ANL-19/19

Financial Analysis of the 2018 Glen Canyon Dam Bug Flow Experiment

Energy Systems Division

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by
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Foreword

This report was prepared by Argonne National Laboratory (Argonne) in support of a financial analysis of the Glen Canyon Dam (GCD) flow experiment that was intended to support downstream production of macroinvertebrate, a primary food supply for fishes in the Colorado River. Also known as “bug flow” experiments, these experimental water releases were conducted on the weekends and holidays from May 1 through August 31, 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 the Argonne Energy Systems Division prepared this technical memorandum with assistance from the WAPA CRSP and Energy Marketing and Management Offices (EMMO).

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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
CY	calendar year
EIS	Environmental Impact Statement
EMMO	Energy Management and Marketing Office (WAPA)
GCD	Glen Canyon Dam
GCDEIS	Glen Canyon Dam Environmental Impact Statement
GTMax SL	Generation and Transmission Maximization Superlite
LTEMP	Long-Term Experimental and Management Plan
MPF	Macroinvertebrate Production Flow
MSR	Minimum Schedule Requirement
PO&M-59	Power Operations and Maintenance, Form 59 (a Bureau of Reclamation form titled, *Monthly Report of Power Operations – Powerplants*)
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
WI	Western Interconnection
WRP	Western Regional Partnership
WY	water year

Units of Measure

cfs	cubic feet per second
ft	feet
hr	hour

MW	megawatt(s)
MWh	megawatt-hour(s)
pf	power factor
TAF	thousand acre-feet

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Abstract

This report examines the financial implications of the macroinvertebrate production flows (MPF) experiment conducted at the Glen Canyon Dam (GCD) from May 1, through August 31, 2018. It is the first report examining the financial implications of a MPF experiment since the 2016 Record of Decision (ROD) was adopted in December 2016 (Reclamation 2016). The 2016 ROD implemented the Long-Term Experimental and Management Plan (LTEMP) regime.

Experimental releases may have either a positive or a negative impact on the financial value of energy production. For these experimental releases, financial costs of approximately $165,000 were incurred because this experiment maintained flat releases on the weekends and holidays.

This study identifies the main factors that contribute to MPF 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 MPF operations during the period of the experiment when it complies with the 2016 ROD operating criteria, and (2) a counterfactual Without Experiments scenario that is identical to the baseline except it assumes that the MPF experiment 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). 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 sale prices in the modeling process. In addition to estimating the financial impact of MPFs, 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.

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1 Introduction

The 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 (pf). It is one component of a larger system known as the 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 the plant's power 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). More recently, in January 2017, a new ROD mandating the preferred alternative prescribed by the LTEMP Environmental Impact Statement (EIS) has been adopted. The 2016 ROD operating criteria limit hourly maximum and minimum water release volumes from the dam. The 2016 ROD criteria also constrain the change in the water release between consecutive hours, restrict the range of hourly releases on a rolling 24-hour basis, and limit the monthly water release from Lake Powell.

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);
- Water year (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 a MPF experiment, was conducted from May 1 through August 31, 2018. This MPF Experiment, also known as the “bug flow” experiment, maintained constant release rates on the weekends and holidays at a level equal to the minimum weekday release plus 1,000 cfs. These low water releases during the weekends and holidays produce less energy than normal operations and, under some energy market conditions, result in a financial cost to the WAPA. There are other energy market conditions/profiles in which the MPF Experiment results in a financial WAPA benefit. This report describes the method used to model the SLCA/IP, which includes GCD, and discusses the financial costs and benefits of conducting this experiment.

During normal operations, GCD is governed by stringent operating rules as specified in the 2016 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 operational 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 2018 MPF Experiment, operational flexibility was further reduced to comply with the low steady flow requirement during weekends and holidays. An integrated set of tools was used to estimate the financial impacts of the MPF Experiment by simulating GCD operations under two scenarios: (1) a Baseline scenario that both mimics MPF operations during the experiment and complies with 2016 ROD operating criteria, and (2) a counterfactual Without Experiments scenario that is identical to the baseline except that it assumes that the MPF Experiment 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. Retrospective simulation for the study period made use of extensive sets of data and historical information on SLCA/IP power plants’ characteristics and hydrologic conditions and WAPA’s power sale prices. The GTMax SL model simulated two scenarios. Under the Baseline scenario, GTMax SL mimics the MPF as documented by WAPA and simulates operations that comply with the 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 net energy purchase costs between the two scenarios represent the change in the financial value of power attributed to experimental releases.

In addition to estimating the financial impact of experimental releases, the GTMax SL model was also used to gain insights into the interplay among ROD operating criteria, exceptions made to criteria to accommodate the experimental releases, and WAPA operating practices. Details on the methodology and data sources are more thoroughly described in Section 4 of *Revised Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Years 1997 through 2005* (Veselka et al. 2011).

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2 ROD Criteria and WAPA Operating Practices

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

(1) Hourly and daily operating criteria according to the 2016 ROD,
(2) Exceptions to the 2016 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 2016 ROD are intended to temper the rate of change in hourly and daily water releases. The criteria selected were based on the LTEMP preferred alternative as described in *Record of Decision for the Glen Canyon Dam Long-Term Experimental and Management Plan Final Environmental Impact Statement* (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, along with operational limits in effect prior to October 1, 2016, for comparison. 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/hr and the maximum hourly decrease (i.e., the down-ramp rate) is 2,500 cfs/hr. The 2016 ROD operating criteria also restrict how much the releases can fluctuate during rolling 24-hr periods. This change constraint varies up to 8,000 cfs per day, depending on the monthly volume of water releases. Daily fluctuation is equal to 10 times the monthly volume (in TAF) from June to August and 9 times the monthly volume (in TAF) in other months, and never exceeds 8,000 cfs.

The maximum flow rate is 25,000 cfs under the 2016 ROD operating criteria. Maximum flow rate exceptions are allowed to avoid spills or flood releases during high-runoff periods. Under very wet hydrological conditions, defined as when the average monthly release rate is greater than 25,000 cfs, the flow rate may be exceeded; however, water must be released at a constant rate. Exceptions to the operating criteria are also made to accommodate experimental releases.

Table 2.1: Operating constraints prior to 2017 and under the 2016 ROD (from October 2017)

Operational Constraint	1996 ROD Flows (before October 2017)	2016 ROD Flows (from October 2017)
Minimum release (cfs)	8,000 from 7:00 a.m.–7:00 p.m. 5,000 at night	8,000 from 7:00 a.m.–7:00 p.m. 5,000 at night
Maximum release (cfs)	25,000	25,000
Daily fluctuations (cfs/24 hr)	5,000; 6,000; or 8,000 depending on monthly release volume[a]	**depending on monthly release volume[b]**
Ramp rate (cfs/hr)	4,000 up 1,500 down	4,000 up **2,500** 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 600–800 TAF; and 8,000 cfs/day when monthly water release is greater than 800 TAF.

[b] **Equal to 10 times the monthly volume (in TAF) in Jun.–Aug., and 9 times the monthly volume (in TAF) in other months; daily range not to exceed 8,000 cfs.**

Sources: Reclamation 1996, 2016.

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 by 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 2016 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 both the Baseline and Without Experiments scenarios, actual SLCA/IP monthly water releases, as recorded in Reclamation Form PO&M-59 (Reclamation undated) and available on the Reclamation website (Reclamation 2018), were used for all hydropower plants.

Table 2.2 shows the monthly water release volumes and the end-of-month elevations of the Lake Powell reservoir during the study period.

Table 2.2: Water releases and Lake Powell elevation during the experiment

Calendar Year	Month	Water Release (TAF)	Lake Powell Elevation (ft)
2018	May	705	3,611.54
2018	June	760	3,609.98
2018	July	860	3,603.8
2018	August	900	3,597.12

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; however, within these limitations are innumerable hourly release patterns and dispatch drivers that comply with a given set of operating criteria. Thus, although the operational range was significantly wide prior to the 1996 ROD, it was further restricted under the 2016 ROD. 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 a new model driven by 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 and selling power in 16-hr, on-peak blocks, and 8-hr, off-peak blocks in the day-ahead 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 firm 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 either the day-ahead and/or real-time market. The volumes of these variable market purchases and sales are relatively small under the vast majority of conditions. The GTMax SL model topology and inputs are designed to mimic these guidelines.

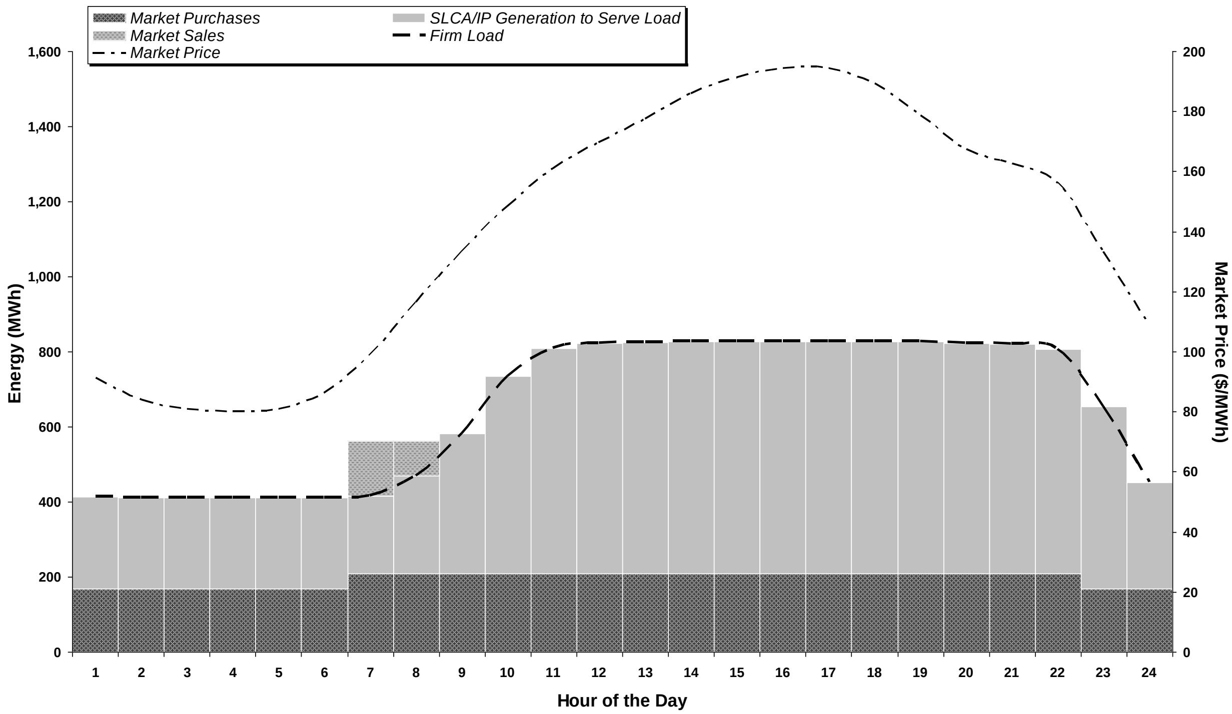

Figure 2.1: Illustration of the firm-load-driven dispatch guideline under the 1996 ROD operating criteria when SLCA/IP resources are short of load

The load-following objective facilitates a strong link between WAPA contractual obligations and SLCA/IP operations, requiring dispatch among SLCA/IP power plants to be closely coordinated. This interdependency exists because loads and hydropower resources are balanced whenever feasible. 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.

In addition, 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.

In addition, during the summer season (the season in which this experiment occurred), 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 as dictated by the hourly load pattern.

Changes in WAPA scheduling guidelines did not occur abruptly, but rather subtly, and over a period of months. These changes not only were the result of the operational constraints imposed by the ROD but also were attributable to changing market conditions, such as persistent drought, electricity market disruptions in 2000 and 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.

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3 Description of Experimental Releases

The MPF experimental release was conducted from May 1 through August 31, 2018. This section describes this experimental release and its characteristics.

The MPF Experiment is requested and described in the 2016 ROD (Reclamation 2016). These MPFs maintain flat releases on the weekends and holidays to a level equal to the minimum release rate during the week plus 1,000 cfs. This experiment is conducted two days a week 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. The experiment is designed to test the hypothesis in *Flow Management for Hydropower Extirpates Aquatic Insects, Undermining River Food Webs* (Kennedy et al. 2016) while minimizing impacts on the hydropower resource at GCD by mandating steady flows on the weekend. This results in a transfer of water from the weekend to the weekdays, increasing the daily minimums and maximums and the range of fluctuation during the week.

The historical flow pattern for the 2018 MPF Experiment is shown graphically in Figure 3.1. For the sake of clarity, only May 2018 is represented.

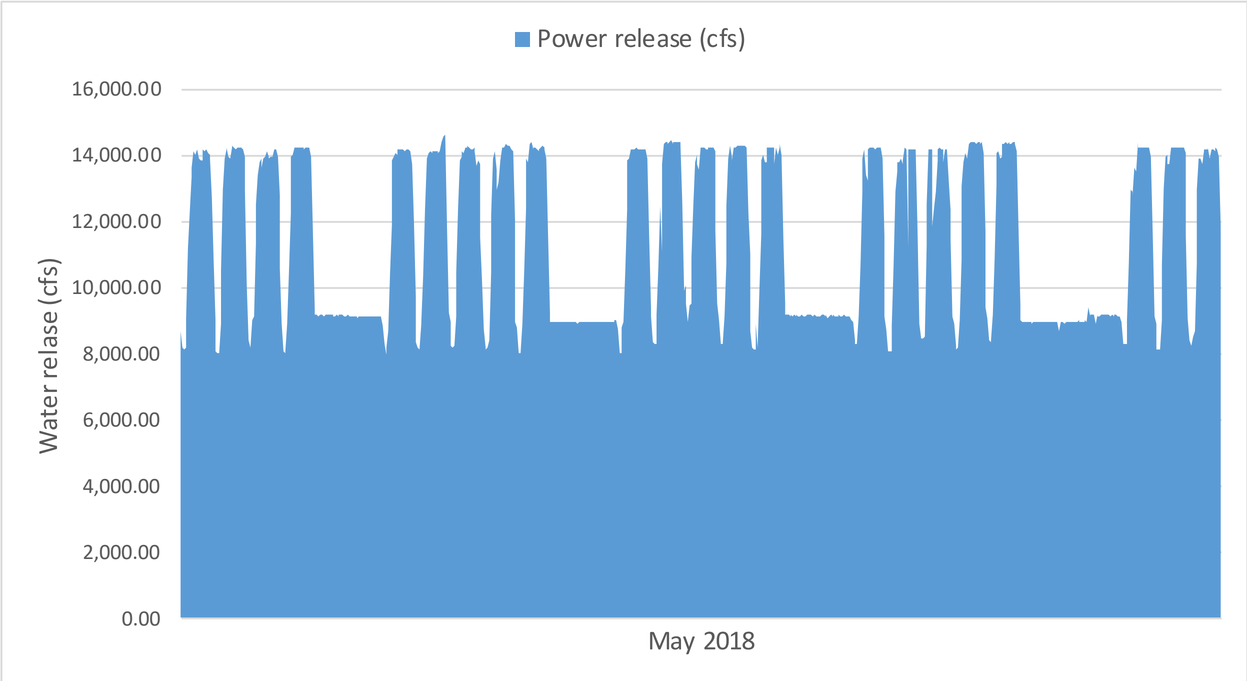

Figure 3.1: Release pattern of MPFs at GCD in May 2018

The 2018 MPF Experiment ran from May 1 to August 31. During the Saturdays, Sundays, and holidays (except Sunday, August 12), the water flows were relatively flat, with a daily fluctuation always less than 1,010.66 cfs. Daily fluctuations during weekends and holidays are illustrated by the orange columns in Figure 3.2. On Sunday, August 12, a forced outage at one unit temporarily forced the Powerplant to reduce its water release to approximately 8,000 cfs for a 12-hour period during the night, leading to an exceptional daily fluctuation of 3,560.13 cfs. During the weekdays, the 2016 ROD operational constraints on daily fluctuations were roughly satisfied. Such daily fluctuation constraints are depicted by black rectangles in Figure 3.2 and actual daily fluctuations are depicted by blue columns.

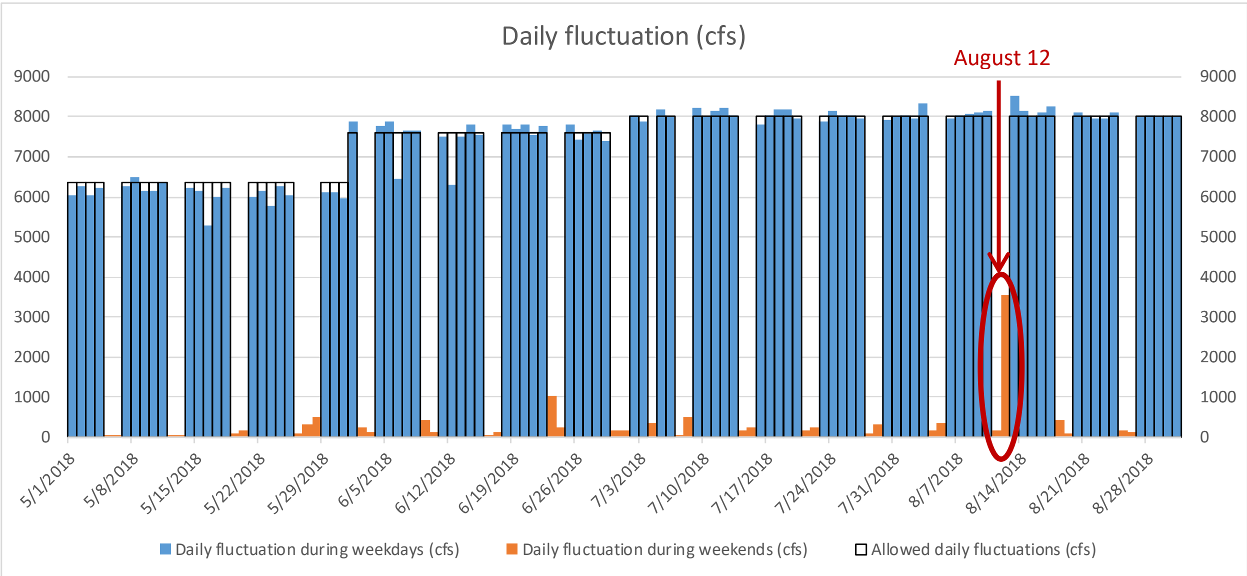

Figure 3.2: Daily fluctuations at GCD during the 2018 MPF Experiment

Apart from the outage of August 12, water flows during weekends and holidays were relatively flat. The relative difference between the minimum and maximum water releases during weekends, or “weekend’s release fluctuations,” was 14% or less during the 18 weeks of the experiments, as shown in Figure 3.3. The fluctuation was even lower than 5% for 16 out of the 18 weeks (Figure 3.3). The two weeks for which the weekend’s release fluctuation was higher than 5% are weeks 22 and 25. The higher weekend’s release fluctuation during week 22 is due to the change of operational constraints between May and June. The Sunday of week 22 is May 27, whereas Saturday is June 2. Because the monthly water release in June is supposed to be higher than the one in May (Table 2.2), the average hourly release during weekends and holidays is also supposed to be higher in June than in May. Because of this, the maximum hourly water release of week 22, reached on Saturday, June 2, was 14% higher than the minimum release, reached on Sunday, May 27. As for week 25, the reason for the higher relative difference lies in the regulation up service provided by the Powerplant. On Sunday, June 23, at 1:00 a.m., the water release was exceptionally slightly higher to provide more generation, as shown in Figure 3.4. Without this regulation up occurring at this hour, the maximum water release during week 25 would have been only 4.4% higher than the minimum water release.

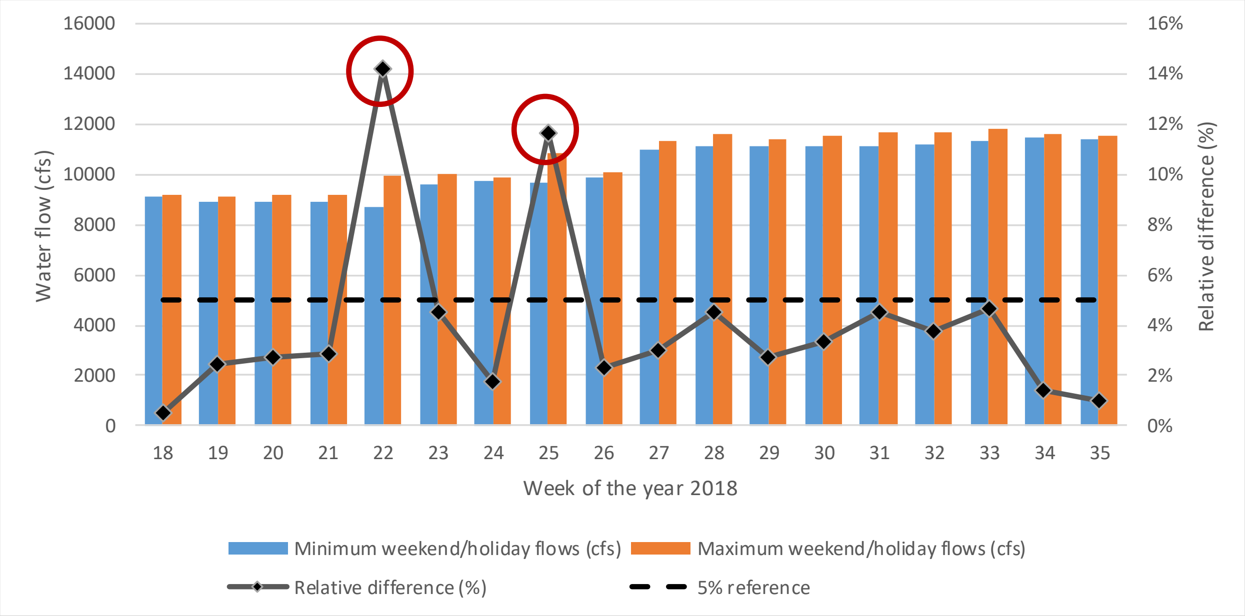

Figure 3.3: Minimum and maximum hourly water flows during weekends and holidays at GCD during the 2018 MPF Experiment

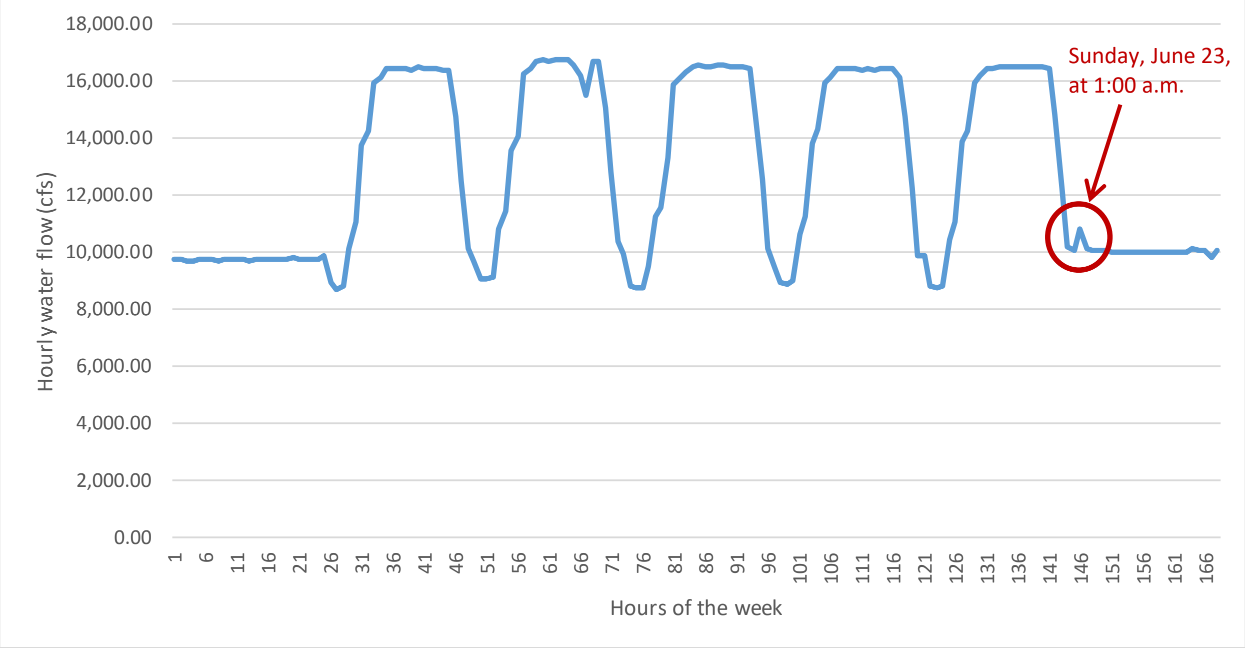

Figure 3.4: Hourly water flows at GCD during the 25th week of 2018

The MPF experimental constraint, requiring the water flows during weekends to be 1,000 cfs higher than the minimum water flows during weekdays, was roughly respected. During the 18 weeks of the experiment, the difference between the average water flows during weekends and holidays, and the minimum water flows during weekdays, ranged from 910 cfs to 1,270 cfs. On average, this difference is equal to 1,110 cfs (Figure 3.5).

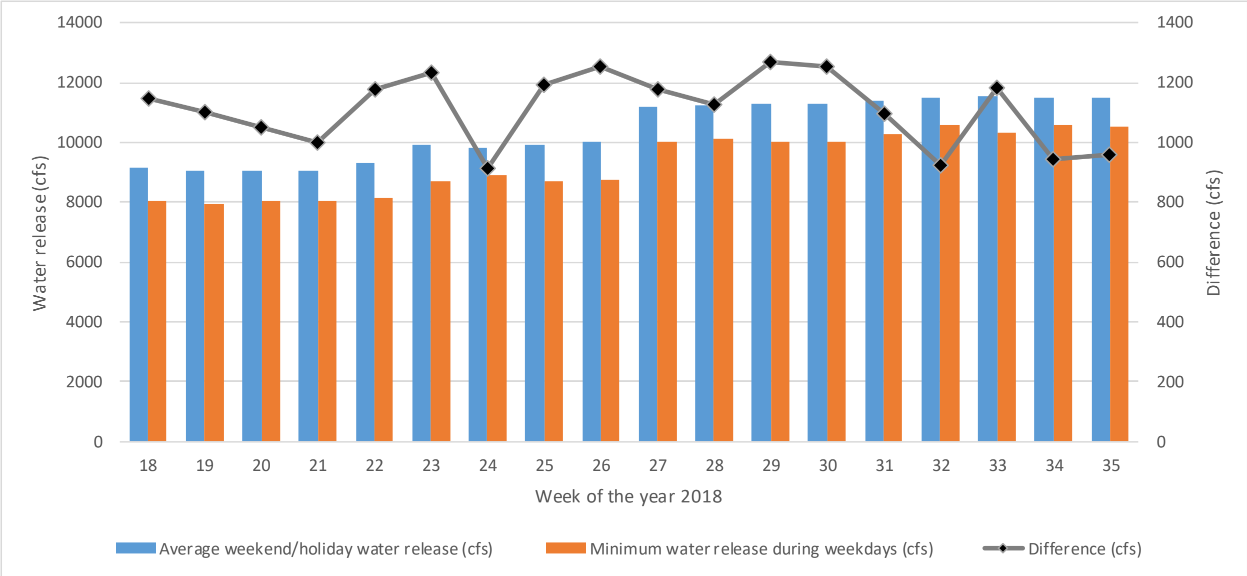

Figure 3.5: Difference between average weekend flows and minimum weekday flows during the 2018 MPF Experiment

The hourly down-ramp rate restriction of 2,500 cfs/hr from 2016 ROD (Reclamation 2016) was violated during 31 of the 2,952 hours of the study period (Figure 3.6), that is, 1% of the time. This is because of the regulation down that the Powerplant offered to the system during those hours. The hourly up-ramp rate restriction of 4,000 cfs/hr, however, was never violated.

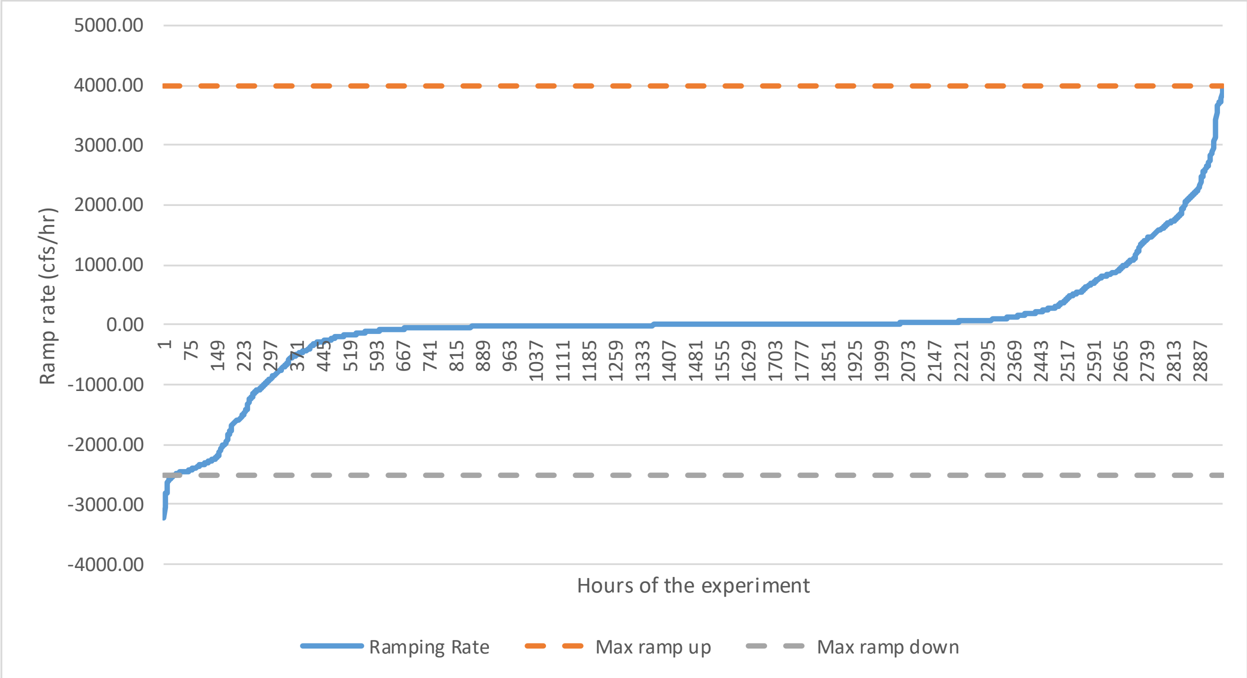

Figure 3.6: Hourly ramp rate at GCD during the 2018 MPF Experiment, plotted in increasing magnitude order

4 Methods and Models

For the 2018 MPF analysis, financial impacts were computed by comparing simulated results between two operating scenarios:

(1) The Baseline scenario**,** which assumes 2016 ROD operating criteria, the occurrence of the 2018 MPF, and historical monthly release volumes; and

(2) The counterfactual Without Experiments scenario**,** which assumes 2016 ROD operating criteria, the absence of any experimental releases, and historical monthly release volumes.

The financial impact was assessed as the difference in *net energy revenue* between the two scenarios. Monthly water releases are identical under both scenarios. MPF financial outcomes are therefore a function of (1) the shifting of water release volumes from weekend to weekdays, (2) the MPF weekend flat-flow requirement, and (3) energy purchase and sale price profiles.

In previous reports, 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 replaced by a “lighter” version called GTMax SL. The GTMax SL model is the main simulation tool used to dispatch SLCA/IP hydropower plants, including GCD. It not only simulates GCD operations but also provides insights into the interplay among the 2016 ROD operating criteria, exceptions to the criteria to accommodate experimental releases, modifications to monthly water volumes, and WAPA scheduling guidelines and goals. The GTMax SL model is supported by several other tools and databases. These support tools include the SLCA/IP Contracts spreadsheet, Customer Scheduling algorithm, 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 the study period. Weekly simulations are scaled up such that each run represents a 1-month time period. The GTMax SL model is supported by an input spreadsheet that contains ROD operating criteria, historical 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 Model Input Data for GCD Reservoir and Powerplant

Data for GCD reservoir and power plant input into GTMax SL are based on historical monthly statistics contained in *Water Operations: Historic Data* (Reclamation 2018) and the supervisory control and data acquisition (SCADA) data. This information includes water releases, forebay elevation, and power conversion factors at GCD.

Because 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. The hour type is defined by the days of the week (i.e., Monday through Sunday) and the 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. in the typical week simulation is scaled by five in GTMax SL model. This methodology therefore accounts for different daily water release volumes while respecting the total monthly water release volume.

Monthly water release volumes, reservoir elevation levels, and power conversion factors at GCD are assumed to be identical under both scenarios, that is, equal to the historical values (see Table 2.2). The factor that relates the conversion of water releases to power production is the ratio between the historical monthly generation and the historical monthly water release. The maximum output capability (output) at GCD is computed monthly. It is the minimum of (1) the physical capacity of the powerplant 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. Historic outage levels provided by Reclamation were used to compute monthly outage factors. These factors were used to derate the maximum output of the plant as computed by the process described above. For example, if one and only one 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 Hydropower Plants

For simplicity, the generation from all the hydropower plants except GCD is not optimized by the GTMax SL Model. Instead, the generation of these power plants is fixed and aggregated into a single equivalent generation profile representing their historical values, more specifically, the total generation produced by the following power plants:

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

Power-plant generation data are from SCADA information (WAPA 2018). However, when data are missing, prescheduled operations from EMMO (Dean 2018) 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 A.1 in the Appendix.

4.3 Model Input Data for Loads and Market Prices

Data for load input into GTMax SL are based on prescheduled operations from EMMO (Dean 2018). 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 equivalent load comprises

- 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 into and out of the system.

The hourly profile of this equivalent load is obtained for the entire study period, that is, for all the hours from May 1, through August 31, 2018. These data are not used directly. Instead, a typical week is used in GTMax SL to represent the equivalent load 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 A.2 in the Appendix.

The real-time sale prices of Western are used as market prices input into GTMax SL and are the main drivers for determining optimal generation patterns at GCD. These data were obtained from EMMO (Dean 2018). In addition to typical weekly demand profiles, a typical week is used in GTMax SL to represent purchase and sale price profiles for each month of the study period. This typical week is constructed in the same way as the load except that actual prices weighted by historical quantities are used.

The optimal generation profile at GCD computed by the model under the Baseline scenario conditions uses the real-time sale price profile for each typical week. The resulting modeled hourly generation profile is very similar to the historical generation patterns, validating the use of the real-time sale 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 A.3 in the Appendix.

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5 Net Financial Cost of the MPF Experiment

The financial impact of the MPF Experiment was assessed as the difference in *net energy revenue* between the Baseline and Without Experiments scenarios. Both scenarios release identical amounts of water each month, as shown in Figure 5.1. Daily water release volumes during each day of the month, however, differ. Under the Without Experiments scenario (counterfactual scenario) it is assumed that the total water release on Saturdays is at least 85% of the average daily water release volume during weekdays (i.e., Monday through Friday inclusive). This 85% rule is also applied to the water release volume on Sundays. In contrast, for each week during the MPF Experiment water flows during weekends and holidays are required to be flat (i.e., constant) and 1,000 cfs higher than minimum flows during weekdays. This constraint generally leads to significantly smaller water releases, less than the 85% assumption, during weekends than during weekdays.

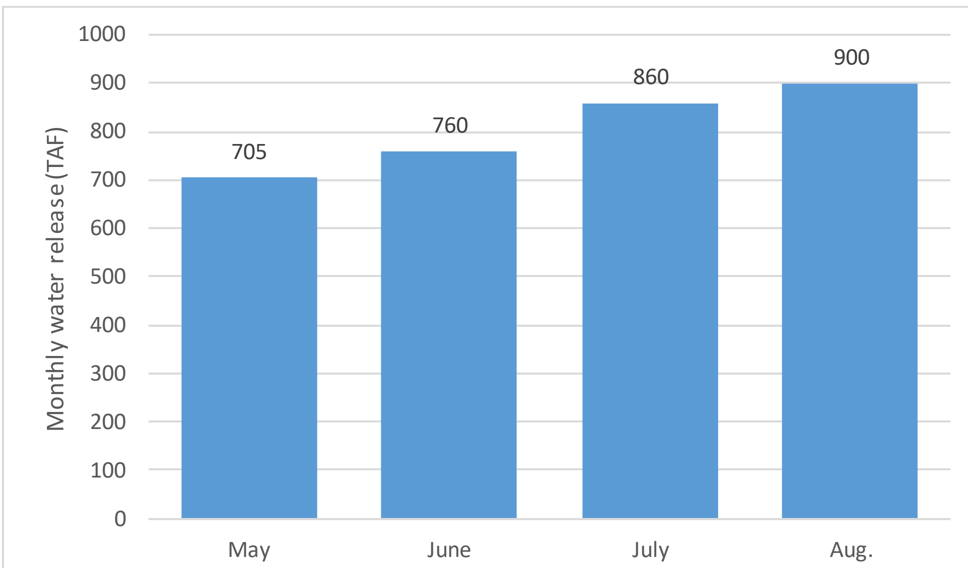


Figure 5.1: Monthly water releases from May 1 to August 31, 2018, under both scenarios

The differences of flow patterns during a typical week between the Baseline (With Experiments) and Without Experiments scenarios are illustrated in the hydrograph in Figure 5.2 (GCDAM 2018). Note that the MPF (labeled “Bug Flow”) weekend flat-flow requirement under the Baseline (With Experiments) also leads to maximum flows during weekdays significantly higher than under the Without Experiments scenario. This occurs because both scenarios are bound by identical daily change restrictions.

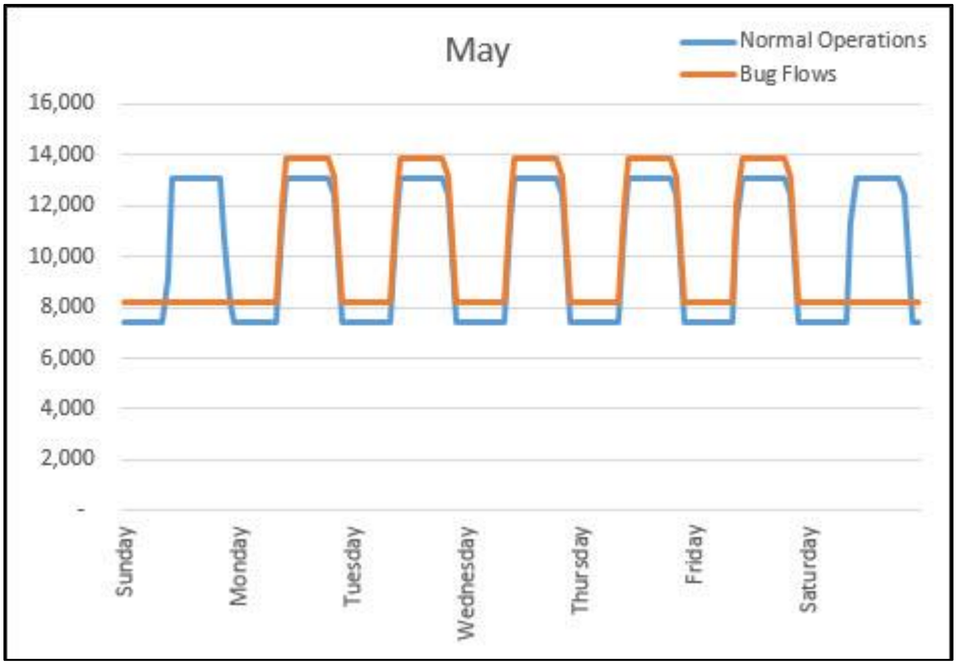
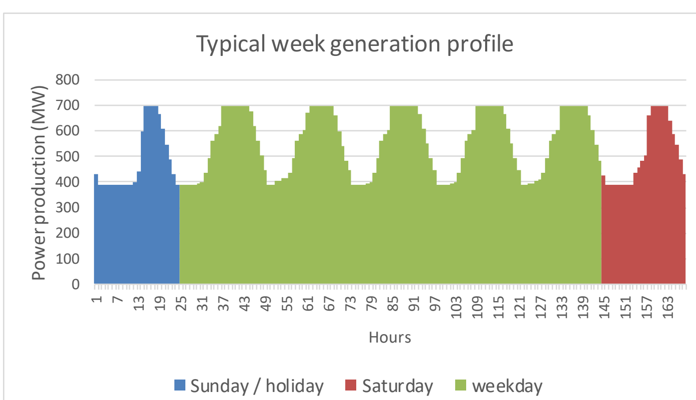


Figure 5.2: Hydrograph (in cfs) at GCD under the Baseline (With Experiments) and Without Experiments scenarios (GCDAM 2018)

5.1 Generation Profile at GCD: Extrapolations of Model Results from a Typical Week to an Entire Month

The hourly generation profile at GCD is expanded from the typical modeled week of 168 hours to an entire month (comprising all the hours in the month). This is done by building a monthly shape in which the hourly profile of each day is set equal to the typical week profile for each day type: weekday, Saturday, or Sunday/holiday. Figure 5.3 illustrates this procedure for GCD generation during the month of July. Note that beginning with the July 1, which is a Sunday, the typical weekly pattern is repeated during the entire month. Also note that on the fourth day of the month, the Sunday generation profile is used because the fourth of July is an official WECC holiday.



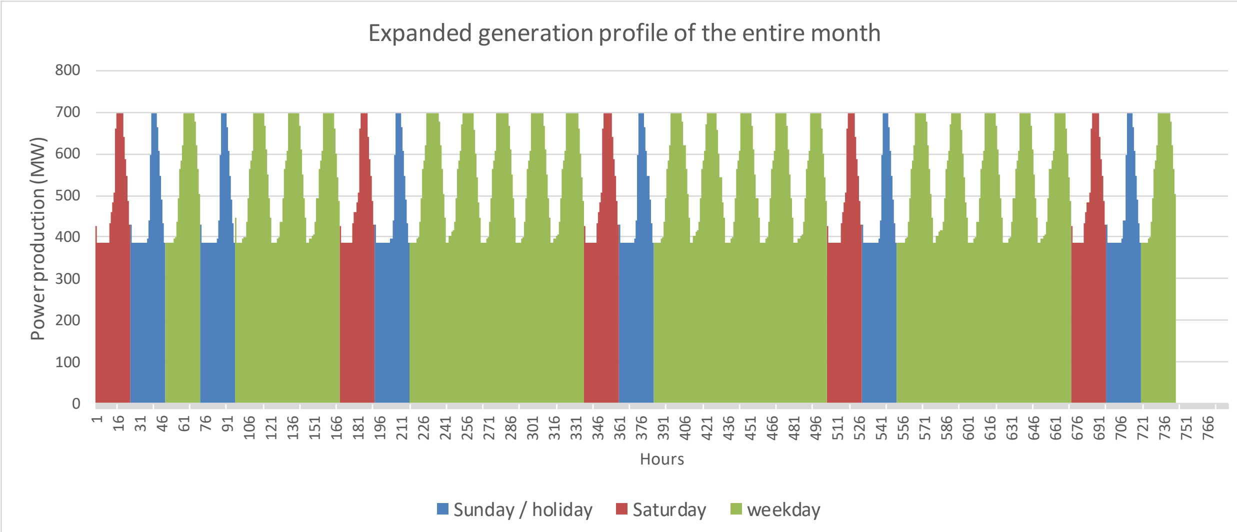


Figure 5.3: Typical week and complete month representation of the generation profile at GCD in July 2017

5.2 Net Energy Purchases and Sales

Once an expanded representation of the generation profile at GCD has been created, the hourly profile of net energy sales and purchase quantities is complete for the SLCA/IP system. For each hour of the entire study period, 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 power plant generation resources were described in section 4.2 and loads were described in section 4.3. Energy purchases in the equation include both day-ahead prescheduled 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 5.3). 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 MPF GCD generation profile has a direct impact on hourly energy transactions 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 Energy 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 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 MPF Experiment 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 MPF.

5.4 Water Release Model Results

The optimal water release profiles at GCD have been computed under the Baseline and Without Experiments scenarios. Modeled water release profiles of a typical week in May under both scenarios are illustrated in Figure 5.4. Results are consistent with the hydrograph depicted in Figure 5.2.

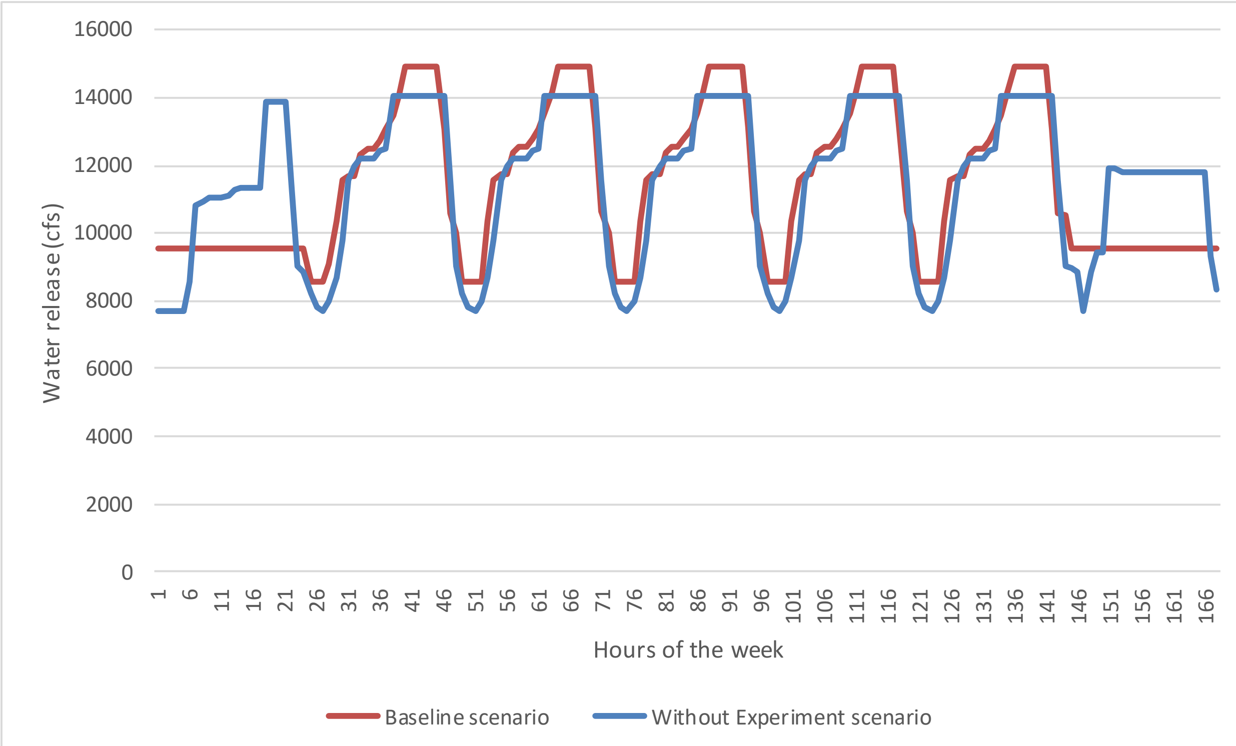


Figure 5.4: Modeled hourly water release profiles during a typical week in May 2018 under the Baseline and Without Experiments scenarios

Water release ranges during weekends and weekdays, under both scenarios, are depicted in Figure 5.5. As shown, under the Baseline scenario (red rectangles), water release ranges during weekends are limited to a single value (labeled “0” in the figure) because of the flat-flow constraint. Moreover, because this value is required to be only 1,000 cfs greater than the minimum water release during weekdays, this water release during weekends is also relatively low. To compensate for the low-water-release volume during weekends, water releases during weekdays are significantly higher than those under the Without Experiments scenario (blue rectangles).

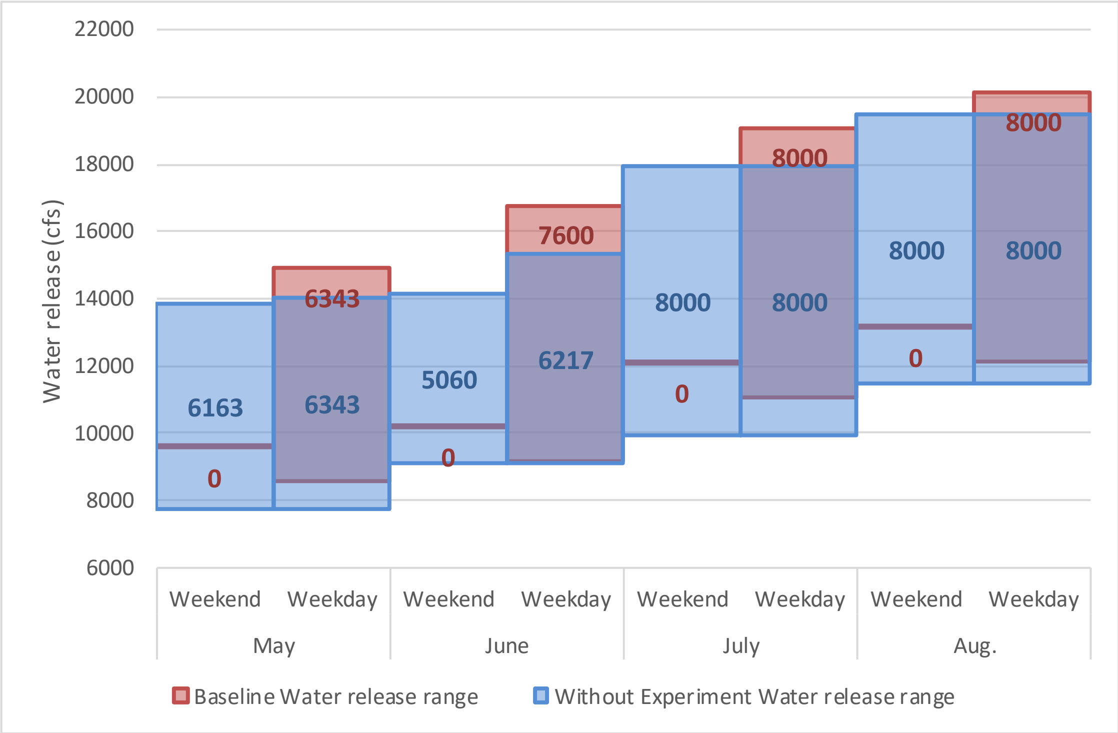


Figure 5.5: Model results of water release range in weekends and weekdays from May to August under the Baseline and Without Experiments scenarios

Monthly differences between the Baseline and the Without Experiments maximum water release during weekdays is shown in Table 5.1. The average over this 4-month period is about 1,030 cfs.

Table 5.1: Weekday increase inmaximum water release under the Baseline (MPF) scenario compared to the Without Experiments scenario

Calendar Year	Month	Maximum Water Release Difference (cfs)
2018	May	840
2018	June	1,463
2018	July	1,151
2018	Aug	669

5.5 Net Revenues from Energy Transactions

The Baseline (MPF) scenario shifts water release volumes and therefore energy production from the weekends to weekdays. Note in Figure 5.6 that this generation shift is the largest in the month of June and the smallest in August.

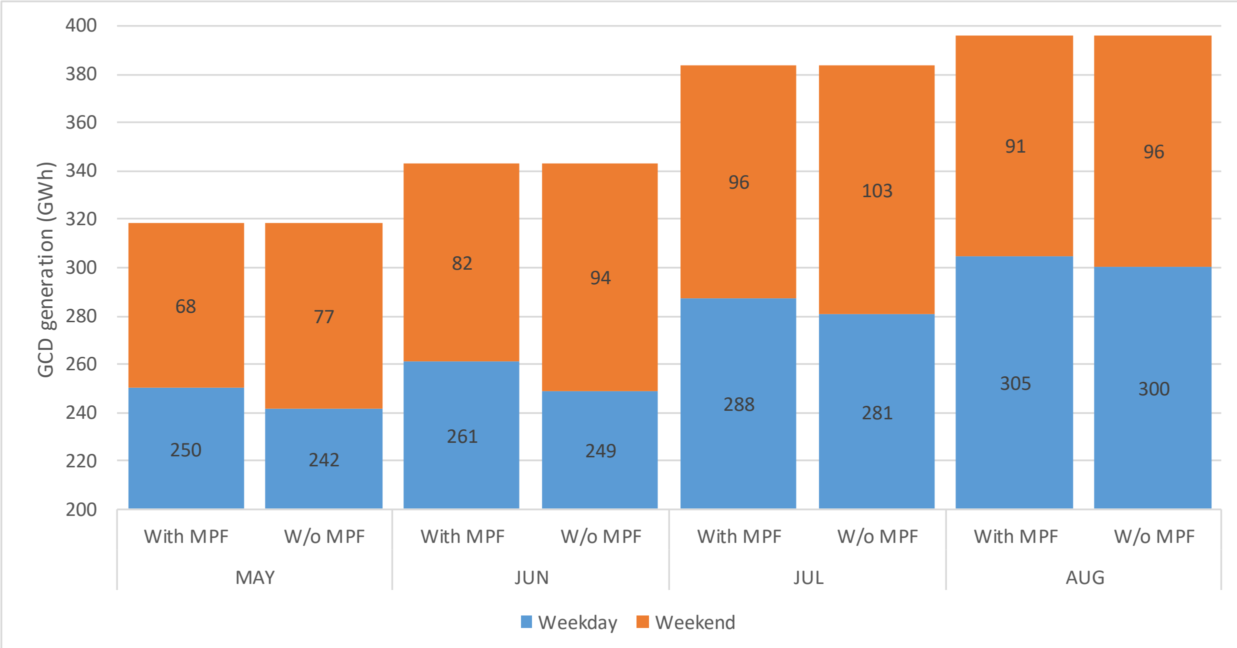


Figure 5.6: Comparison of Baseline and Without Experiments GCD production for weekdays and weekends

This shifting results in a lower net energy position during the weekends under the Baseline (MPF) scenario than under the Without Experiments (counterfactual) scenario. In addition, the MPF flat-flow requirement does not allow WAPA schedulers to follow/respond to market prices during the weekends. A lower release and less power production therefore lower WAPA's net financial position during the weekend during an MPF Experiment.

During weekdays, on the other hand, under the Baseline (MPF Experiment) scenario both net energy and financial positions are higher as a result of higher water release volumes in combination with peak releases that are on average 1,030 cfs higher (see Table 5.1).

Figure 5.7 shows that, for each of the 4 months of the experimental period, the accumulated MPF financial cost during weekdays is always negative (it is a net revenue), whereas the accumulated MPF financial cost during weekends is always positive (it is a net cost). The MPF financial cost therefore trades off weekday net revenues against weekend net costs.

The results of this trade-off are depicted in the waterfall chart shown in Figure 5.8, which depicts cumulative financial impacts at the end of each month. Conducting the MPF Experiment during May and June resulted in an estimated WAPA financial gain of $19,000 and $160,000, respectively, for a total gain of $179,000. On the other hand, it resulted in financial losses in July and August of $210,000 and $135,000, respectively, for a total of loss of $345,000. The net MPF financial cost over the 4-month experimental period are estimated to be about $166,000.

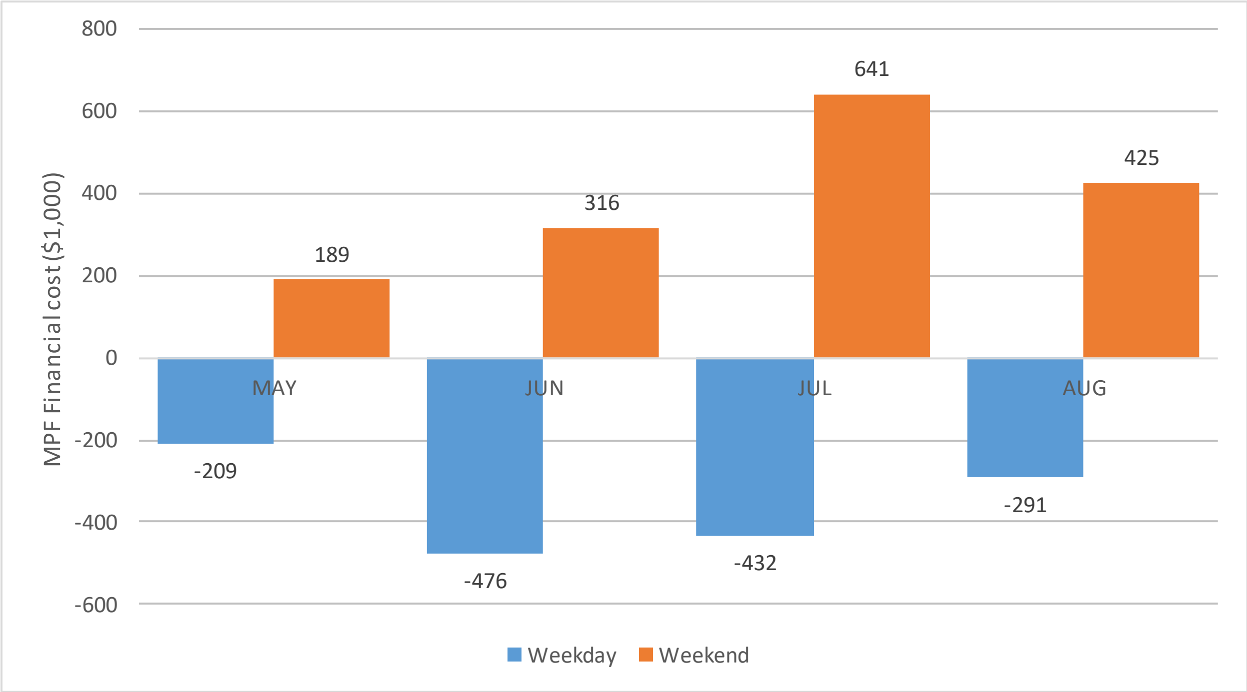


Figure 5.7: Cost of the MPF Experiment conducted from May to August 2018: Comparison of the MPF financial costs between weekdays and weekdends

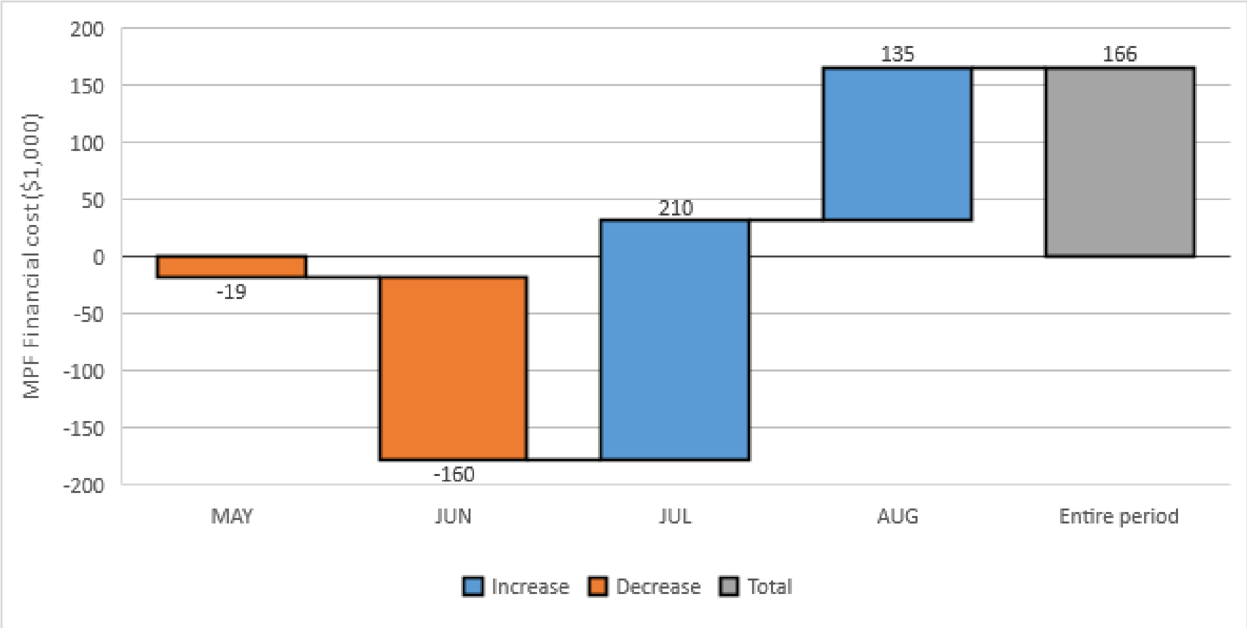
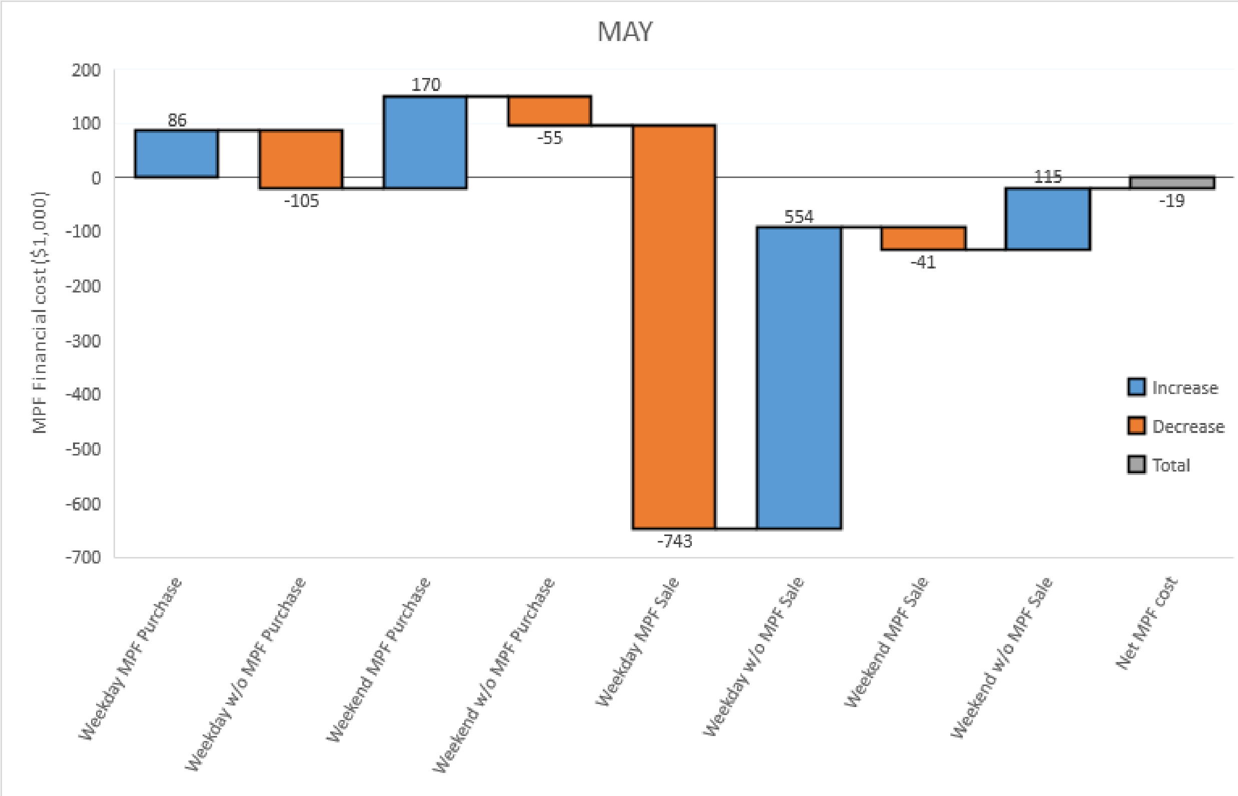
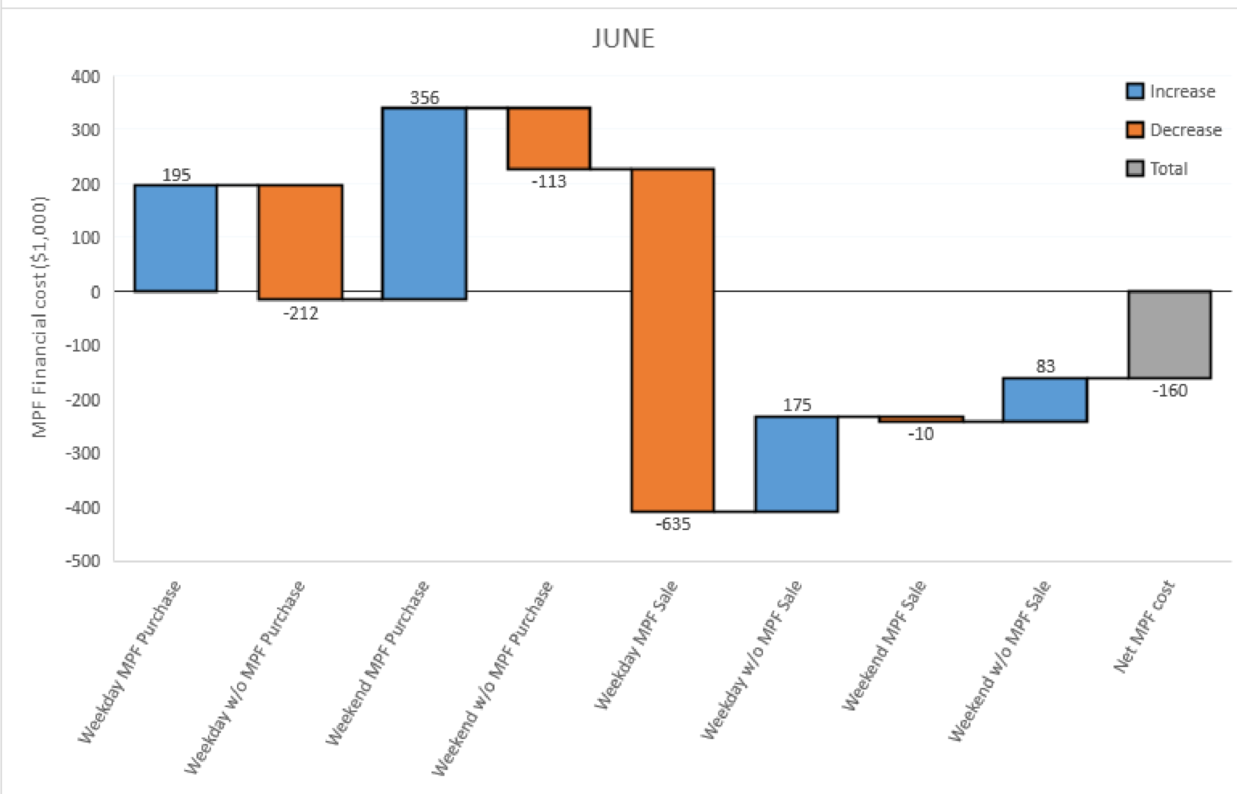
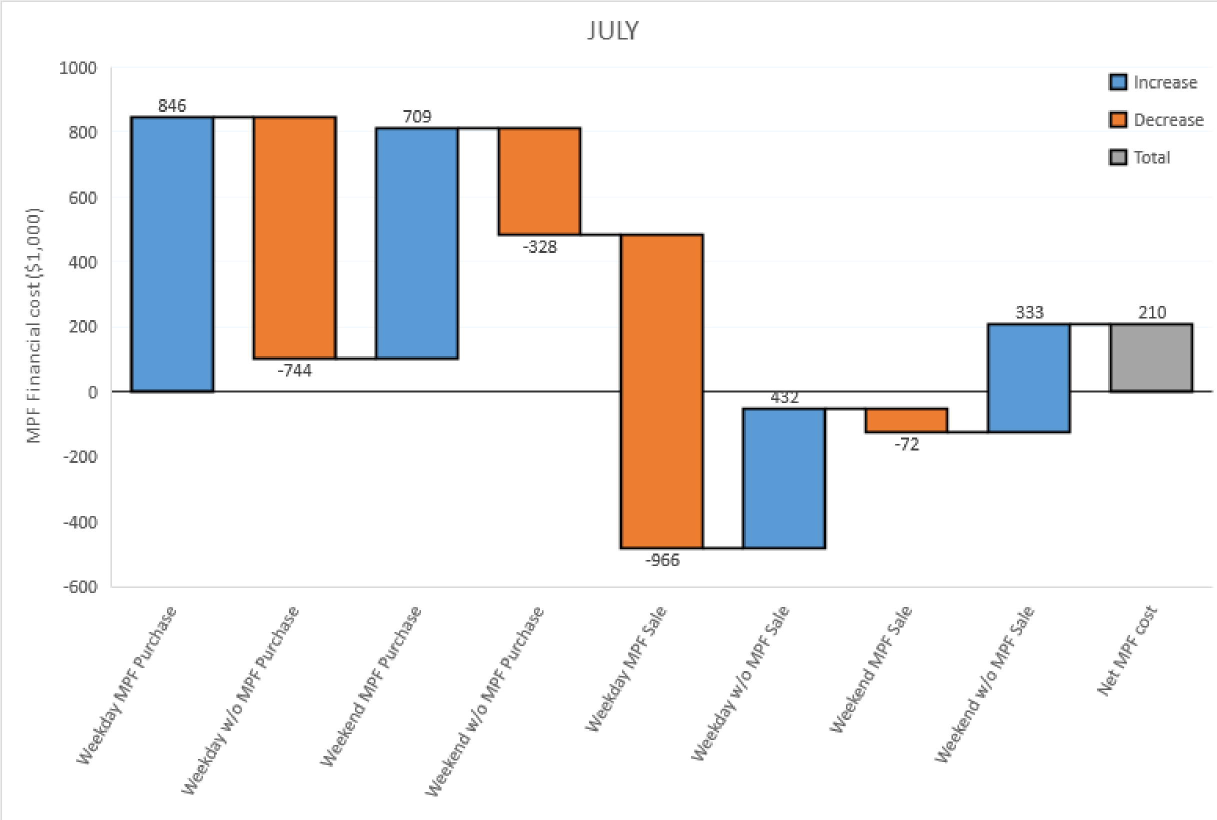


Figure 5.8: Waterfall chart illustrating the cumulative monthly cost of the MPF Experiment conducted from May to August 2018

The MPF Experiment resulted in a significant benefit during June, which also has the largest energy shift from weekends to weekdays (see Figure 5.6). As a matter of fact, June has the largest MPF net benefit during weekdays in June (see Figure 5.7), with a relatively low MPF net cost during weekends. To further investigate this, we disaggregated benefits into the purchase costs and sale revenues for both scenarios during weekends and weekdays. Figure 5.9, a waterfall chart, illustrates this breakdown for each of the 4 months independently. For more details, the hourly profile of the cumulative cost is shown in Figure A.4 in the Appendix.


MAY
MPF Financial cost ($1,000)
200
100
0
-100
-200
-300
-400
-500
-600
-700
86
-105
170
-55
-743
554
-41
115
-19
Increase
Decrease
Total
Weekday MPF Purchase
Weekday w/o MPF Purchase
Weekend MPF Purchase
Weekend w/o MPF Purchase
Weekday MPF Sale
Weekday w/o MPF Sale
Weekend MPF Sale
Weekend w/o MPF Sale
Net MPF cost


JUNE
MPF Financial cost ($1,000)
400
300
200
100
0
-100
-200
-300
-400
-500
195
-212
356
-113
-635
175
-10
83
-160
Increase
Decrease
Total
Weekday MPF Purchase
Weekday w/o MPF Purchase
Weekend MPF Purchase
Weekend w/o MPF Purchase
Weekday MPF Sale
Weekday w/o MPF Sale
Weekend MPF Sale
Weekend w/o MPF Sale
Net MPF cost



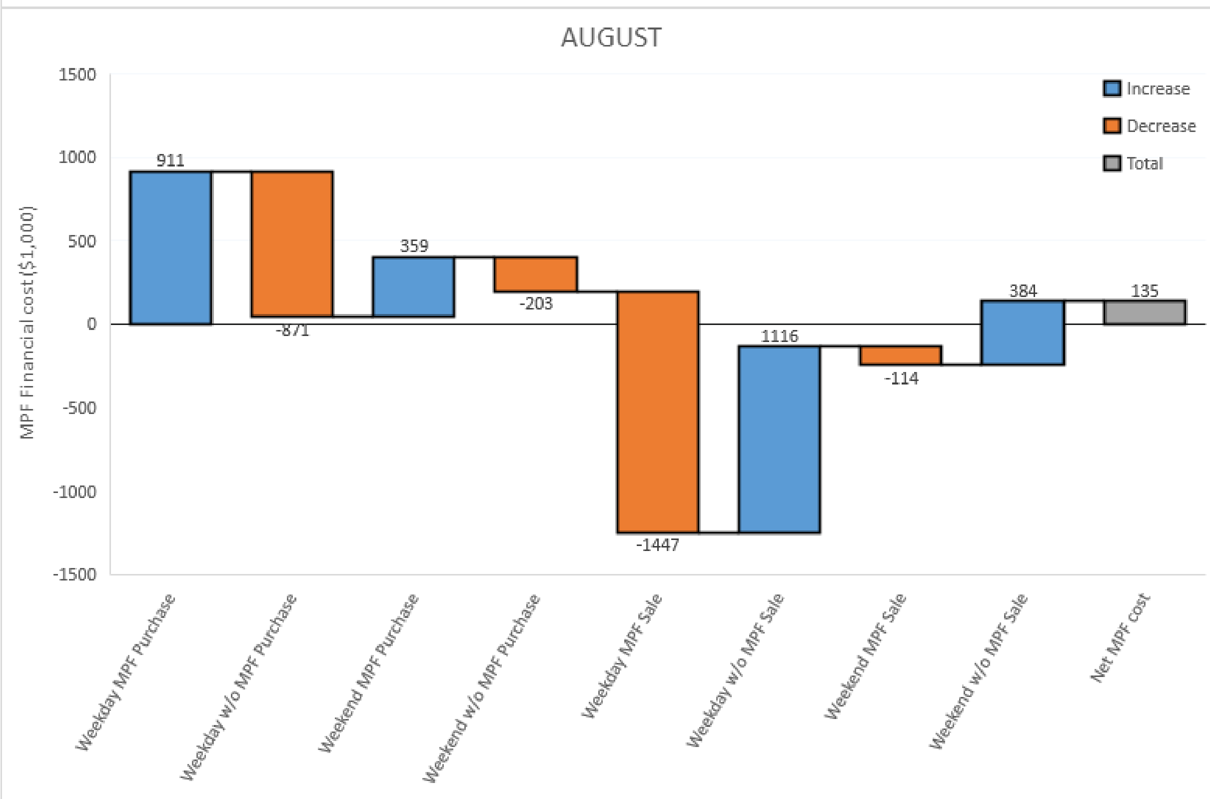


Figure 5.9: Monthly waterfall charts illustrating cummulative MPF financial costs in terms of purchase costs and sale revenues on weekdays and weekends for each month from May to August 2018

In calculating the financial cost of the MPF Experiment, the purchase costs of the Baseline (MPF) scenario are counted as positive, whereas the sale revenues are counted as negative. This is the opposite for the purchase costs and sale revenues for the Without Experiments scenario.

Note that for each of the 4 months the sale revenues during weekdays under the Baseline (MPF) scenario are always the largest component in absolute value. Shown as orange bars with negative values in Figure 5.9, these sales represent a relatively large WAPA financial benefit. However, these revenues are nearly balanced most of the time with the various MPF costs (the blue bars in Figure 5.9), resulting in either a net MPF financial cost or a relatively low MPF benefit for all months except June.

June is the only month during which two specific cost components are relatively low at the same time:

- The purchase costs during weekdays under the Baseline (MPF) scenario, and
- The sale revenues during weekdays under the Without Experiments scenario.

These low June MPF cost components, whose associated energy exchanges are shown as rectangles with thick red borders in Figure 5.10, are a result of:

- A relatively small amount of energy purchased at a low price during weekdays resulting in low expenses under the Baseline (MPF) scenario, and
- A relatively small amount of energy sold during weekdays under the Without Experiments scenario resulting in low sales revenues that in turn contribute to an experimental financial benefit. Note as well the large spread between the MPF and without MPF sales.

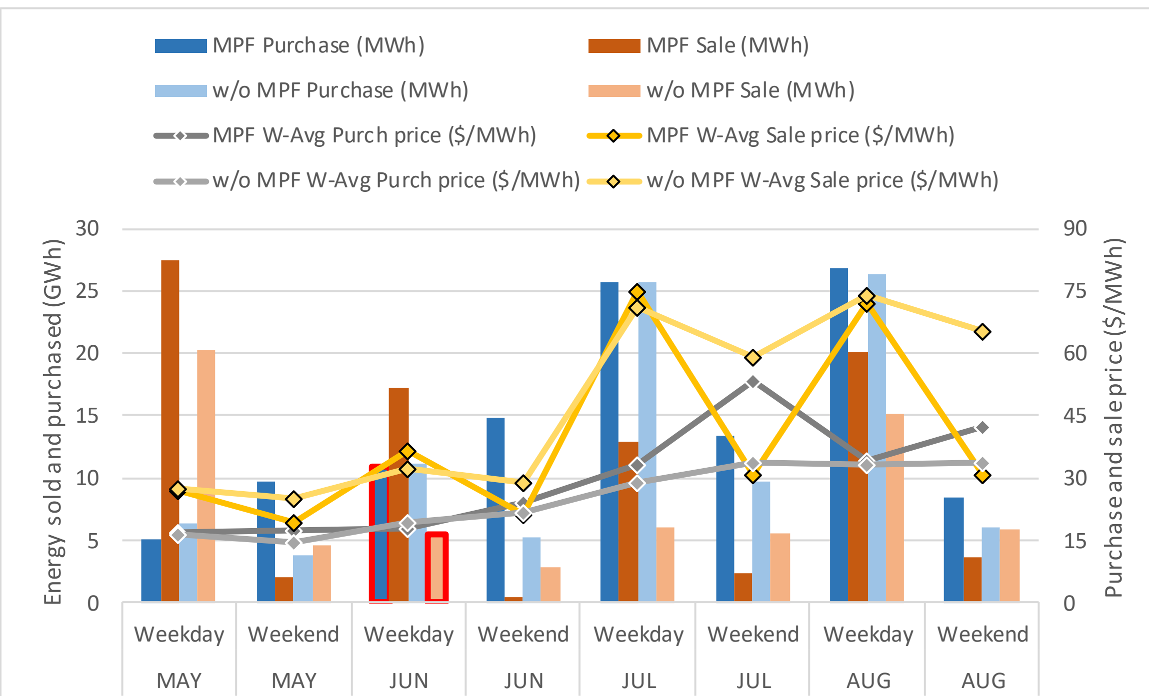


Figure 5.10: Purchased and sold energy, and purchase and sale price, under both scenarios from May to August 2018

6 Summary

In summary, the MPF Experiment imposes flat-flow operating constraints during weekends at GCD lowering WAPA's financial position during the weekend. On the other hand, under a MPF Experiment, the weekend constraint that requires minimum daily water release volume to be 85%, the average weekday volume is lifted. Removing this constraint may be financially beneficial under some conditions.

The trade-off between a lower MPF financial position during the weekend and a higher position during weekdays is either positive or negative depending on hydrological conditions and energy market price profiles during the experiment. Lifting the minimum water release constraint during weekends is, most of the time, not sufficient to counterbalance the costs of the weekend flat-flow constraint imposed by the MPF Experiment.

One situation resulting in a significant MPF financial benefit occurred in June 2018. It arose because of the simultaneous combination of two favorable conditions. On one hand, under the Baseline (MPF) scenario, the additional water available for power production during weekdays resulted in a very low amount of energy purchased. On the other hand, under the Without Experiments scenario, the low amount of water available during weekdays resulted in a very low amount of energy sold. Each of these conditions, taken separately, can be found in the other months, but it is only in June that both conditions occurred at the same time.

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Appendix: GTMax SL Simulations for the 2018 MPF Experiment: Aggregated Demand and Supply (Other than GCD) Profiles

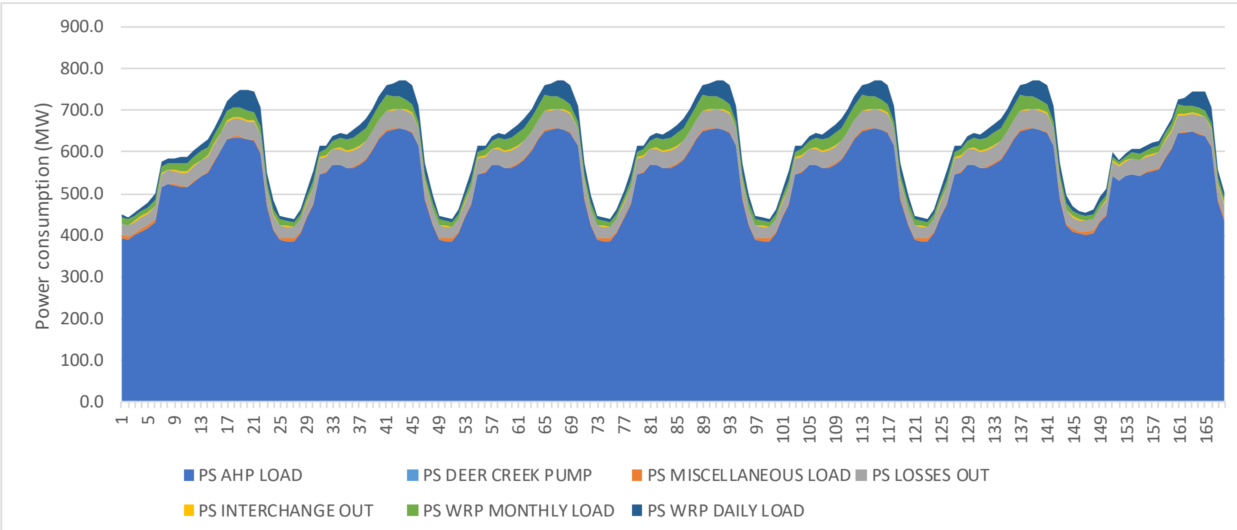


Figure A.1: Typical week aggregated energy demand profile of the SLCA/IP system in May 2018 from historical values

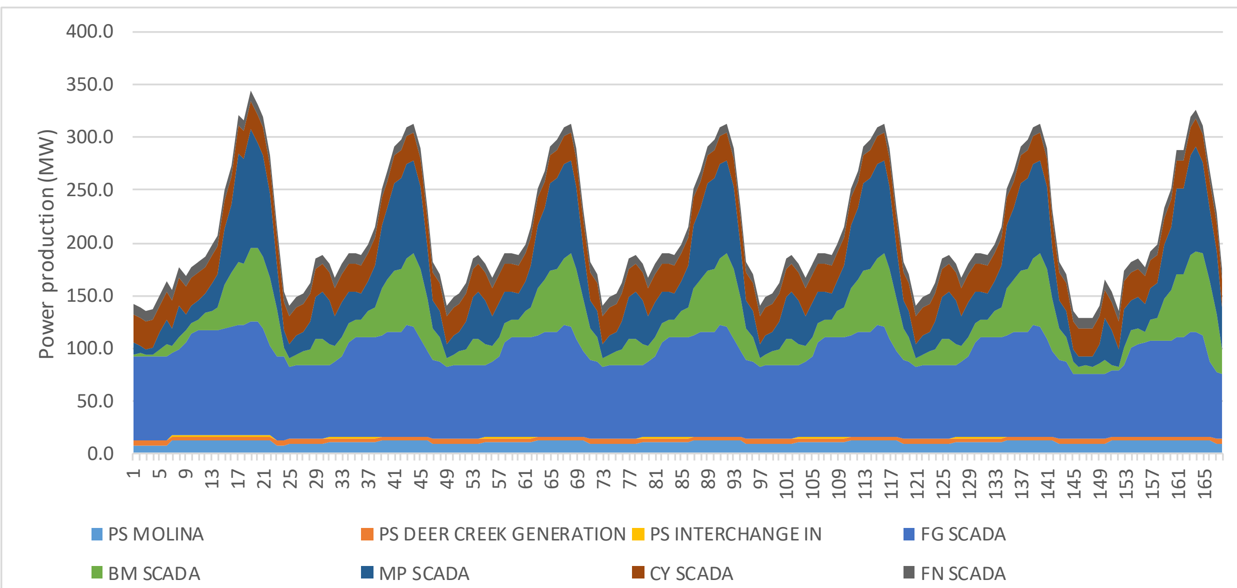


Figure A.2: Typical week aggregated energy supply profile of all plants apart from GCD in May 2018 from historical values

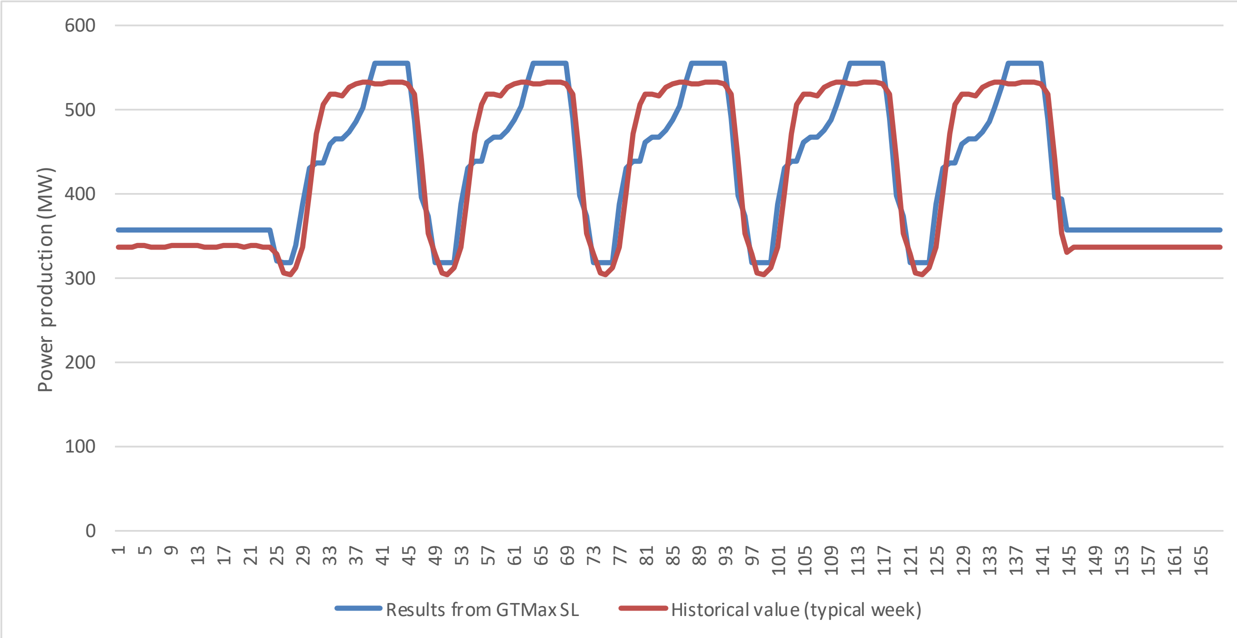
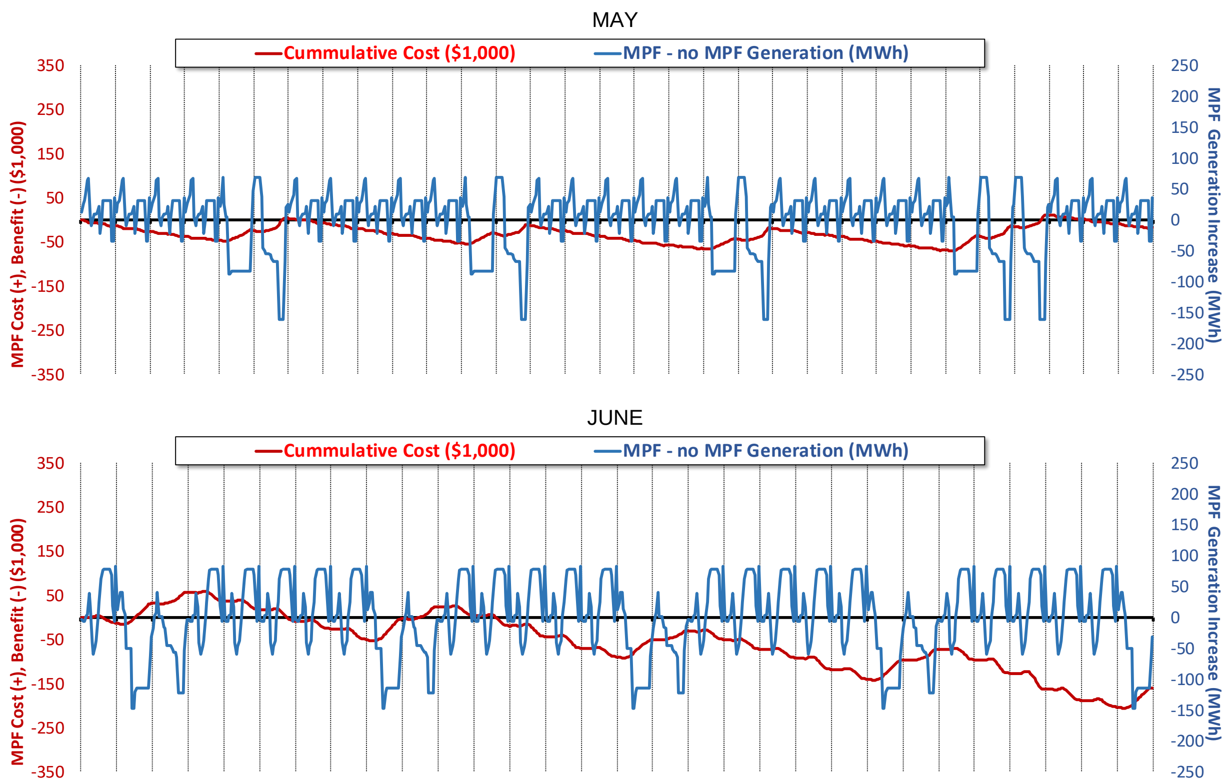


Figure A.3: Typical week energy generation profile at GCD in May 2018 from historical values and calculated by the GTMax SL Model



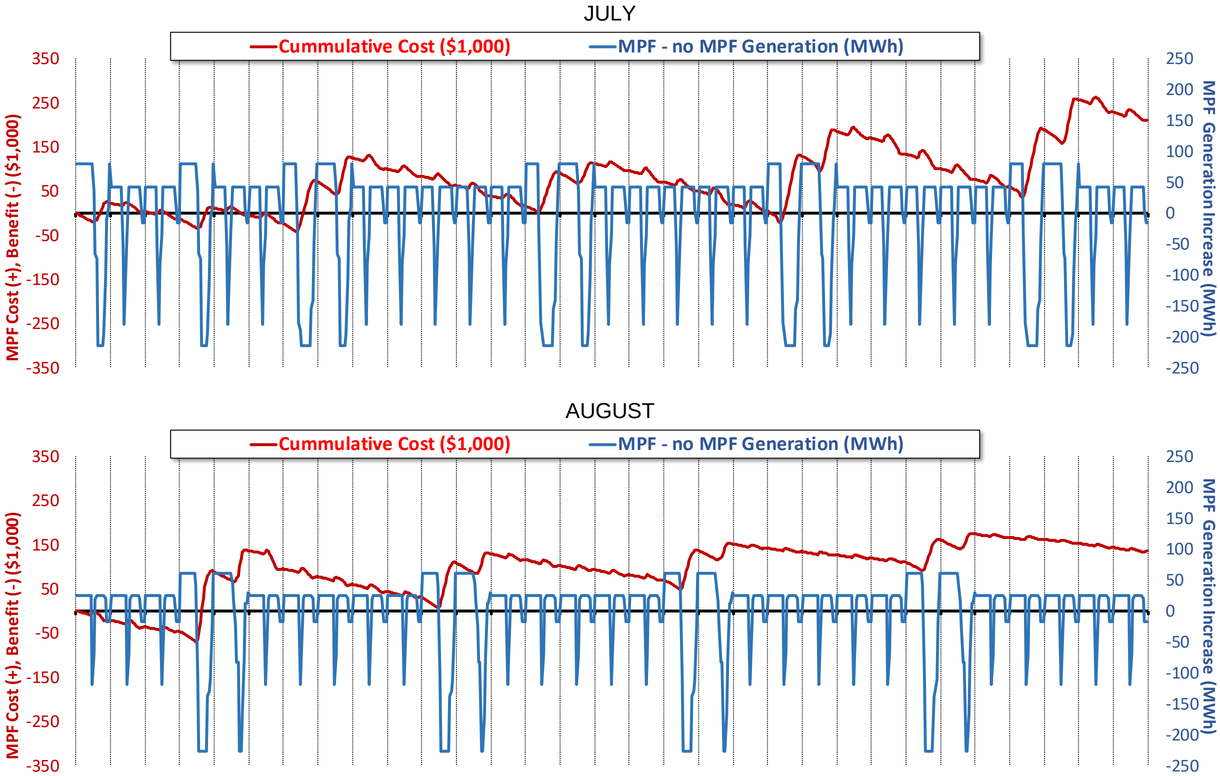


Figure A.4: Hourly GCD power production difference between both scenarios and MPF cumulative cost in May, June, July, and August 2018

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