ANL/DIS-10-7

Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005

Decision and Information Sciences Division

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by
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FOREWORD

This report was prepared by Argonne National Laboratory (Argonne) in support of a financial analysis of experimental releases from the Glen Canyon Dam (GCD) conducted for the U.S. Department of Energy's Western Area Power Administration (Western). Western markets electricity produced at hydroelectric facilities operated by the Bureau of Reclamation. The facilities known collectively as the Salt Lake City Area Integrated Projects include dams equipped for power generation on the Colorado, Green, Gunnison, and Rio Grande rivers and on Plateau Creek in the states of Arizona, Colorado, New Mexico, Utah, and Wyoming.

This report presents detailed findings of studies conducted by Argonne related to a financial analysis of experimental releases periodically conducted at the GCD from 1997 through 2005. Staff members of Argonne's Decision and Information Sciences Division prepared this technical memorandum with assistance from staff members of the Western's Colorado River Storage Project Management Center.

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

LIST OF FIGURES

LIST OF TABLES

ACRONYMS AND ABBREVIATIONS

The following is a list of the acronyms and abbreviations (including units of measure) used in this document.

AHP	Available Hydropower
APSF	Aerial Photography Steady Flow
Argonne	Argonne National Laboratory
BHBF	Beach/Habitat-Building Flow
CROD	Contract Rate of Delivery
CRSP	Colorado River Storage Project
DOE	United States Department of Energy
EIS	Environmental Impact Statement
EOM	End of Month
EPM-EIS	Electric Power Marketing Environmental Impact Statement
FGEIS	Flaming Gorge Dam EIS
GCD	Glen Canyon Dam
GCDEIS	Glen Canyon Dam Environmental Impact Statement
GCMRC	Grand Canyon Monitoring and Research Center
GCPA	Glen Canyon Protection Act of 1992
GTMax	Generation and Transmission Maximization
HMF	Habitat Maintenance Flow
LDC	Load Duration Curve
LSSF	Low Summer Steady Flow
LTF	Long-Term Firm
MSR	Minimum Schedule Requirement
NAPI	Navajo Agricultural Products Industry
NNFSF	Non-Native Fish Suppression Flow
NTUA	Navajo Tribal Utility Authority
PO&M-59	Power Operations and Maintenance, Form 59 (a Bureau of Reclamation form entitled, *Monthly Report of Power Operations – Powerplants*)
Reclamation	Bureau of Reclamation
ROD	Record of Decision
SHP	Sustainable Hydropower
SLCA/IP	Salt Lake City Area Integrated Projects
SSARR	Streamflow Synthesis and Reservoir Regulation
Western	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WY	Water Year

UNITS OF MEASURE

AF	acre feet
cfs	cubic feet per second
ft	feet
GWh	gigawatt-hour(s)

hr	hour
MAF	million-acre feet
MMBtu	millions of British thermal units
MW	megawatts
MWh	megawatt-hour(s)
TAF	thousand-acre feet

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ABSTRACT

Because of concerns about the impact that Glen Canyon Dam (GCD) operations were having on downstream ecosystems and endangered species, the Bureau of Reclamation (Reclamation) conducted an Environmental Impact Statement (EIS) on dam operations (DOE 1996). New operating rules and management goals for GCD that had been specified in the Record of Decision (ROD) (Reclamation 1996) were adopted in February 1997. In addition to issuing new operating criteria, the ROD mandated experimental releases for the purpose of conducting scientific studies. This paper examines the financial implications of the experimental flows that were conducted at the GCD from 1997 to 2005.

An experimental release may have either a positive or negative impact on the financial value of energy production. This study estimates the financial costs of experimental releases, identifies the main factors that contribute to these costs, and compares the interdependencies among these factors. An integrated set of tools was used to compute the financial impacts of the experimental releases by simulating the operation of the GCD under two scenarios, namely, (1) a baseline scenario that assumes operations comply with the ROD operating criteria and experimental releases that actually took place during the study period, and (2) a "without experiments" scenario that is identical to the baseline scenario of operations that comply with the GCD ROD, except it assumes that experimental releases did not occur.

The Generation and Transmission Maximization (GTMax) model was the main simulation tool used to dispatch GCD and other hydropower plants that comprise the Salt Lake City Area Integrated Projects (SLCA/IP). Extensive data sets and historical information on SLCA/IP power plant characteristics, hydrologic conditions, and Western Area Power Administration's (Western's) power purchase prices were used for the simulation. In addition to estimating the financial impact of experimental releases, the GTMax model was also used to gain insights into the interplay among ROD operating criteria, exceptions that were made to criteria to accommodate the experimental releases, and Western operating practices.

Experimental releases in some water years resulted in financial benefits to Western while others resulted in financial costs. During the study period, the total financial costs of all experimental releases were $11.9 million.

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[*] Palmer, Loftin, and Osiek are employed by Western Area Power Administration Colorado River Storage Project Management Center, Salt Lake City, Utah.

1 INTRODUCTION

The Glen Canyon hydroelectric powerplant consists of eight generating units with a sustained operating capacity of 1,320 megawatts (MW) and an instantaneous maximum output of 1,356 MW (Veselka et al. 1995). The powerplant electricity production serves the demands of 5.8 million consumers in 10 western states that are located in the Western Electricity Coordinating Council (WECC) region of the North American Electric Reliability Corporation. Except for a minimum water release requirement at Glen Canyon, the daily and hourly dam operations initially were restricted only by the physical limitations of the dam structures, the powerplant, and its storage reservoir, Lake Powell. This approach — of adjusting the powerplant's output principally in response to market price signals — often resulted in large fluctuations in powerplant energy production and associated water releases.

Concerns about the impact of Glen Canyon Dam (GCD) operations on downstream ecosystems and endangered species, including those in Grand Canyon National Park, prompted the Bureau of Reclamation (Reclamation) to conduct a series of research releases from June 1990 to July 1991 as part of an environmental studies program. On the basis of an analysis of these releases, Reclamation imposed operational flow constraints on August 1, 1991 (Western 2010a). These constraints were in effect until February 1997, when new operational rules and management goals specified in the Glen Canyon Dam Environmental Impact Statement (GCDEIS) Record of Decision (ROD) were adopted (Reclamation 1996). The ROD operational criteria limit the maximum and minimum amounts of water released from the dam during a one-hour period. The ROD criteria also constrain adjustments in water releases in consecutive hours and restrict the range of hourly releases on a rolling 24-hour basis.

In addition to operating criteria, the ROD established the Glen Canyon Dam Adaptive Management Program to conduct scientific studies on the relationship between dam operations and downstream resources. During a study period from 1997 through 2005, several types of experimental water releases were performed to conduct specific studies. They included:

(1) Aerial photography steady flow (APSF),
(2) Low summer steady flow (LSSF),
(3) Beach/habitat-building flow (BHBF),
(4) Habitat maintenance flow (HMF), and
(5) Non-native fish suppression flow (NNFSF).

The first two types of experimental releases are generally characterized by steady flows. Aerial photography releases last only a few days. During these periods, water is released from the dam at a constant rate. Typically, these flows are relatively low at 8,000 cubic feet per second (cfs); however, some flows are higher at 15,000 cfs. An LSSF was conducted in 2000 that continued from the end of March through September. Flows were nearly constant for weeks or months, changing in several transition phases to reach either a higher or lower constant flow rate. LSSF operations also include several spike flows that are interspersed throughout the steady flow and that can reach 2 to 4 times the steady flow rate for periods lasting several hours or several days.

Both HMFs and BHBFs release relatively large amounts of water. The HMFs are high steady releases within powerplant capacity and may occur annually. Water releases ramp up to the maximum power plant level in a prescribed pattern. These releases continue for one to two weeks before ramping down to lower levels. Releases during a BHBF are similar to HMFs; however, depending upon the Lake Powell water level, the high sustained flow rate can exceed the powerplant's maximum flow rate by 11,800 cfs or more. These events persist up to 14 days but occur less frequently than do the HMFs. Exceptions to maximum flow rates specified by the ROD operating criteria are allowed to accommodate both HMFs and BHBFs.

In contrast to an HMF or a BHBF, an NNFSF varies on a fixed hourly pattern between 8,000 cfs and 20,000 cfs. Releases are highest in the daytime and reduced at night. NNFSFs have historically occurred during the winter and persist for three months. Daily release changes during an NNFSF exceed the level specified in the ROD operational criteria.

While stringent operating rules may have environmental benefits, these rules also have financial and economic effects on the value of the energy produced by the GCD Powerplant. These criteria reduce the flexibility of operations, diminish dispatchers' ability to respond to market price signals, and decrease the economic and financial benefits of power production. Power benefits are affected by the ROD in two ways. First, the loss of operable capability must eventually be replaced by other power generation resources. Second, the hydropower energy cannot be used to its fullest extent during hours of peak electricity demand when the market price and economic benefits are relatively high.

During experimental releases, operational flexibility is essentially eliminated — water must be released according to a fixed and pre-specified schedule. Relative to the operational restrictions specified under the ROD, an experimental release may have either a positive or negative impact on the financial and economic value of GCD Powerplant energy production. The deviation in the value of power relative to ROD operations that can be directly attributed to an experimental release depends on several complex and interdependent factors. Work performed in this study estimates the financial costs of the experimental releases and identifies the main factors that contribute to these costs and the interdependencies among these factors.

Financial costs are estimated by Generation and Transmission Maximization (GTMax) model simulations of the Salt Lake City Area Integrated Projects (SLCA/IP). This tool uses an integrated systems modeling approach to dispatch power plants in the system while recognizing interactions among supply resources over time. Retrospective simulation for the 1997-through-2005 period made use of extensive sets of data and historical information on SLCA/IP power plants' characteristics, hydrologic conditions, and Western's power purchase prices. The GTMax model simulated two scenarios. The "Baseline" scenario assumes that operations comply with ROD operating criteria and experimental releases that actually took place as documented by Western and Reclamation. The second scenario, "Without Experiments," is identical to the first one, except it assumes that experimental releases did not occur during the study period. Differences in the value of GCD energy production between the two scenarios are used to estimate the change in power value attributed to experimental releases. In addition to estimating the financial impact of experimental releases, the GTMax model was also used to gain insights into the interplay among ROD operating criteria, exceptions that are made to criteria to accommodate the experimental releases, and Western operating practices.

2 ROD CRITERIA AND WESTERN'S OPERATING PRACTICES

Important factors that explain the financial impacts of experimental releases are:

(1) ROD operating criteria,
(2) Exceptions to the ROD made to accommodate the experimental releases,
(3) Monthly and annual water release distribution of annual volumes, and
(4) Western's scheduling guidelines that were adapted in response to ROD restrictions.

This section provides background information for each of these factors.

2.1 ROD Operating Criteria and Exceptions

Reclamation implemented ROD operating criteria to temper water release variability. On October 9, 1996, Bruce Babbitt, then-Secretary of the U.S. Department of the Interior, signed the ROD on operating criteria for the GCD. The criteria selected were based on the Modified Low Fluctuating Flow Alternative as described in the final GCDEIS. These criteria were put into practice by Western beginning in February 1997.

Flow restrictions under the ROD, along with operational limits in effect prior to June 1, 1991, are shown in Table 2.1. The ROD criteria require water release rates to be 8,000 cfs or greater between the hours of 7:00 a.m. and 7:00 p.m., and at least 5,000 cfs at night. The criteria also limit how quickly the release rate can increase and decrease in consecutive hours. The hourly maximum increase (i.e., the up-ramp rate) is 4,000 cfs/hour (hr), and the hourly maximum decrease (i.e., the down-ramp rate) is 1,500 cfs/hr. ROD operating criteria also restrict how much the releases can fluctuate during rolling 24-hour periods. This change constraint varies between 5,000 cfs and 8,000 cfs per day, depending on the monthly water release volume. Daily fluctuation is limited to 5,000 cfs in months when less than 600 thousand-acre feet (TAF) are released. The limit increases to 6,000 cfs when monthly release volumes are between 600 TAF and 800 TAF. When the monthly water release volume is 800 TAF or higher, the daily allowable fluctuation is 8,000 cfs.

The maximum flow rate is limited to 25,000 cfs under the ROD operating criteria. Maximum flow rate exceptions are allowed to avoid spills or flood releases during high runoff periods. Under very wet hydrological conditions, defined as when the average monthly release rate is greater than 25,000 cfs, the flow rate may be exceeded, but water must be released at a constant rate.

Table 2.1 Operating Constraints Prior to 1991 and under the ROD (Post 1997)

Operational	Historic Flows	ROD Flows

Source: Reclamation (1996)

Exceptions to the operating criteria in Table 2.1 are made to accommodate experimental releases. For example, maximum flow rates above 25,000 cfs are allowed during both HMFs and BHBFs. In addition, exceptions to the daily fluctuation limits are made during an NNFSF because water releases typically ramp up from 5,000 cfs at night to 15,000 cfs during the day.

Exceptions granted during some experimental releases can potentially increase the financial value of the GCD power resource relative to operations under ROD constraints. Scheduling guidelines adopted by Western's Energy Management and Marketing Office in Montrose, Colorado, can also influence the financial value. An experimental release yields higher financial value when power generation from a prescribed release is concentrated during periods when market prices are relatively high (and power is relatively expensive). This value may exceed the Without Experiments scenario because normal ROD operational criteria do not permit such high generation levels. Also, experimental releases that are only a few days in length and have generation levels that are lower than the ROD during times of relatively low market prices (and relatively inexpensive power) may also yield higher financial value than does the Without Experiments scenario. Releasing relatively small amounts of water during low-price hours allows for larger releases during higher-priced hours.

On the other hand, experimental releases that require high water flows during low-price hours typically yield financial values that are lower than those found in the Without Experiments scenario. The situation is exacerbated when an experimental release requires flow rates to exceed turbine capacity because water is released through bypass tubes, producing no energy. Spills also increase the tailwater elevation, thereby reducing the effective head and power conversion rate of water passing through the power plant's turbines.

2.2 Monthly Water Release Volumes

Monthly water releases in the Upper and Lower Colorado River Basin are set by Reclamation to be consistent with various operating rules and guidelines, acts, international water treaties, consumption use requirements, State agreements, and the "Law of the River" (Reclamation 2008). In addition to power production, monthly release volumes are set considering other uses of the reservoirs, such as for flood control, river regulation, consumptive uses, water quality control, recreation, and fish and wildlife enhancement and to address other environmental factors. One requirement is that a minimum of 8.23 million-acre feet (MAF) of water must be released from Glen Canyon Dam each water year (WY) (Reclamation 1970).

Because future hydrologic conditions of the Colorado River Basin cannot be predicted with 100% accuracy, release decisions are made by using current runoff projections provided by the National Weather Service's Colorado Basin River Forecast Center. To be consistent with its annual operating plan, Reclamation adjusts its release decisions on a monthly basis to reflect projections made by rolling 24-month studies that are updated monthly.

For this study, historical SLCA/IP monthly water releases as recorded in Reclamation's Form PO&M-59 (Reclamation undated *a*) were used for the Baseline scenario. In addition, GCD hourly water release data obtained from Reclamation were used for experimental release periods. Under the Without Experiments scenario, monthly water releases during some water years were assumed to be identical to historical levels. However, in other years it was apparent that monthly water releases would have been different if one or more experimental releases had not occurred during the year.

The redistribution of monthly water releases made to accommodate an experimental release may either increase or decrease the financial value of power produced by the GCD Powerplant. Water releases that were shifted to times of the year with higher power market prices, such as during July and August, tend to increase financial value. The opposite occurs when more water is shifted to months when power prices are lower.

2.3 Montrose Scheduling Guidelines

The GCD restrictions shown in Table 2.1 describe operational boundaries; however, within these limitations are innumerable hourly release patterns and dispatch drivers that comply with a given set of operating criteria. The operational range was significantly wider prior to the ROD; however, a wide range of ROD-compliant operational regimes still exists. In addition to operational constraints at the GCD, other SLCA/IP projects must also comply with various operational limitations. For example, Flaming Gorge releases are patterned such that downstream flow rates are within Jensen Gauge flow limits. Also, Aspinall releases cannot result in reservoir elevations that are outside of a specified range of forebay elevation levels and limits on changes in reservoir elevations over one- and three-day periods.

Prior to 1990, SLCA/IP powerplant dispatch was primarily driven by market prices. This dispatch philosophy, coupled with a high level of operating flexibility at SLCA/IP projects, allowed Western to produce energy in a pattern that was often distinctly different from its firm loads. As illustrated in Figure 2.1, Western routinely purchased energy during off-peak periods to meet firm loads, storing the water for power generation during on-peak periods when prices were more expensive. By using price as the main driver for SLCA/IP powerplant operations, Western was able to maximize the economic value of electricity sales from GCD Powerplant. Although total daily SLCA/IP energy is short of total load in the example shown in Figure 2.1, the net purchase cost is minimized because purchases are concentrated in hours when prices are relatively low while sales are made when prices are highest.

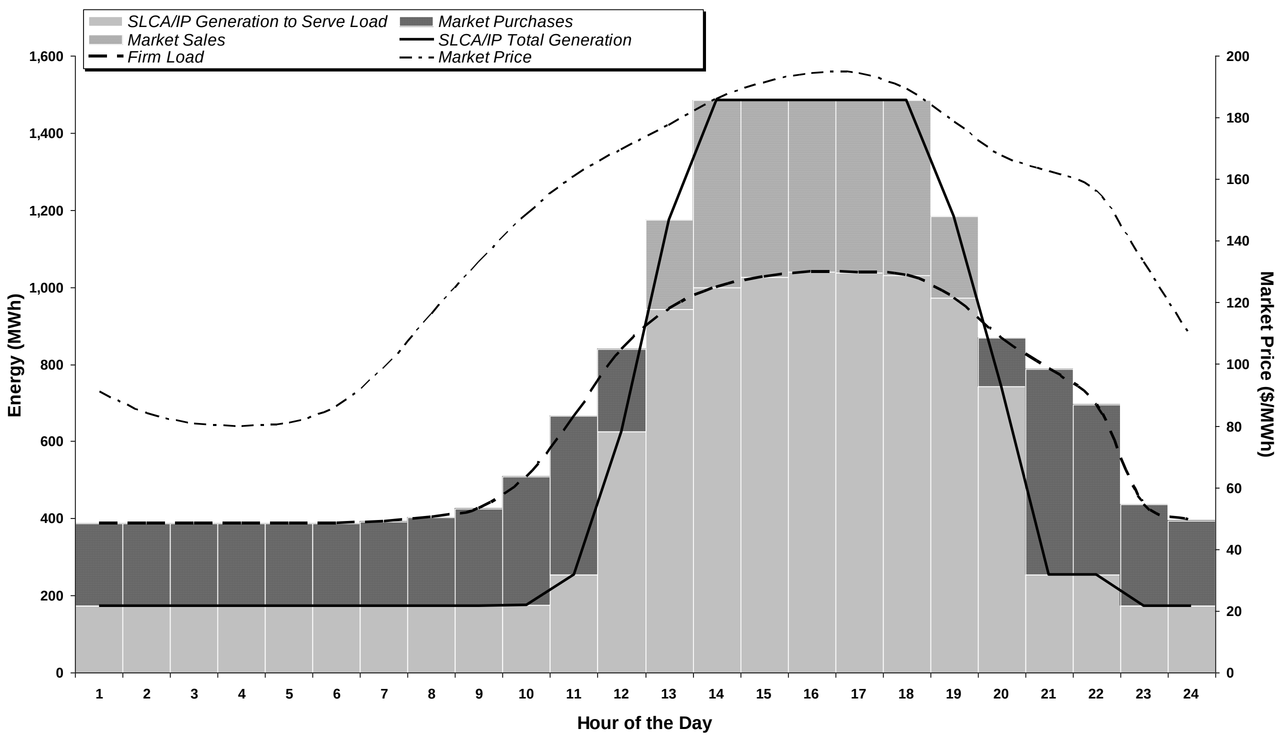

Figure 2.1 Illustration of the Pre-1990 Market-Price-Driven Scheduling Guideline with Flexible Hydropower Operations

As operational constraints were imposed on SLCA/IP resources, including those at the GCD, powerplant scheduling guidelines and goals shifted from a model driven primarily by market prices to a new model driven by customer loads. Within the boundaries of these operating constraints, SLCA/IP power resources are used to serve firm load. Western also places a high priority on purchasing power in 16-hour, on-peak blocks and 8-hour, off-peak blocks.

As illustrated in Figure 2.2, SLCA/IP generation resources are typically “stacked” on top of the block purchases as a means of following firm customer load. Because of operational limitations, Western staff may need either to purchase or sell varying amounts of energy on an hourly basis. The volumes of these variable market purchases are relatively small under the vast majority of conditions.

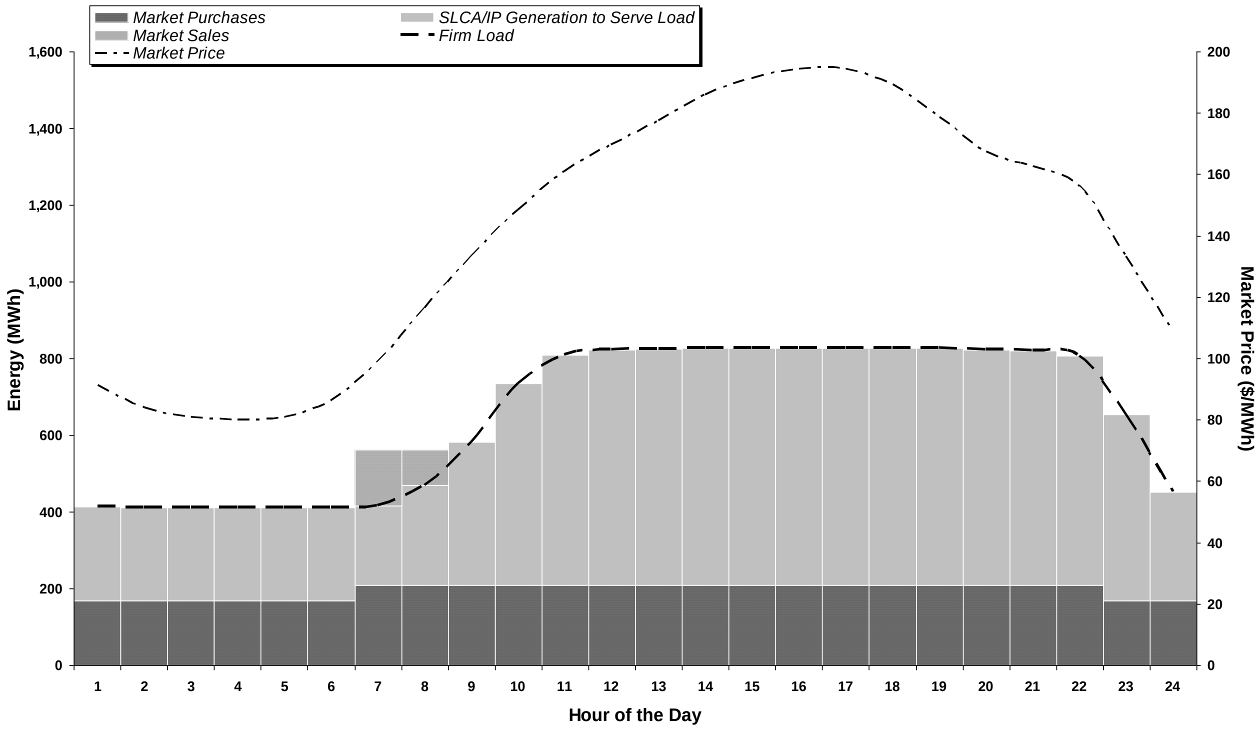

Figure 2.2 Illustration of the Firm-Load-Driven Dispatch Guideline under the 1996 ROD Operating Criteria when SLCA/IP Resources Are Short of Load

Market sales can be significant when SLCA/IP resources exceed firm load. Under load-following guidelines, excess hydropower generation is sold during hours with the highest price while complying with operational limits. On-peak sales are limited by maximum SLCA/IP generation levels that are constrained by limits on hourly ramp rates and daily change constraints. However, significant excess power generation rarely occurs, because projected power production in excess of sustainable hydropower (SHP) is sold to SLCA/IP customers on a short-term basis as available hydropower (AHP). SHP is a fixed level of long-term capacity and energy available from SLCA/IP facilities during summer and winter seasons, which is based on an established risk level; this amount is the minimum commitment level for capacity that Western will provide to all SLCA/IP customers. AHP is the monthly capacity and energy actually available based on prevailing water release conditions, which is the amount that Western offers to its customers above and beyond their SHP levels. These terms are explained in greater detail in Section 4.1.

The load-following scheduling objective facilitates a strong link between Western's contractual obligations and SLCA/IP operations, requiring dispatch among SLCA/IP power plants to be closely coordinated. This interdependency exists because loads and hydropower resources are balanced whenever feasible. Western is therefore able to indirectly affect SCLA/IP power plant operations and hourly reservoir releases via specifications in its contract amendments. Contract terms that indirectly affect power plant operations include SHP and AHP capacity and energy sales, as well as Minimum Schedule Requirement (MSR) specifications. The MSR is the minimum amount of energy that a customer must schedule from Western in each hour.

In contrast, the market price dispatch objective only weakly links firm power sales contracts to SLCA/IP operations, if at all. Except for coordinating releases from the Aspinall and Molina units, the market price objective allows for independent dispatch among power plant operations, whereby each plant is dispatched to maximize net revenues. Hourly differences between loads and resource production are reconciled though market purchases and sales.

In addition to load following, dispatchers follow other practices that are specific to GCD Powerplant operations. These practices fall within ROD operational boundaries but are not ROD requirements. Therefore, these institutional practices may be altered or abandoned by Western at any time. One practice involves reducing generation at Glen Canyon to the same minimum level every day during low-price, off-peak hours. Western also avoids drastic changes to total water volume releases when they occur over successive days. In this analysis, it was assumed that the same volume of water was released each weekday.

Another Western scheduling practice addresses water releases occurring on both Saturdays and Sundays; these releases cannot be less than 85% of the average weekday release. In addition, during the summer season, one cycle of increasing and decreasing GCD Powerplant output is recommended. This practice increases to a maximum of two cycles during other seasons of the year as dictated by the hourly load pattern.

Scheduling guidelines are practiced not only at Glen Canyon but also at other SLCA/IP power plants. For example, the Collbran Project's daily generation produced by Upper and Lower Molina power plants is scheduled at or near power plant maximum capability for continuous blocks of time, the lengths of which are based on the amount of water that is available for release during a 24-hour period. Western also has scheduling guidelines for daily water releases from Blue Mesa Reservoir. Water is released from Blue Mesa seven days a week to accommodate higher runoffs, except from November through February, when water is not released on Saturdays. The decision not to release water on Saturdays was made for economic reasons so that more water could be released during higher-priced hours during the week.

3 DESCRIPTION OF EXPERIMENTAL RELEASES

A number of experimental releases were conducted during the study period: (1) non-native fish suppression flows; (2) habitat maintenance flows; (3) low summer steady flows; (4) aerial photography steady flows; and (5) beach/habitat-building flows. This section describes each type of experimental release, its characteristics, and when each occurred. Table 3.1 summarizes the operational characteristics of the GCD Powerplant during the experimental releases, such as maximum and minimum flows, maximum daily fluctuation, and maximum and minimum ramp rates. The term water year (WY) will be used from this point forward in the report. It is defined as a 12-month period from October 1 to September 30. For example, WY 2001 runs from October 1, 2000 to September 30, 2001.

3.1 Non-Native Fish Suppression Flow (NNFSF)

This release pattern is used to control the numbers of non-native fish known to prey on the endangered humpback chub downstream of the GCD. It is also used to prevent overpopulation at the Lees Ferry trout fishery. Humpback chub are not found in the Lees Ferry reach; therefore the impact on chub predators is directed downstream. Flow fluctuations in an NNFSF reduce the number of non-native fish by disrupting spawning activity, desiccating embryos in spawning gravels, and reducing survival of young trout after they emerge from spawning gravels.

The flow pattern is a prescribed hourly release ranging from approximately 5,000 cfs to 20,000 cfs each day. Releases are highest during the daytime and reduced at night; these experimental releases may persist for three months. This flow is typically conducted during the winter months. An example of an NNFSF flow pattern conducted from January to March of 2005 is shown graphically in Figure 3.1.

Three such flows occurred during the study period: from January to March in 2003, 2004, and 2005. For all three NNFSFs, water was redistributed from other months within the water year to support these events.

3.2 Habitat Maintenance Flow (HMF)

Habitat maintenance flows are high, steady releases at maximum turbine flow that last for several days to two weeks and may be scheduled on an annual basis. Water releases are ramped up to the maximum power plant level in a prescribed pattern. The intent of these flows is to help maintain existing camping beaches and wildlife habitat along the river.

During the study period, one such release occurred in November 1997. It lasted for 48 hours at the maximum turbine flow of about 30,700 cfs. The objective of this event was to conserve sizable sand inputs that had been washed away from the Paria River by transferring sand to banks and sandbars before it could be transported downstream. The flow pattern for the HMF is shown graphically in Figure 3.2.

Table 3.1 Characteristics of GCD Powerplant Experimental Release Events, By Dates of Releases

Event	Date	Maximum Flow (cfs)	Minimum Flow (cfs)	Hourly Up-Ramp Rate (cfs/hr)	Hourly Down-Ramp Rate (cfs/hr)	Maximum Daily Fluctuation (cfs/day)	Water Reallocated within Year	Exception to ROD Criteria
APSF	8/30/1997–9/2/1997	8,240	7,950	80	70	9,890[1]	No	Exceeded maximum daily fluctuation when entering and exiting the flow regime
HMF	11/3/1997–11/5/1997	30,770	NA	4,320	1,590	NA	No	Exceeded maximum release rate of 25,000 cfs
APSF	9/4/1998–9/8/1998	15,080	14,960	80	90	7,610[1]	No	
APSF	9/3/1999–9/7/1999	15,140	14,920	120	120	7,650[1]	No	
LSSF	3/25/2000–9/30/2000	30,580	7,500	7,590	1,810	22,770	Yes (and also within WY 2001)	Exceeded maximum release rate, daily fluctuation, and down-ramp rate
APSF	6/28/2001–7/2/2001	8,100	7,620	200	200	8,370[1]	No	Exceeded maximum daily fluctuation when exiting the flow regime
APSF	5/24/2002–5/31/2002	8,130	7,710	310	260	NA	No	
NNFSF	1/1/2003–3/31/2003	20,490	4,800	10,030	4,390	15,480	Yes	Exceeded maximum daily fluctuation and up- and down-ramp rates
APSF	5/23/2003–5/27/2003	8,250	7,960	200	200	5,820[1]	No	
NNFSF	1/1/2004–3/31/2004	20,826	4,840	6,450	4,750	15,817	Yes	Exceeded maximum daily fluctuation and up- and down-ramp rates
APSF	5/28/2004–5/31/2004	8,120	7,660	390	330	6,020[1]	No	
APSF	11/17/2004–11/20/2004	10,040[2]	6,110	1,870	2,020	8,020[1]	No	Exceeded maximum daily fluctuation when exiting steady flow and entering BHBF

Event	Date	Maximum Flow (cfs)	Minimum Flow (cfs)	Hourly Up-Ramp Rate (cfs/hr)	Hourly Down-Ramp Rate (cfs/hr)	Maximum Daily Fluctuation (cfs/day)	Water Reallocated within Year	Exception to ROD Criteria
BHBF	11/21/2004–11/25/2004	40,000	NA	1,620	1,570	NA	Yes	Exceeded maximum release rate of 25,000 cfs
APSF	11/26/2004–11/30/2004	8,370	7,930	260	320	NA	No	
APSF	12/3/2004–12/5/2004	12,710	6,010	180	190	6,700[1]	No	
NNFSF	1/1/2005–3/31/2005	20,440	4,790	6,800	6,650	15,530	Yes	Exceeded maximum daily fluctuation and up- and down-ramp rates

[1] This fluctuation would only occur when Glen Canyon Dam was either ramping up or ramping down to or from the steady flow

[2] Nominal flow of this event was 8,000 cfs, but several short peaks of as high as 10,000 cfs were reached.

3.3 Low Summer Steady Flow (LSSF)

An LSSF is performed for ecological reasons, namely, to benefit the endangered humpback chub and to assist in compliance with the Endangered Species Act of 1973. The LSSF regime consists of alternating periods of low and high steady flows interspersed with several spike flows, which can reach 2 to 4 times the steady flow rate for periods lasting from several hours to several days.

One such flow occurred in the study period, lasting from March 25 to September 30, 2000. The flow pattern is displayed graphically in Figure 3.3. The flow pattern began at about 8,000 cfs for a few days and rose to about 17,000 cfs from early April to the end of May. In early May, the flow spiked to almost 31,000 cfs for several days. In early June, flow was lowered to 8,000 cfs until early September; then, another spike to about 31,000 cfs occurred for several days, followed by another drop-off to 8,000 cfs, followed in turn by another smaller spike to about 16,000 cfs for a few hours in mid-September, and concluding with a drop-off to 8,000 cfs, the level which obtained until the end of the specified release.

The spike flow in May was intended to create ponding and other beneficial habitat conditions at the confluence of the Little Colorado River that would allow young humpback chub to grow more quickly and survive. The spike flow in early September was intended to adversely affect non-native fish (Schmidt 2007).

To have a sufficient amount of water to support the LSSF, water was reallocated in WY 2000, and the reallocation was also extended into WY 2001.

3.4 Aerial Photography Steady Flow (APSF)

This release pattern provides a constant water release ranging from 3 to 5 days. It is performed so that aerial photographs can be taken over the river to monitor the status of natural and cultural resources along the river and to see how these resources change in response to dam operations. These flows are performed during weekends and holiday periods to minimize impacts to power customers. The flow pattern for the APSF in December 2004 is displayed graphically in Figure 3.4.

Typically, these flows are relatively low at 8,000 cfs; however, they can be as high as 15,000 cfs. During the study period, low steady flows occurred in June/July 2001, May 2002, May 2003, May 2004, and December 2005. High steady flows occurred in September 1998 and 1999. APSFs often precede and follow BHBFs, as was the case in November 2004 when a steady flow of about 8,000 cfs occurred before a BHBF and another of about 8,000 cfs followed the BHBF.

3.5 Beach/Habitat-Building Flow

This flow mimics natural flood events by releasing relatively large volumes of water from the dam. Releasing large quantities of water helps maintain and preserve natural and cultural resources. The flows redistribute tributary-derived sediments from the channel to channel margin sand bars. This type of flow benefits both the river ecosystem and the endangered humpback chub and builds beaches used by recreational campers.

Maintaining sand bars for camping helps preserve cultural resources by providing alternative camp sites to campers so they avoid old highwater zones where most archaeological sites are located. In addition, sandbars created by the BHBF increase the windborne transport of sand toward archaeological sites, which may help reduce erosion and increase preservation potential at the sites (GCMRC 2008).

One BHBF occurred during the study period: a 5-day flow in November 2004. Aerial photography flows preceded and followed the BHBF. The peak maximum flow of the BHBF reached about 40,000 cfs for 60 hours. This flow rate exceeded the capability of the turbines at that time, so water released through the bypass tubes reached 15,000 cfs. No electricity was generated by the water released through the bypass tubes. To have sufficient water to perform this event, water that would otherwise have been used in months before or after this event was redistributed for use during the BHBF. The flow pattern for this BHBF is shown graphically in Figure 3.5.

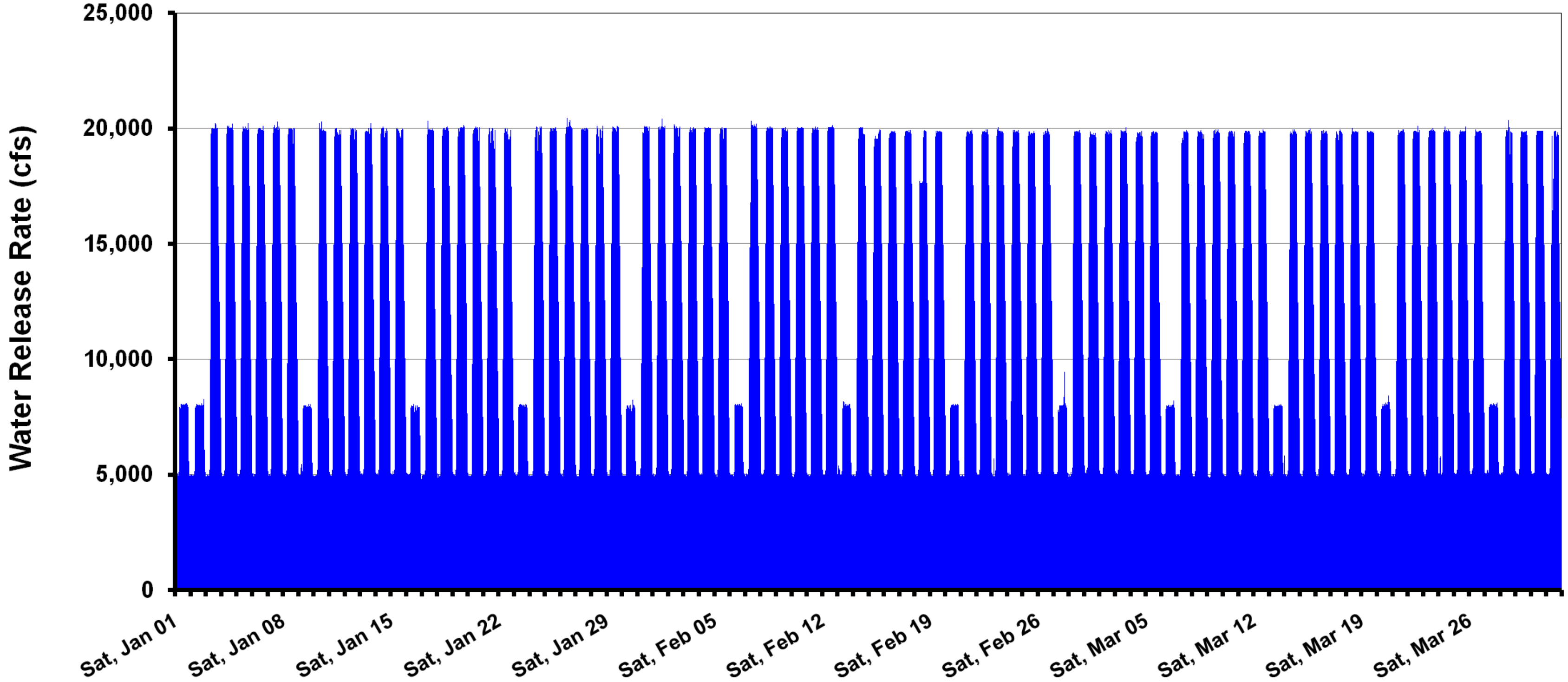

Figure 3.1 Release Pattern of the Non-Native Fish Suppression Flow from January to March of 2005

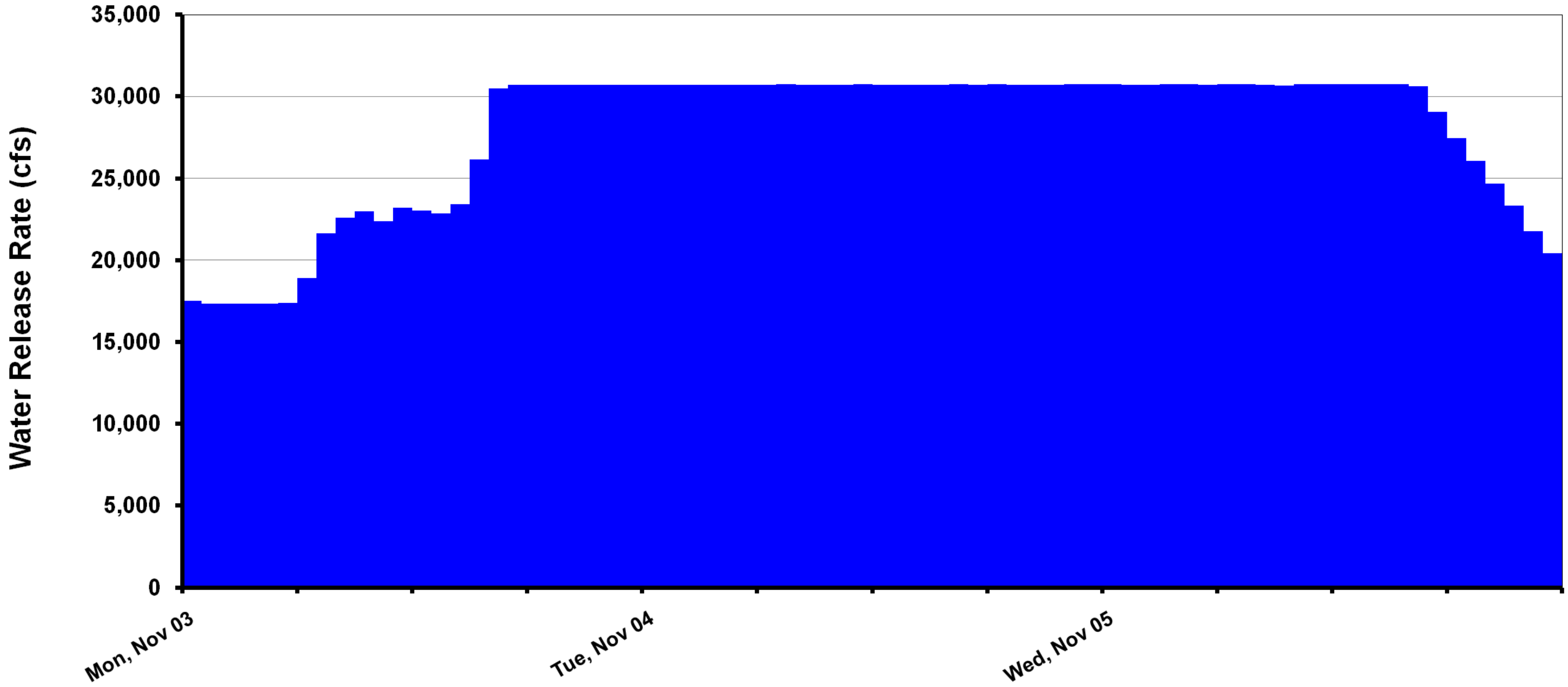

Figure 3.2 Release Pattern of the Habitat Maintenance Flow in November 1997

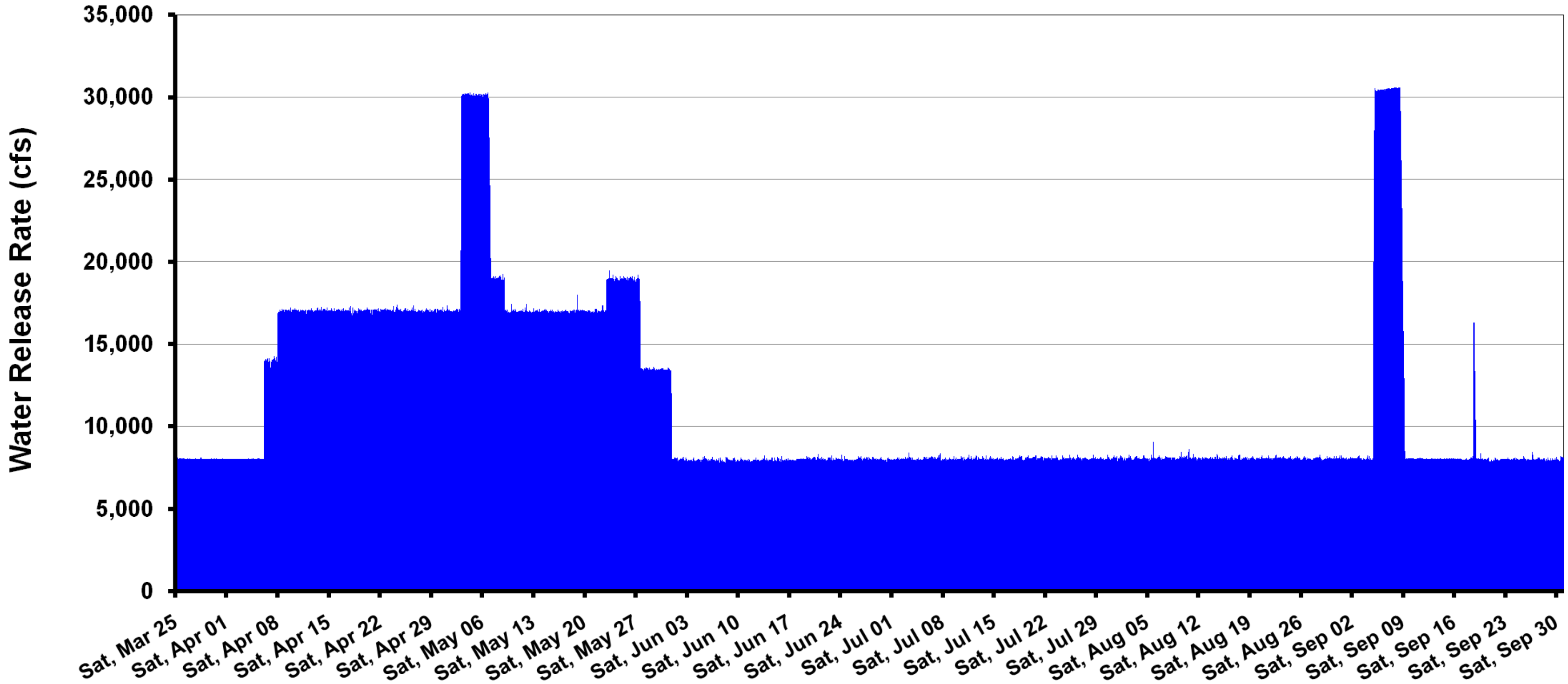

Figure 3.3 Release Pattern of the Low Summer Steady Flow from March 25, 2000, to September 30, 2000

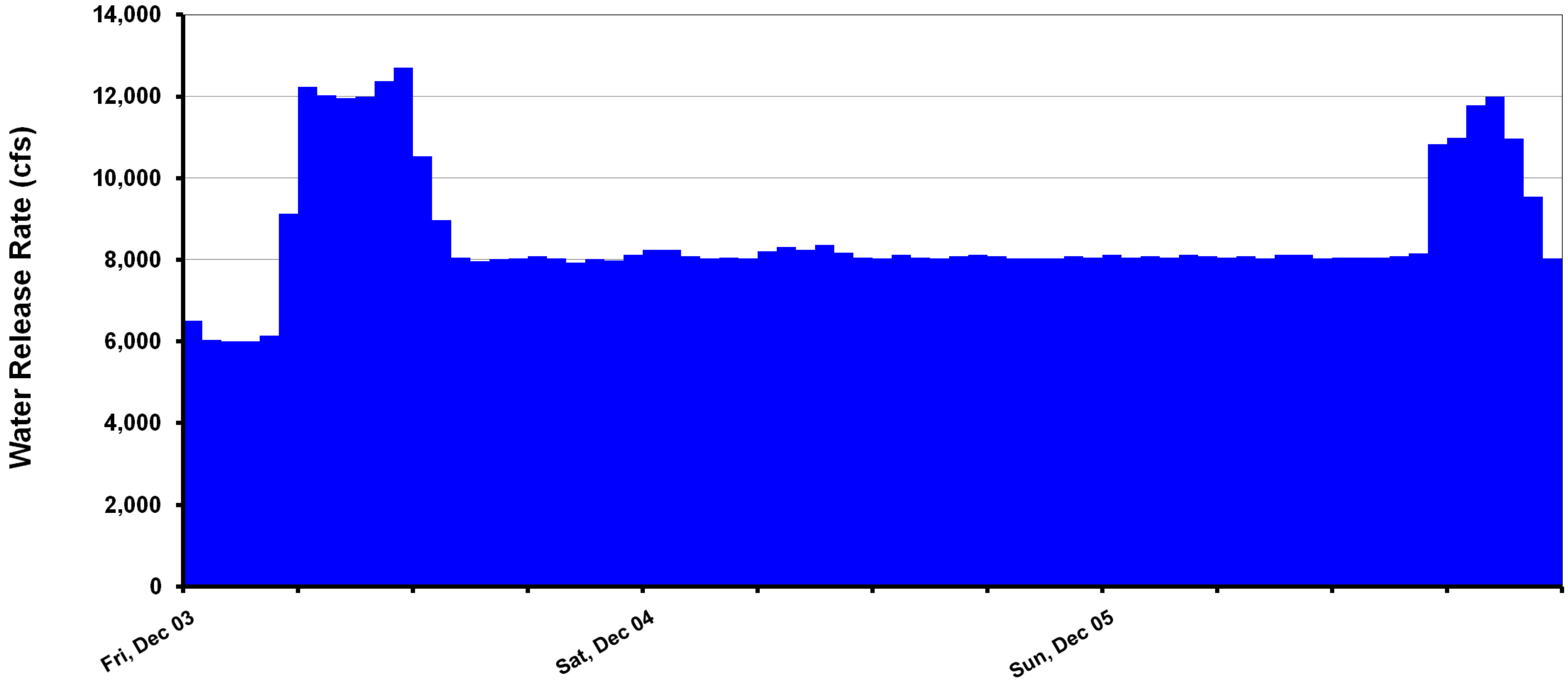

Figure 3.4 Release Pattern for the Aerial Photography Steady Flow in December 2004

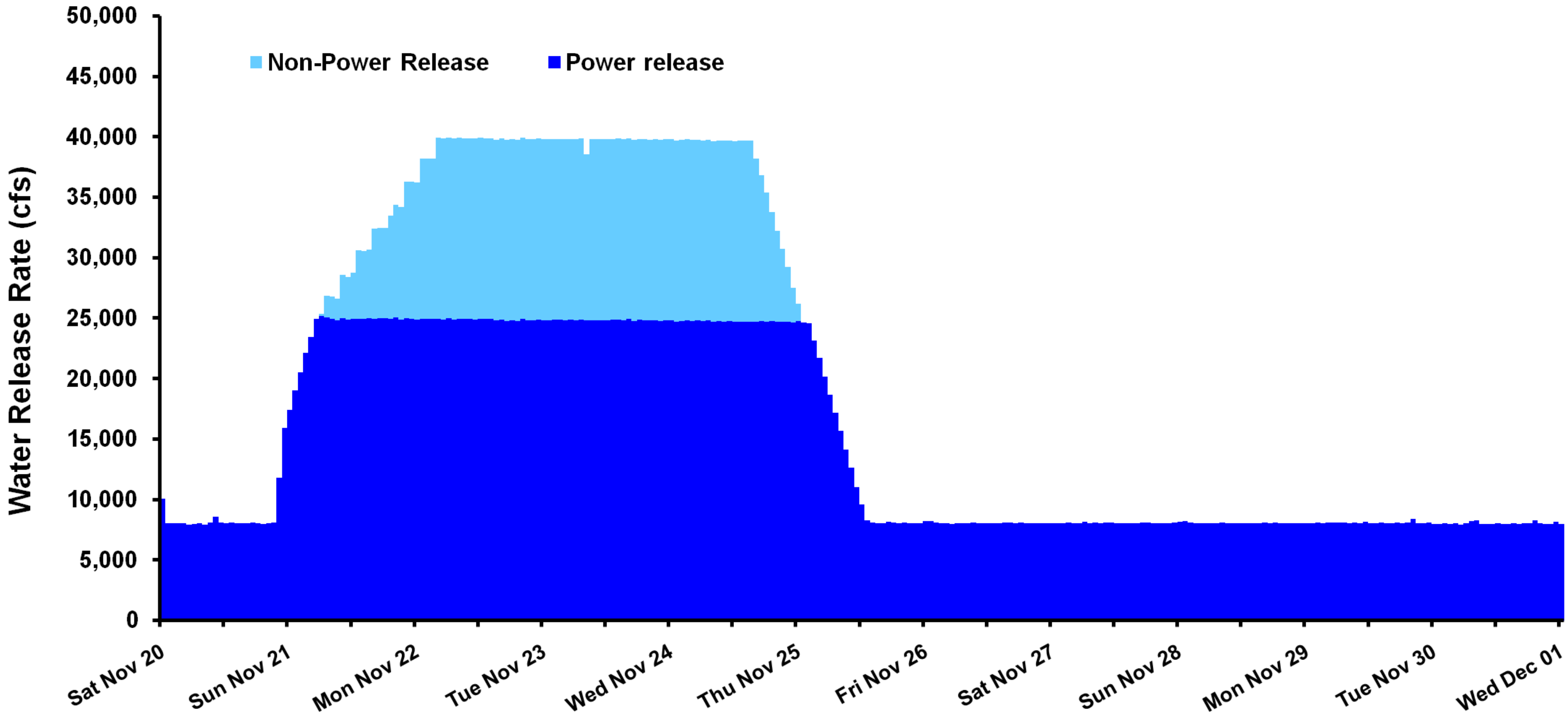

Figure 3.5 Release Pattern of the BHBF in November 2004

4 METHODS AND MODELS

This section describes the methods, models, and data used to estimate the financial impacts of conducting experimental releases at the GCD Powerplant. The modeling process uses an integrated set of tools that share historical data, simulation results, and other information. Some modeling components were constructed specifically for this study, while others were based on existing tools with modifications to meet the specific requirements of this analysis.

Financial impacts are computed as the difference in the value of Glen Canyon Dam energy production between two simulated operating scenarios, as follows:

(1) The **Baseline scenario,** which assumes ROD operating criteria, the occurrence of exceptions to the ROD criteria that could accommodate a series of experimental releases, and historical monthly release volumes; and
(2) The **Without Experiments scenario,** which assumes ROD operating criteria without exceptions, that no experimental releases took place, and monthly release volumes that may differ from historical levels in some years.

The GTMax model is the main simulation tool used to dispatch SCLA/IP hydropower plants, including Glen Canyon. It not only simulates Glen Canyon operations, but it also provides insights into the interplay among ROD operating criteria, exceptions to the criteria to accommodate experimental releases, modifications to monthly water volumes, and Western scheduling guidelines and goals. The GTMax model is supported by several other tools and databases as described in the following sections. These support tools include: SLCA/IP Contracts spreadsheet, Customer Scheduling algorithm, Market Price spreadsheet, Experimental Release spreadsheet, and a Financial Value Calculation spreadsheet.

The GTMax model is supported by an input spreadsheet that contains ROD operating criteria, historical hydropower operations data, and parameters for Western scheduling guidelines. The input spreadsheet also performs various computations and prepares input data for the model. GTMax results are transferred to another spreadsheet to summarize simulation results, perform cost calculations, extrapolate weekly results to a monthly total, and produce a variety of tables and graphs.

4.1 SLCA/IP PROJECT CONTRACT SPREADSHEET

The marketing of SLCA/IP, including the Glen Canyon component, is currently under the auspices of Western’s Colorado River Storage Project (CRSP) Management Center headquartered in Salt Lake City, Utah. Western’s principal marketing program is the sale of long-term firm (LTF) capacity and energy at LTF rates. As described in Section 2, Western’s hourly customer loads, along with the load-following scheduling guidelines, influence the operation of all SLCA/IP power plants. Therefore, by setting firm power terms that limit customers’ hourly energy requests, Western indirectly influences power plant operations and market transactions.

The SLCA/IP Contract spreadsheet contains historical information about Western's sales under firm contract. This information includes seasonal Contract Rate of Delivery (CROD) levels, along with monthly capacity and energy sales. It also contains information on the Minimum Schedule Requirement (MSR), which is the lowest amount of power that a customer can schedule from Western. Data are provided individually for the eight Western customers that have the largest purchase contracts. These customers account for approximately 75% of SLCA/IP LTF capacity and energy sales. The other 124 customers account for the remaining 25%.

When the ROD operating criteria were first implemented in 1997, Western sold LTF capacity and energy under its post-1989 marketing criteria (GPO 1986). Following an extensive public process and preparation of an Electric Power Marketing Environmental Impact Statement (EPM-EIS) (DOE 1996), Western selected the post-1989 level as the SLCA/IP preferred alternative (Veselka et al. 1995). A seasonal summary of CROD and energy sold under these marketing criteria by division is shown in Table 4.1.

Table 4.1 SLCA/IP Divisional Allocations under the Post-1989 Marketing Criteria

Division	Winter Season		Summer Season	
	CROD (MW)	Energy (megawatt-hours [MWh])	CROD (MW)	Energy (MWh)
Southern	119.0	264,842	210.0	463,854
Northern	1,287.6	2,839,180	1104.1	2,439,734
Total	**1,406.6**	**3,104,022**	**1314.1**	**2,903,588**

Because changes imposed by the ROD on Glen Canyon Dam's operating criteria affected the powerplant's operating capability, Western amended its firm contracts, with input from its customers (Western 1998). The amended contracts closed the gap between the CROD and the operating capability and energy that can be supplied by the SLCA/IP resources. The contract amendments were designed and implemented in accordance with the Glen Canyon Protection Act (GCPA) of 1992, in which Western established a "Replacement Resources Process" to compensate for reductions in the maximum power production level that could be achieved and sustained on a daily basis at GCD Powerplant (Western 1998). The GCPA required that economically and technologically feasible methods be identified to replace power resources that had been made unavailable because of changes in long-term operating criteria at GCD.

The amendments established a long-term commitment level of sustainable hydropower (SHP) that set the minimum commitment level of both capacity and energy that Western offers to all SLCA/IP customers through an LTF contract period. A long-term SHP for each season is based on a 10% risk level and the anticipated hydrological conditions through the long-term contract period. The cost of purchases or exchanges by Western to fulfill the SHP commitment is included as part of SLCA/IP wholesale firm power rates.

When anticipated hydropower conditions less project use commitments exceed the SHP level, additional capacity or energy or both are offered to customers for an upcoming month as available hydropower (AHP). As shown in Figure 4.1, an AHP capacity offer varies between SHP, which is the contractual minimum, and CROD, which is the contractual ceiling. The amount of energy offered also varies by month, depending on the aggregate SLCA/IP hydropower condition consistent with AHP capacity offers.

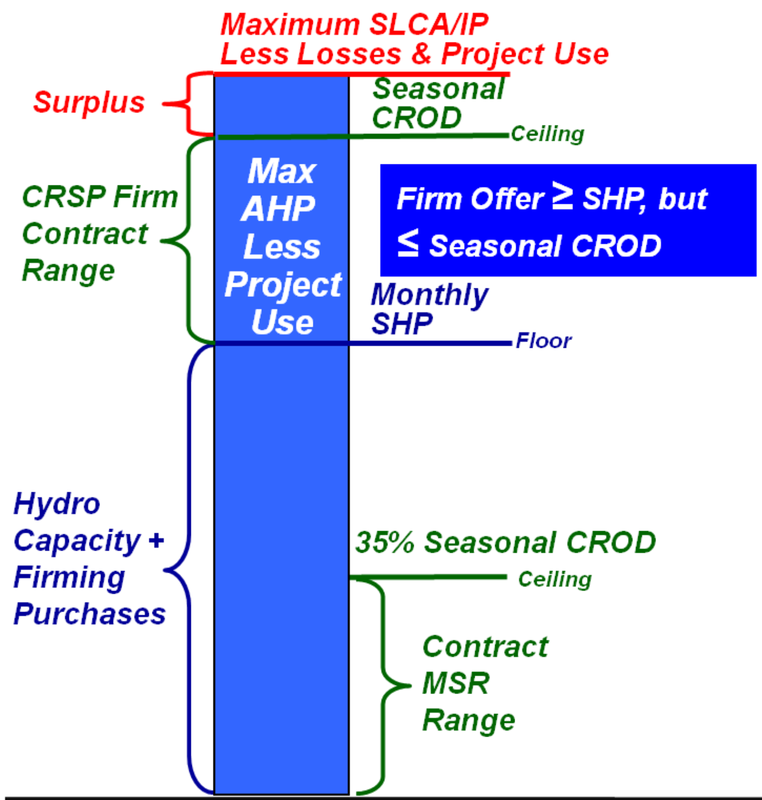

Figure 4.1 Illustration of an AHP Capacity Offer

Historical monthly LTF sales data for the 1997-through-2005 study period and contained in the SLCA/IP spreadsheet are shown in Figure 4.2. Both the Baseline and Without Experiments scenarios use this information. Both scenarios assume that the absence of experimental releases would not have altered LTF offers to customers.

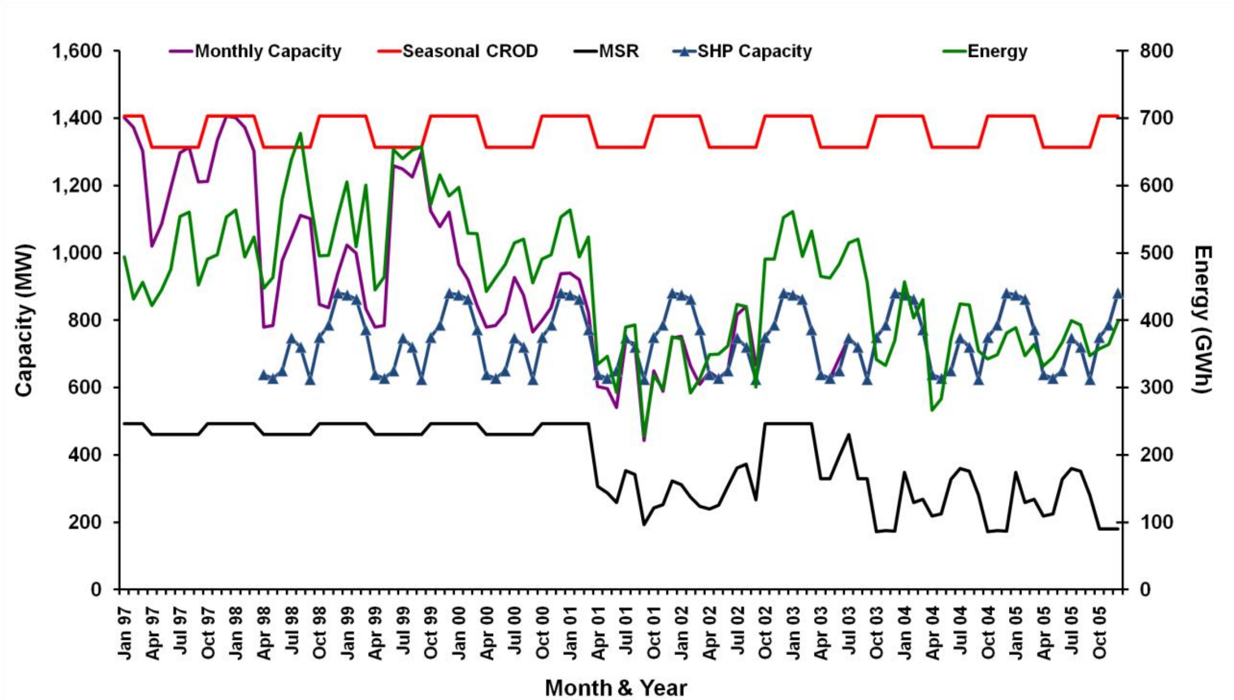

Figure 4.2 Western LTF Contract Sales (note: SHP offering began in April 1998)

When the ROD operating criteria were first implemented in 1997, Western sold LTF capacity and energy under its post-1989 marketing criteria. This strategy continued until the beginning of April 1998, at which time contract amendments became binding. As shown in Figure 4.2, average monthly capacity offered to customers reflects an SHP level about 455 MW less than the CROD-based capacity offered before the 1998 contract amendment. Lower capacity offers are consistent with the reduction in the maximum output capability at the GCD Powerplant, which can be attributed to the ROD operating criteria. Beginning in the spring of 2002 through the end of 2005, capacity offers were at the SHP levels, reflecting the drought conditions that persisted in the basin during that time.

The minimum amount of energy customers must schedule in an hour is set by Western's MSR. Historically, this level was set to 35% of the CROD. However, beginning in early 2001, downward adjustments to this requirement were made on a monthly basis to provide customers with a reasonable amount of energy to schedule SLCA/IP peaking capacity. The 35% CROD level acts as a ceiling for the MSR.

Although Western's post-1989 marketing criteria contracts were scheduled to terminate in 2004, they were extended in 2004. A summary of the revised contract, referred to as the post-2004 marketing criteria, is provided in Table 4.2. Although the total amounts of capacity sold under both marketing criteria are similar, less energy is sold under the post-2004 criteria. In addition, the post-2004 criteria reallocated capacity and energy sales among its customers; namely, the amount of energy sold to the Southern Division increased slightly, while the amount of energy sold to the Northern Division decreased slightly.

Table 4.2 SLCA/IP Divisional Allocations under the Post-2004 Marketing Criteria

Division	Winter Season CROD (MW)	Winter Season Energy (MWh)	Summer Season CROD (MW)	Summer Season Energy (MWh)
Southern	157.1	291,681	246.5	447,013
Northern	1,246.7	2,266,483	1,071.2	1,946,609
Total	**1,403.8**	**2,558,164**	**1317.7**	**2,393,622**

4.2 CUSTOMER SCHEDULING ALGORITHM

Western's loads during the study period are a key input to GTMax. The Customer Scheduling Algorithm takes aggregate annual hourly customer data and uses a load-shaping routine to adjust the hourly load profiles to match the terms of Western's customer contracts each month. Figure 4.3 shows a flow diagram of the process.

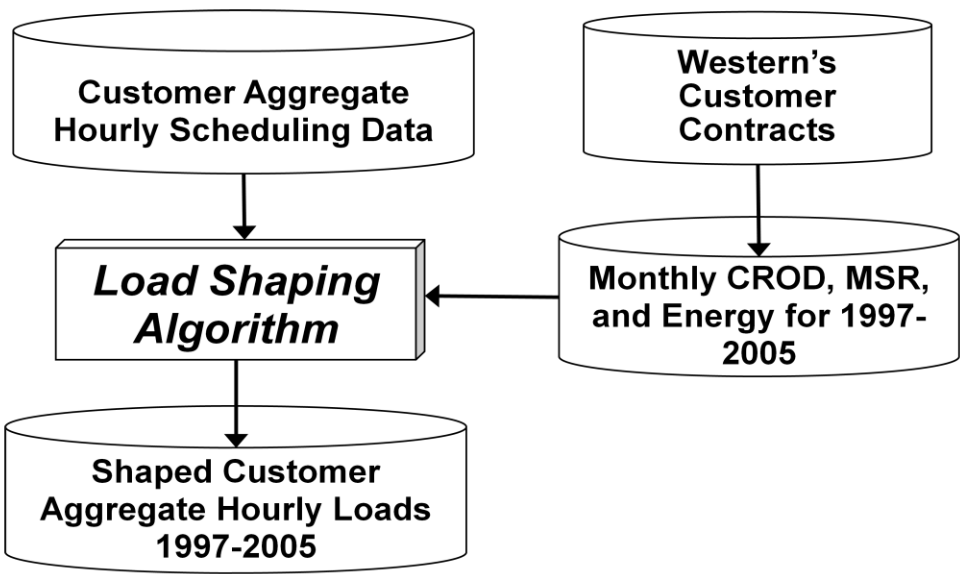

Figure 4.3 Flow Diagram of Customer Scheduling Algorithm

Western maintains customer scheduling data at the CRSP Energy Management and Marketing Office in Montrose, Colorado. These data are hourly schedules of aggregated capacity commitments Western made to all its customers, both large and small, that are used for day-ahead scheduling and are representative of the actual aggregate customer hourly load profile. The Load Shaping Algorithm adjusts the aggregated hourly load profiles so that they exactly match monthly CROD, MSR, and energy from the aggregated customer contracts.

The Load Shaping Algorithm uses a quadratic programming technique that minimizes differences between a normalized Load Duration Curve (LDC) constructed from historical data and a reshaped LDC generated by the model. Figure 4.4 shows the original LDC, which was constructed from Western's scheduling data in August 2005, and the reshaped LDC. The reshaped curve is consistent with a monthly load factor computed from the aggregated peak and total load values of Western's contracts. Upper and lower load constraints are specified by the user to bind the model's solution. For each point in the LDC, a scaling factor is then computed as the ratio of the reshaped load to the original load. Finally, the algorithm constructs a scaled chronological hourly profile based on the load scaling factors and an associated original hourly load. The end product, as shown in Figure 4.5, is a chronological load profile that exactly matches the aggregated monthly CROD, MSR, and energy in Western's contracts.

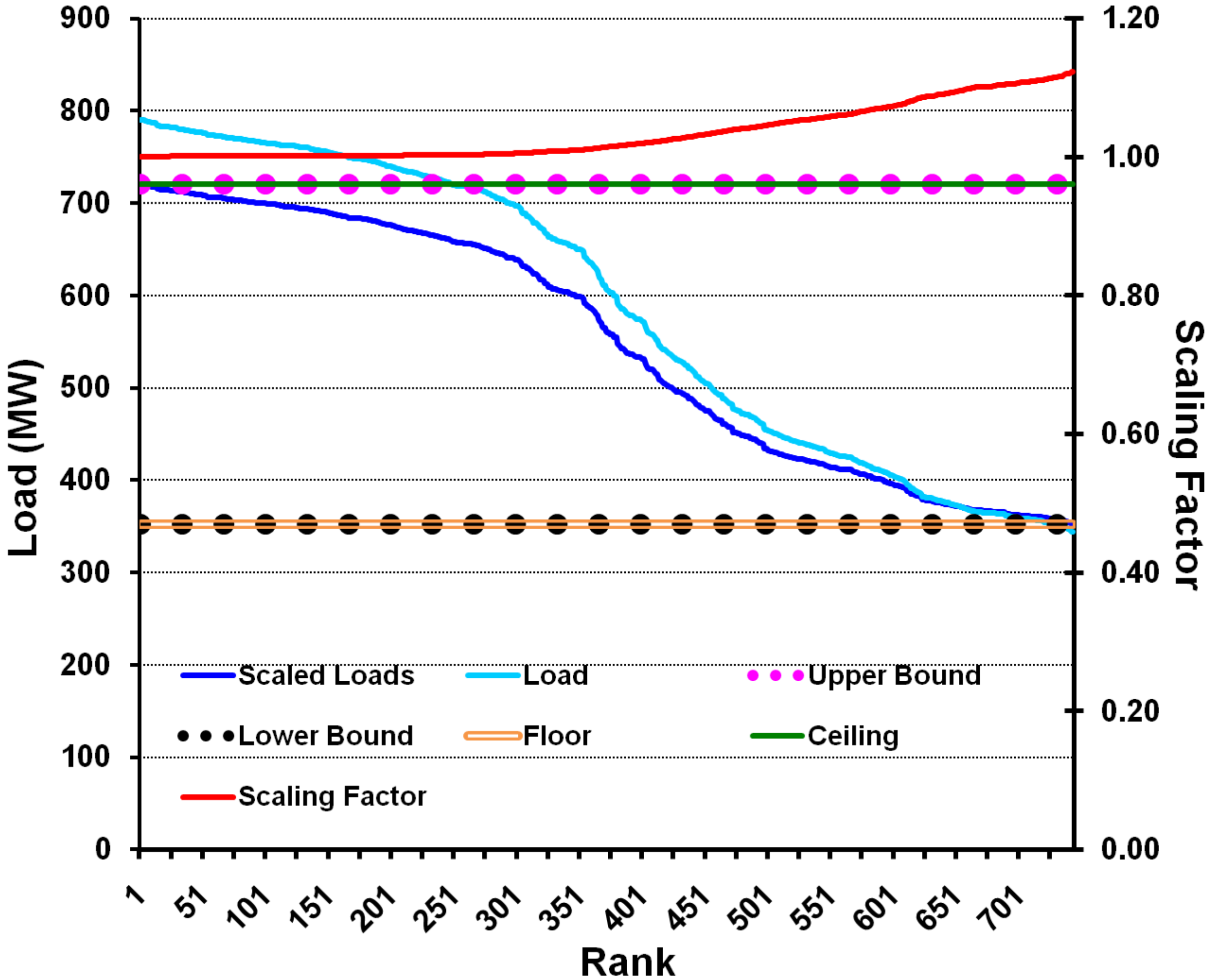

Figure 4.4 Illustration of Load Duration Curve Shaping to Match a Target Load Factor

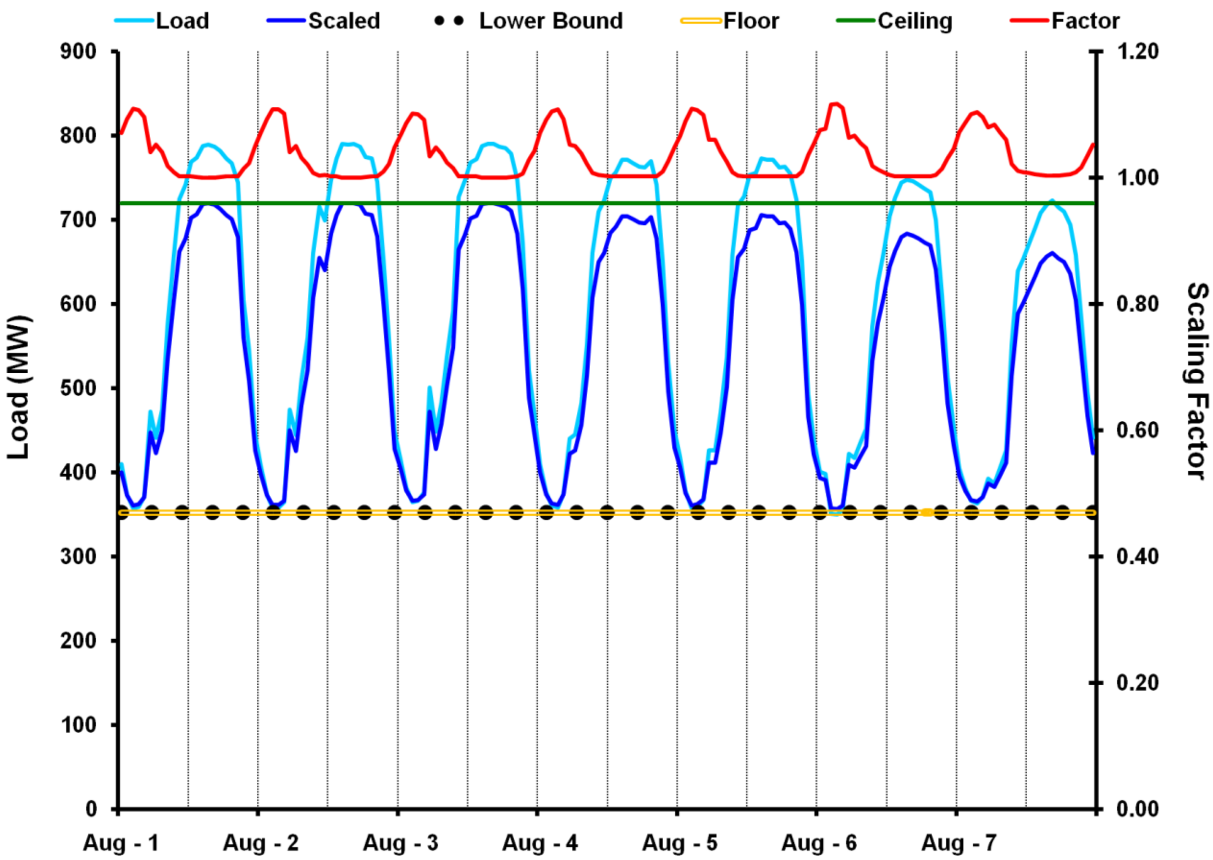

Figure 4.5 Original and Shaped Chronological Load Curve

4.3 MARKET PRICE SPREADSHEET

The prices that Western paid to purchase power are key inputs to the GTMax model. Hourly prices that Western paid for power during the study period were available from the Montrose Office and compiled into the Market Price spreadsheet. Western purchases power in advance whenever it anticipates a shortage of hydropower. Western negotiates contracts with suppliers to purchase power when power is needed.

Figure 4.6 shows on- and off-peak market prices at the Southwest hub in the WECC region compared to prices Western paid to purchase power. The large price spike at the Southwest hub that began in the spring of 2000 and lasted though the middle of 2001 coincides with the California energy crisis. During the crisis, prices exceeded levels that cannot be explained by production costs (i.e., by fuel plus other operating expenses) alone. Many attributed these price spikes to a market design problem in which some market participants influenced prices for financial gain. Once market difficulties were alleviated, electricity prices once again began to more closely reflect marginal production costs. Electricity prices trended upward as a result of higher fuel prices in 2005.

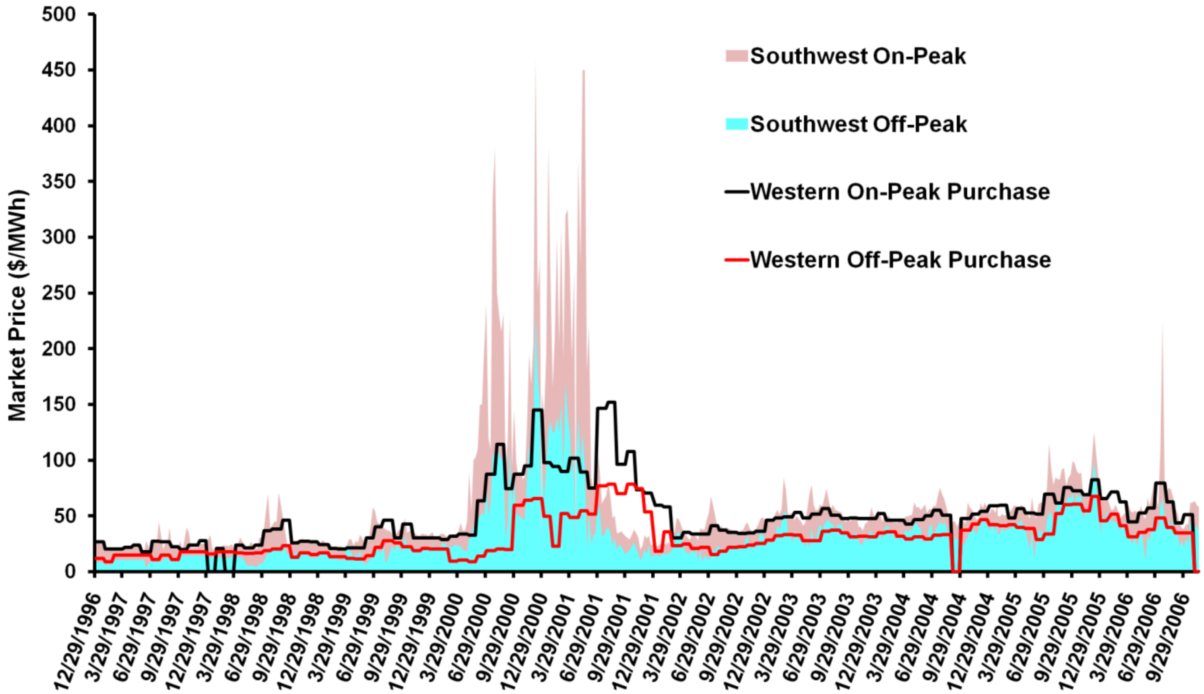

Figure 4.6 Western's On- and Off-Peak Prices Compared to Market Prices at the South West Hub

Western’s prices also spiked during the California crisis but were not nearly as high. Western’s prices were lower during the market peak because they negotiated some purchase contracts months before the market price rose. However, in the middle of 2001 when market prices fell, Western’s prices remained higher than the market price until the spring of 2002. Western’s prices were higher at this time because some of its purchase contracts were negotiated during the California crisis when prices were high. Because Western was locked into purchase contracts at higher prices than those that could be obtained in the market, its price for purchased power remained higher for a number of months after spot market prices fell.

4.4 EXPERIMENTAL RELEASE SPREADSHEET

Data on experimental releases conducted at the GCD during the study period were obtained from Reclamation and compiled in this spreadsheet. It contained hourly flow rates through the turbines during the experiment and the total hourly flow rate, which included water released through the turbines and water released through the bypass tubes. It also contained hourly generation data at the GCD during each experiment. The spreadsheet calculated the hourly value of water by multiplying the price Western paid for power by the GCD's hourly generation. The data were input to the GTMax model to simulate operation of the GCD during experimental releases. The spreadsheet also produced graphs showing the hourly flow pattern during each experiment.

4.5 GTMAX MODEL

For this study, the main function of the GTMax model is to simulate the operations of SLCA/IP power plants, including GCD. Glen Canyon does not operate and is not marketed as an isolated entity by Western. Instead, it is one component of a larger hydropower system, and it is packaged along with other power plants for marketing purposes. Therefore, the modeling process used for this study simulates the entire SLCA/IP system.

The GTMax model is well suited for this application because it uses a systemic modeling approach to represent all system components while recognizing interactions among supply, demand, and water resources over time. GTMax represents GCD in the same manner it is operated and marketed by Western. It simulates the system on an hourly time step as a large set of mathematical equations that are solved using linear programming software. All operations are within component limitations and system dispatch goals that are formulated as a set of linear constraints and bounds.

The model formulation contains a single objective function that maximizes the financial value of the entire SLCA/IP system over a one-week time period. All hours are solved simultaneously, allowing the model to recognize that the dispatch of supply resources in any one hour affects the dispatch during all other times in a simulated week. GTMax also accounts for the spatial dependencies among power plants that are at cascaded reservoirs, such as those in the Wayne N. Aspinall Unit on the Gunnison River.

The model and topologies developed for this study consider customer loads, historical power plant and reservoir information, environmental constraints, Western purchase prices, and Montrose load-following scheduling objectives. GTMax topology nodes represent hydropower plants, aggregate customer load, power market energy transactions, and river flow gauges. Each node contains information about the specific attributes of the entity that it represents. For example, hydropower plants in the topology contain information about reservoir water releases, operating constraints, and the power plant specified at weekly, daily, and hourly time scales. The flow of energy between connected grid points and water channel flows are represented in the model by links that connect node objects together. Water links along with gauge nodes are used to estimate flows at specific points on river channels for environmental monitoring and compliance.

For each scenario, the GTMax model is run for one typical week per month for all months during the study period. Weekly simulations are scaled up such that each run represents a one-month time period. These results, along with actual operations that occurred during experimental periods, are used to evaluate the financial impact of the ROD.

4.5.1 GTMax Model Input Data for Power Plants and Reservoir

Data for reservoirs and power plants input into GTMax are based on historical monthly statistics contained in Form PO&M-59. This information includes water releases, forebay elevation, and power conversion factors. Because reservoir water release data are monthly and GTMax runs simulate a single week, releases are equally apportioned to each week of a simulated month. For example, February's typical weekly water release is set to 25% of the monthly value (i.e., 7/28). Form PO&M-59 also reports end-of-month (EOM) reservoir elevations. Because it is assumed that the GTMax simulated week occurs approximately in the middle of the month, reservoir elevations input into the model for the Aspinall cascade of reservoirs are interpolated from previous and current monthly forebay elevations.

When simulated monthly water release volumes from GCD in the Without Experiments scenario differ from historical volumes, reservoir elevation levels and power conversion factors must be adjusted accordingly. A higher-than-historic monthly water release results in a lower-than-historic forebay elevation, while a lower-than-historic monthly water release results in a higher elevation. Equation 4.1 is used to estimate the reservoir water storage (*S*) volume, in acre-feet (AF) for GCD (*GC*) under the Baseline scenario (*b*) based on historical monthly forebay elevations listed in Form PO&M-59. The water storage in the Without Experiments scenario (*wo*) resulting from monthly water releases (*R*) that differ from the Baseline scenario is computed by Equation 4.2. It is based on the sum of releases in each scenario from the first simulation month through the current month (*m*). Whenever the storage volume under the Without Experiments scenario differs from the Baseline scenario, the forebay elevation under the Without Experiments scenario must be computed using Equation 4.3. The equation relates reservoir elevation to storage volume.

$$S_{GC,m,b} = -14{,}708{,}784 + 13{,}033.4x\, E_{GC,m,b} - 3.8597\, xE^2_{GC,m,b} + 3.8199^{-4} xE^3_{GC,m,b} \qquad \textit{EQ 4.1}$$

$$S_{GC,m,wo} = S_{GC,m,w} + \sum_{j=1}^{m} R_{GC,j,wo} - \sum_{j=1}^{m} R_{GC,j,b} \qquad \textit{EQ 4.2}$$

$$E_{GC,m,wo} = 3{,}413 + 0.02255xS_{GC,m,wo} - 6.7874^{-7}xS^2_{GC,m,wo} + 9.78155^{-12}xS^3_{GC,m,wo} \qquad \textit{EQ 4.3}$$

The factor that relates the conversion of water releases to power production is a function of the forebay elevation. Therefore, a different reservoir elevation means that the power conversion factor must also be computed. The power conversion factor under the Baseline scenario is based on a historical value as recorded in Form PO&M-59. This value is used as a benchmark from which the Without Experiments conversion factor is estimated. It is assumed that a change in reservoir elevation under the Without Experiments scenario will either increase or decrease the total power production during the month. The power conversion factor (*PCF*) used in the

Without Experiments scenario is computed by using Equation 4.4. Polynomial coefficients were derived by Western using historical Glen Canyon forebay levels and power conversion factors.

$$PCF_{GC,m,wo} = PCF_{GC,m,b} + \left(-7.8633 + 3.6679x\ E_{GC,m,wo}^{-3} - 3.7993^{-7} x E_{GC,m,wo}^{2}\right) - \left(-7.8633 + 3.6679x\ E_{GC,m,b}^{-3} - 3.7993^{-7} x E_{GC,m,b}^{2}\right) \qquad EQ\ 4.4$$

The maximum output capability (*Output*) at GCD is computed monthly. It is the minimum of (1) the physical capacity of the power plant turbines as shown in Table 4.3 and (2) the maximum production level based on the forebay elevation as computed by Equation 4.5. This equation computes the maximum turbine flow rate and multiplies it by the power conversion factor to obtain the maximum output level. Table 4.3 shows a timeline of GCD Powerplant capacity improvements during the 1997-through-2005 study period.

$$Output_{GC,m,k}^{max} = CF_{GC,m,k} x\left(-731.298 + 0.0379784x\ E_{GC,m,k} - 4.676345^{-5} x E_{GC,m,k}^{2}\right), for\ each\ scenario\ where\ k = b, wo \qquad EQ\ 4.5$$

Further adjustments are made to the maximum generation level at the GCD Powerplant to account for unit outages. These adjustments includes all types of outages, both scheduled and random, that take units off-line because of unforeseen problems at the plant. Historic outage levels provided by Reclamation were used to compute monthly outage factors. These factors were used to derate the maximum output of the plant as computed by the process described above. For example, if one and only one turbine was out of service for a month, the maximum output was reduced by approximately 12.5% (i.e., 1/8). As will be described in greater detail in Section 5, capacities and outages are important factors in determining the financial cost of the ROD.

Table 4.3 Glen Canyon Improvements during the Study Period

Month, Year	**Event**	**Total Plant Output Capacity (MW)**
Feb. 1997	ROD operating criteria began	1,314.63
Oct. 1997	Unit 8 rewind	1,315.97
2000	New unit switchgear	1,315.97
Aug. 2003	Unit 2 rewind	1,317.31

Source: Reclamation (2004).

4.5.2 GTMax Model Input Data, Loads, and Market Prices

There are two types of load data input into GTMax that include firm customer loads and project use loads. Hourly firm customer loads that obtained during the study period are estimated by the methodology described in Section 4.2. These data are not used directly. GTMax firm loads are instead based on customer energy schedules that represent a typical week. This week is constructed from results from the Customer Scheduling algorithm that produce estimates of hourly customer schedules for an entire month. Simulated hourly schedules are processed to create typical shapes for three types of days, including a weekday, Saturday, and Sunday. Holidays are assigned to the Sunday load profile. Typical profiles for each type of day are average values for a specific hour. For example, the typical load at 1:00 a.m. on a weekday in January is the average of all 1:00 a.m. loads during weekdays in that month.

Project use loads are based on contract levels obtained from Western's Montrose office. Monthly values for capacity and energy are provided in Tables 4.4 and 4.5, respectively. Compared to firm customer loads, these values are small. Although some of these individual schedules can vary somewhat from one hour to the next, others are scheduled at a constant rate. As a simplification for modeling purposes, it was assumed that all project use loads are scheduled flat; that is, each hour has a schedule that equals the monthly level divided by the number of hours in the week. As will be described later in this section, additional modifications to these loads are made to account for generation, represented as negative load, from smaller SLCA/IP hydroelectric power plants.

Table 4.4 Monthly Project Capacity Use, By Customer

	Capacity (MW)										
	Dolores	**Heber**	**NAPI[1]**	**NAPI/ NTUA[1]**	**Silt**	**Uintah**	**Ute Moun-tain**	**Wasatch**	**Dutch**	**Camp**	**Total**
Jan	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Feb	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Mar	0.50	0.60	0.50	12.00	0.00	0.02	0.00	3.00	0.19	0.64	17.45
Apr	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
May	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Jun	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Jul	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Aug	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Sep	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Oct	0.50	0.60	0.50	12.00	0.00	0.02	0.00	3.00	0.19	0.64	17.45
Nov	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Dec	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Annual Average	**4.40**	**0.60**	**11.33**	**8.00**	**0.18**	**0.07**	**0.00**	**3.00**	**0.19**	**0.81**	**28.59**

[1] NAPI = Navajo Agricultural Products Industry, NTUA = Navajo Tribal Utility Authority

Table 4.5 Monthly Project Energy Use, By Customer

	Energy (MWh)										
	Dolores	**Heber**	**NAPI[1]**	**NAPI/ NTUA[1]**	**Silt**	**Uintah**	**Ute Moun-tain**	**Wasatch**	**Dutch**	**Camp**	**Total**
Jan	67	229	0	0	0	14	0	2,232	88	475	3,105
Feb	60	197	0	0	0	13	0	2,016	94	429	2,809
Mar	67	197	1,106	8,928	0	14	0	2,232	94	475	13,113
Apr	2,447	184	8,006	8,640	263	86	0	2,160	99	707	22,591
May	2,529	184	8,272	8,928	272	89	0	2,232	102	730	23,339
Jun	2,447	203	8,006	8,640	263	86	0	2,160	65	707	22,576
Jul	2,529	242	8,272	8,928	272	89	0	2,232	65	730	23,359
Aug	2,529	256	8,272	8,928	272	89	0	2,232	66	730	23,374
Sep	2,447	218	8,006	8,640	263	86	0	2,160	71	707	22,599
Oct	67	192	1,106	8,928	0	14	0	2,232	82	475	13,096
Nov	65	205	0	0	0	14	0	2,160	86	460	2,989
Dec	67	231	0	0	0	14	0	2,232	88	475	3,107
Annual Total	**15,321**	**2,537**	**51,046**	**70,560**	**1,606**	**607**	**0**	**26,280**	**1,000**	**7,100**	**176,058**

[1] NAPI = Navajo Agricultural Products Industry, NTUA = Navajo Tribal Utility Authority

Market prices input into GTMax are the prices Western paid to purchase power. This data was obtained from the Montrose Office and described in detail in Section 4.3.

4.5.3 GTMax Topologies

Two topologies are utilized in this study. Both were originally designed and are currently used to assess future Western purchase requirements for the CRSP Management and Marketing Office located in Montrose, Colorado. The topologies include one that has a highly specialized representation of the Flaming Gorge Dam and the downstream river system below the dam and another one that represents the entire SLCA/IP system.

Using these two topologies, the GTMax model is run three times to produce final results. Figure 4.7 is a flow chart that shows the sequence of operations and the flow of information for the GTMax simulations.

The first simulation estimates Flaming Gorge operations by using the relatively simple Flaming Gorge topology, as shown in Figure 4.8. This run simulates Flaming Gorge operations on an hourly basis over a one-week time period. It also estimates downstream water flows at the confluence of the Green and Yampa Rivers and at the Jensen Gauge. Hourly water releases at Flaming Gorge are constrained such that flows at the Jensen Gauge comply with environmental limits. Results from this simulation are input into the second GTMax run that simulates the Without Experiments scenario.

The second run simulates SLCA/IP operations under the Without Experiments scenario. It employs a more complex topology that contains all major SLCA/IP hydropower plants and market components as shown in Figure 4.9. GTMax inputs for Flaming Gorge operations in this second model run constrain the simulation such that it produces the exact same results for Flaming Gorge as the "Only Flaming Gorge" simulation. Therefore, model results for Flaming Gorge in these first two runs are identical. The second run also simulates operations for other major SLCA/IP hydropower plants and energy transactions (i.e., Western's purchases and sales) with the market.

The third and final GTMax run simulates the Baseline scenario. While this run uses the same topology as the second run, the attributes assigned to some of the nodes and links differ; most important among these are the water releases at GCD. Also, except for Glen Canyon, operations at all other hydropower plants and reservoirs are constrained such that they produce identical results as in the Without Experiments scenario. Using this approach isolates the effects of the ROD to operations at Glen Canyon only. Although the ROD only applies to Glen Canyon, operations at other SLCA/IP power plants may change operations in response to changes in production at Glen Canyon. By requiring identical operations under the two scenarios at all facilities except at Glen Canyon, the impacts are restricted to one facility.

In the final step of the process, the financial costs of the ROD are computed. As shown at the bottom of Figure 4.7, this process uses GTMax simulation results for the two scenarios and historical releases and power production from experimental flow periods.

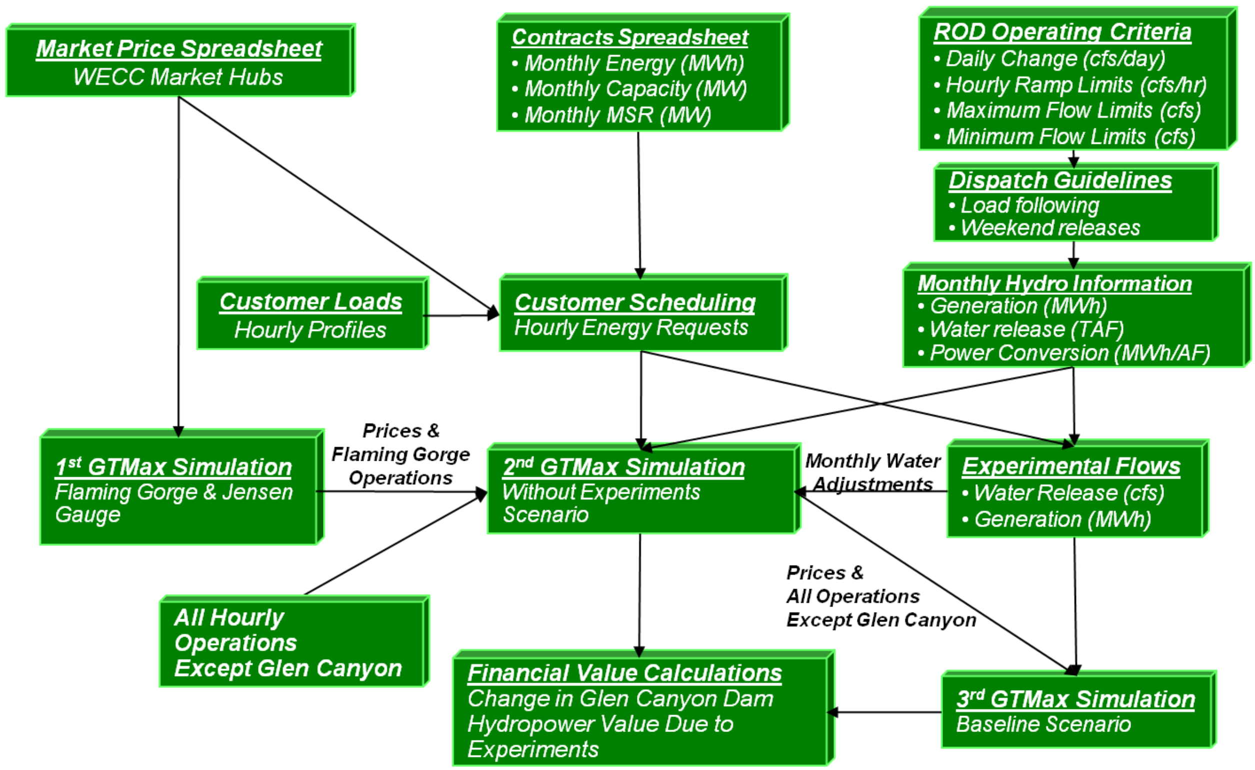

Figure 4.7 Sequence of Operations for Simulating SLCA/IP Marketing and System Operations

4.5.3.1 Flaming Gorge Topology

The first topology utilized in this study is shown in Figure 4.8. It simulates the operation of the Flaming Gorge Dam Reservoir and Powerplant such that water releases comply with downstream flow limitations at the Jensen Gauge while maximizing the value of the power resource. The gauge is located about 95 miles downstream of Flaming Gorge near Jensen, Utah. To protect endangered fish species, the stage change at the gauge is limited to 0.1 meters per day. Moreover, the amount of water that passes the gauge during a calendar day cannot vary by more than 3% from one day to the next.

The Flaming Gorge topology only represents the Western's purchase prices (dark turquoise square in Figure 4.8), Flaming Gorge (dark blue square), the Green and Yampa river channels (dashed blue lines), the confluence of the two rivers, and the Jensen Gauge (blue water drop). Energy prices are conveyed to the Flaming Gorge node via the black line in the figure. To compute Jensen Gauge flows, GTMax uses a Water Time Travel Distribution function to represent a wave of water as it is released, moves, and attenuates downstream. This function is derived from model outputs produced by the Streamflow Synthesis and Reservoir Regulation (SSARR) model. Yampa River flows are based on historical U.S. Geological Survey stream flow records.

The Flaming Gorge topology and associated model formulation were originally developed to support the Flaming Gorge Dam EIS (FGEIS). Using an iterative methodology developed for the FGEIS, the SSARR and GTMax models share information such that the value of power is maximized while downstream flows are within gauge limits. In addition to gauge constraints, Flaming Gorge Dam operations are also subject to a minimum release of 800 cfs, and both up-ramp and down-ramp rates are limited to 800 cfs/hr. The daily release patterns at Flaming Gorge are limited to a single-cycle pattern during the summer and a double-cycle pattern during the winter, which are consistent with customer load patterns.

Western's power purchase prices are input into the GTMax market node as a measure of the financial value of energy.

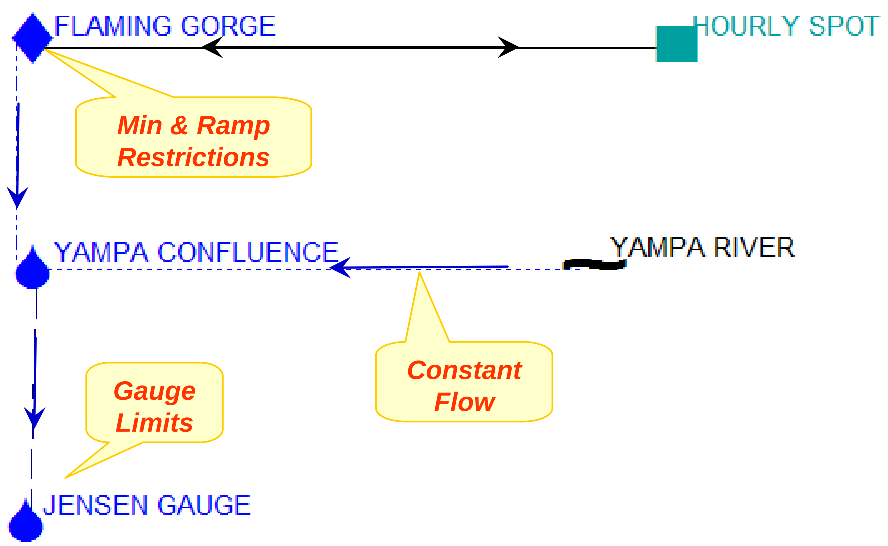

Figure 4.8 Topology Used for Flaming Gorge Dispatch and Jensen Gauge Simulations

4.5.3.2 SLCA/IP Topology

The second GTMax topology consists of all SLCA/IP system components, including Western's power purchase prices, Western LTF and project use loads and power resources in the CRSP, the Seedskadee Project, the Collbran Project, and the Rio Grande Project. This topology, which is shown in Figure 4.9, also includes the Green, Yampa, and Gunnison Rivers along with side flows into the Aspinall group of dams.

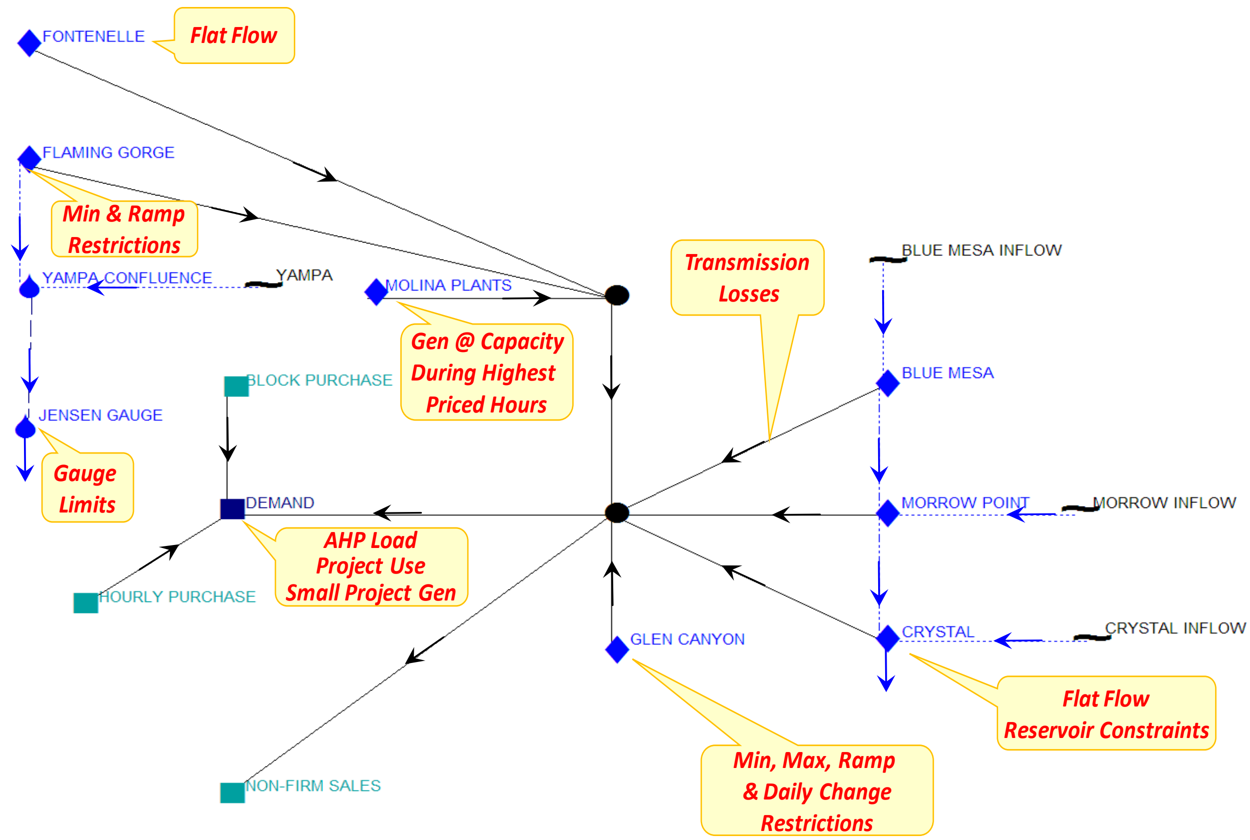

Figure 4.9 SLCA/IP Topology Used for Power Plant Dispatch Simulations

The load or demand node (dark blue square in Figure 4.9) includes typical customer energy requests and net project use load. Energy consumed by the projects is based on levels that Western reserved for this purpose. Some of this load is served by local generation produced by the Elephant Butte Dam, McPhee Dam, and Towaoc Canal power plants. Elephant Butte Dam is part of the Rio Grande Project and the McPhee Dam and Towaoc Canal are part of the Dolores Project; both projects are discussed later in this section. The net project use load calculation assumes that generation levels from all three small power plants are constant during the entire month. This method is similar to the one practiced in the Montrose Office when assessing future monthly energy purchase needs. To account for transmission losses, the project use load is increased by 5.5%.

These three small power plants are not represented individually in the topology but are aggregated in the demand node. Their entire generation is used to satisfy project use load and because they are represented at the demand node, their generation is shown as a negative load.

Using water channel links (i.e., the dotted blue lines in Figure 4.9), the SLCA/IP topology represents the Wayne N. Aspinall Unit on the Gunnison River as a tightly coupled cascade to account for the spatial dependencies among power plants. The Blue Mesa Dam and hydropower plant is at the top of the cascade (i.e., highest elevation level), followed by Morrow Point and then Crystal. This group of three dams is often referred to as the Aspinall Cascade. The Blue Mesa reservoir capacity is 940.8 TAF, which is the largest water storage capacity in the group. It is more than 8 times larger than the Morrow Point Reservoir and more than 36 times larger than the Crystal Reservoir.

Water channels connected to nodes represent both side flows from non-point water sources and reservoir evaporation. In the SLCA/IP topology, this node-channel configuration is used to represent the following aspects of the Aspinall Cascade: (1) Gunnison River flows into the Blue Mesa Reservoir, (2) side flows between the Blue Mesa and Morrow Point Reservoirs, and (3) side flows between the Morrow Point and Crystal Reservoirs. It is assumed that flows in these channels are constant throughout a simulated week. Monthly flows are based on water balance equations that use Form PO&M-59 water releases and forebay elevations along with reservoir-elevation curves. When applying the water balance equation, some errors were discovered in the Form PO&M-59 data. These issues were resolved by using data found on the Reclamation (undated *b*) and Western (2010b) Web sites.

The daily amount of water released from a reservoir in the Aspinall Cascade is identical each day of the week. One exception is the Blue Mesa Reservoir, where water typically is not released on Saturdays during the months of November through February. Each separate reservoir typically has a different daily release volume to accommodate side flows and to achieve historical EOM reservoir elevation levels.

Hourly releases from Crystal are constant. However, as dictated by Reclamation, operations change occasionally to reflect evolving hydrological conditions and downstream water requirements. Other than the physical limitations of the reservoirs and release restrictions from the power plant, bypass tubes, and spillways, there are no operational limitations at Blue Mesa and Morrow Point. However, given flat releases from the Crystal Dam, Morrow Point releases are constrained such that the reservoir elevations at Crystal are within minimum and maximum levels and do not change more than specified levels over 1-day and 3-day calendar periods.

The Seedskadee Project is in the Upper Green River Basin in southwestern Wyoming. It provides storage and regulation of the flows of the Green River for power generation, municipal and industrial use, fish and wildlife, and recreation. The Fontenelle Dam has the only power plant associated with the Seedskadee Project. Releases and associated power production levels are constant throughout a simulated week.

The Collbran Project, located in west central Colorado about 35 miles northeast of Grand Junction, was authorized by Congress in July 1952. It developed a major part of the water in Plateau Creek and its principal tributaries. Major project works include Vega Dam and Reservoir, two power plants, two major diversion dams, about 37 miles of canal, and about 18 miles of pipeline and penstock. East Fork Diversion Dam and Feeder Canal, along with the Bonham-Cottonwood Collection System, carry water to Bonham Reservoir, which supplies water to operate the Molina power plants. Collbran project daily generation produced by the Upper and Lower Molina power plants is scheduled at or near power plant maximum capability for continuous blocks of time, the length of which is determined by the amount of water that is available for release during a 24-hour period. Generation is first dispatched at capacity during hours with the highest market price. If more water is available, generation is then dispatched during low-price hours.

The Rio Grande Project, which is 125 miles north of El Paso, Texas, was authorized by the U.S. Congress in 1905 and began operation in 1916. It established a much-needed irrigation project on the Rio Grande River in south central New Mexico and west Texas. The only dam with electric generating facilities within the Rio Grande Project is Elephant Butte Dam. As described earlier, generation produced by this plant is constant, serving local project use loads.

The Dolores Project is located in the San Juan and Dolores River basins of the Upper Colorado River Basin in southwestern Colorado. It extends through portions of Montezuma and Dolores counties and uses water from the Dolores River for irrigation, municipal and industrial use, recreation, fish and wildlife, and production of hydroelectric power. As described earlier, the two hydroelectric power plants at this project are the McPhee Dam and the Towaoc Canal and their generation is constant, serving local project use loads.

In addition to water channels, links in the SLCA/IP topology represent the flow of energy from generation resources and market purchases to serve SLCA/IP customer load and for sale to non-firm markets. It is assumed that 8.8% of the energy generated by the GCD Powerplant will be lost when it is transported to customer delivery points. A lower transmission loss rate of 5.5% is assumed for all other SLCA/IP hydropower plants, including those previously mentioned small plants that serve project use load.

4.5.4 Ancillary Services

Ancillary services help maintain reliable system operations in accordance with good utility practice. Some of these services include spinning reserve, non-spinning reserve, replacement reserve, regulation/load following, black start, and voltage support. Quick start times, fast ramping capabilities, and the ability for rapid corrective responses to changes in grid conditions make hydropower plants an excellent resource for providing ancillary services.

Two ancillary services, spinning reserves and regulation, were included in GTMax simulations for this analysis. It was assumed that Glen Canyon would provide both services under the Without Experiments and Baseline scenarios. The only exception is during experimental flows, for which it was assumed that these duties would be performed by Morrow Point. As depicted in Figure 4.10, ancillary services reduce the operating range of a power plant. Spinning reserves reduce maximum scheduled operations. On the other hand, regulation affects both maximum and minimum production levels. On the basis of information provided by Western, spinning reserves are assumed to be 80 MW, and regulation is assumed to be 40 MW. The extent to which these services affect operations is described below.

Regulation is the amount of operating reserve capacity required by the control area to respond to automatic generation control to assure that the Area Control Error meets these two conditions: that it (1) equals zero at least one time in all 10-minute periods and (2) falls within specified limits to manage the inadvertent flow of energy between control areas.

It was assumed that Glen Canyon would provide regulation services by responding quickly to moment-by-moment up and down movements in control area electricity demand using Automatic Generation Control. Glen Canyon is well suited for providing this service because at least one or more of its turbines are always on-line, and it operates at sufficiently high levels such that sudden decreases in load will not reduce generation below either its technical or regulatory minimums.

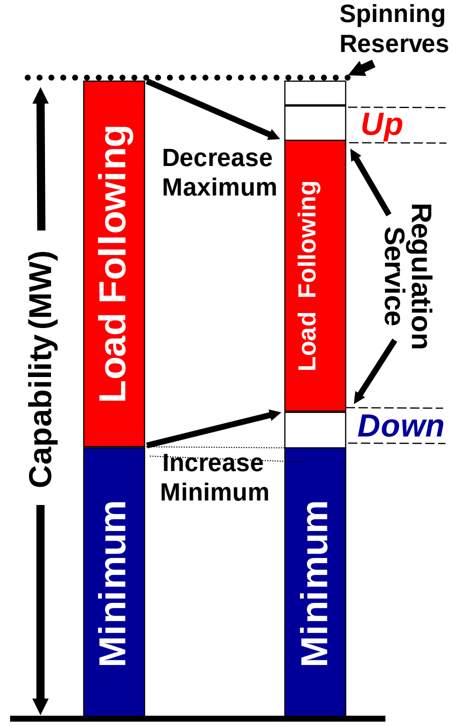

Figure 4.10 Operating Range Reduction When Providing Ancillary Services

Glen Canyon provides regulation-down service without incurring any opportunity costs when it is not necessary to alter its hourly generation pattern to provide the service. The amount of regulation-down service that can be provided without incurring costs is as high as the power production level generated when the plant is operating at the mandated minimum release. Because the regulatory minimum release is on an hourly average basis, the service can be provided without costs because, during some moments, water releases may be less than the minimum flow rate as long as there are compensating releases greater than the minimum flow rate at other times within the hour. This interpretation is consistent with regulation services in which the net power production level over a one-hour period sums to zero. Opportunity costs are only incurred when regulation-down service requires Glen Canyon to be operated at a higher level than required by the minimum release rate. At a 40-MW level of service, this situation never occurs under either scenario because the minimum flow requirement under the ROD always produces significantly more than 40 MW.

To provide regulation-up service, generation levels must be sufficiently low such that a power plant can respond to instantaneous decreases in grid loads without exceeding the output capability. Regulation-up services will incur an opportunity cost when maximum power plant sales during peak periods are required to be lower than the plant's capability. The power plant's average hourly production level must be at or below the plant's capability minus the regulation-up service level. Under either scenario, regulation-up service does not incur any opportunity costs under all but very high hydropower conditions since the dam is operating below the maximum power plant capacity. It is of note that at many times, the regulatory flow rate is significantly below the physical plant limit. The ROD requires that, under most hydrologic conditions, the maximum average hourly release rate from Lake Powell be no more that 25,000 cfs. This release rate falls below the maximum turbine flow rate by 5,000 cfs to 6,000 cfs most of the time. Assuming a power conversion factor of 40 MW per 1,000 cfs, 200 MW or more of regulation-up reserves could be provided without incurring an opportunity cost. It should also be noted that providing regulation services will not affect either hourly ramping or daily changes at Glen Canyon. It is also assumed, on the basis of personal communication with Western staff at the Montrose Office, that both up- and down-regulation services will be provided by the GCD Powerplant at a 40-MW level.

Spinning reserves are defined as generating capacity that is running at a zero load, connected to an output bus, synchronized to the electric system, and ready to take immediate load. The portion of unloaded synchronized generating capacity, controlled by the power system operator, must be capable both of being loaded in 10 minutes and of running for at least two hours. On the basis of personal communication with Western staff at the Montrose Office, it is assumed that 80 MW of spinning reserves will be provided by the GCD Powerplant.

When a generator supplies spinning reserve services, it will increase output in response to an outage situation. The increased output fills the generation void created by a generator in a balancing authority that suddenly ceases to produce power. Spinning reserves may also be called upon when an abrupt transmission line outage will no longer permit the reliable transport of power into a region. Generation levels in normal conditions must be sufficiently low such that when an outage occurs, it can increase output levels by its spinning reserve obligation without exceeding the maximum capability of the generator.

Spinning reserve services require that maximum production levels do not exceed the plant’s capability minus the amount of spinning reserves required. Providing spinning reserves also requires that one or more turbines operate below capability or in a spinning state without producing power. The former condition may require the unit to operate in a sub-optimal state, while the latter releases water without power production to spin the turbines under no load. These additional requirements typically incur opportunity costs, because capacity must be reserved at the high end of operations to accommodate the spinning reserves. Unlike regulation-down services, spinning reserves do not affect minimum generation levels. Under either scenario, spinning services at GCD can be provided under most conditions because exception criteria allow for the maximum release constraint to be relaxed to support grid operations. The exception criteria also allow this service to be provided at little or no costs during most hydrological conditions. Similar to the situation with providing regulation-up service, there is ample room for increased production levels (200 MW or more) because ROD release regulations require that the GCD Powerplant is loaded significantly below its physical capability.

4.6 FINANCIAL VALUE CALCULATION SPREADSHEET

A spreadsheet is used to calculate the financial value of SLCA/IP resources under both the Baseline and Without Experiment scenarios. In this spreadsheet, GTMax financial benefits are calculated by multiplying generation levels by Western's power purchase price for each hour in a typical one-week simulation.

GTMax results for a typical week are scaled up to a month for all system components. A monthly estimate is obtained by multiplying simulated results for specific types of days by the number of occurrences of that type of day in the month. For example, the average weekday result from the GTMax simulated week is computed and then multiplied by the number of weekdays in the month. Results for all Sundays and Saturdays in the month are scaled by using a similar process. As mentioned previously, any holidays in the month are treated as a Sunday. However, when an experiment is conducted at GCD, the days of duration of the experiment are removed from the scaling process. Instead, actual historical generation data are used for these periods. The monthly scaling process applied to the GCD Powerplant accounts for the type of day on which the experiment was conducted, that is, the number of weekdays, Saturdays, Sundays, and holidays that occurred during the experiment. The financial value of the experiment is computed as the difference between the two scenarios.

5 RESULTS

This section discusses the results of the simulation runs during the study period of 1997 to 2005. The results are displayed by water year (WY), which runs from October 1 to September 30, and the costs are in nominal dollars.

There are two broad categories of experiments that occurred during this period. Experiments in the first category (Category 1) are relatively short in duration and require changes in hourly release volumes from the normal pattern. Changes in releases during the experiment may require an increase or decrease in releases during non-experimental periods in the month they occur compared to the Without Experiments scenario. The monthly water volumes are identical under both scenarios.

Experiments in the second category (Category 2) are relatively long in duration and have different monthly water release volumes than the Without Experiments scenario. This second category of experiment also exhibits an hourly release pattern that differs from the pattern during non-experiment periods.

The financial impacts of the experimental releases that occurred in each year are discussed in detail below. In some cases, financial impacts can be determined for an individual experimental release, while in others, financial impacts cannot be assigned to a specific experiment. In these cases, results are reported for the year. Financial impacts cannot be determined when both of the following two conditions occur in the same year:

(1) There were multiple experimental releases in the same year; and,
(2) One or more of the experiments required a redistribution of water release volumes among the months of a year.

Table 3.1 provides characteristics of the experimental releases, including the dates on which they occurred, minimum and maximum flows, hourly up- and down-ramp rates, maximum daily fluctuations, whether monthly water reallocations were required, and whether ROD operating criteria were relaxed during the experiment.

The spread between on- and off-peak prices Western pays for power is a key factor in the estimation of the financial impacts of experiments conducted at GCD. Except for BHBF spills and the resulting lowering of the Lake Powell reservoir forebay elevation, most experiments have relatively little effect on the amount of electricity generated by the GCD Powerplant over the course of a year. Experiments that incur a financial loss shift water releases and power generation from times when electricity prices are high to times when prices are low. The greater the difference between on-peak and off-peak prices, the higher the financial loss. The absolute price is of little or no importance. For example, if the price of electricity is constant at $1,000 MWh during a month, an experiment that does not reallocate monthly water volumes would incur little or no cost. The experiment merely affects the hourly timing of releases and not the total monthly value.

The price spread between hours in a month is important for the first category of experiments because a reallocation of hourly water releases within a month is required. When an experiment requires shifting water among months of the year, not only is the price spread within the hours of the month important, but price spreads among the months of the year are also important. Experiments that shift higher release volumes from months of the year that have higher prices, such as July and August, to months of the year with lower prices, such as April and May, incur relatively high financial costs.

5.1 Cost of Experiments in WY 1997

This year had a single category one experimental release, an APSF, that occurred from August 30 - September 2, which was Labor Day weekend. It consisted of a constant release of about 8,000 cfs. This year also had a total flow of almost 14,000 TAF, making it the fifth-highest annual release in the dam's history. Although the experiment spanned two months, water was only reallocated within each month, not between the two months. Therefore, the amount of water released in August and September was the same in both scenarios.

Figure 5.1 shows that in both August and September, the experiment resulted in a financial benefit of $133,000 and $86,000, respectively, for a total of $219,000. The secondary y-axis on this chart shows the difference, or spread, in the average monthly on-peak and off-peak prices Western pays to purchase power. The experiment had a financial benefit to Western because it occurred during a holiday period when prices Western paid to purchase power were relatively low, and less water was released compared to amounts released in the Without Experiments scenario. Under ROD constraints, typical simulated minimum releases during off-peak periods were about 18,000 cfs during August, 1997 and about 17,000 cfs during September, 1997. This amount compares to only 8,000 cfs during the experiment. High releases under the Without Experiment scenario during low-priced periods are due to the ROD daily change requirement in combination with Montrose scheduling guidelines that seek identical minimum releases each day of the week and that releases on weekends are at least 85% of the average weekday release. Low flows during the experiment, particularly during the low-priced weekend hours, allows more water to be used during non-experimental release periods in these two months relative to the Without Experiment scenario. Generation in the Baseline scenario was higher during hours when electricity prices were high, such as during peak weekday hours. Therefore, because Montrose scheduling guidelines were suspended during the experimental period in the Baseline scenario but in effect during the same time period in the Without Experiments scenarios, this experiment resulted in a benefit, not a cost.

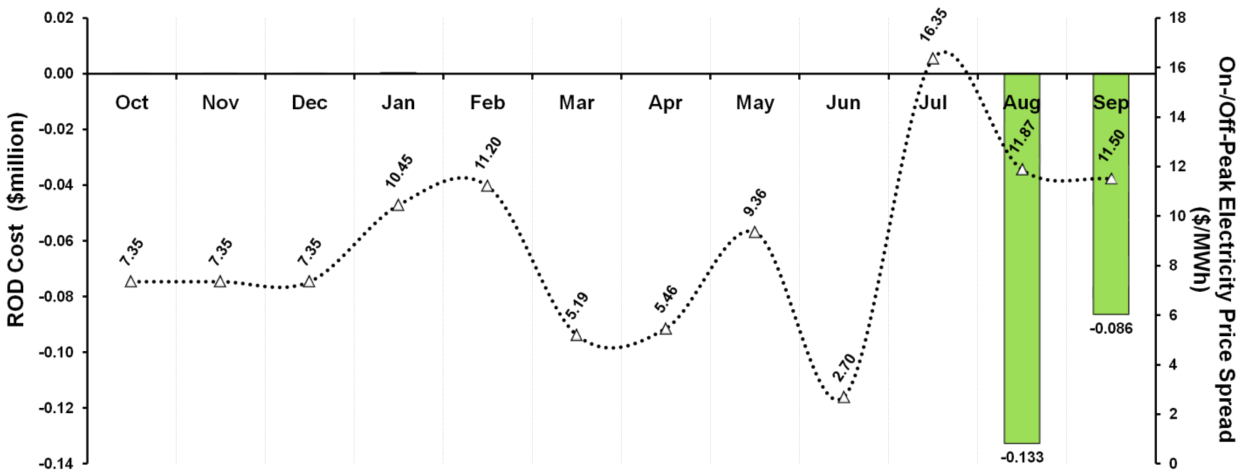

Figure 5.1 Cost of Experimental Release in WY 1997

5.2 Cost of Experiments in WY 1998

Two experimental flows were conducted in this year: an HMF from November 3–5 and an APSF from September 4–8, which was also a Labor Day weekend. Water releases were 30,000 cfs during most of the three-day HMF experiment and 15,000 cfs during the APSF. Because the HMF and APSF experiments were of a short duration, they required reallocation of water only within the months of November and September, not to other months of the water year. Therefore, both scenarios had the same water releases in each month of this water year.

Figure 5.2 shows that the HMF resulted in a financial loss of about $10,600 in November. The financial loss occurred because water was released at a steady flow of 30,000 cfs even during off-peak periods. By comparison, typical simulated minimum releases during off-peak hours in the Without Experiments scenario averaged about 18,300 cfs. Because water was released at a high rate during the experiment, less water was available for release during the remainder of November. GTMax simulation results show that on a typical November weekday in an on-peak period without experiments, there is a flow rate of almost 24,000 cfs. However, in this November with the HMF, that flow rate fell to under 23,000 cfs.

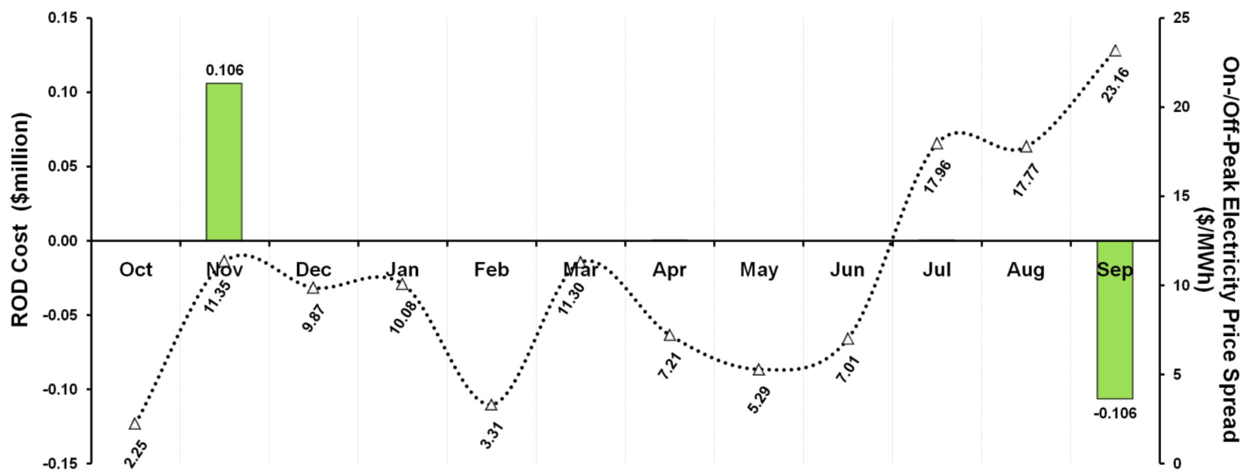

Figure 5.2 Cost of Experimental Releases in WY 1998

Figure 5.2 also shows that the APSF resulted in a financial benefit of $10,600 in September. The financial benefit occurred because during the experiment, there was a steady flow of 15,000 cfs even during on-peak periods. Under the Without Experiments scenario, typical simulated releases during weekend and holiday on-peak hours often exceeded 15,000 cfs. Less water released over the Labor Day weekend and holiday during the experiment allowed more water to be released in other weekday on-peak hours. In addition, because the experiment occurred during a holiday, electricity prices were lower than during a comparable period over the remainder of the month. On-peak prices during the holiday period were as much as 18% lower than on-peak prices occurring the rest of the month. Hence, because more water was released during on-peak hours (i.e., when electricity is priced higher), a financial benefit resulted.

When the benefits/losses are totaled over the year for these two experiments, the loss of the HMF is exactly cancelled by the benefit of the APSF. Therefore, the experiments resulted in neither a net loss nor a net benefit in WY 1998.

5.3 Cost of Experiments in WY 1999

There was only a single Category 1 experimental release in this year. It was an APSF, which ran from September 3 to 9, which was again a Labor Day weekend. The APSF had a constant water release of about 15,000 cfs.

Figure 5.3 shows that the experiment resulted in a financial benefit to Western of $8,900 in September. The financial benefit occurred because during the experiment, there was a steady flow of 15,000 cfs even during on-peak periods. Under the Baseline scenario, typical simulated minimum releases during on-peak hours on a Saturday and Sunday were about 21,500 cfs and 18,000 cfs, respectively. These release rates compared to a steady 15,000 cfs rate during the experiment. Even in off-peak hours, simulated releases exceeded 16,000 cfs. Therefore, low flows during the experiment allow more water to be used during hours when electricity prices are high (such as during peak weekday hours) and consequently resulted in a financial benefit.

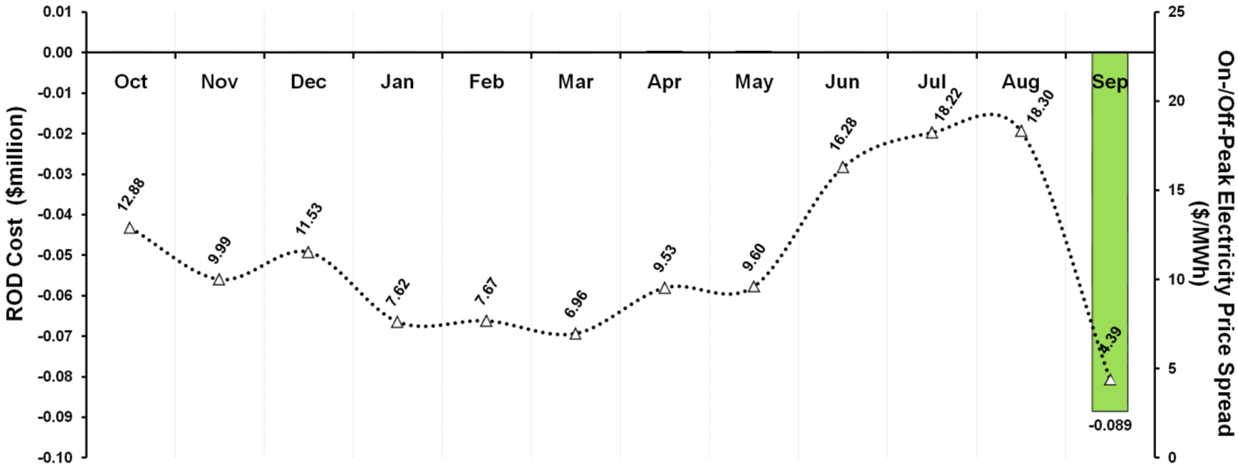

Figure 5.3 Cost of Experimental Release in WY 1999

5.4 Cost of Experiments in WYs 2000 and 2001

The costs of experiments in WYs 2000 and 2001 were combined because the single experimental release that occurred in WY 2000, a low summer steady flow (LSSF), required water to be reallocated not only within WY 2000, but also in WY 2001. In fact, in WY 2000, the Baseline scenario released 618 TAF more water than the Without Experiments scenario. However, to compensate for this larger release, the Baseline scenario released 618 TAF less water in WY 2001.Because of this water reallocation between two water years and multiple experimental releases occurring in this time period, the financial impacts of each experiment could not be determined individually.

The LSSF in WY 2000 was a Category 2 experimental release which lasted for more than 6 months from March 25 to September 30. The GCD's flow pattern during this time period is shown in Figure 3.3. High flows occurred from April to the end of May. After June 1, water releases, and therefore generation levels, were very low for the remainder of the experiment, because the required release rate was 8,000 cfs for most of that period aside from two very short high spikes in September.

Although there were two short spike flows that were above 30,000 cfs in May and again in September, no water was spilled because GCD Powerplant’s outage rate was less than 2% in those months. The turbines had enough capacity available to accommodate those short-term high flows.

Figure 5.4 shows the monthly water releases; the amounts of water released in each scenario differed in the months of April to September because of the reallocation of water to support the LSSF experiment. Releases during the LSSF were characterized by high flows from April to the end of May, followed by low flows in June, July, and August, and for most of September. To accommodate the high flows in the early months of the release, water was reallocated from June, July, and August to other months. Because the Without Experiments scenario is a hypothetical case, its monthly releases are based on Riverware model simulations performed by Reclamation. The Baseline scenario had higher releases than the Without Experiments scenario had in April, May, and September, and lower releases in June, July, and August.

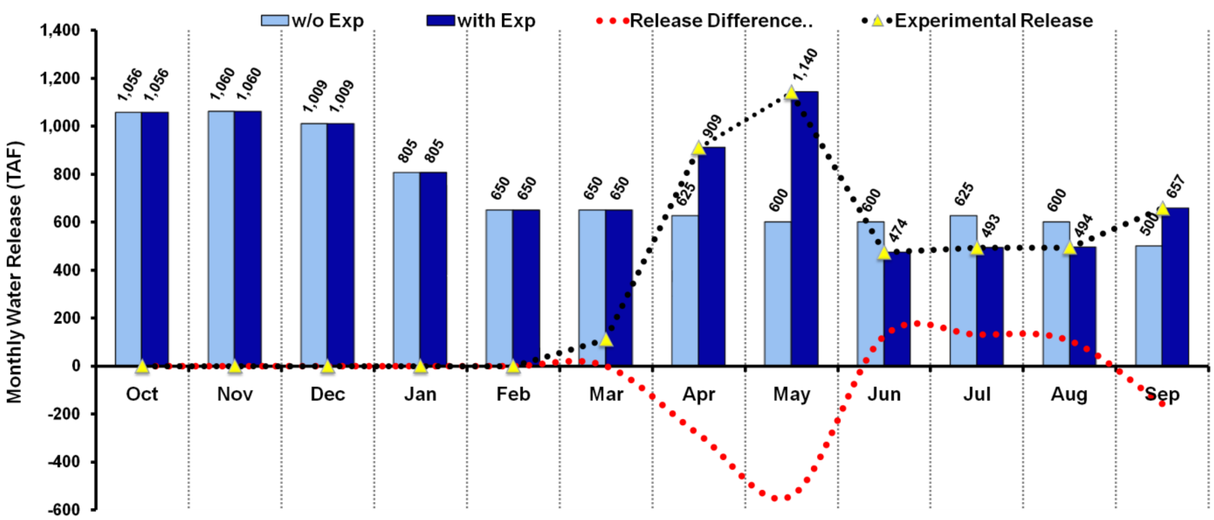

Figure 5.4 Monthly Water Releases in WY 2000

Figure 5.5 shows the monthly costs and benefits of the LSSF. The experiment resulted in net benefits of $4.6 million, $9.6 million, and $6.4 million in the months of April, May, and September, respectively. Benefits occurred in these months because more water was released in the Baseline scenario than in the Without Experiments scenario. Over those three months, an average of 327 TAF more water was released in the Baseline scenario. In May, 540 TAF more water was released, which resulted in the largest monthly benefit of the experiment.

Similarly, the experiment resulted in net costs of $1.2 million, $2.98 million, and $5.94 million in the months of June, July, and August, respectively. Costs occurred in these months because less water was released in the Baseline scenario than in the Without Experiments scenario. Over those three months, an average of 121 TAF less water was released in the Baseline scenario. Increasing the cost of the experiment were the higher electricity prices in these three months than those that occurred in other months of the year. Because flows were higher and more electricity was produced in these months under the Without Experiments scenario than under the Baseline scenario, the costs of the experiment were greater.

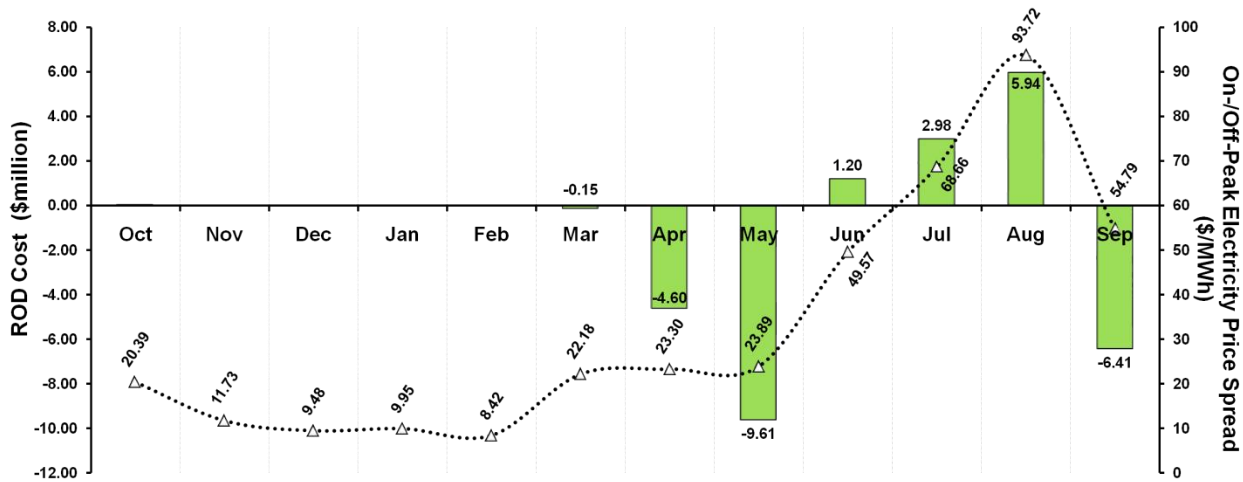

Figure 5.5 Cost of Experimental Release in WY 2000

Finally, because there was a low, steady release during these three months, generation from the GCD was unable to follow Western's load pattern, which follows the pattern of daily electricity price fluctuations. That is, the value starts low before dawn, increases through the day, peaks in mid-afternoon, and then falls to the pre-dawn low value. Therefore, this experiment incurred a substantial cost in these months because system dispatchers could not release more water when electricity prices were highest.

Water year 2001 had a single Category 1 experimental release, an APSF that occurred from June 28 to July 2. It had a steady release of 8,000 cfs; water was reallocated within the months in which the APSF occurred. Although only a single experiment was performed in this year, the LSSF from the previous year required a redistribution of water release volumes among months within the year. Therefore, financial impacts cannot be determined for the APSF by itself.

Figure 5.6 shows the monthly water releases, including the water reallocated to accommodate the previous year's LSSF. Because the Baseline scenario released 618 TAF more water in WY 2000 than did the Without Experiments scenario, it released 618 TAF less water in this WY. Monthly water releases under the Without Experiments scenario were estimated by Argonne staff on the basis of the actual release pattern and the tendency to release higher water volumes during the summer and winter months to take advantage of higher market prices during these periods. Less water was released in the Baseline scenario during the months of January, February, June, July, August, and September as compared to the Without Experiments scenario. Slightly more water was released in the months of March, April, and May in the Baseline scenario compared to the Without Experiments scenario.

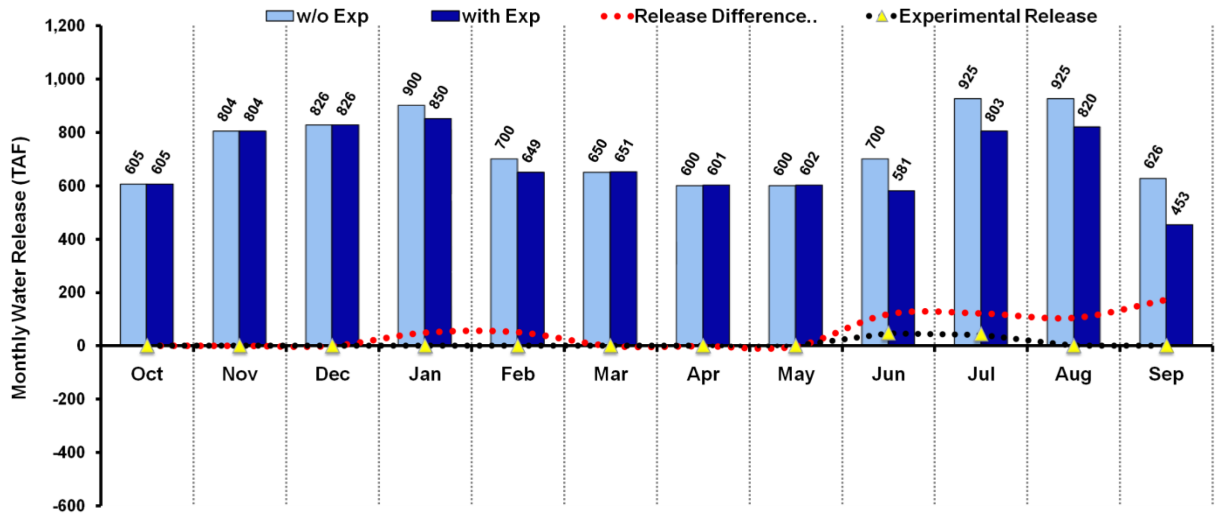

Figure 5.6 Monthly Water Releases in WY 2001

Figure 5.7 shows the monthly costs from the APSF and the reallocation of water because of the previous year's LSSF. There are large costs in six months of the year and relatively lower costs in the remaining months. The first grouping of lower costs occurs in October, November, and December, which have costs of $160,000, $240,000, and $340,000, respectively. Although both scenarios have the same monthly release rates in those months, the Lake Powell reservoir has different elevation levels, as shown in Figure 5.8. The reservoir is lower in the Baseline scenario because of the LSSF that occurred the previous year, reducing the GCD Powerplant's power conversion factor. Therefore, less energy is produced in the Baseline scenario for each unit of water passing through the turbines than is produced in the Without Experiments scenario; thus, the experiment resulted in a cost to Western.

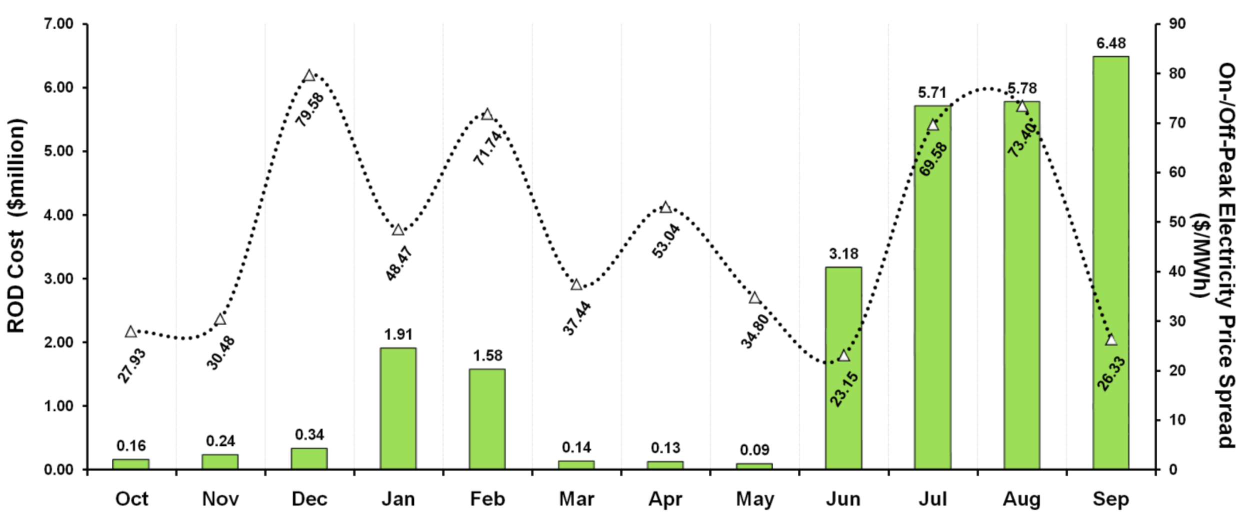

Figure 5.7 Cost of Experiments in WY 2001

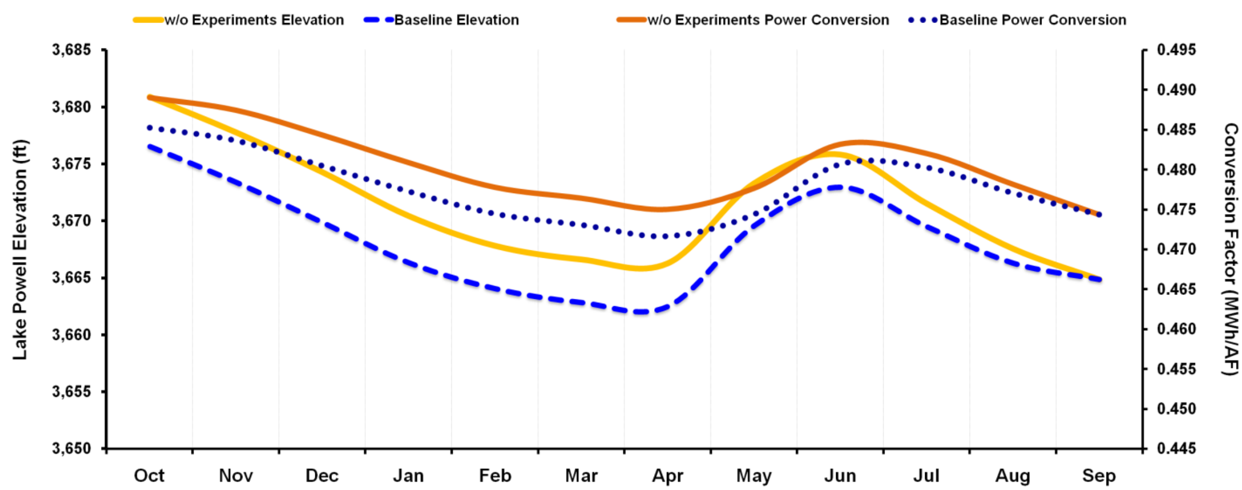

Figure 5.8 Comparison of Lake Powell Elevations and Power Conversion Factor in WY 2001

Another grouping of lower costs occurs in March, April, and May; costs in those months are $140,000, $130,000, and $9,000, respectively. Although slightly more water is released in these months in the Baseline scenario, Lake Powell's elevation is still lower than it is in the Without Experiments scenario. The increase in the amount of water released in the Baseline scenario could not compensate for the reduced amount of energy produced per unit of water.

The costs of the experiments are larger in the months of January, February, June, July, August, and September. The costs in these months are $1.9 million, $1.6 million, $3.2 million, $5.7 million, $5.8 million, and $6.5 million, respectively. These costs are a result both of (1) there being more water released in the Without Experiments scenario than in the Baseline scenario and (2) the difference in the elevations of Lake Powell. In January and February, about 50 TAF more water is released in the Without Experiments scenario, but in June, July, and August, the differences in the amounts of water released are more than 100 TAF each month and rise to a difference of more than 170 TAF in September (Figure 5.6). The elevation of Lake Powell equalizes in both scenarios by September, so the cost in that month is largely because of the difference in water releases between the two scenarios.

In conclusion, the experimental releases in WY 2000 resulted in a benefit of $10.5 million and in WY 2001 resulted in a cost of $25.7 million. However, because the LSSF in WY 2000 required water to be reallocated between two water years, the financial costs must be summed over both WYs. Therefore, the total cost of the LSSF that occurred in WY 2000 and the APSF that occurred in WY 2001 was more than $15.7 million.

5.5 Cost of Experiments in WY 2002

A single Category 1 experimental release occurred in 2002; it was an APSF, which occurred from May 24 to May 31 and included the Memorial Day weekend. It had a steady release rate of

8,000 cfs. Water was only reallocated within May. Thus, both scenarios had the same water release amounts in each month of this water year.

Figure 5.9 shows that the experiment resulted in a cost of $29,000. The cost occurred because the experiment released water at a constant flow of 8,000 cfs for 8 consecutive days. Therefore, water could not be released at a higher rate even during on-peak hours when electricity prices are the highest. Although water was reallocated within the month so that the same amount of water was released in both scenarios, the financial benefit obtained by increased generation earlier in the month was offset by losses sustained during the week of the experiment.

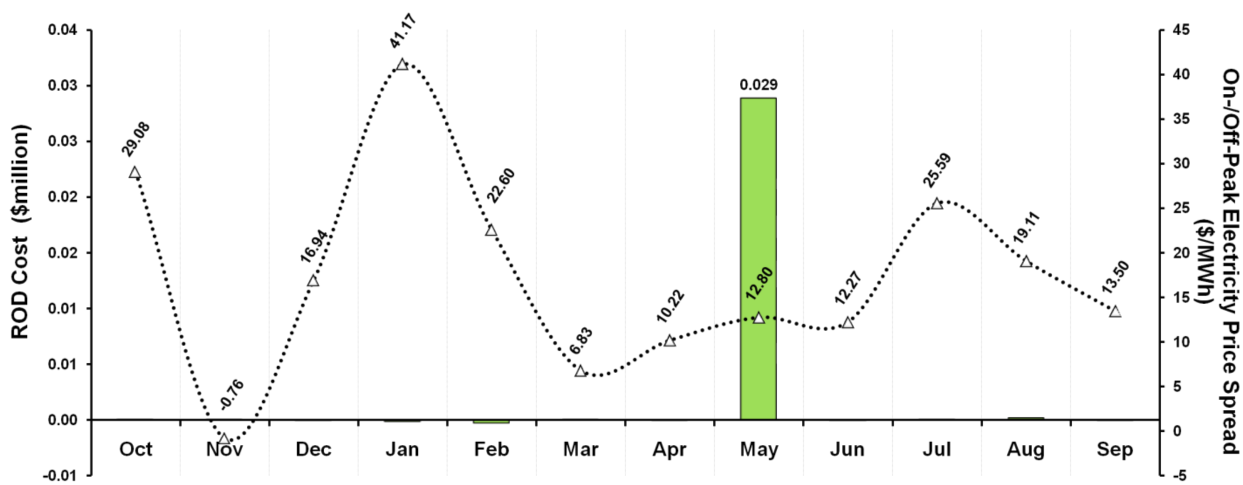

Figure 5.9 Cost of Experimental Release in WY 2002

5.6 Cost of Experiments in WY 2003

Two experimental releases were conducted in this year, namely, a Category 2 NNFSF and a Category 1 APSF. The NNFSF was a lengthy flow that ran from January 1 to March 31 and required water reallocation to other months of the water year. The APSF took place from May 23 to May 27, which included the Memorial Day weekend, and had a steady release rate of 8,000 cfs.

Figure 5.10 shows the monthly water releases; there are differences in almost every month between the two scenarios in the amounts of water released. This result is mostly attributable to the reallocation of water to accommodate the NNFSF. The NNFSF followed a prescribed hourly release rate, ranging from approximately 5,000 cfs to 20,000 cfs each day. Releases were highest during the day and were reduced at night. The Without Experiments monthly release pattern was based on a typical 8.23 MAF release year, that is, the minimum allowable annual release. In general, for the Baseline scenario, more water was released in the months of February, March, May, June, and July, and less water was released in the months of October, November, December, January, and September.

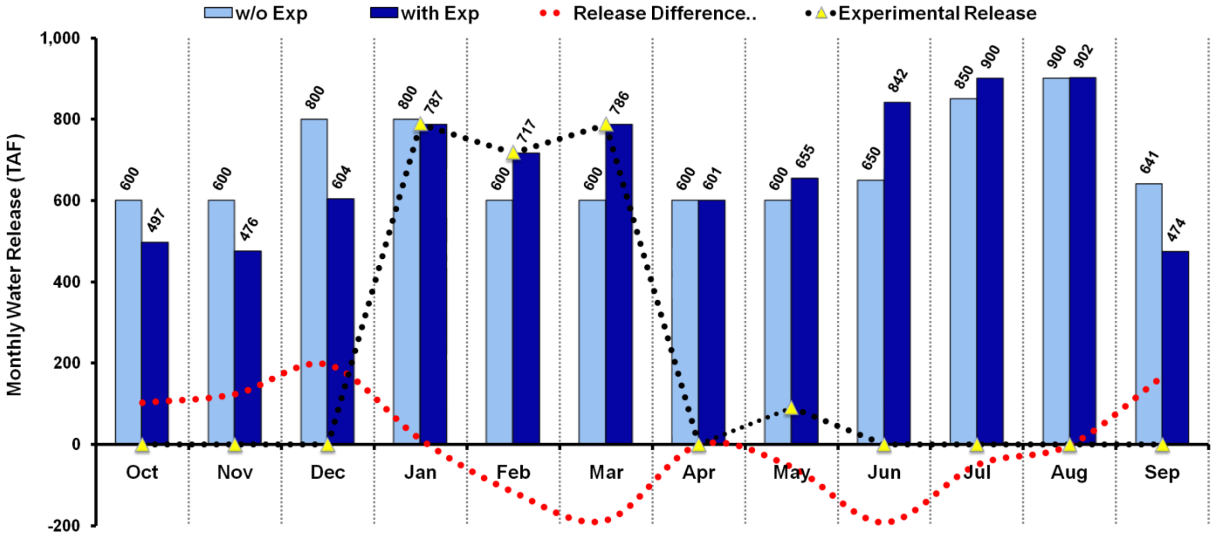

Figure 5.10 Monthly Water Releases in WY 2003

Figure 5.11 shows the monthly costs and benefits resulting from these two experimental releases. Because there were two experiments performed in this year and one of them, the NNFSF, required a redistribution of water release volumes among months within the year, the financial impacts of each experimental release cannot be determined individually. A benefit generally occurs in months when the monthly releases in the Baseline scenario exceed those in the Without Experiments scenario. There is a benefit because more water is available for use in the high-priced hours in the Baseline scenario. The benefit can be enhanced in the months when the NNFSF occurs because of the favorable flow patterns; that is, releases are higher during the day and lower at night than would otherwise have occurred without the experiment. Limits on the criteria for up- and down-ramp rates were suspended so that water could be released more quickly to reach high daytime hour releases and could be lowered more quickly to reach low nighttime releases.

Conversely, a loss occurs in months when the monthly releases in the Baseline scenario are lower than those in the Without Experiments scenario. The loss occurs because less water is available for use in the high-priced hours in the Baseline scenario.

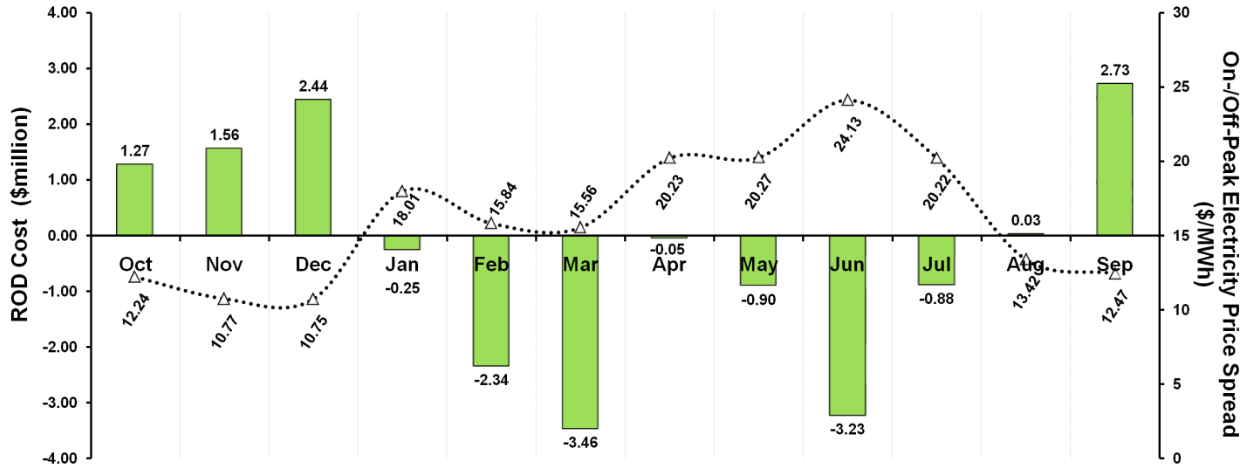

Figure 5.11 Cost of Experiments in WY 2003

There is an anomaly in January because water releases in the Baseline scenario are lower than they are in the Without Experiments scenario, and yet there is still a benefit. This benefit occurs for two reasons. First, the NNFSF flow pattern generally has higher releases during the higher-priced daytime hours. Second, the Lake Powell water level, and consequently the power conversion factor, are each higher in the Baseline scenario than each is in the Without Experiments scenario. Figure 5.12 shows the Lake Powell elevations and power conversion factors in this WY. Therefore, more energy is produced in the Baseline scenario for each unit of water passing through the turbines than is produced in the Without Experiments scenario, resulting in a benefit to Western in that month.

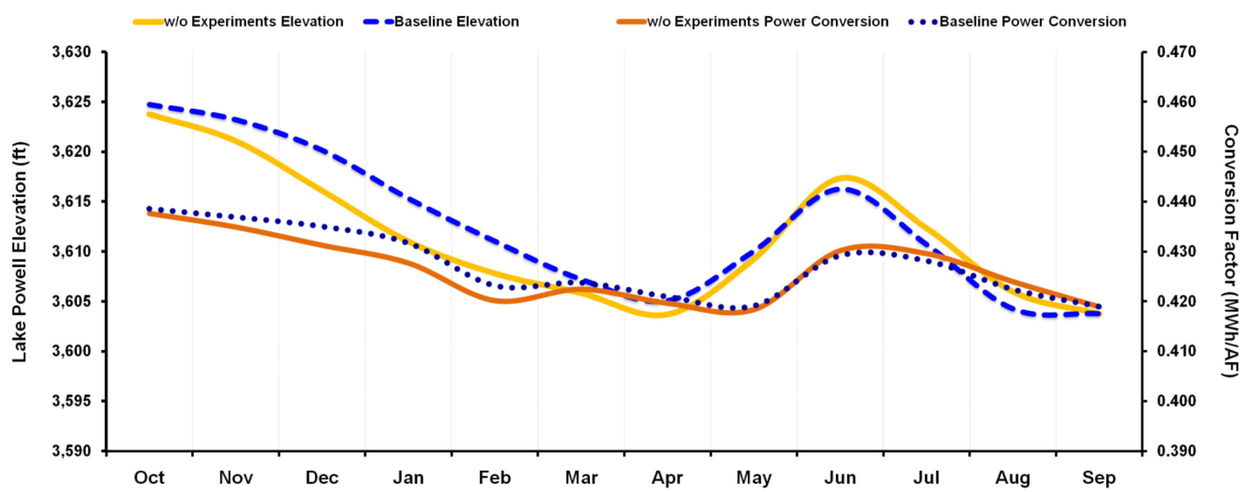

Figure 5.12 Comparison of Lake Powell Elevations and Power Conversion Factor in WY 2003

This difference in reservoir elevation would have also reduced the cost of the experiments in the months of November and December. The cost would have been higher had the reservoir elevation been the same in both scenarios. More energy was produced per unit of water released through the turbines in the Baseline scenario compared to that produced in the Without Experiments scenario.

Monthly benefits in this WY can be as high as $3.5 million (March), while monthly costs can be as high as almost $2.7 million (September). Over the entire year, there was a combined net benefit of about $3.1 million from these two experiments.

5.7 Cost of Experiments in WY 2004

There were two experimental releases during WY 2004: namely, a Category 2 NNFSF and a Category 1 APSF. The NNFSF was a lengthy flow that ran from January 1 to March 31 and required water reallocation to other months of the water year. The flow pattern for this release was similar to the one that occurred in 2005, which was shown in Figure 3.1. The APSF occurred from May 28 to May 31, which included the Memorial Day weekend, and had a steady release rate of 8,000 cfs.

Figure 5.13 shows the monthly water releases; the amounts of water released in each scenario were different in almost every month. This result occurs largely because of reallocating water to accommodate the NNFSF. The Without Experiments monthly release pattern was based on a typical 8.23 MAF year. The NNFSF was a prescribed hourly release ranging from approximately 5,000 cfs to 20,000 cfs each day during the month of January. Releases were highest during the day and were reduced at night. During February and March, the release pattern was even more favorable, as water releases on Sundays were lower than they were on the weekdays. On Sundays, releases ranged from about 5,000 cfs at night to approximately 8,000 cfs during the day. In general, for the Baseline scenario, more water was released in the months of February, March, April, June, and July, and less water was released in the months of October, November, December, January, and September.

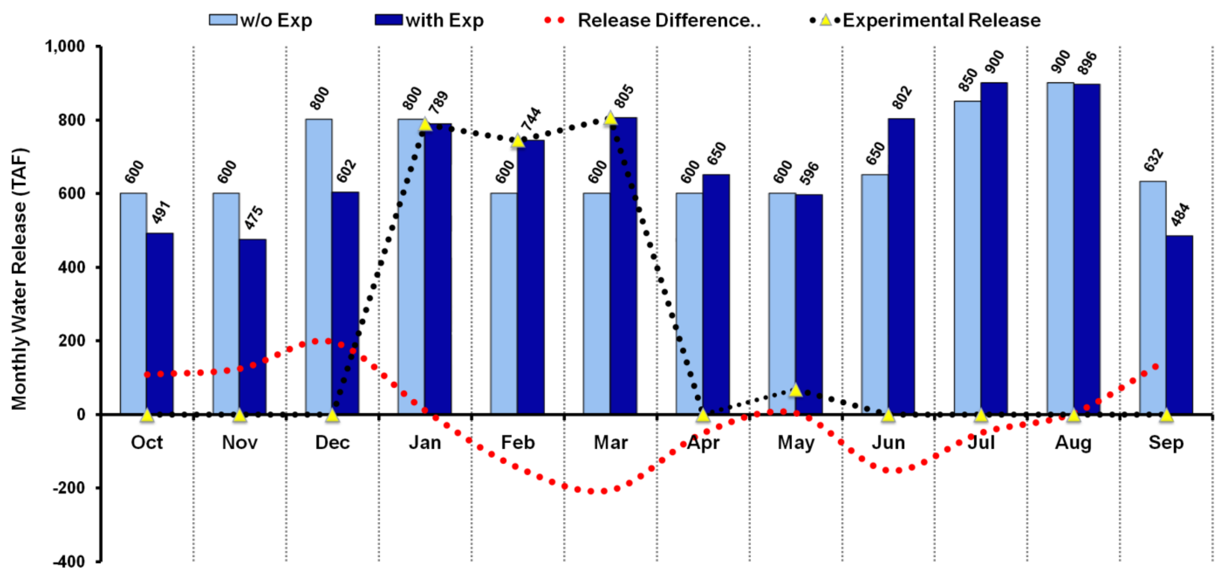

Figure 5.13 Monthly Water Releases in WY 2004

Figure 5.14 shows the monthly costs and benefits resulting from these two experimental releases. Because there were two experiments performed in this year and one required a redistribution of water release volumes among months within the year, the financial impacts for each experimental release cannot be determined individually. A benefit generally occurs in months when the monthly releases in the Baseline scenario exceed those in the Without Experiments scenario. There is a benefit because more water is available for use in the higher-priced hours in the Baseline scenario. Limits on the criteria for up- and down-ramp rates were suspended so water could be released more quickly to reach high daytime hour releases and could be lowered more quickly to reach low nighttime releases.

Conversely, a loss occurs in months when the monthly releases in the Baseline scenario are lower than those in the Without Experiments scenario. The loss occurs because less water is available for use in the higher-priced hours in the Baseline scenario.

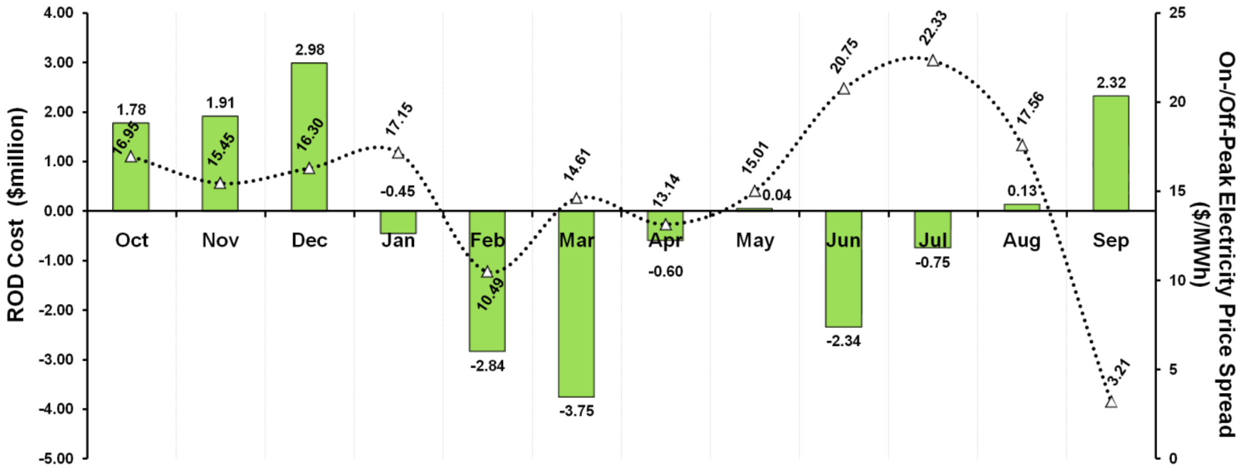

Figure 5.14 Cost of Experiments in WY 2004

As in WY 2003, there is an anomaly in January because water releases in the Baseline scenario are lower than they are in the Without Experiments scenario, and yet there is still a benefit. This benefit occurs for two reasons. First, the NNFSF flow pattern generally has higher releases during the higher-priced daytime hours. Second, the Lake Powell water elevation level, and consequently the power conversion factor, are each higher in the Baseline scenario than each is in the Without Experiments scenario. Figure 5.15 shows the Lake Powell elevations and power conversion factors in this WY. Therefore, more energy is produced in the Baseline scenario for each unit of water passing through the turbines than is produced in the Without Experiments scenario, resulting in a benefit to Western in that month.

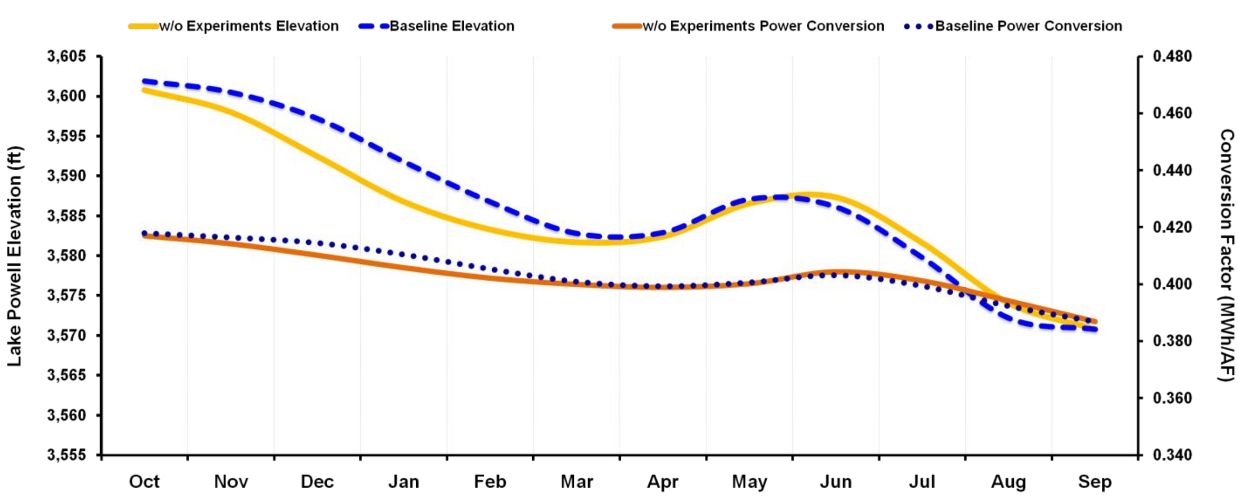

Figure 5.15 Comparison of Lake Powell Elevations and Power Conversion Factor in WY 2004

This difference in reservoir elevation may have also reduced the cost of the experiments in the months of November and December. The cost might have been higher had the reservoir elevation been the same in both scenarios. More energy was produced per unit of water released through the turbines in the Baseline scenario compared to that produced in the Without Experiments scenario.

Monthly benefits in this WY can be as high as $3.8 million (March), while monthly costs can be as high as almost $3 million (December). Over the entire year, there was a combined net benefit of about $1.6 million from these two experiments.

5.8 Cost of Experiments in WY 2005

There were five experimental releases in this year, as follows: a Category 2 NNFSF, a Category 1 BHBF, and three Category 1 APSFs. The NNFSF was a lengthy flow, which ran from January 1 to March 31 and required water reallocation within the year. One APSF occurred from December 3 to December 5 and had a steady flow rate of 8,000 cfs. A BHBF occurred from November 21 to November 25, which was scheduled between an APSF that occurred prior to the BHBF (from November 17 to November 20), with another following (from November 26 to November 30). The entire sequence of experimental flows lasted 14 days. The BHBF required water to be reallocated within the WY. Because the BHBF ramped up to a flow rate of 40,000 cfs for 60 hours, the turbine capability was exceeded, and water was released through bypass tubes at 15,000 cfs. Another factor was that the GCD Powerplant was limited to a maximum flow of 25,000 cfs because one turbine was out of service during the BHBF. Maximum turbine flow was also limited because of the low Lake Powell reservoir elevation. Total spills during the BHBF were about 93 TAF. The APSFs that occurred before and after the BHBF had flow rates of 8,000 cfs.

Figure 5.16 shows the monthly water releases; the amounts of water released in each scenario were different in almost every month. This result was largely attributable to a reallocation of water to accommodate the NNFSF. The NNFSF flow pattern followed a prescribed hourly release rate, ranging from approximately 5,000 cfs to 20,000 cfs each day from Monday through Saturday. Releases on Sunday ranged from about 5,000 cfs to 8,000 cfs. Releases were highest during the day and reduced at night. In the Baseline scenario, more water was released in the months of November, February, March, and June, and less water was released in the months of October, December, January, April, August, and September.

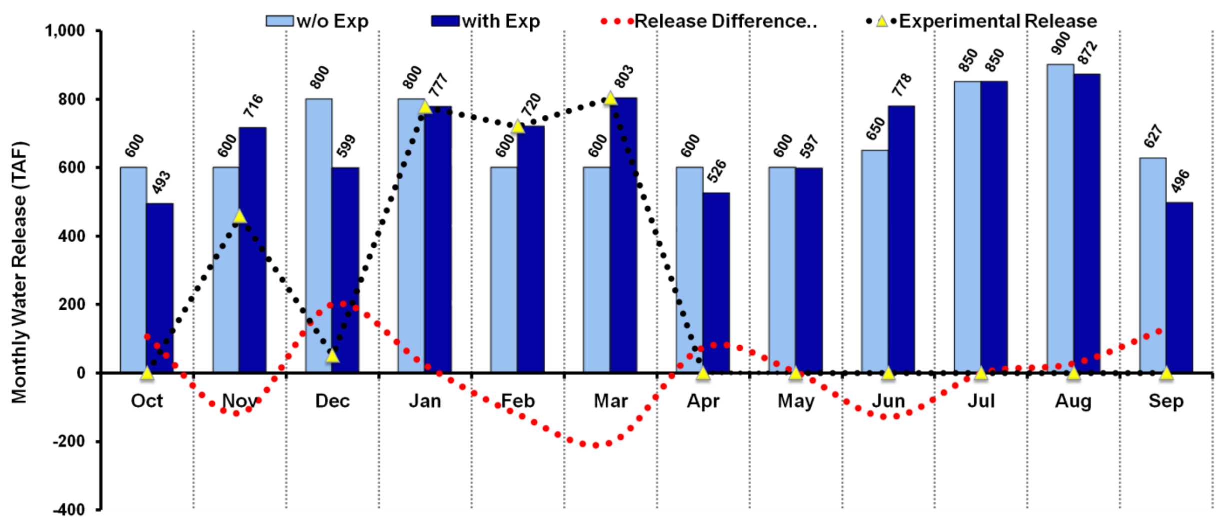

Figure 5.16 Monthly Water Releases in WY 2005

Figure 5.17 shows the monthly costs and benefits resulting from these five experimental releases. Because there were multiple experiments performed in this year and one required a redistribution of water release volumes among months within the year, the financial impacts for each experimental release cannot be determined individually. A benefit occurs in months when the monthly releases in the Baseline scenario exceed those in the Without Experiments scenario. There is a benefit because more water is available for use in the higher-priced hours of the Baseline scenario. The benefit can be enhanced in the months when the NNFSF occurs because of the favorable flow patterns; that is, releases are higher during the day and lower at night than would otherwise have occurred without the experiment. Limits on the criteria for up- and down-ramp rates are suspended during experimental releases so water could be released more quickly to reach high daytime hour releases and could be lowered more quickly to reach low nighttime releases.

Conversely, a loss occurs in months when the monthly releases in the Baseline scenario are lower than those in the Without Experiments scenario. The loss occurs because less water is available for use in the higher-priced hours in the Baseline scenario.

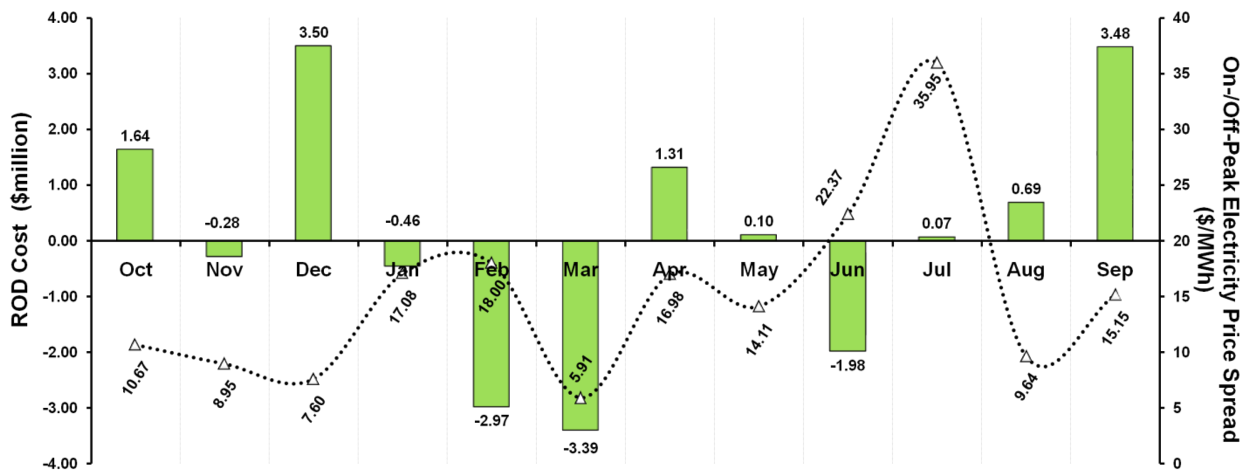

Figure 5.17 Cost of Experiments in WY 2005

As in WYs 2003 and 2004, there is an anomaly in January because water releases in the Baseline scenario are lower than they are in the Without Experiments scenario, and yet there is still a benefit. This benefit occurs for two reasons. First, the NNFSF flow pattern generally has higher releases during the higher-priced daytime hours. Second, the Lake Powell water elevation level, and consequently the power conversion factor, are each higher in the Baseline scenario than each is in the Without Experiments scenario. Figure 5.18 shows the Lake Powell elevations and power conversion factors in this WY. Therefore, more energy is produced in the Baseline scenario for each unit of water passing through the turbines than is produced in the Without Experiments scenario, resulting in a benefit to Western in that month.

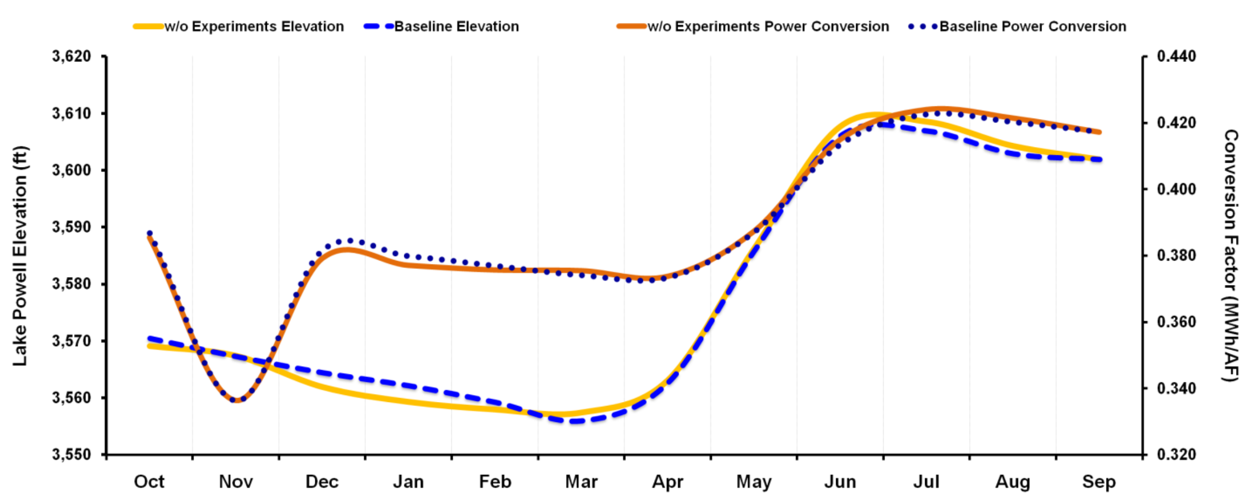

Figure 5.18 Comparison of Lake Powell Elevations and Power Conversion Factor in WY 2005

Monthly benefits in this WY can be as high as $3.4 million (March), while monthly costs can be as high as almost $3.5 million (December and September). Over the entire year, there was a combined net cost of almost $1.7 million from these two experiments.

5.9 Summary

Table 5.1 summarizes the results of the experiments conducted during the study period. Each experiment is listed in the year (s) in which it occurred along with the cost of the experiment and the total water released during the experiment. In those cases where the cost of the individual experiment could not be determined, the total costs for all experiments that occurred in that year are calculated.

Table 5.1 Summary of Experimental Flow Characteristics by Year

Water Year	Experiment (s)	Cost of Experiment(s) ($ millions)	Total Experimental Releases (TAF)
1997	APSF	−0.22	86
1998	HMF	0.106	166
1998	APSF	−0.106	161
1999	APSF	−0.089	167
2000/2001[1]	LSSF, APSF	−15.7	4,368
2002	APSF	0.029	126
2003	NNFSF, APSF	-3.1	2,381
2004	NNFSF, APSF	-1.6	2,406
2005	NNFSF, BHBF, 3 APSFs	1.7	2,809
TOTAL DURING STUDY PERIOD		**$11.9**	**12,670**

[1] WYs 2000 and 2001 are combined because water was reallocated between both WYs for the LSSF

The largest benefit from experiments was $3.1 million, while the largest cost was $15.7 million. The total cost of all experiments during the study period was $11.9 million.

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