ANL-19/18

Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2017

Energy Systems Division

About Argonne National Laboratory
Argonne is a U.S. Department of Energy laboratory managed by UChicago Argonne, LLC under contract DE-AC02-06CH11357. The Laboratory's main facility is outside Chicago, at 9700 South Cass Avenue, Argonne, Illinois 60439. For information about Argonne and its pioneering science and technology programs, see www.anl.gov.

DOCUMENT AVAILABILITY

Online Access: U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free at OSTI.GOV (http://www.osti.gov/), a service of the US Dept. of Energy's Office of Scientific and Technical Information.

Reports not in digital format may be purchased by the public from the National Technical Information Service (NTIS):

U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Rd
Alexandria, VA 22312
www.ntis.gov
Phone: (800) 553-NTIS (6847) or (703) 605-6000
Fax: (703) 605-6900
Email: **orders@ntis.gov**

Reports not in digital format are available to DOE and DOE contractors from the Office of Scientific and Technical Information (OSTI):

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
www.osti.gov
Phone: (865) 576-8401
Fax: (865) 576-5728
Email: **reports@osti.gov**

ANL-19/18

Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2017

by
Q. Ploussard, and T.D. Veselka
Energy Systems Division, Argonne National Laboratory

Work sponsored by the United States Department of Energy
and the Western Area Power Administration

June 2019

Foreword

This report was prepared by Argonne National Laboratory (Argonne) in support of a financial analysis of the Glen Canyon Dam high-flow experimental release that was intended to mobilize the sand in the river with high-volume water releases from the dam and redeposit it downstream as sandbars along the Colorado River. These sandbars serve, among other things, as habitat for wildlife. This experimental release was conducted during the period from November 7 to November 12, 2016. This analysis was funded by the Colorado River Storage Project (CRSP) Office of the U.S. Department of Energy Western Area Power Administration (WAPA). CRSP markets electricity produced by hydroelectric facilities collectively known as the Salt Lake City Area Integrated Projects including 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.

Staff members in Argonne's Energy Systems Division prepared this technical report with assistance from the WAPA CRSP and Energy Marketing and Management Offices.

This page is intentionally left blank.

Contents

Figures

Tables

Acronyms and Abbreviations

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

AHP	Available Hydro Power
Argonne	Argonne National Laboratory
CRSP	Colorado River Storage Projects
CY	Calendar Year
EIS	Environmental Impact Statement
EMMO	Energy Management and Marketing Office (WAPA)
FES	Firm Electric Service
GCD	Glen Canyon Dam
GCDEIS	Glen Canyon Dam Environmental Impact Statement
GTMax SL	Generation and Transmission Maximization Superlite
HFE	High-Flow Experiment
L&R	Loads and Resources
LTEMP	Long-Term Experimental and Management Plan
MLFF	Modified Low Fluctuating Flow
MSR	Minimum Schedule Requirement
PO&M-59	Power Operations and Maintenance, Form 59 (a Bureau of Reclamation form entitled, *Monthly Report of Power Operations – Powerplants*)
PCF	Power Conversion Factor
Reclamation	Bureau of Reclamation
ROD	Record of Decision
SCADA	supervisory control and data acquisition
SHP	Sustainable Hydro Power
SLCA/IP	Salt Lake City Area Integrated Projects
WAPA	Western Area Power Administration
WI	Western Interconnection
WRP	Western Replacement Power
WY	Water Year

Units of Measure

cfs	cubic feet per second
ft	feet
hr	hour
MW	megawatt(s)
MWh	megawatt-hour(s)
TAF	thousand acre-feet

Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2017

by

Q. Ploussard and T.D. Veselka

Abstract

This report examines the financial implications of the high-flow experiment (HFE) conducted at Glen Canyon Dam (GCD) during water year (WY) 2017. It is the eighth in a series of reports examining the financial implications of experimental flows conducted since the 1996 Record of Decision (ROD) was adopted in February 1997 (Reclamation 1996). The 1996 ROD implemented the Modified Low Fluctuating Flow (MLFF) regime. This is the first report since the 2016 ROD was adopted in January 2017 (Reclamation 2016). The 2016 ROD implemented the Long-Term Experimental and Management Plan (LTEMP) regime for monthly water releases, daily and hourly operating criteria, and experimental releases.

A report released in January 2011 examined WYs 1997 to 2005 (Veselka et al. 2011); a report released in August 2011 examined WYs 2006 to 2010 (Poch et al. 2011); a report released in June 2012 examined WY 2011 (Poch et al. 2012); a report released in April 2013 examined WY 2012 (Poch et al. 2013); a report released in June 2014 examined WY 2013 (Graziano et al. 2014); a report released in September 2015 examined WY 2014 (Graziano et al. 2015); and a report released in November 2016 examined WY 2015 (Graziano et al. 2016).

An experimental release may have either a positive or a negative impact on the financial value of energy production. Only one experimental release was conducted at GCD in WY 2017, specifically, a HFE release in November 2016. For this experimental release, financial costs of approximately $1.15 million were incurred because the HFE required sustained water releases exceeding the power plant's maximum flow rate. In addition, during the month of the experiment, operators were not allowed to shape GCD power production, neither to follow firm electric service (FES) customer day-ahead energy deliveries nor to respond to market prices.

This study identifies the main factors contributing to HFE costs and examines the interdependencies among these factors. It applies an integrated set of tools to estimate financial impacts by simulating GCD operations under two scenarios: (1) a Baseline scenario that mimics HFE operations both during the experiment and during the rest of the year when it complies with the 1996 daily/hourly operating criteria and the 2016 ROD monthly water release mandates, and (2) a counterfactual Without Experiments scenario identical to the Baseline scenario except it assumes that the HFE did not occur.

The Generation and Transmission Maximization Superlite (GTMax SL) model was the main simulation tool used to simulate the dispatch of the GCD hydropower plant and associated water releases from Lake Powell. GCD is a Colorado River Storage Project (CRSP) power resource

that is a component of the Salt Lake City Area Integrated Projects (SLCA/IP). In the modeling process the research team used extensive data sets and historical information on SLCA/IP power plant characteristics, hydrologic conditions, and Western Area Power Administration's (WAPA's) power purchase and sale prices. In addition to estimating the financial impact of the HFE, the team used the GTMax SL model to gain insights into the interplay among ROD operating criteria, exceptions made to criteria to accommodate the experimental releases, and WAPA operating practices.

1 Introduction

GCD (also known as the Powerplant) consists of eight generating units with a continuous operating capacity of 1,320 megawatts (MW) at unity power factor. It is one component of a larger system known as SLCA/IP. Electricity produced by the Powerplant serves the demand of 5.8 million consumers in 10 western states located in the Western Interconnection (WI). In the early days of its operation, the Powerplant had few restrictions. Except for a minimum water release requirement, the daily and hourly operations of the Powerplant were initially constrained only by the physical limitations of the dam structures, the Powerplant, and its storage reservoir, Lake Powell. The Powerplant's dispatch was principally driven by CRSP loads and market price signals, which often resulted in large fluctuations in Powerplant output and associated water releases.

Concerns about the impact of 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 (WAPA 2010). 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) ROD were adopted (Reclamation 1996). The 1996 ROD operating criteria, which implement the MLFF regime, limit hourly maximum and minimum water release volumes from the dam. The 1996 ROD criteria also constrain the change in the water release between consecutive hours and restrict the range of hourly releases on a rolling 24-hour basis.

More recently, in January 2017, a new ROD, referred to as the 2016 ROD, implemented the LTEMP Environmental Impact Statement (EIS) preferred alternative operating criteria. During WY 2016, the 2016 ROD started to be phased in via the implementation of 2016 ROD GCD monthly water release restrictions, but the 1996 ROD operating criteria continued to limit hourly and daily water releases. The 2016 ROD hourly and daily operational criteria were not implemented until the beginning of WY 2018, that is, after the end of the time period that is studied and documented in this report.

The Glen Canyon Dam Adaptive Management Program, established by the GCDEIS ROD (Reclamation 1996), conducts scientific studies on the relationship between Powerplant operations and downstream resources. Experimental water releases are performed periodically to monitor river conditions, conduct specific studies, enhance native fish habitat, and conserve fine sediment in the Colorado River corridor in Grand Canyon National Park.

This report follows several other financial analyses of GCD experiments that began in 1997. These experiments and their associated financial analyses, in chronological order, are as follows:

- Calendar year (CY) 1997–2005 experiments were reported in *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005* (Veselka et al. 2011);

- CY 2006–2010 experiments were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 2006 through 2010* (Poch et al. 2011);
- WY 2011 experiments were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2011* (Poch et al. 2012);
- WY 2012 experiments were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2012* (Poch et al. 2013);
- WY 2013 experiments were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2013* (Graziano et al. 2014);
- WY 2014 experiments were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2014* (Graziano et al. 2015); and,
- WY 2015 experiments were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2015* (Graziano et al. 2016).

One experiment, referred to as an HFE, was conducted during WY 2017. Occurring in November 2016, the HFE prescribed a fixed pattern of GCD water releases over a 6-day period. During 109 hours, prescribed releases exceeded the Powerplant's maximum flow rate by up to 15,000 cubic feet per hour (cfs). This "spilled" water did not flow through the plant's turbines to produce energy and thus resulted in a financial cost to WAPA. This report describes the method that was used to model the operation of SLCA/IP hydropower resources, which includes GCD, and discusses the financial costs of conducting this experiment.

During normal operations, GCD is governed by stringent operating rules as specified in the 1996 ROD. Although these rules yield environmental benefits, they also have financial and economic implications. These criteria reduce the flexibility of operations, diminish dispatchers' ability to respond to market price signals, and lower 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 the HFE period that occurred during November 2016, operational flexibility was essentially eliminated—water had to be released according to a fixed and prespecified schedule. An integrated set of tools was used to estimate the financial impacts of the HFE by simulating GCD operations under two scenarios, namely, (1) a Baseline scenario that mimics HFE operations during the experiment and during the rest of the year in compliance with 2016 ROD monthly operating criteria and 1996 ROD daily/hourly water release limits, and (2) a counterfactual Without Experiments scenario identical to the Baseline scenario except that it assumes that the HFE did not occur.

The GTMax SL model simulates the SLCA/IP power plant dispatch from which WAPA's financial revenues are computed. This tool uses an integrated systems modeling approach to dispatch power plants in the system, while recognizing interactions among supply resources over time. The retrospective simulation of WY 2017 SLCA/IP operations made use of extensive sets of data and historical information on SLCA/IP power plants' characteristics and hydrologic conditions. It also used actual WAPA power sale and purchase prices for transactions conducted during WY 2017.

The GTMax SL model simulated two scenarios. Under the Baseline scenario, GTMax SL mimics the HFE as documented by WAPA and Reclamation and, for the rest of the year, simulates operations that comply with the 1996 and 2016 ROD operating criteria. The second scenario, Without Experiments, is identical to the Baseline scenario, except it assumes that the experimental release did not occur. Differences in the financial position between the two scenarios represent the change in the monetary value of power attributed to experimental releases. In addition to estimating the financial impact of experimental releases, the GTMax SL model was used to gain insights into the interplay among ROD operating criteria, exceptions made to criteria to accommodate the experimental releases, and WAPA operating practices.

This page is intentionally left blank.

2 ROD Criteria and WAPA Operating Practices

Important factors that explain the financial impacts of experimental releases include the following:

(1) Hourly and daily operating criteria according to the 1996 ROD,
(2) Exceptions to the ROD criteria made to accommodate the experimental releases,
(3) Monthly water release (2016 ROD), and
(4) WAPA scheduling guidelines.

This section provides background information on each of these factors.

2.1 Hourly and Daily Operating Criteria and Exceptions

Operating criteria specified in the 1996 ROD are intended to temper the rate of change in hourly and daily water releases. The criteria selected were based on the MLFF Alternative as described in the final GCDEIS (Reclamation 1996). These criteria were put into practice by WAPA from February 1997.

Flow restrictions under the 1996 ROD are shown in Table 2.1, along with operational limits in effect prior to June 1, 1991, for comparison. The 1996 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 maximum hourly increase (i.e., the up-ramp rate) is 4,000 cfs/hour (hr), and the maximum hourly decrease (i.e., the down-ramp rate) is 1,500 cfs/hr. The 1996 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/day, depending on the monthly volume of water releases. 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 1996 ROD operating criteria. It is, however, allowed to exceed this limit in order 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 also be exceeded; however, water must be released at a constant rate. Exceptions to the operating criteria are also made to accommodate experimental releases. For the experiment discussed in this report, maximum flow rates above 25,000 cfs were allowed during the HFE conducted in November 2016.

Table 2.1: Operating constraints prior to 1991 and under the 1996 ROD (after 1997)

Operational Constraint	Historic Flows (before 1991)	ROD Flows (after 1997)
Minimum release (cfs)	*3,000 during the summer* *1,000 during the rest of the year*	*8,000 from 7:00 a.m. to7:00 p.m.* *5,000 at night*
Maximum release (cfs)	31,500	25,000
Daily fluctuations (cfs/24 hr)	28,500 during the summer 30,500 during the rest of the year	5,000, 6,000, or 8,000 depending on release volume[a]
Ramp rate (cfs/hr)	Unrestricted	4,000 up 1,500 down

[a] Limited to 5,000 cfs/day when monthly water release is less than 600 TAF; 6,000 cfs/day when monthly water release is 600 TAF to 800 TAF; and 8,000 cfs/day when monthly water release is greater than 800 TAF.

Source: Reclamation 1996.

2.2 Monthly Water Release Volumes

Reclamation sets the monthly water releases in the Upper and Lower Colorado River Basin 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 flood control, river regulation, consumptive uses, water quality control, recreation, and fish and wildlife enhancement, and to address other environmental factors (Reclamation 2013). Moreover, since January 2017, monthly water releases at GCD have complied with the LTEMP ROD operating criteria (Reclamation 2016).

Release decisions are made by using current runoff projections provided by the National Weather Service Colorado Basin River Forecast Center. Because future hydrologic conditions in the Colorado River Basin are not known with certainty and because events do not unfold as previously projected, Reclamation periodically adjusts its annual operating plan. Its release decisions are adjusted on a monthly basis to reflect projections made by rolling 24-month studies, which are updated monthly.

For the Baseline and Without Experiments scenarios, actual SLCA/IP monthly water releases, as recorded in Reclamation’s Form PO&M-59 (Reclamation undated) and available on the Reclamation website for WY 2017 (Reclamation 2018), were used for all hydropower plants except for GCD. Reclamation provided the GCD monthly water release input data for both scenarios and the hourly water releases during the HFE (Patno 2018).

Table 2.2 shows the monthly water release volumes and the end-of-month elevations of the Lake Powell reservoir for each scenario during the study period. The HFE conducted in November 2016 required water to be reallocated among months; specifically, flows were reduced in March and May (Patno 2018). This reallocation is seen in monthly water releases between the Baseline and Without Experiments scenarios.

Table 2.2: Monthly water releases and Lake Powell elevations for both scenarios in WY 2017

		Baseline (With Experiments)		Without Experiments		Difference (With−Without)	
Calendar Year	Month	Water Release (TAF)	Lake Powell Elevation (ft)	Water Release (TAF)	Lake Powell Elevation (ft)	Water Release (TAF)	Lake Powell Elevation (ft)
2016	Oct.	600	3,609.5	600	3,609.5	0	0
2016	Nov.	744	3,605.9	600	3,607.3	144	−1.5
2016	Dec.	900	3,600.5	900	3,602.0	0	−1.5
2017	Jan.	900	3,595.7	900	3,597.2	0	−1.5
2017	Feb.	700	3,594.3	700	3,595.8	0	−1.5
2017	Mar.	578	3,597.4	650	3,598.1	−72	−0.7
2017	Apr.	600	3,605.7	600	3,606.5	0	−0.7
2017	May	628	3,620.9	700	3,620.9	−72	0
2017	June	800	3,636.0	800	3,636.0	0	0
2017	July	950	3,634.9	950	3,634.9	0	0
2017	Aug.	900	3,631.2	900	3,631.2	0	0
2017	Sept.	700	3,628.3	700	3,628.3	0	0

It should be highlighted that the monthly water releases in the Baseline scenario correspond to those planned by Reclamation ahead of time, not those that actually occurred, that is, historical releases. Historical monthly water releases were slightly different from the planned releases as explained and described in Appendix A and graphed in Figure A.1. Also, because monthly releases differed from actual levels, Lake Powell monthly baseline reservoir elevations were adjusted to reflect and be consistent with Reclamation planned monthly release volumes. As shown in the last column of the table, additional reservoir elevation adjustments are made under the Without Experiments scenario to reflect monthly water release volume that differ from the Baseline scenario.

In addition to analyzing the financial cost of conducting the November 2016 HFE using the "planned" monthly water releases shown above, a second analysis was performed based on actual water releases under the Baseline scenario and the planned water releases differences shown in Table 2.2. This analysis and results are also presented in Appendix A. The estimated cost of the HFE experiment using the "actual" monthly water releases are very similar to the results using the planned releases.

2.3 Montrose Scheduling Guidelines

The actual hourly scheduling of SLCA/IP hydropower plant operations is performed by the WAPA Energy Management and Marketing Office (EMMO) in Montrose, Colorado. Schedulers base their decisions on a set of scheduling priorities and guidelines, including a directive to comply with environmental operating criteria. The GCD restrictions shown in Table 2.1 describe operational boundaries. Within these limitations there are innumerable hourly release patterns and dispatch drivers that comply with a given set of operating criteria. Thus, although the operational range was significantly wider prior to the 1996 ROD, a broad range of GCD ROD-compliant operational regimes still exists. Other SLCA/IP power plants must also comply with various operational limitations. For example, Flaming Gorge releases are patterned such that downstream flow rates are within Jensen Gage flow limits (Reclamation 2006). In addition, releases from the Wayne N. Aspinall Dams cannot result in reservoir elevations that are outside of (1) a specified range of forebay elevation levels and (2) limits on decreases in reservoir elevations over time (Reclamation 2012).

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 one driven by Firm Electric Service (FES) customer loads. Within the boundaries of these operating constraints, SLCA/IP power resources are used to serve firm load. WAPA also places a high priority on purchasing to serve load in 16-hour, on-peak blocks, and in 8-hour, off-peak blocks in the day-ahead market to minimize exposure to real-time price spikes and volatility. Under energy long-positions WAPA also sells blocks of power on the day-ahead bilateral market.

As illustrated in Figure 2.1, when hydropower resources are short of load, SLCA/IP generation resources are typically “stacked” on top of the block purchases as a means of following FES customer load. Because of operational limitations, WAPA staff may need either to purchase or to sell varying amounts of energy on an hourly basis on the day-ahead market, the real-time market, or both.

In other situations, however, market sales can sometimes be significant when SLCA/IP resource generation exceeds firm load. For example, during the off-peak-load hours of the HFE, the GCD Powerplant was operating at full available capacity, while at the same time, firm customer requests for power were relatively low. During this period, day-ahead sales during off-peak hours were as high as 360 megawatt-hours (MWh).

The GTMax SL model logic/methodology and inputs are designed to mimic EMMO guidelines in terms of serving FES customer loads and the selling of power in energy-long positions. The model, however, does not simulate WAPA’s extensive transmission system and the use of transmission pathways to engage in varies activities such as firm transmission line sales, power exchanges with Salt River Projects, and real-time energy arbitrage activities in which WAPA buys energy at one point in the grid and sells it at another point at a higher price.

The load-following objective facilitates a linkage between WAPA's FES contractual obligations to its customers 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. WAPA is able to affect the shape of customer firm load requests indirectly through specifications in its contract amendments. In turn, these customer loads affect both SCLA/IP power plant operations and hourly reservoir releases. Contract terms that indirectly affect load and power plant operations include sustainable hydropower (SHP) and available hydropower (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 WAPA in each hour. The load-following dispatch directive minimizes scheduling problems and helps WAPA avoid noncompliant water releases.

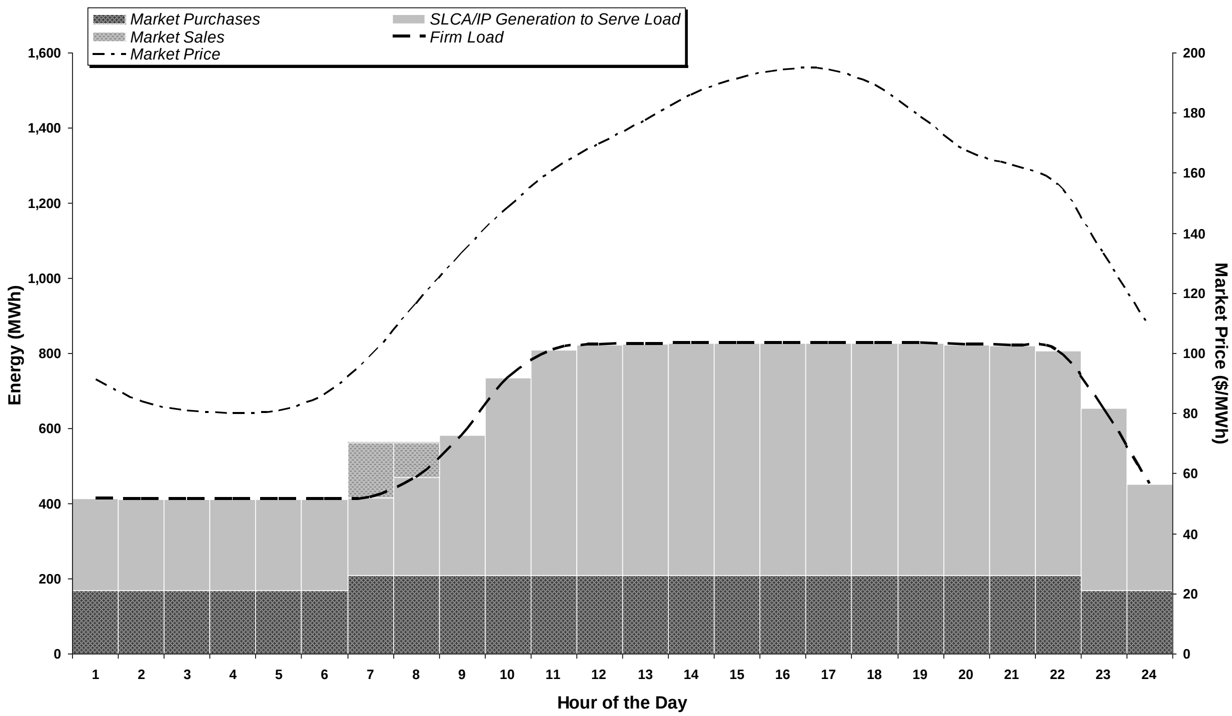


Figure 2.1: Illustration of the firm-load-driven dispatch guideline under the 1996 ROD operating criteria when SLCA/IP resources are short of load

In addition to load-following, dispatchers follow other practices specific to GCD Powerplant operations. These practices fall within ROD operational boundaries but are not ROD requirements. Therefore, WAPA may alter or abandon these institutional practices at any time. One practice involves reducing generation at GCD to the same minimum level every day during low-price, off-peak hours. WAPA also avoids drastic changes to total water volume releases when they occur over successive days. In this analysis, therefore, it was assumed that the same volume of water was released each weekday, except during the HFE month for the Baseline (With Experiments) scenario.

Another WAPA scheduling practice was observed during the examination of historical water releases shown in the CRSP daily Loads and Resource (L&R) preschedule sheets. On both Saturdays and Sundays during WY 2017, Saturday releases were generally not less than 90% of the average weekday release, whereas Sunday releases were generally not less than 85% of the weekday release. This was true for all the months of WY 2017 except for November, when the HFE occurred. During November, weekend release volumes were generally the same as weekday release volumes during non-HFE periods. In addition, during the summer season (from May to November), operations allow one cycle of raising and lowering GCD Powerplant output per day. This practice increases to a maximum of two cycles during other seasons of the year (from December to April) as dictated by the hourly load pattern.

Changes in WAPA's scheduling guidelines did not occur abruptly, but rather subtly, and over a period of months. These changes were not only the result of the operational constraints imposed by the ROD but also attributable to changing market conditions, such as persistent drought, electricity market disruptions in WY 2000 and WY 2001, and extended experimental releases with large fluctuations in daily flow rate. WAPA found that by instituting load-following dispatch, it could better control its exposure and risk to market price fluctuations (Palmer 2010). New scheduling guidelines were implemented during WY 2001.

3 Description of Experimental Releases

One experimental release was conducted during WY 2017, namely, the HFE in November 2016. This section describes this experimental release, its characteristics, and when it occurred. Table 3.1 summarizes the operational characteristics of GCD releases during the experimental release, such as maximum and minimum flows, maximum daily fluctuations, and maximum and minimum ramp rates.

Table 3.1: Characteristics of GCD Powerplant experimental release

Event	Date	Maxi-mum Flow (cfs)	Mini-mum Flow (cfs)	Maximum Hourly Up-Ramp Rate (cfs/hr)	Maximum Hourly Down-Ramp Rate (cfs/hr)	Maximum Daily Fluctuation (cfs/day)	Water Reallocated within Year	Exception to 1996 ROD Criteria
HFE	11/7/2016–11/12/2016	36,481	6,490	4,253	1,992	29,991	Yes	Yes

The November 2016 HFE was conducted according to the 10-year (2011–2020) protocol for short-duration, high-volume controlled releases from GCD during sediment-enriched conditions (Iseman 2016; Reclamation 2011). The objective of this multiyear plan is to investigate how multiple events could be more effective in building sandbars and conserving sand over long periods. As a sediment conservation measure, HFEs are intended to rebuild sandbars and beaches; improve the riparian resources and protect archaeological resources by building up sandbars and redepositing sand at higher elevations; preserve and restore camping beaches; reduce near-shore vegetation; and rejuvenate backwaters, which can be important rearing habitat for native fish.

The HFE ran from Monday, November 7, to Saturday, November 12. The total duration at high flow was 5 days, with 4 days at a nominal peak release of 36,000 cfs. The flow rate exceeded the capability of the turbines for 109 hr, with water released through the dam's hollow jet tubes (river outlet works or bypass), reaching a maximum of about 15,000 cfs. No electricity was generated by the water released through the hollow jet tubes, which totaled 126 TAF. During the HFE, the maximum power release was 21,610 cfs. This release was less than power plant capacity because two units were not operational due to a scheduled rotor repair.

The flow pattern for the HFE is shown graphically in Figure 3.1. To compensate for the HFE water release, the daily water releases during the non-HFE days in November 2016 were cut back to approximately 6,500 cfs in hours 1 to 5, 9,000 cfs in hours 6 to 23, and 8,000 cfs in hour 24. During November 2016, the hourly profile was the same for both weekends and weekdays. So that sufficient water was available to perform this experiment, water that would otherwise have been used in months after this experiment was redistributed for use during the HFE (see Table 2.2).

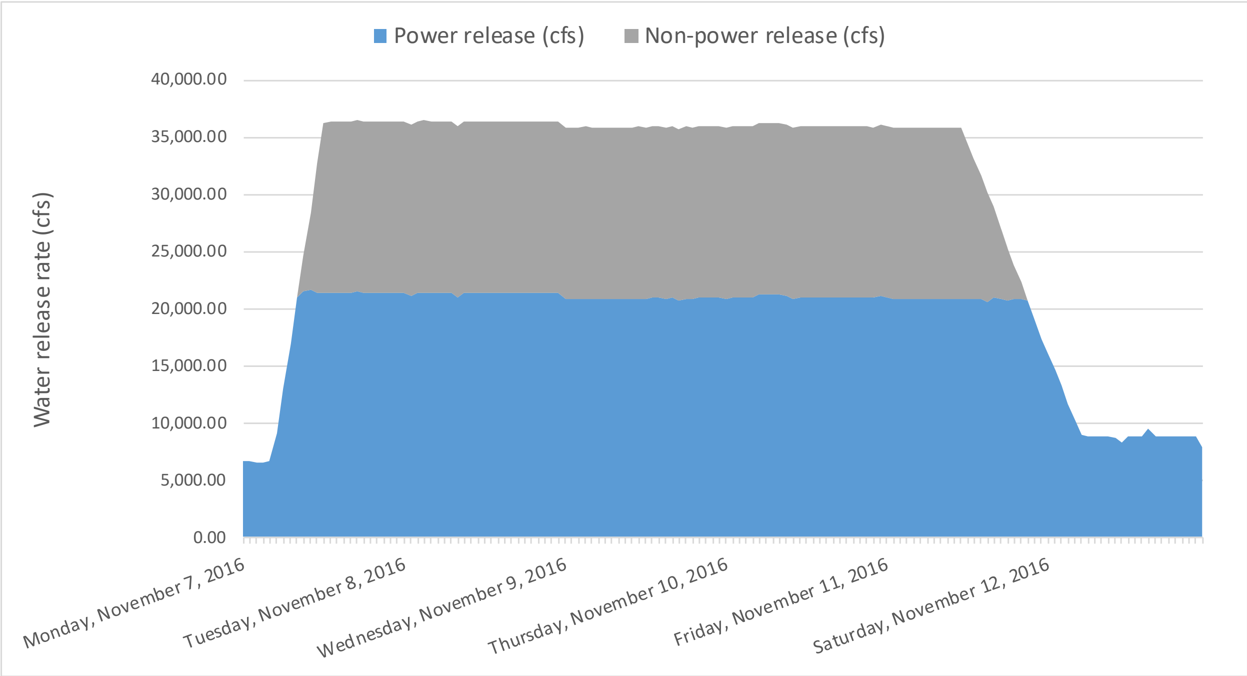


Figure 3.1: Release pattern of the HFE conducted in November 2016

4 Methods and Models

For the WY 2017 analysis, financial impacts were computed by comparing simulated results between two operating scenarios:

(1) The Baseline scenario**,** which assumes 1996 ROD operating criteria for daily and hourly operations, the occurrence of the November 2016 HFE prescribed hourly releases, exceptions to the ROD criteria to accommodate the experimental release, and *planned* monthly release volumes in compliance with the 2016 ROD criteria taking into account the HFE release; and

(2) The Without Experiments scenario**,** which assumes 1996 and 2016 ROD operating criteria, the absence of any experimental releases, and *planned* monthly release volumes that also comply with the 2016 ROD criteria but differ from the Baseline scenario.

In financial analyses of experimental releases prior to WY 2014, the impacts were determined from the difference in the *value of GCD energy* production between the two simulated operating scenarios. For WY 2017, as for WY 2014 and WY 2015, the CRSP Office monetary impact was assessed from the difference in *energy-related financial transactions*. Normally, both methods yield very similar if not identical results. This revised analytic approach was undertaken at the request of WAPA to better capture financial losses associated with the effect of WAPA selling excess energy production at very low energy prices during the HFE release. During the experiment, WAPA sold more prescheduled energy (day-ahead bilateral market) than would have been sold if the experiment had not been conducted. This excess power was sold at an exceptionally low hourly price because EMMO staff could not find buyers that were willing to pay more. Hence, these transactions incurred an additional financial penalty.

The financial methodology used for this HFE analysis was further improved. First, instead of a single financial value for energy, separate prices were computed and applied to energy purchases and sales. This refinement was made because it was observed that during the study period the average purchase price of both real-time and day-ahead transactions was noticeably lower than the sale price. Second, hourly long and short positions were computed mimicking the procedure used in the CRSP L&R spreadsheet. Third, except for GCD all load and resource line items were obtained from the CRSP L&R, which were treated as fixed input values under both the Baseline and Without Experiments scenarios; that is, to limit the financial impact on GCD, only operations at GCD were used as decision variables along with energy purchases and sales.

Finally, in previous HFE analyses, the GTMax model was used to simulate the system dispatch (Graziano et al. 2016; Veselka et al. 2011). For this analysis, the GTMax model was no longer used and was replaced by a “lighter” version called GTMax SL. It is currently the main simulation tool used to simulate the dispatch SLCA/IP hydropower plants, including GCD. It simulates GCD operations and also provides insights into the interplay among the ROD operating criteria, exceptions to the criteria to accommodate experimental releases, modifications to monthly water volumes, and WAPA’s scheduling guidelines and goals. The GTMax SL model is supported by several other tools and databases. These support tools include the Market Price spreadsheet, Experimental Release spreadsheet, and a Financial Value Calculation spreadsheet.

For each scenario, the GTMax SL model is run for one typical week per month for all months during WY 2017. Weekly simulations are scaled up such that each run represents a one-month time period. The GTMax SL model is supported by an input spreadsheet that contains 1996 ROD operating criteria, historical and planned hydropower operations data, and parameters for WAPA scheduling guidelines. The input spreadsheet also performs various computations and prepares input data for GTMax SL. GTMax SL 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 GTMax SL Input Data for the GCD Reservoir and Powerplant

Data for GCD reservoir and power plant input into GTMax SL are based on planned water release volumes (Patno 2018), historical monthly statistics (Reclamation 2018), WAPA CRSP L&R spreadsheets, and supervisory control and data acquisition (SCADA) data. This information includes water releases, forebay elevation, and power conversion factors (PCFs) at GCD. Because planned Reclamation reservoir water release data are monthly and GTMax SL runs simulate a single week, hourly modeled releases are scaled by the number of times each hour "type" occurs during the simulated month. An hour type represents a day of the week (i.e., Monday through Sunday) and an hour of the day numbered from 1 through 24. For example, if in the month of August there are five Sundays, the hourly simulated water release between midnight and 1 a.m. on Sunday in the typical week simulation is scaled by five in the GTMax SL model. This methodology therefore accounts for different daily water release volumes while respecting the total monthly water release volume.

Because simulated monthly water release volumes from GCD in the Baseline and Without Experiments scenarios differ from historical volumes, reservoir elevation levels and PCFs are adjusted accordingly. A higher-than-historical monthly water release results in a lower-than-historical forebay elevation, and vice versa. A second-degree polynomial equation has been used to model the link between the volume of stored water and the pool elevation based on historical values (Figure 4.1). According to the coefficient of determination obtained ($R^2 = 1$), this polynomial curve provides an excellent representation of the relation between the volume of water stored and the pool elevation.

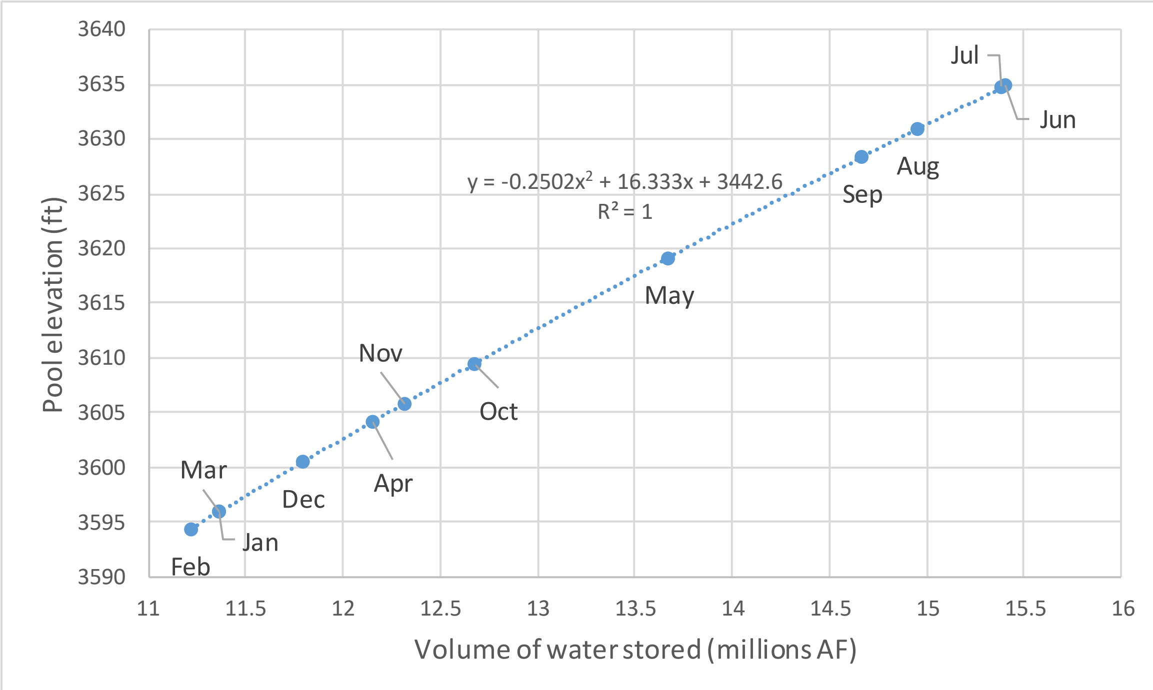


Figure 4.1: Fitting curve between the historical volume of stored water and the historical pool elevation at GCD during WY 2017

The volumes of stored water in each month at GCD under a given scenario (Baseline or Without Experiments) are calculated based on the differences of monthly water releases between the scenario and the historical data. Then the pool elevation at GCD under the scenario is estimated based on the previously calculated volume of stored water and the polynomial equation illustrated in Figure 4.1. More details about these calculations can be found in section 4.5.1 of *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005* (Veselka et al. 2011).

The factor that relates the conversion of Lake Powell water releases to power production, referred to as a PCF, for the GCD Powerplant is primarily driven by the forebay elevation. Therefore, a different reservoir elevation under the simulated scenarios shown in Table 2.2 implies a different PCF than the one that historically occurred. To compute the monthly PCF under both scenarios, first the least-squares fit between Lake Powell historical end-of-month forebay elevation and the GCD PCF during WY 2017, as depicted in Figure 4.2, was computed. In this case, there is no linear curve that perfectly correlates PCF and the forebay elevation. However, there is clearly a strong relationship between the two sets of data. The linear fit results in a coefficient of determination of 0.92. Other forms of curve-fitting equations were also tested such as a second-order polynomial curve. However, the increased accuracy of the more complex curve fits, in terms of a higher coefficient of determination, was close to nil.

Next, the PCF used in a given scenario (Baseline or Without Experiments scenario) in each month is computed by adjusting the historical PCF based on the slope of the linear fit in Figure 4.2 and the change of the forebay elevation under the given scenario. For instance, in April 2017, the historical forebay elevation at GCD is 3,604.14 ft, whereas it is 3,606.50 ft under the Without Experiments scenario. During the same month, the historical PCF is equal to 4,345.68 kWh/AF. The slope from Figure 4.2 shows that there is an increase of approximately 8.415 kWh/AF in the PCF for each additional foot in the forebay elevation. Thus, it is estimated that the PCF under the Without Experiments scenario during this month will be equal to

$$4{,}345.68 + 8.415 \times (3{,}606.50 - 3{,}604.14) = 4{,}365.54 \text{ kWh/AF}.$$

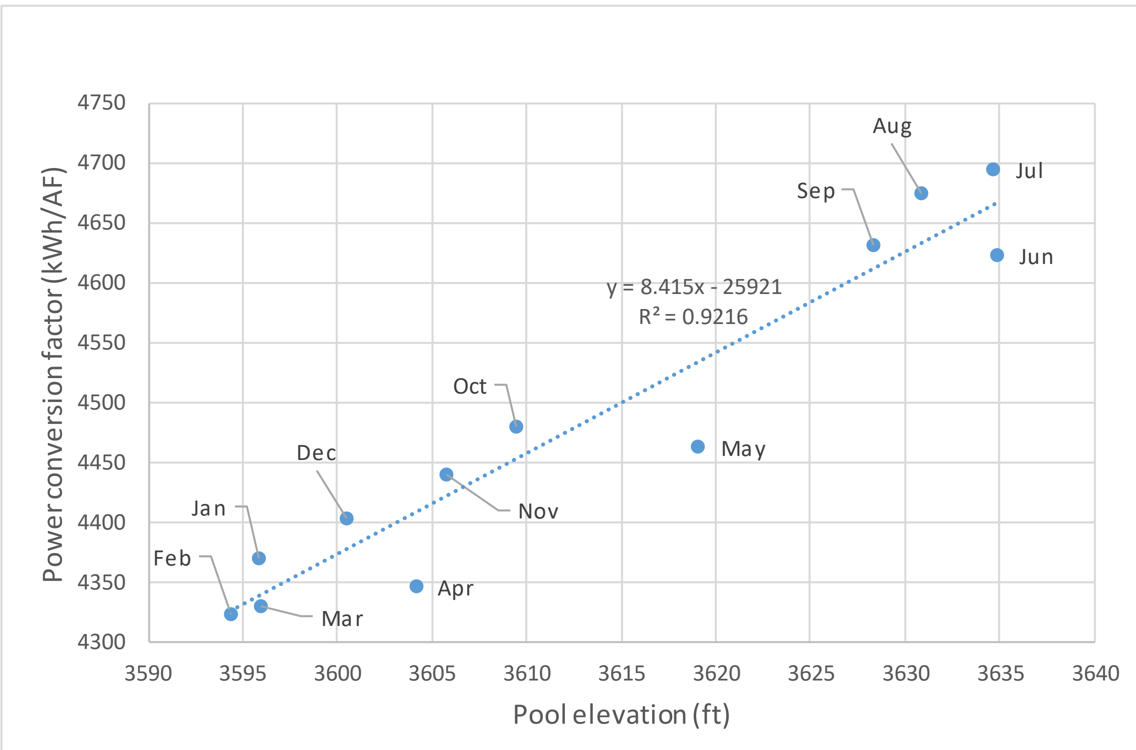


Figure 4.2: Relation between the historical PCF and the historical pool elevation at GCD during WY 2017

The maximum output capability (Output) at GCD is computed monthly. It is the minimum of (1) the physical capacity of the power plant turbines and (2) the maximum production level based on the forebay. Further details about the way the maximum output capability is computed can be found in section 4.5.1 of *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005* (Veselka et al. 2011).

Further adjustments are made to the maximum generation level at the GCD Powerplant to account for unit outages. These adjustments include all types of outages, both scheduled and random, that take units off-line because of unforeseen problems at the plant. Historical outage levels provided by Reclamation (Bishop 2018) 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 of the eight turbines at GCD was out of service for a month, the maximum output was reduced by approximately 12.5% (i.e., one-eighth).

4.2 Model Input Data for Other SLCA/IP Supply Resources

In order to isolate the financial cost of conducting the 2016 HFE to only GCD, the energy supplied by all SLCA/IP sources except GCD is not optimized by the GTMax SL Model. Instead, the hourly energy supplied by other SLCA/IP sources is fixed and aggregated into a single equivalent generation profile representing their historical values. More specifically, the total supply from these resources as defined by the EMMO CRSP L&R spreadsheet includes the following:

- Flaming Gorge hydropower generation,
- Blue Mesa hydropower generation,
- Morrow Point hydropower generation,
- Crystal hydropower generation,
- Fontenelle hydropower generation,
- Upper and Lower Molina hydropower generation,
- Deer Creek hydropower generation, and,
- Energy exchange into the SLCA/IP system.

Power plant generation data are from SCADA information (WAPA 2018). However, when data are missing, pre-scheduled operations contained in historical EMMO (Dean 2018) L&R files are used as a surrogate.

A typical week is used in GTMax SL to represent the supply profile for each month of the study period. This typical week is constructed by calculating the typical profile for three types of days: weekday, Saturday, and Sunday. Holidays are considered to be the same type as Sunday. Typical profiles for each day of the week are average values for a specific hour. For example, the typical generation at 1:00 a.m. on a weekday in January is the average of all 1:00 a.m. generations during weekdays in that month. An illustration of a typical week supply profile is provided in Figure B.1 in Appendix B.

4.3 Model Input Data for Loads and Market Prices

As previously described, the revised methodology mimics the CRSP L&R process. Data for fixed loads input into GTMax SL are based on prescheduled operations from EMMO (Dean 2018) as recorded in CRSP L&R data. For simplicity, customer load is aggregated with other types of loads to represent the total amount of energy withdrawn from the system. More specifically, this aggregate load comprises the following line items from the L&R table:

- Customer AHP load,
- Western Replacement Power (WRP) monthly load,
- WRP daily load,
- Miscellaneous load,
- Pump operations at Deer Creek,

- Transmission losses, and
- SLCA/IP system energy exchanges out of the system.

The hourly aggregated load profile was computed for all hours during the entire WY 2017 study period. These data are not used directly in GTMax SL. Instead, GTMax SL uses a typical load week to represent the demand profile for each month of the study period. This typical week is constructed by calculating the typical profile for three types of days: weekday, Saturday, and Sunday. Holidays are considered to be the same type as Sunday. Typical profiles for each type of day are average values for a specific hour. For example, the typical demand 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. A typical week demand profile is depicted in Figure B.2 in Appendix B.

Real-time sale prices obtained from EMMO (Dean 2018) for actual WAPA transactions are used to create a set of typical-week market prices input into GTMax SL. A weekly price profile is the main driver for determining optimal generation patterns at GCD within operating criteria and EMMO operating guidelines. The optimal GCD Baseline scenario generation profile that uses this set of typical week real-time sale prices is very similar to actual historical patterns. This likeness validates the use of the real-time sales price profile as a key model driver. A comparison between the typical week generation profiles at GCD, based on historical data and generated by the model, is shown in Figure B.3 of Appendix B.

5 Cost of Experiment in WY 2017

WY 2017 had one experiment, namely, the HFE in November 2016, which had a nominal peak flow of 36,000 cfs. Supporting these high flows required reallocations of 144 TAF of water from March and May 2017 to November 2016.

Figure 5.1 shows the monthly water releases in WY 2017 for the two scenarios. The amounts of water released in the Baseline (labeled "With HFE Release") and Without Experiments (labeled "Without HFE Release") scenarios differed in 3 months. For November, water releases were higher in the Baseline scenario to accommodate the HFE. These higher water releases were balanced with lower releases during March and May.

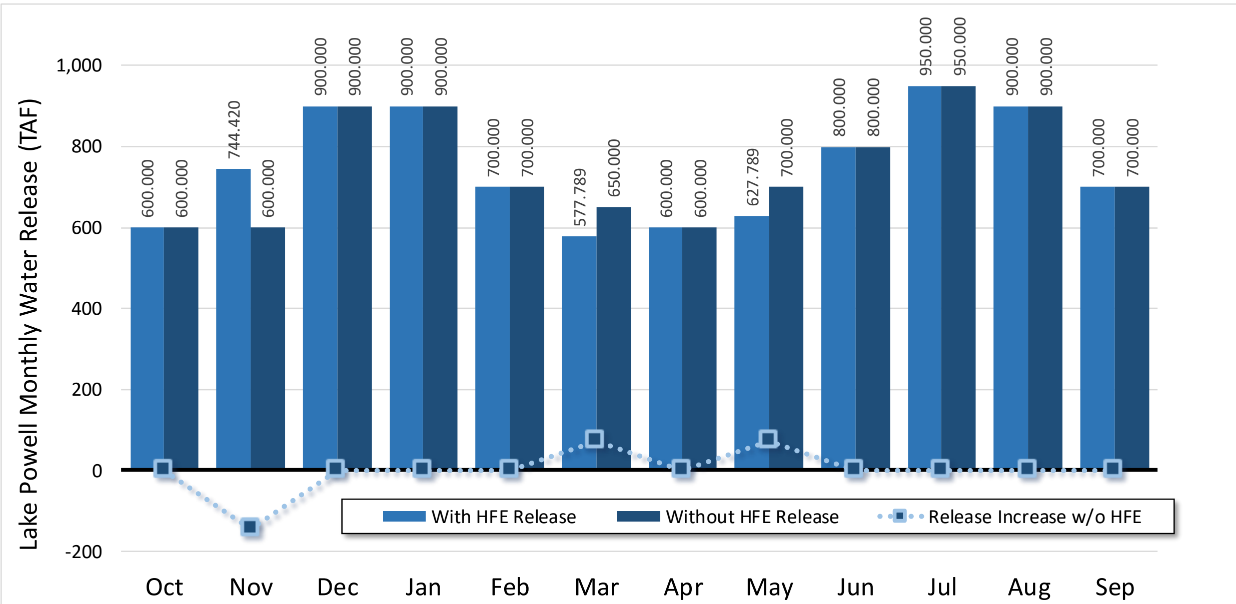
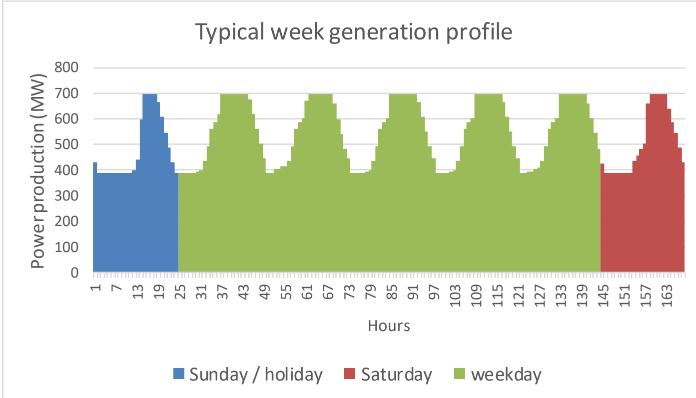


Figure 5.1: Monthly water releases at GCD in WY 2017

The financial analysis for the WY 2017 HFE considers the difference in net energy revenues between the Baseline and Without Experiments scenarios.

5.1 Generation Profile at GCD: From a Typical Week to an Entire Month

The Baseline and Without Experiments scenarios are run with the GTMax SL model. This results in a hourly GCD generation profile for a typical week in each month and each scenario. The hourly generation profile at GCD is expanded from a typical week (comprising 168 hours) to an entire month (comprising all the hours in the month). This is done by building a new one-month hourly profile in which the hourly profile of each day is the profile of its day type — weekday, Saturday, or Sunday/holiday. This procedure is illustrated with the generation profile at GCD in July 2017 in Figure 5.2.



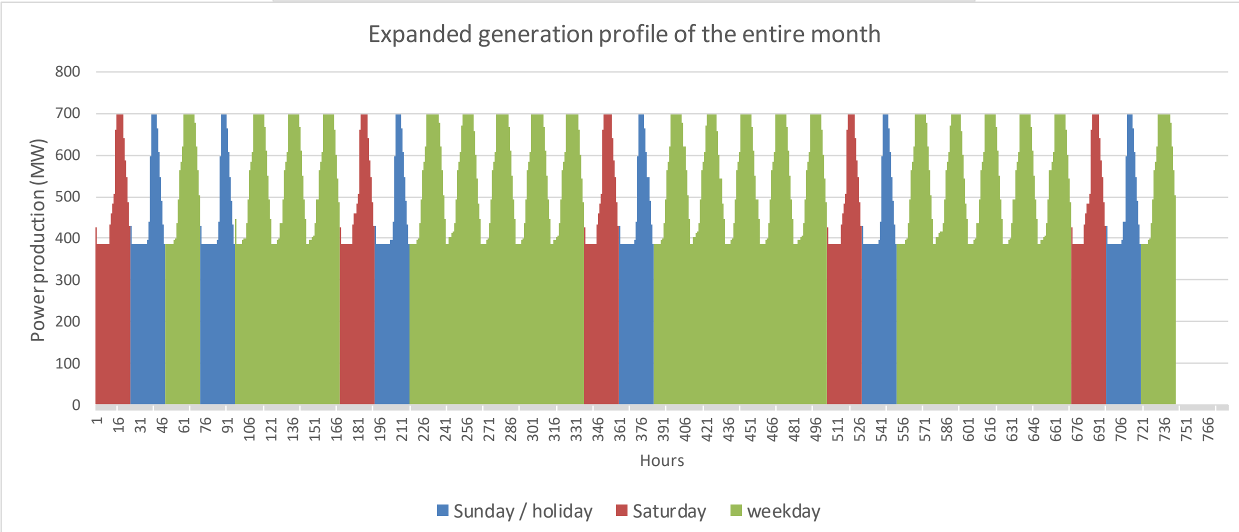


Figure 5.2: Typical week and complete month representation of the generation profile at GCD in July 2017

5.2 Energy Purchased and Energy Sold Profiles

Once an expanded representation of the generation profile at GCD has been created, the hourly profile of net energy sale and purchase quantities are calculated for the SLCA/IP system. For each hour of the entire study time, the following energy balance equation is satisfied by financial spreadsheet calculations:

$$\text{SLCA/IP Generation} + \text{Net Purchases} = \text{SLCA/IP Load} + \text{Net Sales}$$

For this equation, SLCA/IP supply resources are described in Section 4.2. On the other hand, the load profile used here corresponds to the historical hourly profile of total load, whose components are described in Section 4.3, and not the expanded version of the typical weekly load profile. Energy purchases in the equation include both day-ahead and real-time purchases. Likewise, energy sales are a combination of both day-ahead and real-time sales. The energy balance equation is satisfied for each hour of the entire modeled month (i.e., the expanded monthly time period, as shown in Figure 5.2). Except for GCD Powerplant generation, all other SLCA/IP supply resources and loads are identical under both scenarios. All financial differences between the two scenarios are therefore directly attributed to a changed hourly generation pattern at GCD; that is, because loads are fixed and identical under both scenarios, the changed GCD generation profile has a direct impact on hourly energy transaction levels and associate costs and revenues.

For modeling purposes both net energy purchases and net energy sales are always positive. It therefore follows that either one or both of these transaction values is set equal to zero in each hour by applying the following equations:

$$\text{Net Purchases} = \max(0, \text{Load} - \text{Generation})$$
$$\text{Net Sales} = \max(0, \text{Generation} - \text{Load})$$

For example, if there is a positive net energy purchase in a given hour, the net sales in that same hour is zero, and vice versa.

5.3 Purchase and Sale Price Profiles

Under both the Baseline and Without Experiments scenarios, purchase prices used for financial calculations are set equal to the actual EMMO average price of all prescheduled and real-time purchase transactions weighted by purchase quantities. Similarly, sale prices used for financial calculations are the weighted average price of all day-ahead and real-time sales. If, in a given hour of a given day and month, there are no price data, a "typical" price is used as a surrogate value. It is based on the quantity-weighted average price of all weekday, Saturday, or Sunday/holiday transactions for a month during a specific hour of the day (e.g., all purchases that occurred at 1 a.m. on Sunday during January).

When applying these prices in combination with the net purchase and sale quantities described in section 5.2, the methodology implicitly assumes the following:

(1) An incremental *increase* in net **purchase** expenses under the Baseline scenario due to a relatively *lower* generation level than the Without Experiments scenario is based on the historical percentage blend of day-ahead and real-time purchase prices and quantities.
(2) An incremental *decrease* in net **purchase** expenses under the Baseline scenario due to a relatively *higher* generation level than the Without Experiments scenario is based on the historical percentage blend of day-ahead and real-time purchase prices and quantities.
(3) An incremental *increase* in net **sales** revenues under the Baseline scenario due to a relatively *higher* generation level than the Without Experiments scenario is based on the historical percentage blend of day-ahead and real-time sale prices and quantities.
(4) An incremental *decrease* in net **sales** revenue under the Baseline scenario due to a relatively *lower* generation level than the Without Experiments scenario is based on the historical percentage blend of day-ahead and real-time sale prices and quantities,
(5) Hourly energy sales to FES customers are identical under both scenarios and therefore cancel out when the comparative analysis is applied.
(6) All historical non-FES energy sales made in the same hour that the energy was purchased are held identical under both scenarios and therefore cancel out in the comparative cost calculation.

This methodology leads to a reasonable approximation of the financial impacts of the HFE because it is based on the change in finances, not on absolute financial levels. It also circumvents the need for computation of nonhydropower energy arbitrage transactions that are assumed to be unaffected by the HFE.

5.4 Net Energy Revenues from Energy Transactions

In total, the HFE financial cost is estimated to be about $1.15 million.

Monthly net revenue results under both scenarios and estimated HFE financial costs are shown in Figure 5.3. The largest financial cost of the HFE mainly occurred during March and May, with financial losses of about $638,000 and $427,000, respectively. These costs are mainly attributed to water that was essentially reallocated from these two months to November in order to conduct the experiment. Note that although the same amount of water was reallocated from each month (i.e., about 72 TAF), HFE costs are lower in May despite higher market prices during this month. This occurred because the incremental generation from the higher water release under the Without Experiments scenario was essentially sold to FES customers as AHP energy at the FES energy rate of $12.19/MWh instead of at the higher bilateral market rate.

Despite the higher water release in November under the Baseline scenario, the financial gain occurring during this month is relatively insignificant ($7,000). This small difference can be explained by the fact that 126 TAF of the additional 144 TAF of water release during this month was not released through GCD hydropower plant turbines; that is, 87.5% of the water reallocated to support the HFE was actually spilled via bypass tubes. Therefore, in November, only 18 TAF of additional water volume was released through the turbine in the Baseline scenario, compared to 600 TAF in the Without Experiments scenario. Moreover, the additional energy produced during HFE days was sold at a lower price in the Baseline scenario. Figure 5.4 illustrates this point. Both the on-peak and off-peak prescheduled sales prices are lower during the experimental release period than during other days in November. Furthermore, during the experimental release days, both the on-peak and off-peak prescheduled sales prices were actually lower than their counterpart prescheduled purchase prices, accentuating the financial losses associated with net purchases during the 6-day experiment.

HFE costs are also attributed to lower Lake Powell Reservoir elevations due to high HFE releases during November. Lower reservoir conditions under the Baseline (HFE) scenario persist for several months and, as shown Figure 5.5, also resulted in lower water-to-power conversion efficiencies. This resulted in relatively small HFE costs during December through February and April despite the fact that water release volumes in these months are identical under both scenarios.

In summary, the HFE financial costs resulted from (1) the reallocation of monthly water releases, (2) nonpower water releases during the HFE, (3) low sale prices of excess energy during the HFE, and (4) lower power plant efficiencies.

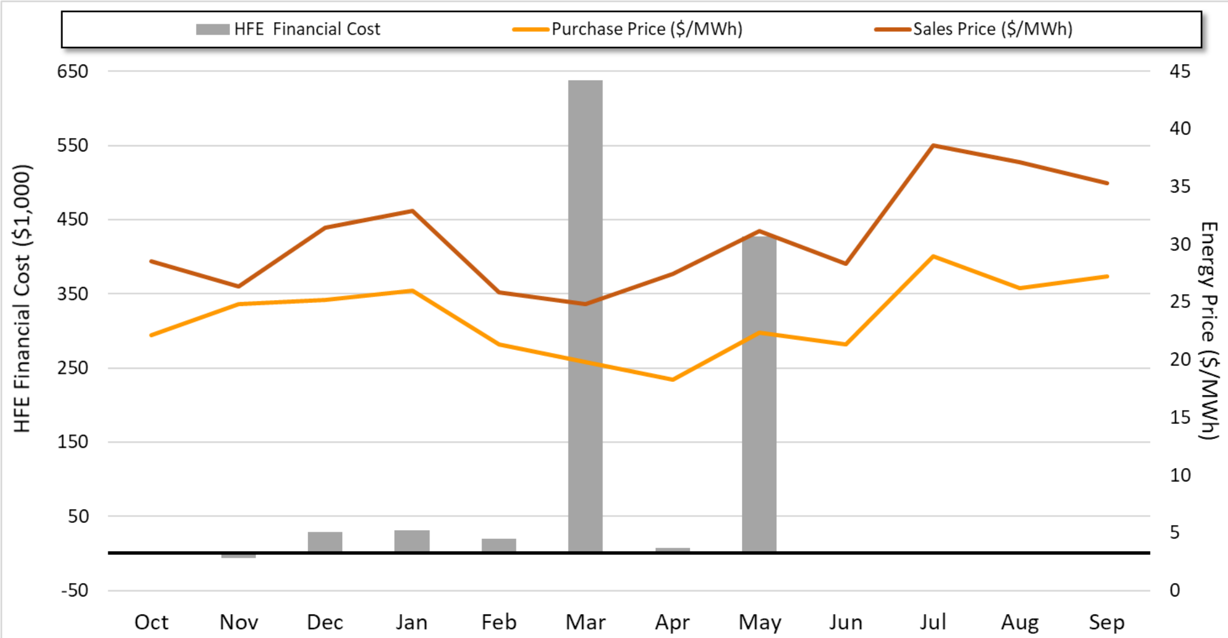


Figure 5.3: Cost of the HFE in WY 2017

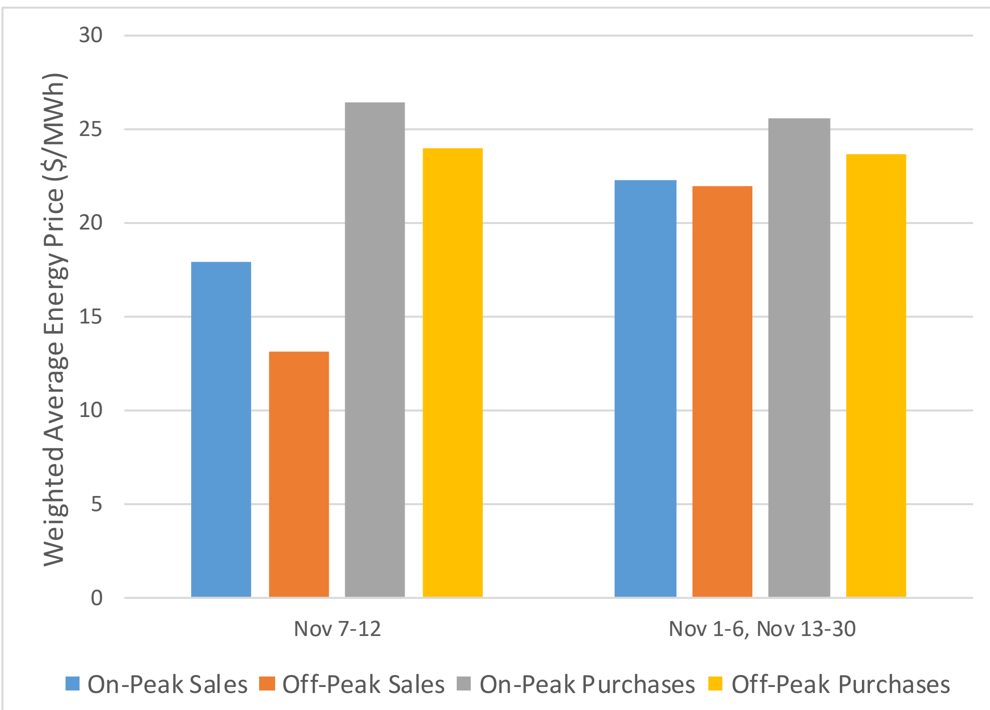


Figure 5.4: On-peak and off-peak prescheduled sales and purchase prices (weighted averages) for experimental release days compared to non experimental days in November

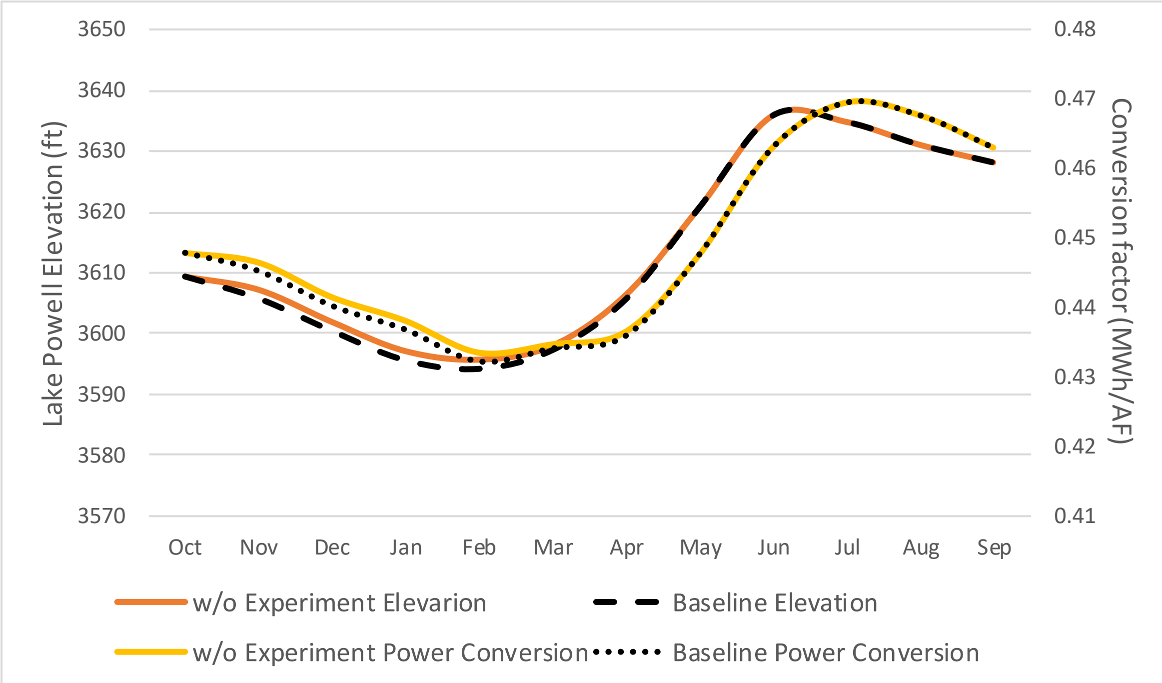


Figure 5.5: Comparison of Lake Powell elevations and PCFs in WY 2017

6 References

Bishop, C., 2018, personal communication from Bishop (Bureau of Reclamation, Salt Lake City, Utah) to T. Veselka (Argonne National Laboratory, Lemont, Ill.), Oct.

Dean, C., 2018, personal communication from Dean (Western Area Power Administration, Montrose, Colo.) to T.D. Veselka (Argonne National Laboratory, Lemont, Ill.), Sept.

Graziano, D.J., L.A. Poch, T.D. Veselka, C.S. Palmer, S. Loftin, and B. Osiek, 2014, *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2013*, ANL/DIS-14/9, Argonne National Laboratory, Lemont, Ill., June.

Graziano, D.J., L.A. Poch, T.D. Veselka, C.S. Palmer, S. Loftin, and B. Osiek, 2015, *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2014*, ANL-15/10, Argonne National Laboratory, Lemont, Ill., Sept.

Graziano, D.J., L.A. Poch, T.D. Veselka, C.S. Palmer, S. Loftin, and B. Osiek, 2016, *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2015*, ANL-16/22, Argonne National Laboratory, Lemont, Ill., Nov.

Iseman, T., 2016, *Approval of Recommendation for Experimental High-Flow release from Glen Canyon Dam, November 7–12, 2016*, U. S. Department of the Interior, Washington, D.C., Oct. Available at http://gcdamp.com/images_gcdamp_com/3/35/HFE_Leadership_Memo_16oct26.pdf. Accessed Nov. 2018

Palmer, C., 2010, personal communication from Palmer (Western Area Power Administration, Colorado River Storage Project Center, Salt Lake City, Utah) to T. Veselka (Argonne National Laboratory, Lemont, Ill.), Jan.

Patno, H., 2008, personal communication from Patno (Bureau of Reclamation, Salt Lake City, Utah) to T. Veselka (Argonne National Laboratory, Lemont, Ill.), Apr.

Patno, H., 2018, personal communication from Patno (Bureau of Reclamation, Salt Lake City, Utah) to T.D. Veselka (Argonne National Laboratory, Lemont, Ill.), Dec.

Poch, L.A., T.D. Veselka, C.S. Palmer, S. Loftin, and B. Osiek, 2011, *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 2006 through 2010*, ANL/DIS-11-4, Argonne National Laboratory, Lemont, Ill., Aug.

Poch, L.A., T.D. Veselka, C.S. Palmer, S. Loftin, and B. Osiek, 2012, *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2011*, ANL/DIS-12-4, Argonne National Laboratory, Lemont, Ill., Jun.

Poch, L.A., D.J. Graziano, T.D. Veselka, C.S. Palmer, S. Loftin, and B. Osiek, 2013, *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2012*, ANL/DIS-13-2, Argonne National Laboratory, Lemont, Ill., Apr.

Reclamation (Bureau of Reclamation), undated, *Monthly Report of Power Operations – Powerplants*, Form PO&M-59, U.S. Department of the Interior.

Reclamation, 1996, *Record of Decision: Operation of Glen Canyon Dam Final Environmental Impact Statement, Appendix G*, U.S. Department of the Interior, Oct. Available at http://www.usbr.gov/uc/rm/amp/pdfs/sp_appndxG_ROD.pdf. Accessed Apr. 1, 2010.

Reclamation, 2006, *Record of Decision Operation of Flaming Gorge Dam Final Environmental Impact Statement*, U.S. Department of the Interior, Feb. Available at http://www.usbr.gov/uc/envdocs/rod/fgFEIS/final-ROD-15feb06.pdf. Accessed Oct. 19, 2016.

Reclamation, 2008, *The Law of the River*, U.S. Department of the Interior, Lower Colorado Region. Available at http://www.usbr.gov/lc/region/g1000/lawofrvr.html. Accessed Apr. 2010.

Reclamation, 2011, *Environmental Assessment: Development and Implementation of a Protocol for High-flow Experimental Releases from Glen Canyon Dam, Arizona, 2011–2020*, U.S. Department of the Interior, Bureau of Reclamation, Upper Colorado Region, Salt Lake City, Utah, Dec. 30.

Reclamation, 2012, *Record of Decision for the Aspinall Unit Operations Final Environmental Impact Statement*, U.S. Department of the Interior, Apr. Available at http://www.usbr.gov/uc/envdocs/eis/AspinallEIS/ROD.pdf. Accessed Oct. 19, 2016.

Reclamation, 2013, *Annual Operating Plan for Colorado River Reservoirs 2014*, U.S. Department of the Interior, Dec. Available at http://www.usbr.gov/lc/region/g4000/aop/AOP14.pdf. Accessed Oct. 19, 2016.

Reclamation, 2016, *Record of Decision for the Glen Canyon Dam Long-Term Experimental and Management Plan Final Environmental Impact Statement*, U.S. Department of the Interior. Available at http://ltempeis.anl.gov/documents/docs/LTEMP_ROD.pdf. Accessed Nov. 27, 2018

Reclamation, 2018, *Water Operations: Historic Data*, U.S. Department of the Interior, Bureau of Reclamation. Available at https://www.usbr.gov/rsvrWater/HistoricalApp.html. Accessed Nov. 30, 2018.

Veselka, T.D., L.A. Poch, C.S. Palmer, S. Loftin, and B. Osiek, 2011, *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005*, ANL/DIS-11-1, Argonne National Laboratory, Lemont, Ill., Jan.

WAPA (Western Area Power Administration), 2010, *Operations of Glen Canyon Dam under the ROD*, CRSP Management Center. Available at http://www.wapa.gov/CRSP/planprojectscrsp/gcopswhite.html. Accessed Apr. 1, 2010.

WAPA (Western Area Power Administration), 2018, *Historical Power Plant Data.* Available at https://www.wapa.gov/regions/CRSP/OpsMaint/Pages/Scada.aspx. Accessed Nov. 2018.

This page is intentionally left blank.

Appendix A: Comparison between Planned and Historical Water Releases

GCD monthly water release volumes based on Reclamation *plans* prior to the time the HFE was conducted for the Baseline (with HFE) and Without Experiments (without HFE) scenarios are shown as shaded blue and orange bars, respectively, in Figure A.1. These releases were used to estimate the HFE financial cost reported in the main body of this report.

Instead of using *planned* water releases, this Appendix shows HFE cost estimates based on actual *historical* water releases. Water release volumes that actually occurred at GCD during WY 2017 are shown as grey shaded bars. The yellow shaded bars are estimates of water releases if the experiment was not conducted using historical water release volumes as a benchmark. The difference between the *planned* and *historical* observed water releases (blue and grey shaded bars, both with HFE releases) is primarily attributed to GCD water inflow forecast error.

The *planned* financial analysis assumed that the HFE required 144 TAF of addition water release during November 2016. To support this higher release volume, 72 TAF was reallocated from March and the remaining 72 TAF was reallocated from May.

The *historical* financial analysis also assumed that the HFE would be supported by an additional water release volume of 144 TAF. It assumed that 80 TAF would be allocated from March while only 64 TAF would be allocated from May. The slightly higher release in March was assumed because the 80 TAF water reallocation would have increased the total water release volume in March to 800 TAF. Under the 1996 ROD operating criteria, 800 TAF is the minimum monthly water release volume that allows GCD to have a daily release change of 8,000 cfs.

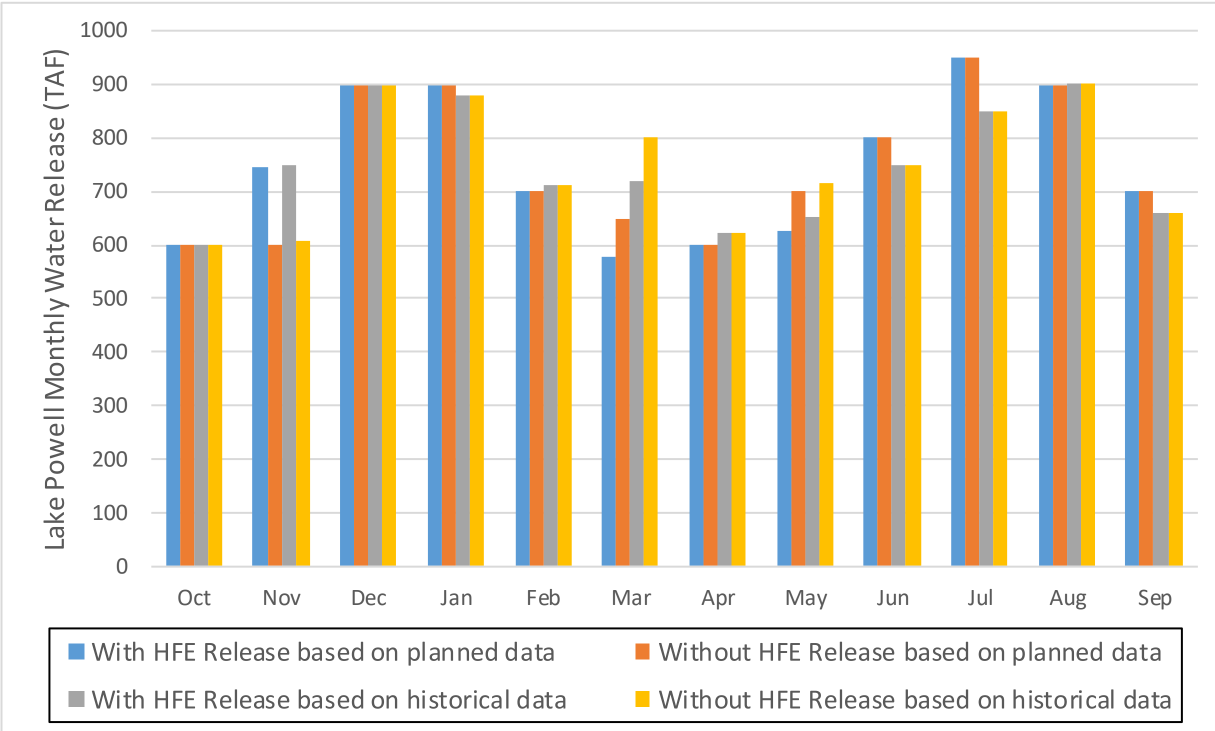


Figure A.1: Comparison of water releases between the Baselne and Without Experiments scenarios, based on planned and historical data

Figure A.2 shows monthly HFE costs based on *historical* water release data. Note that the pattern is very similar to that in Figure 5.3, which is based on *planned* water releases. Total HFE cost estimates are also very similar, that is, $1.15 million using *planned* assumptions versus $1.16 million using *historical* assumptions.

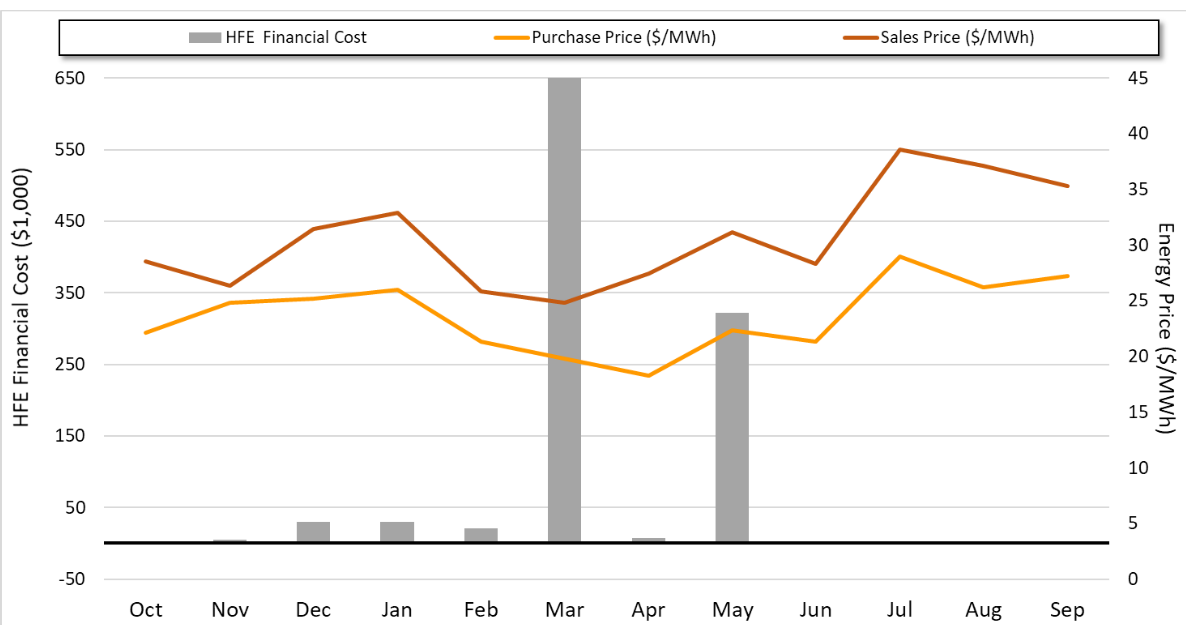


Figure A.2: Cost of HFE in WY 2017, based on historical data

Appendix B: GTMax SL Simulations for Water Year 2017: Aggregated Demand and Supply (Other than GCD) Profiles

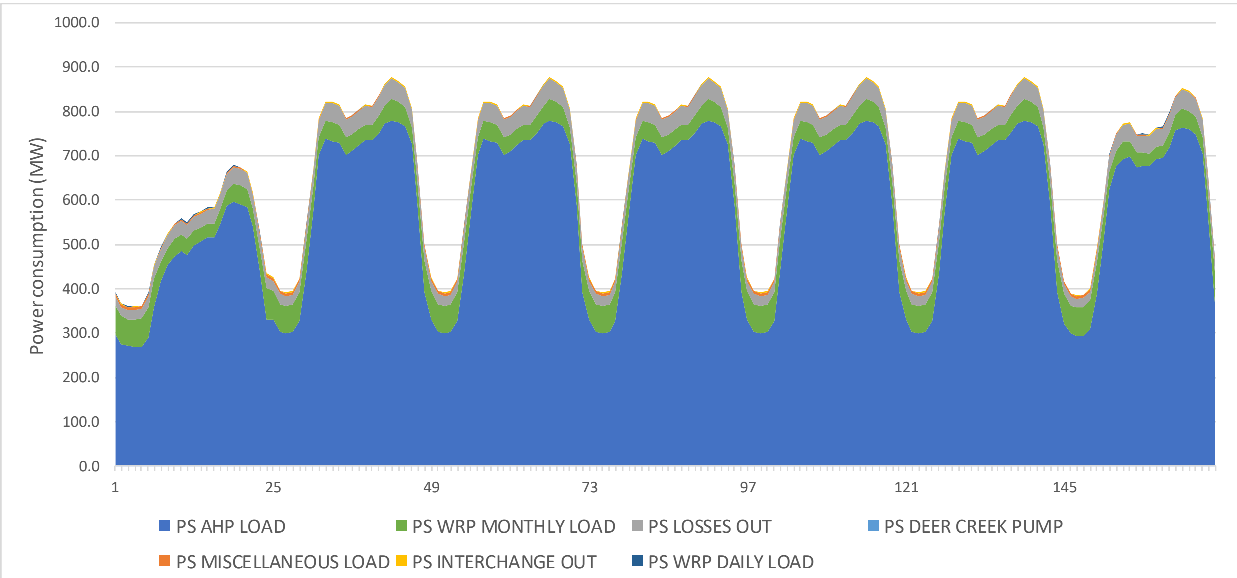


Figure B.1: Typical week aggregated demand profile of the SLCA/IP system in November 2016, excluding HFE days, from historical values

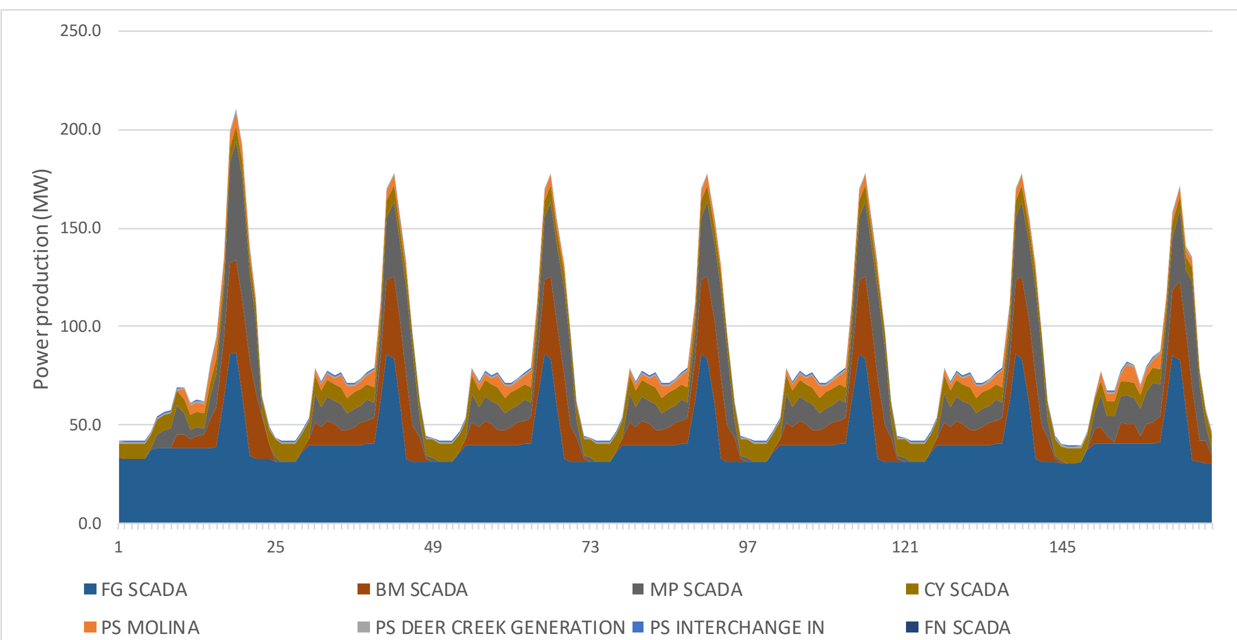


Figure B.2: Typical week aggregated supply profile of all plants apart from GCD in November 2016, excluding HFE days, from historical values

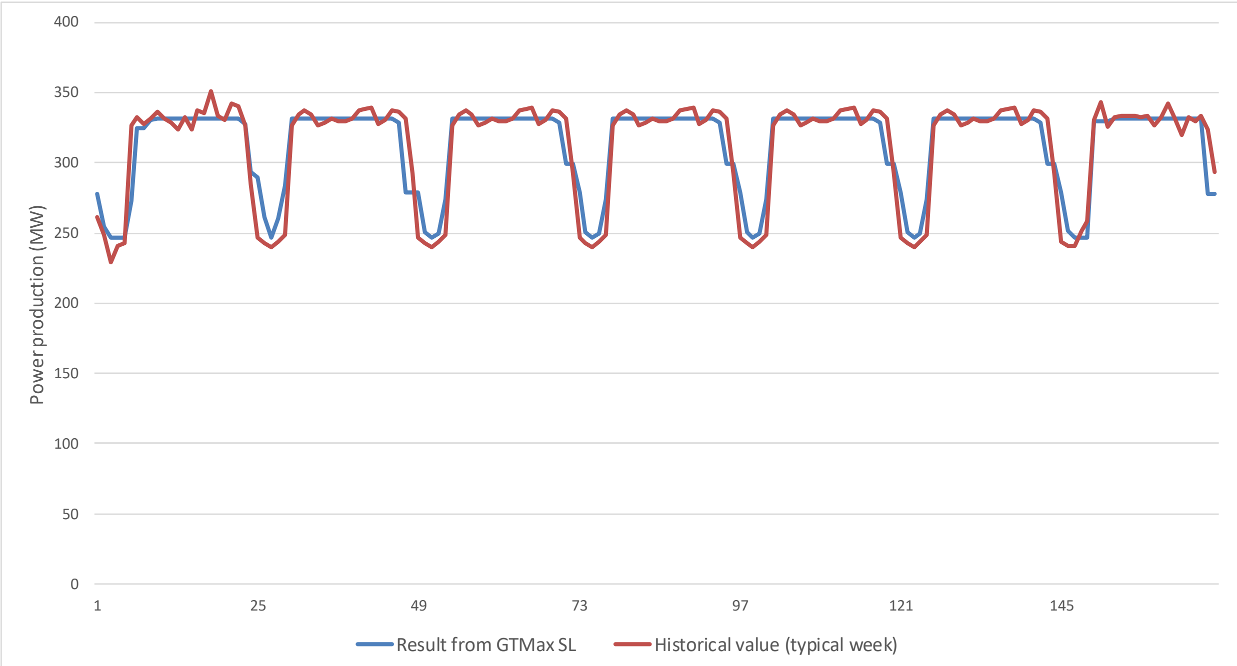


Figure B.3: Typical week generation profile at GCD in November 2016, excluding HFE days, from historical values and calculated by GTMax SL Model

Energy Systems Division
Argonne National Laboratory
9700 South Cass Avenue, Bldg. 362
Argonne, IL 60439

www.anl.gov