worth describing for a clearer understanding of the impact of the LSSF on the operation of Glen Canyon Dam.

An economic impact analysis describes the impact of an action on the society as a whole. A financial impact study concentrates on the impact of an action on an individual body or institution. For example, in the EIS on the operation of Glen Canyon Dam, economic and a financial analysis were conducted on proposed changes in the operation of Glen Canyon Dam [Interior, 1996]. The financial study described how changes in the operation of Glen Canyon Dam would affect Western and its customers. The economic study described how these financial impacts would (or would not) be carried forward to the national economy. This report is strictly a financial study, although much of the data and analysis included herein would be applicable to an economic analysis.

IV. BACKGROUND ON WESTERN AND SALT LAKE CITY AREA INTEGRATED PROJECTS (SLCA/IP) POST – 1989 MARKETING

Western Area Power Administration

Western, a power marketing administration within the Department of Energy, was created with the passage of the Department of Energy Organization Act of 1977 (DOE Act). The DOE Act transferred the power marketing and transmission functions from the Secretary of the Interior (Bureau of Reclamation) to the Secretary of Energy, acting through Western.

Western's mission is to sell and deliver electricity that is in excess of project uses (power that is required for the operation of irrigation projects) generated from power plants that were built as part of certain Federal water projects. Most of the power plants are located on the Upper Colorado River and its tributaries. Western's Colorado River Storage Project Management Center (CRSP MC) is responsible for marketing power from the CRSP, Collbran Project, Rio Grande Project, and Provo River Project. CRSP includes Glen Canyon, Flaming Gorge, Morrow Point, Blue Mesa, and Crystal Dams. On October 1, 1987, the CRSP, Collbran, and Rio Grande projects were integrated for marketing and rate-making purposes and are collectively known as the Salt Lake City Area Integrated Projects (SLCA/IP).

Western's power marketing responsibility begins at the switchyard of Federal hydroelectric power facilities and includes the Federal transmission system to interconnected utility systems. The hydroelectric projects of the SLCA/IP are operated by Reclamation. Reclamation manages and releases water in accordance with the various laws authorizing specific projects and with other enabling legislation. Western's capacity and energy sales must conform to the laws that govern its sale of electrical power. Western's hydropower operations at each facility comply with minimum and maximum flows and other constraints set by Reclamation or other operating agencies, acting in accordance with law or policy. However, Western's CRSP operation is electronically connected to Reclamation's dams and directly signals the dams to change water releases in order to provide for the integrity and reliability of the Federal power system.

The *Reclamation Project Act of 1939* defined the responsibility of Reclamation in irrigation development and permitted revenues from the sale of electricity generated at the Federal facilities to be used to repay some of the irrigation investment, as well as all costs incurred in developing the hydroelectric facilities. The principal purposes of these projects include irrigation, flood control, and navigation. About 90 percent of all revenues received from these projects are from power sales.

An important provision of the *Reclamation Project Act of 1939* was to give preference in the sale of federally generated electricity to municipalities, other public corporations or agencies, cooperatives, and other nonprofit organizations financed under the Rural Electrification Act of 1936. Western sells firm power to non-preference customers only if the available supply exceeds the demands of interested and eligible preference customers.

V. SUMMARY OF STUDY METHOD

Study Overview

The Low Summer Steady Flow (LSSF) study was conducted on conditions that existed during the summer of 2000 at the Glen Canyon Dam. The study was conducted during a summer when hydrologic conditions dictated relatively low releases from the dam. The "LSSF type" study is required during dry conditions, as specified in the 1995 Biological Opinion. According to the *Grand Canyon Protection Act of 1992*, the costs related to conducting the study are non-reimbursable. Nonreimbursable costs are not repayable to the U.S. Treasury. Funds expended by Western deemed as nonreimbursable are "credited" against reimbursable costs.

This report documents the procedures used, and the results obtained, by Western's CRSP Customer Service Center (CSC) in complying with Section 1807 of the "Grand Canyon Protection Act of 1992,"[4] (GCPA) which says:

> *"All costs of preparing the environmental impact statement described in section 1804, including supporting studies, and the long-term monitoring programs and activities described in section 1805 shall be nonreimbursable. The Secretary[5] is authorized to use funds received from the sale of electric power and energy from the Colorado River Storage Project to prepare the environmental impact statement described in section 1804, including supporting studies, and the long-term monitoring programs and activities described in section 1805, except that such funds will be treated as having been repaid and returned to the general fund of*

[4] Title XVIII of the Reclamation Projects Authorization and Adjustment Act of 1992.

[5] The Secretary of the U.S. Department of the Interior.

the Treasury as costs assigned to power for repayment under section 5 of the Act of April 11, 1956 (70 Stat. 170)[6]*."*

Summary of Study Method

The first step of the study method was to define the study period. The next step was to choose and describe a baseline condition. Establishing a baseline means choosing a hydrologic condition, a set of constraints at Glen Canyon Dam, an electrical demand which the electrical generation at Glen Canyon Dam must meet, and a set of baseline conditions at the other CRSP power plants.

Once a baseline has been selected, a description of a changed condition is prepared. The changed condition is referred to as the test case. The test case consists of all the assumptions and data in the base case, except that a new set of operational constraints is imposed on the operation of Glen Canyon Dam. The new constraints are those of the LSSF. Consequently, in order to meet the requirements of the LSSF, modifications were made in the monthly distribution of water released from Glen Canyon Dam over the course of WY 2000.

Although the flat flows associated with the LSSF did not begin until the last week of March (March 26, 2000), water was redistributed into the beginning of March to account for the strict water release requirements of flat flows. During the experimental releases water was redistributed from the winter season into November 2000. This redistribution of water was not part of the experimental releases; rather, water was redistributed at the request of Western to alleviate a cash crunch that CRSP was experiencing due to exorbitant power costs, low water and the LSSF test. This redistribution of water

[6] The Colorado River Storage Project Act.

unassociated with the experimental flows makes it impossible to compare values between the base case and the test case after September 30, 2000. Therefore, the study period ends September 30, 2000.

The analysis of the LSSF compared two different test case scenarios against the base case scenario. The initial test case analysis utilized actual water releases and Glen Canyon dam constraints in the Hydro LP model and the result was an optimized generation pattern. The second test case analysis (SCADA case) utilized the actual generation pattern obtained from Supervisory Control and Data Acquisition (SCADA). SCADA is a centralized remote control system which includes the transmission of numerical quantities and alarms to and from generation stations, substations, and other electrical facilities to a control center. The SCADA system is not completely accurate. There are a few hours that show no generation or generation numbers that are too high to be realistic. When this occurred the preceding hourly generation was extended to cover the incorrectly reported data. SCADA analysis was performed in order to compare the optimized modeled results against the reported values of generation from the six main CRSP units.

The resulting hourly generation for the test case and SCADA case alternative is compared against the resulting hourly generation for the base case. The ability of this generation to respond to scheduled load has been considered. When taking [(L – B) – (L – T)], load subtracts out of the equation and the resulting equation is (T – B).[7] The hourly difference between each of the test cases and the base case generation is then multiplied

[7] Where L = Load scheduled by the customers that complies with available hydropower generation; T = Test case generation; B = Base case generation.

by the applicable month's on- or off-peak price. The difference in terms of purchases and sales is summed by month.

The Hydro-LP Model

The Hydro Linear Program Computer Model (Hydro-LP Model) was developed by Argonne National Laboratory (ANL) under contract to the CRSP-MC's Environmental and Resource Planning Division [Veselka, 1995].[8] Hydro-LP maximizes net revenues of SLCA/IP operations, and minimizes cost, by finding a solution that increases income through optimized water release from the six major CRSP units.

The model is a computer simulation of weekly operations of all or part of the entire physical SLCA/IP, depending upon the user's preference. Various weeks may be put together to produce annual or seasonal data. The Hydro-LP Model allows changes in operating scenarios to be tested so that Western may evaluate possible results in differing situations.

The model looks for the solution that meets hourly demand requirements at minimum cost, subject to a list of restrictions imposed upon it. Restrictions might include how much water is allowed through Glen Canyon power plant over a defined period, flow requirements at Flaming Gorge power plant, or a mandate that no power be sold on the spot market for less than an agreed-upon price.

[8] Other CRSP simulation optimization models exist. See, for example, Edwards, et al. [Edwards, 1999].

The objective function of the Hydro LP is:

$$\min \sum_{i=1}^{n} \sum_{j=1}^{m} P_{ij}X_{ij}$$

Where: X_{ij} is the purchase of the *i*th megawatt of supplemental electrical power during the *j*th hour.

P_{ij} is the price paid (or sales price) of electrical power of the *i*th megawatt in the *j*th hour.

Pursuit of the objective function is subject to a variety of constrains: 1) the water available for release through a given CRSP power plant during a week, 2) restrictions on the operation of a power plant, 3) the technical capabilities of each power plant, and 4) environmental limitations or targets that restrict the operation of the power plants. The model minimizes the objective function subject to these constraints over a specified period of time. When actual historic input data are used, the Hydro-LP Model mimics real world SLCA/IP operations.

The Hydro-LP's projections do not precisely match actual power plant operations because the computer model has nearly perfect information at all times while SLCA/IP operators do not. Operators are also constrained by other, non-modeled, physical constraints, i.e., power outages, scheduled maintenance, etc., while the Hydro-LP is not. This model treats the entire SLCA/IP as one generation site and obtains a combined generation pattern based on the total hydro resources available. Hydro-LP results and actual operations correlate very closely since both operators and the Hydro-LP Model try to optimize power plant operations. The correlation between modeled results and actual generation patterns provide a high degree of confidence in the Hydro-LP's ability to simulate CRSP generations.

Operating conditions within the Hydro-LP Model can be made to simulate almost anything that might occur in the SLCA/IP, including price or demand changes in the spot market, flow decreases or increases at individual power plants, major maintenance at one or more plants, and environmentally-related actions at any point in the power system.

The Hydro-LP Model simulates hydro power plant operations when serving both long-[9] and short-term[10] firm[11] and project use loads[12]. Maximum hydro plant generation levels estimated within any study are based on flows input by the user. The model also incorporates input restrictions into its calculations. Minimum generation levels are based on minimum flow restrictions. Both maximum and minimum outputs are dependent on representative water-to-power conversion factors and are adjusted for spinning reserves[13] and area load control[14] services. The model may use any SLCA/IP hydro power plant generation level between the subject plant's maximum and minimum capability, while

[9] Long-term loads are those for which supply contracts cover a year or more.

[10] Short-term loads are those having supply contracts for less than one year.

[11] Firm loads are those the supplier is obligated to supply, at the agreed-upon price, from its own or other resources. Another type of load, nonfirm, is contingent upon the supplier's resources. It may be interrupted or terminated within an hour's notice to the purchaser if the supplier is unable to provide it.

[12] Project use loads include energy needed to operate irrigation pumps, gates on irrigation dams, salinity control projects, and the like. Western is required by law to serve these loads before any others.

[13] Spinning reserves are those sources of capacity available almost instantly to serve load in an electrical system in the event of failure of a large resource. Spinning reserves differ from other system resources only in that they are not connected to load until and unless they are needed.

[14] Load control is required within a defined geographic load control area. One or more systems within the load control area typically set aside an agreed-upon amount of capacity to stabilize changes in electrical frequency between various suppliers, if they develop. The set-aside capacity is not available for sale to electrical power customers. Because of its size (which makes it capable of absorbing and modulating frequency swings), and the operating flexibility inherent in hydroelectric operations, the SLCA/IP frequently provides load control in the areas in which it operates.

taking the restrictions and production requirements supplied into consideration while searching for its solution.

The user-supplied operating restrictions incorporated into the model include minimum and maximum flows, hourly and daily ramping constraints,[15] and minimum and maximum reservoir water elevations. The Hydro-LP Model simulates hourly operations of the SLCA/IP's hydro power plants for weekly periods. The model also estimates related hourly purchase and sales activities on the spot market. Spot market activities are based on market prices or short-run marginal costs, hydropower operation flexibility, customer load, and the amount of water available for generation. The model also includes a margin requirement[16] for off-peak to on-peak[17] hydropower shifting[18].

Due to ramping restrictions and limited water releases, each hour of operation in a simulated week depends on all other hours in the same week.

Assumptions of the Base Case

The Base Case includes four general categories of assumptions. They are: monthly water release volumes, hourly electrical demands, hourly purchase prices, and the operation of

[15] Ramping refers to the increase or decrease in the volume of water flowing through an individual power plant over a specified period of time.

[16] The margin requirement is the difference between the price of purchased and sold power on the spot market. The model assumes it makes no sense to incur the extra operating expenses entailed in purchases and sales unless there is a 0.5 mill margin.

[17] On-peak hours are 7:00 a.m. through 11:00 p.m. Off-peak hours are 11:00 p.m. through 7:00 a.m.

[18] Power shifting is the practice of trying to minimize off-peak generation so the water that would have been used for it can be used later to generate power during an on-peak period. Off-peak power is generally much less costly on the spot market than on-peak power. It makes economic sense to purchase as much off-peak power as possible to serve the off-peak load, and retain the water that would have been used for off-peak generation for use on-peak. On-peak power usually can be sold at a premium price. This makes it economically desirable to generate even more than the on-peak load demands so the surplus can be sold on

the other CRSP power plants. These data are input into the Hydro-LP model. Glen Canyon Dam is constrained according to the Record of Decision (ROD) within the model. A model simulation is run which produces hourly generation levels at Glen Canyon Dam for each hour of the study period.

Base Case Monthly Water Release Volumes:

Reclamation's Upper Colorado Region Office provides historical and forecasted monthly water releases. Forecasted water releases are generated using *Riverware*. The forecast is referred to as the 24-Month Study because it recounts the actual water releases from each of the CRSP dams for the past 12 months and forecasts water releases for each of these dams for the coming 12 months. The 24-Month Study is updated monthly. Release data in the 24-Month Study is given in acre-feet per month; however, this must be converted into acre-feet per week for the Hydro-LP Model. Therefore, the acre-feet per month figure is divided by the number of days in the month. This results in the daily release volume. Each day of the week is then summed to get the weekly volume. This method also allows the model to account for transition weeks from month to month.

Reclamation, through *Riverware* modeling and its own hydrological analysis, calculated each month of water volumes that would have been released through GCD if the experiment had not been conducted. These volumes were used in the base case. The base case water volume data in thousand acre-feet is set forth in Table V.1.

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the spot market for a profit. A synonymous term-hydro-shifting–is described by Edwards, et al., [Edwards, 1992].

TABLE V.1 Base Case Monthly Water Volumes

Month	Year	Base Water (KAF)
March	2000	650
April	2000	625
May	2000	600
June	2000	600
July	2000	625
August	2000	600
September	2000	500
Study Period Total		**4,200**

Electrical Demand (Load) Data

Load values for the study were based on historical values. The load data used was comprised of a weekly average per month of CRSP scheduled customer load obtained from a Colorado River Energy Distributors Association (CREDA) survey of its members. CREDA is a non-profit organization representing consumer-owned electric systems that purchase federal hydropower and resources of the CRSP. CREDA was established in 1978, and serves as the "voice" for its members in dealing with Reclamation (as the generating agency of the CRSP) and Western (as the marketing agency of the CRSP). CREDA members are all non-profit organizations, serving nearly three million electric consumers in the six western states of Arizona, Colorado, Nevada, New Mexico, Utah and Wyoming.

CREDA polled CRSP customers on their usage for a week for each month throughout a year. Western has made minor modifications to these data to account for the fact that CRSP customers include utilities which are not members of CREDA.

Aside from the base electrical demand generated 24 hours a day, load is distributed into three categories—residential, commercial and industrial. Monday through Friday, demand increases in the morning hours as residential power use increases to prepare for the work day. The demand continues to increase as commercial and industrial centers begin operating and peak demand continues throughout the day as commercial and industrial centers maintain operation. Demand declines as commercial and industrial operations cease and the work day ends. Demand continues to decline until nighttime when most households sleep, and base electrical generation occurs. Sunday and Saturday show lower peak generation because they are not typical work days. Figure V.1 is a representation of a week of load data.

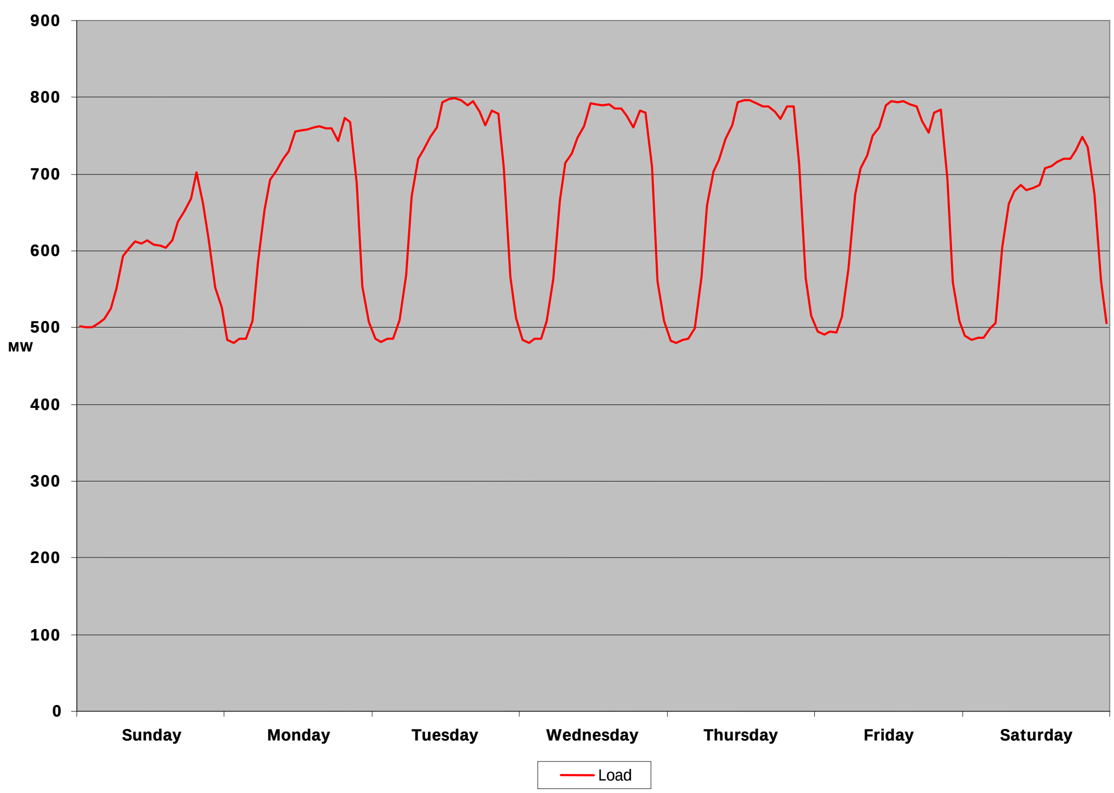


FIGURE V.1 Representative Demand Week

Modeling and Analysis Prices

Analysis Prices

Western's marketing office purchases power in seasonal firm blocks as opposed to spot market because it is more economical to do so. The marketing office provides the hourly advance purchases (pre-schedule purchases) based upon Reclamation's forecasted water release values from the 24-Month Study and Western's estimated inability to meet contractual obligations using the forecasted water. Sometimes the pre-schedule purchases do not meet CROD obligations and Western purchases additional power on the spot market on a day-before basis (firming purchases). An hourly weighted average of the pre-schedule and firming purchases are used from May 2002 to July 2003, when that information was available. Table V.2 illustrates the estimated monthly weighted average of CRSP pre-schedule and firming purchases calculated from the hourly prices used from March 2000 to September 2000.

TABLE V.2 Average Monthly On and Off Peak Market Price

Month	Year	On-Peak Prices	Off-Peak Prices
March	2000	$31.67	$9.49
April	2000	$33.62	$10.32
May	2000	$32.95	$9.06
June	2000	$63.62	$14.50
July	2000	$87.49	$18.83
August	2000	$114.29	$20.57
September	2000	$74.74	$19.95

Modeling Prices

To create a representative price week for each month, and in order to simplify the comparison between the test case and the base case, the prices of $1 for off-peak and $2 for on-peak hours were used in the modeling of the test case and the base case. While these are not actual prices, previous study results have shown that they do not change how the model acts or operates because the model works to optimize efficiency and reacts only to the fact that a price difference exists, regardless of how small. Simplified prices were also used in order to eliminate errors that may occur from using actual prices. The simplified price structure was then input and every week of the study period optimized to produce the pattern used for base case and test case generation.

Power Plant Operations

Operation of Glen Canyon Dam

GCD operates under the constraints set out in the ROD. Descriptions of these constraints are discussed in Section III and repeated in Table V.3 below.

TABLE V.3 Operating Restrictions at Glen Canyon Dam under the ROD

Max Capacity (MW)	Max Hourly Release (cfs)	Min Hourly Release (cfs)	Max Daily Change (cfs)	Ramping Restrictions (cfs)
1,288	25,000	8,000 from 7 am-7 pm 5,000 from 7 pm-7 am	8,000 w/ monthly releases ≥ 800 KAF 6,000 w/ monthly releases ≥ 600 KAF 5,000 w/ monthly releases < 600 KAF	Up 4,000 Down 1,500

Operation of other CRSP Units

The other CRSP power units of note are those at Flaming Gorge Dam and the Aspinall Units. Flaming Gorge Dam is assumed to operate under the conditions of the 1992 Biological Opinion. The Aspinall Units are constrained in that Crystal Dam is required to “even out” the peaking release from the other two upstream dams. Descriptions of these constraints are found in Table V.4 below.

Table V.4 Unit Operating Constrains Utilized in the Experiment

Power Plant	# of Units	Max Capacity (MW)	Max Hourly Release (cfs)	Min Hourly Release (cfs)	Ramping Restrictions
Flaming Gorge	3	153	12.5% @ Jensen Gage	12.5% @ Jensen Gage	None
Blue Mesa	2	96	3,700	None	None
Morrow Point	2	174	5,300	None	None
Crystal	1	31	1,600	300*	Target is steady flows
Fontenelle	1	10	1,700	500	None
Lower Molina	1	5	50	None	None
Upper Molina	1	9	50	None	None
Elephant Butte	3	24	2,400	2	None

* Below the Gunnison Diversion Tunnel

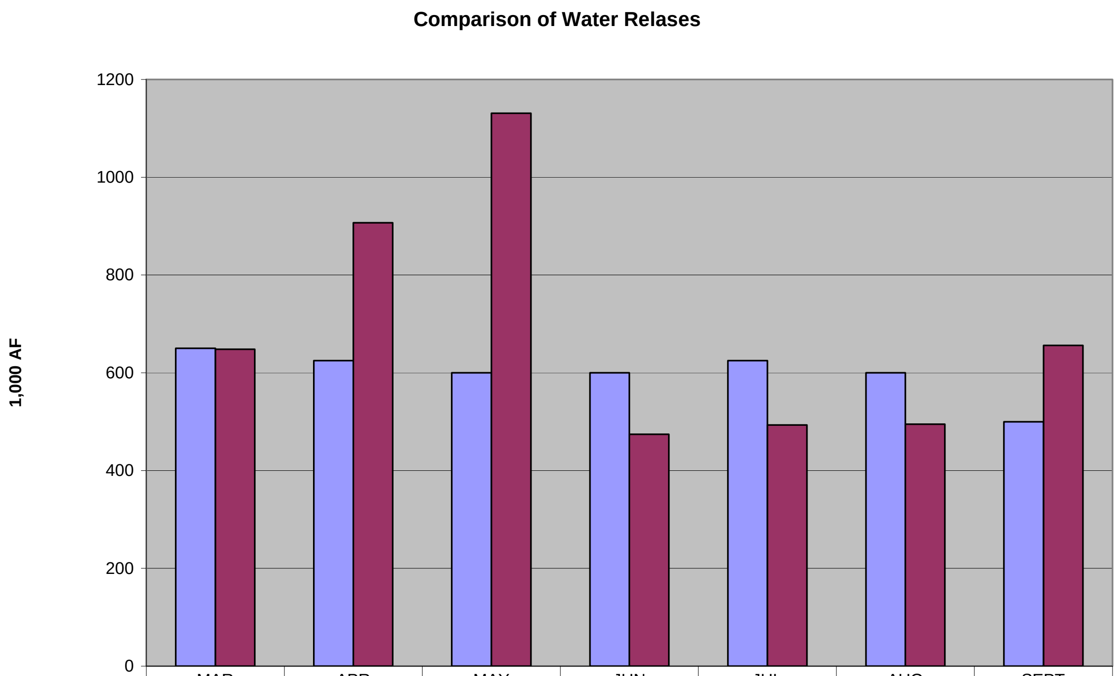
VI. COMPARISON OF BASE CASE AND TEST CASE

The test case replicated the actual monthly water volumes and hourly water release patterns from Glen Canyon Dam that occurred during the study period. The test case used the same hourly demand, hourly purchase prices, and operating constraint information as contained in the base case. In sum, everything in the test case is the same as the base case except that hourly generation amounts are actual ones produced over the study period instead of those the Hydro-LP model would have predicted to occur if the study were not in place.

Customer demand, hourly purchase prices, and operating constraints stayed consistent between the base case and test case. The difference between the two cases is that the monthly water volumes for the base case are those that Reclamation would have selected under similar hydrological conditions, and the test case are actual monthly water volumes. The hourly releases in the base case and test case are optimized for power production by the Hydro-LP model within the constraints of the Glen Canyon Dam ROD. The SCADA case utilizes the actual water release values.

Water Allocation and Release Data

Water releases for the six largest dams/power plants were compared between the test case and the base case. As demonstrated in Figure VI.1, the results of this comparison showed that in both cases, all water releases for every dam were the same except for Glen Canyon.



	MAR	APR	MAY	JUN	JUL	AUG	SEPT
Base Water	650	625	600	600	625	600	500
Test Water	648	907	1131	474	493	495	656

FIGURE VI.1 Comparison of Water Releases – Base Case and Test Case

Due to late changes in runoff forecasts, too much water was released from Glen Canyon dam for the LSSF study. In order to maintain the integrity of the test, no changes were made to remedy this over release. Due to continued low water, equalization has still not been accomplished.

The test case released 604,000 acre-feet (604 KAF) more water than the base case. Drought conditions have existed in the Upper Colorado River Basin from 1999 to present. Because of the drought conditions in the region, equalization of the 604 KAF of water has not occurred. Quantification of the 604 KAF of water is required for a complete analysis of the LSSF.

Calculation of value of "Non-Equalized Water"

For this analysis it was assumed that under normal conditions equalization of 604 KAF would occur within the water year immediately following the LSSF. Quantification of the 604 KAF water release required for equalization was calculated over a six-month and one-year period. The six-month period spans from October 1, 2000 to March 31, 2001. The one-year period spans water year 2001 from October 1, 2000 to September 30, 2001. Hourly conversion factors were calculated from the SCADA generation reported in megawatts and power release reported in cubic feet per second (cfs). The hourly cfs power release was converted to acre-feet and divided into the hourly generation data. A six-month and one-year weighted average conversion factor was calculated from the hourly conversion factors for the applicable period.

As discussed in Section V. Summary of the Study Method, Western's marketing office purchases power in seasonal firm blocks as opposed to spot market because it is more economical to do so. The marketing office provides the hourly advance purchase (pre-schedule purchases) based upon the Bureau of Reclamation's forecasted water release values from the 24-month study and Western's estimated inability to meet contractual obligations using the forecasted water. Sometimes the pre-schedule purchases do not meet Western's contractual power delivery obligations and Western purchases additional power on the spot market on a day-before basis (firming purchases). An hourly weighted average is calculated using both the pre-schedule and firming purchases. This hourly price is then separated into an average on-peak and off-peak price for the six-month and one-year period. The monthly average prices are illustrated in Table VI.1. With the assumption that the 16-hour on-peak purchases account for two-thirds of total purchases and eight-hour off-peak purchases account for one-third of total purchases, an overall weighted average was calculated for the entire study period. The 604 KAF was then converted into megawatts using the weighted average conversion factor and multiplied by the overall weighted average price for a total impact. The converted water release was also multiplied by the on-peak average and off-peak average to quantify the impact of both. Table VI.2 contains the calculated value of the non-equalized water.

Table VI.1 On- and Off-Peak Average Monthly Purchase Price

Month	Year	On-Peak Avg.	Off-Peak Avg.
October	2000	$87.64	$59.71
November	2000	$94.77	$64.29
December	2000	$145.11	$65.53
January	2001	$98.04	$49.57
February	2001	$94.41	$22.67
March	2001	$89.80	$52.36
Six Month Average		**$101.63**	**$51.65**
April	2001	$101.92	$48.88
May	2001	$89.67	$54.87
June	2001	$75.05	$51.90
July	2001	$146.59	$77.01
August	2001	$151.86	$78.46
September	2001	$96.21	$69.88
One Year Average		**$105.92**	**$57.93**

Table VI.2 Calculated Value of the Non-Equalized Water

	Off-Peak Impact	On-Peak Impact	Overall Impact
Six Month Equalization Period	$(29,481,922)	$(14,984,408)	$(24,649,417)
One Year Equalization Period	$(30,727,911)	$(16,804,886)	$(26,086,902)

VII. COMPARISON OF BASE TEST AND TEST CASE: HYDRO-LP RESULTS

This section provides a brief summary of the comparison between the base case and test cases. Most of the numeric data that supports this comparison is to be included in an appendix yet to be prepared by the authors. This report merely summarizes and highlights the analysis.

Figure VII.1 compares the base case analysis with the test case for a typical week in August 2000. Two generation patterns are shown: one is for the total CRSP generation during the LSSF test. Glen Canyon Dam is constantly running a steady release of 8,000 cfs. Other CRSP power plants are responding to changes in demand. Total CRSP generation is significantly below total demand; however, resulting in a purchase of electrical energy by Western of approximately 350 MW during on-peak hours. The base case CRSP generation is also shown. During a typical August week, Western's generating resource exceeds its customer demand for all days but Sunday.

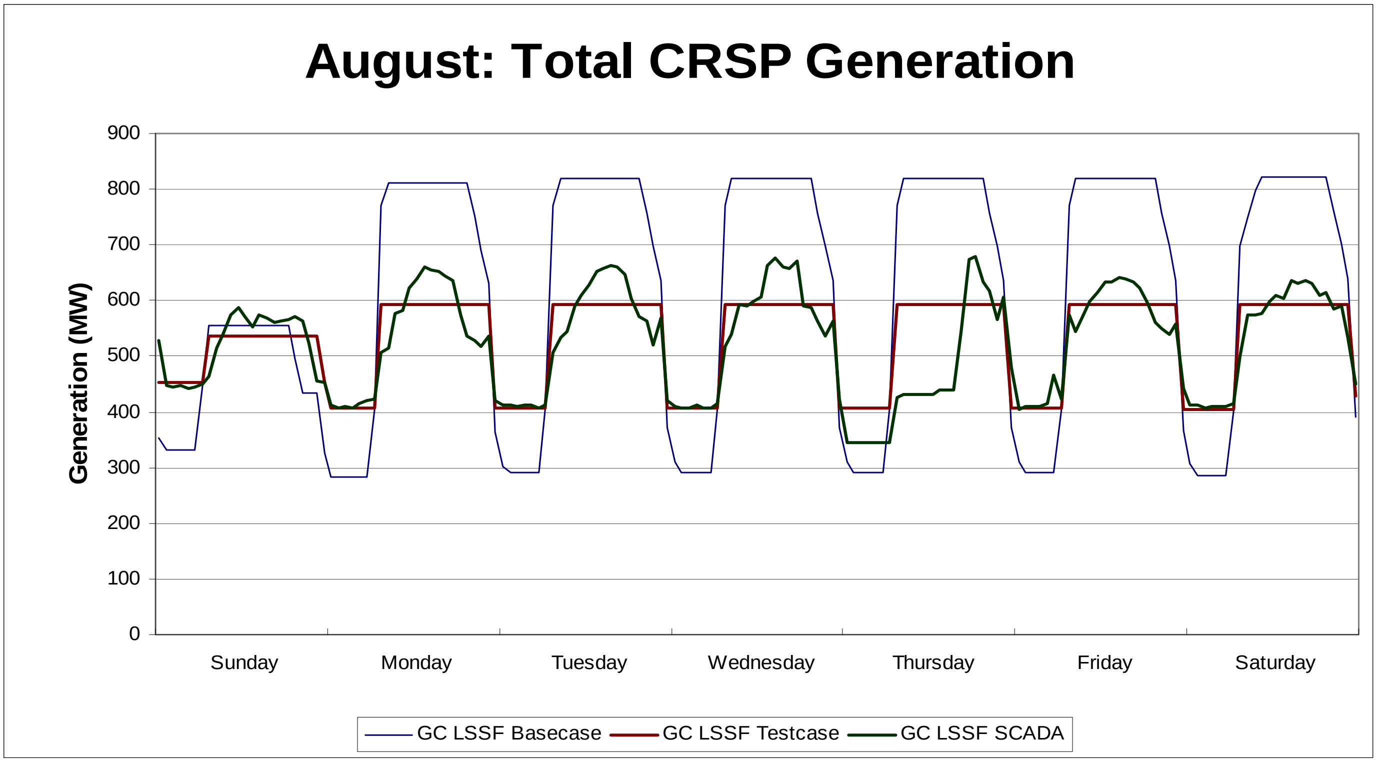


FIGURE VII.1 Comparison of Base Case and Test Case for a Typical Week August 2000.

The significant difference in magnitude between these two cases is a result of different monthly volumes of water released through Glen Canyon Dam between the base and test cases. In essence, water that would be available in August during normal operations is moved to April and May to conduct the LSSF test.

This can be seen from Figure VII.2. This is a week in May 2000 when Glen Canyon Dam's release increases to maximum powerplant capacity in the LSSF test case. Notice the coincidence between customer demand and total CRSP generation in the base case. In contrast, the test case produces much more electrical generation that is needed to meet customer demand in this May week.

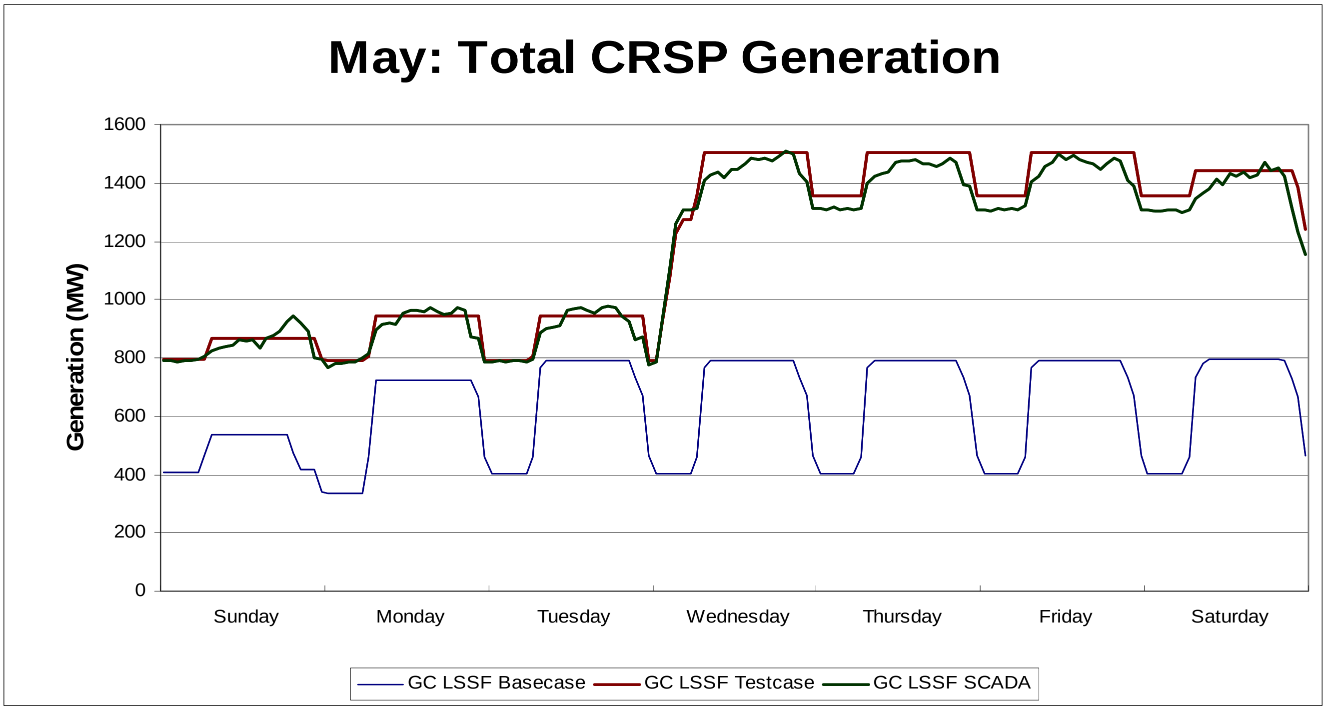


FIGURE VI.2 Comparison of Base Case and Test Case for a Typical Week May 2000.

The monthly summaries of financial information are shown in Table VII.1. This is the net result of comparing the amount of electrical system purchases and sales when the base case is subtracted from the test case. Note that since the test case has significant amounts of water released through Glen Canyon Dam during the months of April and May, that Western can meet customer power demand during these months and even has a surplus to sell to the electricity market. For the test case, this results in a net financial gain of about $3.6 and $6.8 million in April and May, respectively. The SCADA case results in a net financial gain of about $3.6 and $7 million in April and May, respectively.

Water release volumes in June through August are reduced in the test case as compared to the base case. Therefore, Western was required to make purchases from other electrical generators to meet customer demand. Some part of this number also consists of opportunity sales that would have occurred in the base case that does not occur in the test case. The most significant purchase occurs as a result of non-equalized flows. This result renders a loss of approximately $26 million over a one-year period when flows are decreased for equalization.

TABLE VII.1 Results: Total $ by Month

Month	Year	Financial (Test – No Test)	Financial (SCADA – No Test)
March	2000	($207,000)	($275,000)
April	2000	$3,576,000	$3,622,000
May	2000	$6,831,000	$6,972,000
June	2000	($4,406,000)	($4,423,000)
July	2000	($6,398,000)	($6,351,000)
August	2000	($7,680,000)	($7,704,000)
September	2000	$2,474,000	$2,609,000
Equalization	One Year	($26,087,000)	($26,087,000)
Total		**($31,900,000)**	**($31,637,000)**

The net result, once the months of the study period are summed is also shown in Table VII.1. Accordingly, the financial impact of the LSSF test based on the assumptions and methods of this study is slightly less than $32 million.

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