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| Financial Analysis of Experimental Releases  Conducted at Glen Canyon Dam  during Water Year 2019 |
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| Energy Systems Division |

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| 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  September 2019 |

# Foreword

This report was prepared by Argonne National Laboratory in support of a financial analysis of the Glen Canyon Dam high-flow experimental release that is intended to mobilize the sand in the Colorado River with high-volume water releases from the dam and redeposit it downstream as sandbars along the river. These sandbars serve, among other things, as habitat for wildlife. This experimental release was conducted during the period from November 5 to November 8, 2018. 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.

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# List of Acronyms and Abbreviations

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

AHP available hydropower

Argonne Argonne National Laboratory

CRSP Colorado River Storage Project

EMMO Energy Management and Marketing Office

FES firm electric service

GCD Glen Canyon Dam

GTMax SL Generation and Transmission Maximization Superlite

HFE High Flow Experiment

LTEMP Long-Term Experimental and Management Plan

MLFF Modified Low Fluctuating Flow

MPF Macroinvertebrate Production Flow

MSR Minimum Schedule Requirement

PCF Power Conversion Factor

Reclamation Bureau of Reclamation

ROD Record of Decision

SCADA supervisory control and data acquisition

SHP sustainable hydropower

SLCA/IP Salt Lake City Area Integrated Projects

WAPA Western Area Power Administration

WY water year

# Units of Measure

AF acre-feet

cfs cubic feet per second

ft feet

hr hour

MW megawatts

MWh megawatt-hour(s)

p.u. per unit

TAF thousand acre-feet

**Financial Analysis of Experimental Releases Conducted   
at Glen Canyon Dam during Water Year 2019**

by

Q. Ploussard, and T.D. Veselka

# Executive Summary

The 2016 Record of Decision (ROD) for the Glen Canyon Dam (GCD) Long-Term Experimental and Management Plan (LTEMP) final Environmental Impact Statement (EIS) specified criteria for GCD monthly water releases, daily and hourly operating limits, and experimental releases. This report examines the financial implications of the high-flow experiment (HFE) conducted at GCD during water year (WY) 2019 as required by the LTEMP HFE Protocol. It is the third report in a series that described the financial costs of LTEMP experimental releases since the 2016 ROD was adopted in January 2017 (Reclamation 2016). Two prior LTEMP experimental releases were analyzed and documented. These include analyzes of the GCD HFE conducted during WY 2017 and the WY 2018 Macroinvertebrate Production Flow (MPF) experiment (a.k.a., bug flows) (Ploussard et al. 2019b). This is the third ex post LTEMP ROD analysis that described the financial costs of the CY 2019 LTEMP experimental releases. In addition, a fourth experiment, a 2019 bug flow, was conducted under the LTEMP ROD during May, June, July, and August, but has not yet been analyzed.

This report focuses only on the HFE conducted in November 2018. For this experimental release, financial costs of approximately $1.31 million were incurred because the HFE required sustained water releases exceeding the power plant’s maximum turbine flow rate. In addition, during the experiment, operators were not allowed to shape GCD power production, either to follow firm electric service (FES) customer day-ahead energy deliveries or 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 Western Area Power Administration (WAPA) financial impacts by simulating GCD under two types of cases; namely, (1) a Factual case that mimics the operations that actually occurred and (2) a Counterfactual case that simulates operations under the assumption that the HFE did not occur. The Factual case mimics operations during the HFE and all of the other affected months of WY 2019. It complies with LTEMP hourly and daily operating criteria and summertime bug flow experiment requirements.

Because of uncertainties regarding GCD monthly water release volume decisions the Bureau of Reclamation (Reclamation) staff would have made had the HFE not occurred, three Counterfactual cases were examined. All three Counterfactual cases assume that the HFE did not occur. Each, however, assumes different monthly water releases volumes; that is, under the Counterfactual case less water is released in November and reallocated to late spring/early summer months (i.e., March, April, and May). Because this report aims to isolate the HFE costs from the cost of other experiments, the summertime Bug Flow experiment was assumed to occur in all Factual and Counterfactual cases

The Generation and Transmission Maximization Superlite (GTMax SL) model was the main modeling 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 WAPA’s power purchases and sales 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 HFE, and WAPA operating practices.

# Introduction

The Glen Canyon Dam (GCD) Powerplant (referred to as the Powerplant in this report) consists of eight generating units with a continuous operating capacity of 1,320 megawatts (MW) at unity power factor. It is the largest component of a system of coordinated resources known as the Salt Lake City Area Integrated Projects (SLCA/IP) that 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 the water storage level in Lake Powell, the GCD reservoir. The Powerplant dispatch was principally driven by CRSP loads and market price signals, which often resulted in large fluctuations in Powerplant output and associated reservoir 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. Based on impact analyses of these releases, Reclamation imposed operational flow constraints on August 1, 1991 (WAPA 2010). These constraints were implemented through 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 monthly low fluctuating flow (MLFF) regime, limited 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 implemented a daily change limit that restrict the range of hourly releases on a rolling 24-hour basis.

1996 ROD restrictions were eventually replaced by criteria specified under the Long-Term Experimental and Management Plan (LTEMP) ROD that was phased in during calendar year 2017. It required changes to (1) the allocation of monthly Lake Powell water releases, (2) daily and hourly operating criteria, and (3) experiments that are periodically conducted at GCD. Limitation do not allow Powerplant operators to fully utilize GCD water and hydropower resources when it is has the most valuable resulting in grid economic costs in terms of both firm capacity and energy production.

In the first phase that began on January 1,2017, LTEMP altered monthly Lake Powell water release volumes. GCD, hourly and daily operating criteria were implement in a second phase that began on October 1, 2017 (i.e., the first day of WY 2018). LTEMP experiments were conducted in both WY 2017 and 2018.

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).
* WY 2017 experiments were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2017* (Ploussard et al. 2019a).
* WY 2018 experiments were reported in *Financial Analysis of the 2018 Glen Canyon Dam Bug Flow Experiment* (Ploussard et al. 2019b).

The WY 2017 and WY 2018 reports listed above describe analyses of the first two experiments that were conducted under the LTEMP ROD. This is the third ex post LTEMP ROD analysis that described the financial costs of the CY 2019 LTEMP experimental releases. In addition, a fourth experiment, a 2019 bug flow, was conducted under the LTEMP ROD during May, June, July, and August, but has not yet been analyzed.

This report focuses on the third experiment that was an HFE conducted in November 2018. The HFE prescribed a fixed pattern of GCD water releases over a 4‑day period. During 71 hours, the prescribed releases exceeded the Powerplant’s maximum turbine flow rate by up to 14,400 cubic feet per hour (cfs). Water release in excess of the Powerplant’s maximum turbine flow rate was routed through GCD bypass tubes. This “non-power” water release did not produce energy and thus resulted in a financial cost to WAPA; that is, the opportunity to route non-power water releases through the Powerplant a later time to produce energy was lost. Non-power water releases also increase the tailwater elevation below the dam thus reducing the hydraulic head and water-to-power conversion efficiency. This report describes the method that was used to model the operation of SLCA/IP hydropower resources, which includes GCD, and discusses the estimated financial costs of conducting this experiment.

During the 2019 HFE period, operational flexibility was essentially eliminated—water had to be released according to a fixed/prespecified schedule. An integrated set of tools was used to estimate the financial impacts of the HFE by simulating GCD operations under two types of cases; namely, (1) a Factual case that mimics the operations that actually occurred and (2) a Counterfactual case that simulated operations under the assumption that the HFE did not occur. The financial cost of the HFE is set equal to difference between WAPA’s financial position under the Factual and Counterfactual cases.

The Factual case mimics operations under the HFE and during the rest of the affected months of WY 2019. It complies with LTEMP hourly and daily operating criteria and summertime bug flow requirements. Because of uncertainties regarding GCD monthly water release volume decisions the Bureau of Reclamation (Reclamation) staff would have made had the HFE not occurred, three Counterfactual cases were examined. All three Counterfactual cases assume that the HFE did not occur. Each, however, assumes different monthly water releases volumes; that is, under the Counterfactual case less water is released in November and reallocated to late spring/early summer (i.e. March, April, and May). Because this report aims to isolate the HFE costs from the cost of other experiments, the “bug flow” experiment was assumed to occur in all Factual and Counterfactual cases.

During normal daily operations (i.e., periods without experiments), GCD is governed by stringent operating rules as specified by the 2016 LTEMP ROD. Although these rules yield environmental benefits, the criteria 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 the maximum release limit and a daily change constraint that lowers energy production during hours of peak electricity demand when the market price and economic benefits are relatively high. It also mandates minimum water release rates that use limited water resources during times when energy has a lower value. Hourly ramp rate restrictions dampen hydropower production responses to changes in energy market price signals.

This study only computes the economic costs of the 2019 HFE -- not the financial impacts of daily and hourly operating criteria. Daily and hourly operating criteria are, however, included in the Factual and Counterfactual cases because these criteria affect the financial implications of both HFE non-power water releases and monthly water reallocations needed to conduct the HFE. Similarly, the Bug Flow experiment that occurred during the summer of 2019 was included in all Factual and Counterfactual cases. This way, WAPA’s financial HFE costs only capture the impact of the HFE, not LTEMP daily/hourly operating criteria and the Bug Flow experiment.

It should be noted that, for the present study, only the period from October 2018 through May 2019 was being considered, instead of the entire WY 2019 (i.e., from October 2018 to September 2019). This is so because it was assumed that the operating conditions from June 2019 to September 2019 were exactly the same under all the Factual and Counterfactual cases. Therefore, these last four months had no financial impact. This assumption is later justified in section 2.2.

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 2019 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 2019.

The GTMax SL model simulated four cases: one Factual case and three Counterfactual cases. Under the Factual case, GTMax SL mimics the HFE as documented by WAPA and Reclamation and, for the rest of the year, simulates operations that comply with the 2016 ROD operating criteria. The three Counterfactual cases are identical to the Factual case, except they assume that the experimental release did not occur. Differences in the financial position between the Factual and Counterfactual cases 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.

# LTEMP ROD Criteria and WAPA Operating Practices

As discussed in the previous section, the LTEMP ROD affects the financial cost of conducting the HFE. Important ROD factors affecting HFE financial costs include the following:

1. Hourly and daily operating limitations,
2. Exceptions to the ROD criteria made to accommodate the experimental releases,
3. Monthly water release volume allocations, and
4. Conducting experiments other than an HFE.

HFE financial costs estimates are also impacted by WAPA SLCA/IP hydropower plants scheduling/dispatch goals and guidelines.

This section provides background information on each of these factors.

## Hourly and Daily Operating Criteria and Exceptions

Operating criteria specified in the 2016 ROD are intended to temper the rate of change in hourly and daily water releases. The criteria selected were based on the LTEMP Alternative as described in the final ROD (Reclamation 2016). These criteria were put into practice by WAPA from October 2017.

Flow restrictions under the 2016 ROD are shown in Table 2.1. For comparison purposes, they are represented along with operational limits in effect between February 1997 and October 2017 that were complying with the 1996 ROD, and operational limits prior to June 1, 1991. The 2016 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 2,500 cfs/hr.

The 2016 ROD operating criteria also restrict the range of release rates during rolling 24-hour periods. This change constraint depends on the monthly volume of water releases. Daily fluctuation (in cfs/24 hr) is limited to 10 times the monthly release specified in thousands of acre-feet (TAF) from June to August. From September to May, it is limited to 9 times the monthly release volume. The daily range can never exceed 8,000 cfs. In November 2018, during the non-HFE days (November, 1-4 and 9-30), the daily range was further reduced to 2,500 cfs/24 hr to avoid the disruption of sediment in the system before and after the HFE. This small range also reduced the amount of additional water that released during November to support the HFE (Dean 2019b).

The maximum flow rate is limited to 25,000 cfs under the 2016 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 4 days of the HFE.

Table 2‑1 Evolution of operating constraints at GCD

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Operational Constraint | | Historical Flows (before 1991) | 1996 ROD Flows (from 1997 to 2017) | 2016 ROD Flows (after 2017) |
| Minimum flows (cfs) | | *3,000 during the summer*  *1,000 during the rest of the year* | *8,000 from 7:00 a.m. to 7:00 p.m.*  *5,000 at night* | *8,000 from 7:00 a.m. to  7:00 p.m.*  *5,000 at night* |
|  | |  |  |  |
| Maximum non-experimental flows (cfs)*a* | | *31,500* | *25,000* | *25,000* |
| Daily fluctuations (cfs/24 hr)b, c | | *28,500 during the summer*  *30,500 during the rest  of the year* | *5,000, 6,000, or 8,000*  *depending on release*  *volume* | *Equal to 10 X monthly water release (in TAF) during June-August,  and equal to 9 X monthly water release the rest of the year,  but never exceeding 8,000 cfs* |
| Ramp rate (cfs/hr)d | | *Unrestricted* | *4,000 up 1,500 down* | *4,000 up* ***2,500 down*** |
| a b c d | Except during HFE days (November 5-8, 2018) when it was allowed to reach up to 38,000 cfs  Except during the HFE month (November 2018) when it was limited to 2,500 cfs  Except during the weekdays of the “bug flow” period (May 2019) when it was limited to 4,500 cfs  Except during the Saturdays, Sundays, and Holidays of the “bug flow” period (May 2019) when it was fixed to 0 cfs/hr (flat flows) | | | |

## 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 are complying 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 Factual and Counterfactual cases, 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 2019 (Reclamation 2019), were used for all hydropower plants except for GCD. Reclamation provided the GCD monthly water release input data for both cases and the hourly water releases during the HFE (Patno 2019).

Table 2.2 shows the monthly water release volumes and the end-of-month elevations of the Lake Powell reservoir for each case during the study period. The HFE conducted in November 2018 required water to be reallocated from two months among March, April, and May 2019. A priori, there was no preference regarding water reallocations. Therefore, in this study, three likely reallocations assumptions were modeled. Each reallocated equal amounts of HFE water from two months as follows: March and April (Counterfactual case 1), March and May (Counterfactual case 2), and April and May (Counterfactual case 3). These water reallocations are highlighted in bold in Table 2.2 for the Factual case and the three Counterfactual cases. Reclamation estimated that the HFE required an additional 37 TAF of water released in November 2018. In the Counterfactual cases, this excess of water release was reallocated in equal quantity among the two months of reallocation, that is, 18.5 TAF in each month.

Table 2‑2 Monthly water releases and Lake Powell elevations   
for both types of cases in WY 2019

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  |  | Factual Case  (with HFE) | | Counterfactual Case 1 (reallocation of HFE release in March and April) | | Counterfactual Case 2 (reallocation of HFE release in March and May) | | Counterfactual Case 3 (reallocation of HFE release in April and May) | |
| Calendar Year | Month | Water Release (TAF) | Lake Powell Elevation (ft) | Water Release (TAF) | Lake Powell Elevation (ft) | Water Release (TAF) | Lake Powell Elevation (ft) | Water Release (TAF) | Lake Powell Elevation (ft) |
| 2018 | Oct. | 625 | 3590.5 | 625 | 3590.5 | 625 | 3590.5 | 625 | 3590.5 |
| 2018 | Nov. | **662** | 3586.5 | 625 | 3586.9 | 625 | 3586.9 | 625 | 3586.9 |
| 2018 | Dec. | 740 | 3581.8 | 740 | 3582.3 | 740 | 3582.3 | 740 | 3582.3 |
| 2019 | Jan. | 860 | 3575.7 | 860 | 3576.1 | 860 | 3576.1 | 860 | 3576.1 |
| 2019 | Feb. | 740 | 3571.1 | 740 | 3571.5 | 740 | 3571.5 | 740 | 3571.5 |
| 2019 | Mar. | 765 | 3568.8 | **783.5** | 3569.0 | **783.5** | 3569.0 | 765 | 3569.3 |
| 2019 | Apr. | 670 | 3571.2 | **688.5** | 3571.2 | 670 | 3571.5 | **688.5** | 3571.5 |
| 2019 | May | 670 | 3585.3 | 670 | 3585.3 | **688.5** | 3585.3 | **688.5** | 3585.3 |

As explained in the introduction, the study period for the present report extends from October 2018 to May 2019, instead of the entire WY 2019 (from October 2018 to September 2019). This is so because the operating conditions at GCD are exactly the same for the last four months of WY 2019 (from June 2019 to September 2019). That is the monthly releases and hourly operating criteria are identical from June to September 2019 and both Factual and Counterfactual cases have identical monthly water release requirements, Furthermore, Lake Powell water elevation is the same under both cases from June 1, 2019 and onward.. Therefore, the operations at GCD are identical from June 2019 under all cases, and there is no financial impact of the HFE during the four last months of WY 2019.

It should be highlighted that the monthly water releases in the Factual case 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 reservoir elevations in the Factual case were adjusted to reflect and be consistent with Reclamation planned monthly release volumes. As shown in Table 2.2, additional reservoir elevation adjustments are made under the three Counterfactual cases to reflect monthly water release volume that differ from the Factual case.

In addition to analyzing the financial cost of conducting the November 2018 HFE using the “planned” monthly water releases shown above, a second analysis was performed based on actual water releases under the Factual case and 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 is very similar to the estimated cost using the planned releases.

## 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 Reservoirs must comply with (1) a specified range of forebay elevation limits 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. Also, to minimize exposure to real-time price spikes and volatility, WAPA places a high priority on purchasing energy in the day-ahead bilateral market to serve load in 16-hour, on-peak blocks, and in 8-hour, off-peak blocks . 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 to either purchase or sell varying amounts of energy on an hourly basis in the real-time market.



Figure ‑ Illustration of the firm-load-driven dispatch guideline   
when SLCA/IP resources are short of load

In other situations, 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 400 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 creates a linkage between WAPA’s FES contractual obligations to its customers and SLCA/IP operations because it necessitates that the 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, FES 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.

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. This operational practice however is not followed during the HFE under the Factual case (with HFE).

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 2019, 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 2019 except for November, when the HFE occurred. During November, outside of the four days of high release (from November 5 to November 8) weekend release volumes (in both Saturday and Sunday) were generally the same as weekday release volumes. 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 several factors such as changing market conditions, persistent drought, electricity market disruptions (e.g., WY 2000 and WY 2001 California Energy Crisis), 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 beginning in WY 2001 and with some modifications continue to be practiced up to the present day.

# Description of Experimental Releases

Two experiments were conducted during WY 2019: an HFE and a Bug Flow experiment. This report only focuses on the financial analysis of the HFE.

## HFE

This section describes when the WY 2019 HFE occurred and its characteristics (e.g., hourly release pattern). Table 3.1 summarizes the operational characteristics of GCD releases during the HFE in terms of maximum and minimum flow rate constraints, maximum daily fluctuation limits, and maximum and minimum ramp rate restrictions.

Table 3‑1 Characteristics of the 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 2016 ROD Criteria |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| HFE | 11/5/2018–11/8/2018 | 38,283 | 6,671 | 4,206 | 2,519 | 31,612 | Yes | Yes |

The November 2018 HFE was conducted in accordance with the 10-year (2011–2020) HFE 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 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 5, to Thursday, November 8. The total duration at high flow was 80 hours, with 60 hours at a nominal peak release of 38,000 cfs. The flow rate exceeded the capability of the Powerplant turbines for 71 hours, with water released through the dam’s hollow jet tubes (river outlet works or bypass), reaching a maximum of about 14,400 cfs. No electricity was generated by the water released through the hollow jet tubes, which totaled 77 TAF. During the HFE, the maximum water flow through the turbines was 23,900 cfs. This release was less than the power plant capacity because one of the eight units was not operational due to a scheduled rotor repair. In addition, the elevation at Lake Powell did not create sufficient hydraulic head for the seven operational turbines to reach each turbine’s maximum potential.

The flow pattern for the HFE is shown graphically in Figure 3.1. To compensate for HFE water release requirements, the daily water releases during the non-HFE days in November 2018 were cut back to approximately 6,700 cfs in hours 1 to 4 and 22 to 24, and 9,000 cfs in hours 6 to 21. During November 2018, 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 released in months after this experiment was reallocated to November (see Table 2.2).

Figure ‑ Release pattern of the HFE conducted in November, 5-8, 2018

## Bug Flow experiment

In addition to the HFE that is described above, and on which this report is focusing, another experiment called “Bug Flow” occurred in the last month of the study period. This experiment, also known as macroinvertebrate production flows (MPF), was conducted from May 1, through August 31, 2019. It is the second time this experiment has been conducted at GCD.

The MPF Experiment is requested and described in the 2016 LTEMP ROD. These MPFs maintain flat releases on the weekends and holidays to a level equal to the minimum release rate during the week plus an additional flow rate called “flat flow adder.” This is to allow aquatic insects throughout the river corridor to be able to lay their eggs at a stage where they would not be at risk of being dewatered or desiccated. The experiment includes monitoring to evaluate whether the flows increase the diversity and production of aquatic insects. More details about this experiment can be found in (Ploussard et al. 2019b).

The average historical flow pattern during a typical week in May 2019 is shown graphically in Figure 3.2. In 2019, the “flat flow adder” was equal to 750 cfs. Because of exceptional water and power conditions, the daily fluctuations were much lower than the ones allowed by the 2016 ROD and described in Table 2.1. This is due to a combination of factors including unit outages, regulation requirements and a low off-peak flow rate. Also, maximum daily fluctuations were limited to 4,500 cfs instead of the 6,500 cfs allowed by the ROD. A double cycle of raising and lowering the flow rate at GCD twice each weekday, instead of normal single cycle pattern that usually scheduled during this month was related to WAPA’s energy short position during off-peak hours (Dean 2019b).

The financial impact of the Bug Flow experiment is out of the scope of the present report. Therefore, it was assumed that the “bug flow” experiment occurred in all Factual and Counterfactual cases. This way, it was ensured that the calculated financial costs were only impacted by the HFE. Consistently with the historical data, in all Factual and Counterfactual cases, the GTMax SL model uses a flat flow adder of 750 cfs, a maximum daily fluctuations of 4,500 cfs, and a double cycle of raising and lowering the flow rate at GCD during weekdays.



“Flat flow adder”

Flat flows during weekend

Minimum flows during weekdays

Figure 3‑2 Typical week release pattern of the Bug Flow experiment in May 2019

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# Methods and Models

For the WY 2019 analysis, WAPA HFE financial impacts were computed by comparing simulated results between two types of cases:

1. Factual**:** assumes that (a) daily and hourly operations, and *planned* monthly release volumes to be in compliance with the LTEMP ROD criteria, (b) the occurrence of the Bug Flow experiment in May, (c) the occurrence of the November 2018 HFE prescribed hourly releases, and (d) the exceptions to the ROD criteria to accommodate the experimental release; and
2. Counterfactual**:** assumes (a) the same ROD operating criteria as in the Factual case, (b) the occurrence of the Bug Flow experiment in May, (c) the absence of the November 2018 HFE release, and (d) *planned* monthly release volumes that also comply with the ROD criteria, but differ from the Factual case by shifting the excess of HFE release from November to two other months among March, April, and May.

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 two simulated operating cases. For WY 2019, as for WY 2014, WY 2015, and WY 2017, 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 more accurately estimate the WAPA’s financial losses associated 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 cost.

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 supervisory control and data acquisition (SCADA) hourly measurements (WAPA 2019) or the CRSP L&R spreadsheet when the SCADA data for some powerplants were not available, and were treated as fixed input values under both the Factual and Counterfactual cases. This methodology limited the financial impact of the HFE to GCD because along with energy purchase and sale quantities only operations at GCD were used as decision variables.

Finally, in financial analyses of experimental release prior to WY 2017, the GTMax model was used to simulate the system dispatch (Graziano et al. 2016; Veselka et al. 2011). For the WY 2017 analysis and the present analysis, GTMax 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 case, the GTMax SL model is run for one typical week per month for each of the eight first months of WY 2019. 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 2016 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.

## 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 2019), historical monthly statistics (Reclamation 2019), WAPA CRSP L&R spreadsheets, and SCADA data. This information includes water releases, reservoir 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 simulated hourly 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 Factual and Counterfactual cases 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 ‑ Fitting curve between the historical volume of stored water and the historical pool elevation at GCD during WY 2019

The volumes of stored water in each month at GCD under a given case (Factual or Counterfactual case) are calculated based on the differences of monthly water releases between this case and the historical data. Then the pool elevation at GCD under the given case 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 turbine water releases to power generation, referred to as a PCF, is primarily driven by the reservoir 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 types of cases, first the least-squares fit between Lake Powell historical end-of-month forebay elevation and the GCD PCF during WY 2019, 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 0.82.

Next, the PCF used in a given case (Factual or Counterfactual case) 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 March 2019, the historical forebay elevation at GCD is 3,569.28 ft, whereas it is 3,568.81 ft under the Factual case. During the same month, the historical PCF is equal to 410.71 kWh/AF. The slope from Figure 4.2 shows that there is an increase of approximately 0.8662 kWh/AF in the PCF for each additional foot in the forebay elevation. Thus, it is estimated that the PCF under the Factual case during this month will be equal to

410.71 + 0.8662 × (3,568.81 − 3,569.28) = 410.30 kWh/AF**.**



Figure ‑ Relation between the historical PCF and the historical pool elevation at GCD during WY 2019

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 elevation. 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 2019) 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).

## Model Input Data for Other SLCA/IP Supply Resources

In order to isolate the financial cost of conducting the November 2018 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 2019). However, when data are missing, pre-scheduled operations contained in historical EMMO (Dean 2019a) 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.

## Model Input Data for Loads

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 2019a) 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 2019 HFE 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.

## Model Input Data for Market Prices

A weighted-average of real-time and prescheduled sale and purchase prices, obtained from EMMO (Dean 2019a) for actual WAPA transactions, are used to create a set of typical-week market prices input into GTMax SL. A weekly price profile, smoothened by a 5-hr moving average filter, 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.

# Cost of Experiment in WY 2019

The HFE conducted during November 2018 had a nominal peak flow of 38,000 cfs. Supporting these high flows required reallocations of 37 TAF of water from two months between March and May 2019 to November 2018.

Figure 5.1 shows the monthly water releases in WY 2019 for the Factual case and the Counterfactual case that assumes a water reallocation in March and April, called “Counterfactual case 1.” The amounts of water released in the Factual case and in Counterfactual case 1 differ during three months. For November, water releases were higher in the Factual case by 37 TAF to accommodate the HFE. These higher water releases were balanced with 18.5 TAF lower releases in March and 18.5 TAF lower releases in April. Two other water reallocations were also analyzed for this study, namely: water from March and May is reallocated to November (Counterfactual case 2), and water from April and May to is reallocated to November (Counterfactual case 3).



Figure 5‑1 Monthly water releases at GCD in WY 2019

The financial analysis for the WY 2019 HFE is based on the difference in net energy revenues between the Factual and Counterfactual cases.

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

The Factual case and the three Counterfactual cases are optimized with the GTMax SL model. This results in a hourly GCD generation profile for a typical week in each month and each case. 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.

## 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:

SLCA/IP Generation + Net Purchases = SLCA/IP Load + 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 described in section 5.2). Except for GCD Powerplant generation, all other SLCA/IP supply resources and loads are identical under all cases. All financial differences between the Factual and Counterfactual cases are therefore directly attributed to a changed hourly generation pattern at GCD; that is, because loads are fixed and identical under all cases, 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:

Net Purchases = max(0, Load – Generation)

Net Sales = max(0, Generation – 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.

## Purchase and Sale Price Profiles

Under all Factual and Counterfactual cases, 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 transactions occurring during the same month, at the same hour of the day and during the same day-types (i.e. weekdays, Saturdays, or Sundays/holidays) as for the missing price data.

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 Factual case due to a relatively *lower* generation level than the Counterfactual case 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 Factual case due to a relatively *higher* generation level than the Counterfactual case 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 Factual case due to a relatively *higher* generation level than the Counterfactual case 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 Factual case due to a relatively *lower* generation level than the Counterfactual case 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 cases 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 cases 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 non-hydropower energy arbitrage transactions that are assumed to be unaffected by the HFE.

## Net Energy Revenues from Energy Transactions

In total, the HFE financial cost is estimated to be about $1.31 million.

This financial cost has been calculated as the average of the three HFE financial costs that have been obtained for the three computed HFE water reallocation cases shown below.

* Counterfactual Case 1: $1,363,000 when reallocating water in March and April,
* Counterfactual Case 2: $1,335,000 when reallocating water in March and May, and
* Counterfactual Case 3: $1,241,000 when reallocating water in April and May.

Monthly HFE financial costs associated to the three Counterfactual cases analyzed in this study are shown in Figure 5.2.



Figure ‑ Cost of the HFE in WY 2019

All three of the Counterfactual water reallocation cases show the largest financial cost of the HFE occur during November with the same financial losses of about $950,000. These costs are mainly attributed to the reduced turbine releases during the non-HFE days (i.e., between November 1-4 and November 9-30). As shown in Table 5.1, the HFE costs during non-HFE days amount to $1,671,000. They were partially compensated by net benefits of $721,000 during the 4 days of the experiments, because of an exceptionally high generation level of 830 MW during 70 hours of high releases. However, due to a lack of trading partners willing to buy the energy at the prevailing market price, the excess energy generation (i.e., productions above FES load) sold during the HFE was on average at a very low price.

Table 5‑1 Repartition of HFE costs

| HFE costs in November 2018 | |
| --- | --- |
| During HFE days (5-8) | - $721,000 |
| During non-HFE days | $1,671,000 |
| Total | $950,000 |

Relative to the Counterfactual case, November’s monthly water release was 37 TAF higher than the Factual case to support the HFE. More than 77 TAF of water however was bypassed during the HFE days instead of being converted into electricity. Therefore, despite an increase of 37 TAF of total water release, there was actually a decrease of 40 TAF of turbine water releases in the Factual case in November (i.e., 77 TAF minus 37 TAF) compared to the Counterfactual cases. This resulted in 18 GWh less energy production during November under the Factual case. More specifically, 248 GWh of electricity was generated by GCD Powerplant under the Factual case (with the HFE), compared to 266 GWh of electricity in each of the three Counterfactual cases. These non-power releases are the primary cause of the large HFE costs in November.

After November, all three Counterfactual cases also have identical HFE costs during December, January, and February even though the Factual and all Counterfactual cases release identical amount of water during each of these three months. These small costs are attributed to a lower Lake Powell elevation and hence a lower Powerplant PCF under the Factual case because 37 TAF more water was released to support the HFE.

The remaining financial costs occurred during the months in which the 37 TAF of HFE water were reallocated. When two water reallocation cases have a common reallocation month, their HFE cost during that month is either the same or almost identical. For example, HFE financial costs for **March** are identical under Counterfactual cases 1 and 2 as shown by the blue and orange bars in Figure 5.2.

Also in Figure 5.2, note that the financial costs are lower when HFE water is reallocated from later months. Note that the height of all bars for months with reallocated water steadily decrease from March through May. The essential factor explaining this difference is the average monthly purchase price, as shown by the blue line in Figure 5.2, decreases over time. Under all Factual and Counterfactual cases, there were significant energy purchases, but almost no energy sales during March, April, and May. This occurs because WAPA’s hydropower energy production was less than FES energy delivery obligations resulting in an energy short position that is covered via purchases. HFE water reallocated from a specific month to November results in a relatively lower Powerplant energy generation under the Factual case during that month. This leads to relatively higher Factual case energy purchases during the month from which the HFE water was reallocated. Because purchase prices were higher during March than April, and higher during April than May, HFE financial costs decrease when water is reallocated from later months.

To further demonstrate the strong link between monthly purchase price and monthly HFE costs, Figure 5.3 compares average March, April, and May HFE costs based on GTMax SL model runs (blue bars) to results produced by a simple equation that uses energy purchase prices (orange bars labeled “Estimated Costs”). The equation estimates HFE financial costs in a given month as the product of 3 terms:

* the average purchase price during this month (the blue line in Figure 5.2),
* the volume of water reallocated, that is, 18.5 TAF, and
* the average PCF of all Factual and Counterfactual cases during March, April, and May which equals 0.412 MWh/AF.

It is clear from this comparison that the purchase price is the main driver of the HFE costs during the months from which the HFE water is reallocated. However, there are still some differences between the HFE costs and estimated costs (the blue and orange bars in Figure 5.3) that can be explained by significant hourly fluctuations in energy purchase prices and the small fluctuations of the PCF (i.e., less than 2 percent).

In summary, the HFE financial costs resulted from (1) the decrease of 40 TAF in the amount of turbine release in November despite the increase of 37 TAF in total release from the HFE, (2) the decrease of 18.5 TAF of turbine release during the months from which HFE water would have been reallocated, and (3) the purchase price during those reallocation months.



Figure ‑ Comparison between HFE costs and estimated costs based on purchase prices

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# Appendix A: Comparison between Planned and Historical Water Releases

Figure A.1 shows GCD monthly water release volumes based on Reclamation *plans* prior to the time the HFE was conducted (blue bars). The planned releases represent the Factual (with HFE) case. Actual monthly water releases are shown as grey bars. The difference between the *planned*and *historical* observed water releases (blue and grey shaded bars, both with HFE releases) is primarily attributed to Upper Colorado River Basin water inflow forecast error.

The Counterfactual case 1 (without HFE that has water reallocated from March and April to November) is shown orange bars. For the sake of clarity, the Counterfactual cases 2 and 3 are not represented in the Figure.



Figure A‑ Comparison of water releases between the Factual and a Counterfactual case, based on planned and historical data

Instead of using *planned* water releases, this Appendix shows HFE cost estimates based on actual *historical*water releases. Water release volumes from Lake Powell that actually occurred during WY 2019 (grey bars) were used to represent the Factual case and the yellow shaded bars are estimates of water releases had the experiment not been conducted. This Counterfactual case assumes that HFE water was reallocated from March and April to November. This Counterfactual case uses historical water release volumes as a benchmark from which the water is reallocated (i.e., 18.5 MAF more water volume than the actual historical level during each of the 2 months).

Figure A.2 shows a comparison of the monthly HFE costs based on *historical*and *planned*water release assumptions. Note that the two patterns are very similar. Total HFE cost estimates are nearly identical, that is, **$1.31 million** using both *planned* assumptions *historical* assumptions.

Figure A‑ Comparison of monthly costs of HFE in WY 2019, based on planned and historical data

# Appendix B: GTMax SL Simulations for Water Year 2019: Aggregated Demand and Supply (Other than GCD) Profiles



Figure B‑1 Typical week aggregated demand profile of the SLCA/IP system in November 2018, excluding HFE days, from historical values



Figure B‑2 Typical week aggregated supply profile of all plants apart from GCD in November 2018, excluding HFE days, from historical values



Figure B‑3 Typical week generation profile at GCD in November 2018, excluding HFE days, from historical values and calculated by GTMax SL Model



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