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ANL-20/81

Financial Analysis of the 2019 Glen Canyon Dam Bug Flow Experiment

Energy Systems Division

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Financial Analysis of the 2019 Glen Canyon Dam Bug Flow Experiment

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 macroinvertebrate production that are 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 the beginnings of May 2019 through the end of August 2019. This analysis was funded by the Colorado River Storage Project (CRSP) Office of the U.S. Department of Energy’s 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 memorandum with assistance from WAPA’s CRSP and Energy Marketing and Management Offices (EMMO).

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Contents

Figures

Tables

Acronyms and Abbreviations

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

AHP	available hydropower
Argonne	Argonne National Laboratory
BA	Balancing Authority
CRSP	Colorado River Storage Project
CY	calendar year
EIS	Environmental Impact Statement
EMMO	Energy Management and Marketing Office (WAPA)
FES	firm electric service
GCD	Glen Canyon Dam
GTMax SL	Generation and Transmission Maximization Superlite
LTEMP	Long-Term Experimental and Management Plan
MPF	Macroinvertebrate Production Flow
MSR	Minimum Schedule Requirement
N/A	Non applicable
PCF	Power conversion factor
PO&M-59	Power Operations and Maintenance, Form 59 (a Bureau of Reclamation form entitled, *Monthly Report of Power Operations – Powerplants*)
Reclamation	Bureau of Reclamation
ROD	Record of Decision
SHP	sustainable hydropower
SLCA/IP	Salt Lake City Area Integrated Projects
WACM	Western Area Power Administration, Colorado Missouri
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 macroinvertebrate production flows (MPF) conducted at the Glen Canyon Dam (GCD) from the beginning of May 2019 through the end of August 2019. It is the second report examining the financial implications of MPF, 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 negative impact on the financial value of energy production. For these experimental releases, financial costs of approximately $327,000 were incurred, mainly driven by the flat and low 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 the 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 did not occur.

The Generation and Transmission Maximization Superlite (GTMax SL) model was the main 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 powerplant characteristics, hydrologic conditions, and Western Area Power Administration’s (WAPA’s) energy prices in the modeling process. In addition to estimating the financial impact of the MPF, the team used the GTMax SL model to gain insights into the interplay among ROD operating criteria, exceptions that were made to criteria to accommodate the experimental releases, and WAPA operating practices.

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1 Introduction

The Glen Canyon Dam (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 Salt Lake City Area Integrated Projects (SLCA/IP). Electricity produced by the Powerplant serves the demand of 5.8 million consumers in 10 western states that are located in the Western Interconnection (WI). Before 1990, the Powerplant had few operating 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. CRSP loads and market price signals were the principal dispatch drivers, often resulting in large fluctuations of 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. Based on 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) Record of Decision (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 limits 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, restricts the range of hourly releases on a rolling 24-hour basis, and limits 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 associated financial analyses listed in chronological order below include:

- Calendar year (CY) 1997 through 2005 experiments 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 through 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 were reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2011* (Poch et al. 2012);
- WY 2012 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);
- 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 reported in *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2017* (Ploussard et al. 2019a); and,
- WY 2018 experiments reported in *Financial Analysis of the 2018 Glen Canyon Dam Bug Flow Experiment* (Ploussard et al. 2019b).

One experiment, referred to as a Macroinvertebrate Production Flow experiment (MPF), was conducted from the beginning of May 2019 through the end of August 2019. A previous MPF experiment was conducted in 2018 during the same months. These MPF, also known as "bug flows", maintained constant release rates on the weekends and holidays. During the 2019 MPF experiment, these constant weekend release rates were maintained at a level equal to the minimum weekday release plus 750 cfs. These low water releases during the weekends and holidays produce less energy with less operational flexibility than under normal operations, resulting in a financial cost to the Western Area Power Administration (WAPA) during those days. On the other hand, higher weekday releases under MPF in combination with a lifted minimum water release during weekends generally leads to relatively higher financial value of Powerplant operations during weekdays. Net costs of conducting the MPF is therefore a tradeoff between generally higher financial outcomes during weekdays versus lower financial outcomes during weekends. Under some hydrological and market conditions, MPF results in an overall net financial gain, while under other conditions WAPA losses money. This report describes the method that was used to model the SLCA/IP, which includes GCD, and discusses Argonne's estimates of 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 operable capability must eventually be replaced by other power generation resources. Second, the hydropower energy cannot be used to its fullest extent during hours of peak electricity demand when the market price and economic benefits are relatively high.

During the 2019 MPF 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 by simulating GCD operations under two scenarios, namely, (1) a "Baseline" scenario that mimics both MPF operations during the experiment and that complies with 2016 ROD operating criteria by optimizing the Powerplant operations under these conditions, 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 Generation and Transmission Maximization Super Lite (GTMax SL) model simulates the SLCA/IP powerplant dispatch from which WAPA's financial revenues are computed. This tool uses an integrated system modeling approach to dispatch powerplants 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 powerplants' 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 2016 ROD operating criteria. The second scenario, Without Experiments, is identical to the first one, except it assumes that the experimental release did not occur. Differences in the net financial position between the two scenarios represent the change in the financial value of power attributed to experimental releases. To measure MPF costs, GTMax SL runs were only made for May 2019 through the end of August 2019 period. It was not necessary to run other months of the year because, unlike GCD high flow experiments, MPF monthly water release volumes under the with and without Bug Flow scenarios are identical; therefore, the comparative financial cost of the MPF during non-experimental months is assumed to be zero. 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 that are 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's Operating Practices

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

(1) Hourly and daily operating criteria – the 2016 Record of Decision (ROD),
(2) Exceptions to the 2016 ROD made to accommodate the experimental releases,
(3) Monthly water release (2016 ROD), and
(4) WAPA's 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 (Reclamation 2016). These criteria were put into practice by WAPA beginning in 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/hour (hr), and the maximum hourly decrease (i.e., the down-ramp rate) is 2,500 cfs/hr. 2016 ROD operating criteria also restrict how much the releases can fluctuate during rolling 24-hour periods. This change constraint varies up to 8,000 cfs per day, depending on the monthly volume of water releases. Daily fluctuation (in cfs) 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 limited to 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 TAF to 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.

Source: (Reclamation 1996) and (Reclamation 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 considering other uses of the reservoirs, such as for flood control, river regulation, consumptive uses, water quality control, recreation, and fish and wildlife enhancement, and to address other environmental factors (Reclamation 2013). Besides, from January 2017, monthly water release at GCD 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’s 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 that are updated monthly.

For both the Baseline and Without Experiment scenarios, actual SLCA/IP monthly water releases, as recorded in Reclamation’s Form PO&M-59 (Reclamation undated) and available on Reclamation website (Reclamation 2020), 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 under both the with and without experiment scenarios. The maximum daily fluctuations, based on the 2016 ROD rules described in Table 2.1, have also been included.

Table 2.2: Water releases, Lake Powell elevations, and maximum daily fluctuations

Calendar Year	Month	Water Release (TAF)	Lake Powell Elevation (feet [ft])	Maximum daily fluctuations (cfs/day)
2019	May	720	3,584.65	6,480
2019	June	765	3,611.82	7,650
2019	July	857	3,621.60	8,000
2019	August	900	3,618.55	8,000

2.3 Montrose Scheduling Guidelines

The actual hourly scheduling of SLCA/IP hydropower plant operations is performed by WAPA's Energy Management and Marketing Office (EMMO) located in Montrose, Colorado. Schedulers make decisions based 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, the operational range was significantly wider prior to the 1996 ROD and was further restricted under the 2016 ROD. Other SLCA/IP powerplants 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 the Crystal reservoir has 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 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-hour, on-peak blocks, and 8-hour, 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 sell varying amounts of energy on an hourly basis on the day-ahead and/or real-time market. The volumes of these variable market purchases and sales are relatively small under most conditions. The GTMax SL model topology and inputs are designed to mimic these guidelines.

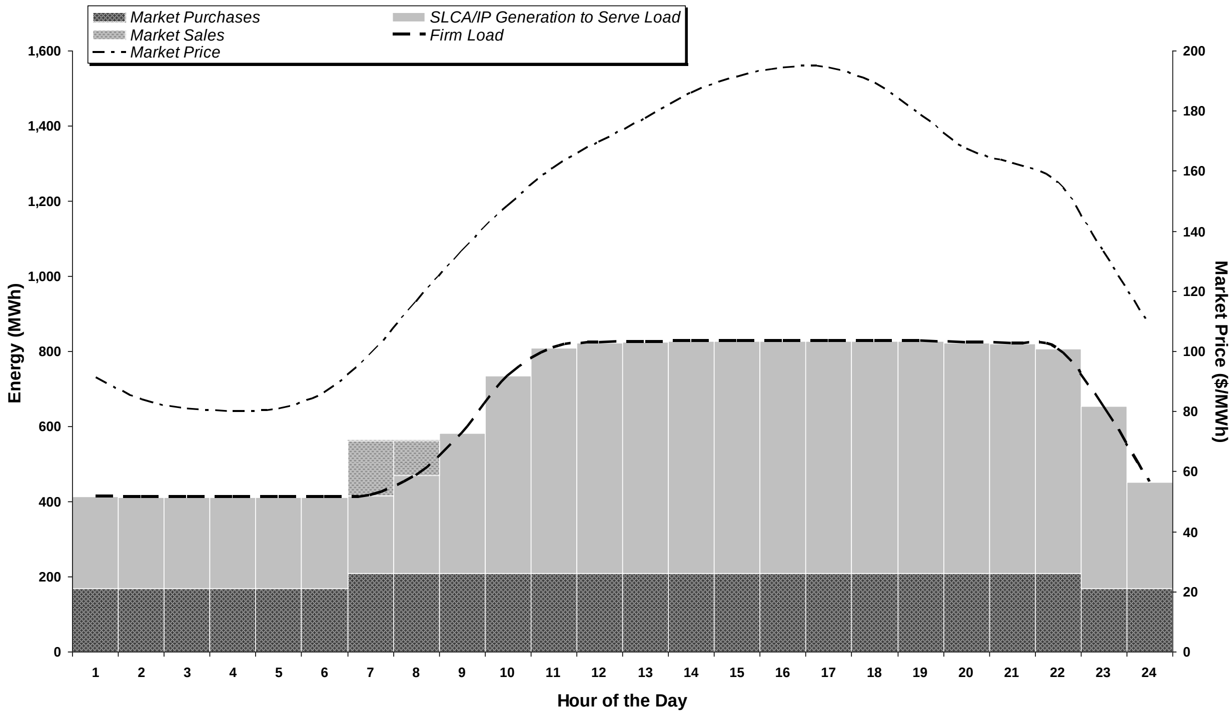

Figure 2.1: Illustration of the firm-load-driven dispatch guideline under the 1996 ROD operating criteria when SLCA/IP resources are short of load

The load-following objective facilitates a strong link between WAPA's contractual obligations and SLCA/IP operations, requiring dispatch among SLCA/IP powerplants to be closely coordinated. This interdependency exists because loads and hydropower resources are balanced whenever feasible. WAPA is able to affect the shape of its Firm Electric Service (FES) customer load requests indirectly through specifications in its contract amendments. In turn, these customer loads affect both SCLA/IP powerplant operations and hourly reservoir releases. Contract terms that indirectly affect load and powerplant 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 that are 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 release volumes over successive days. In this analysis, therefore, it was assumed that the same volume of water was released each weekday, and that, under the without experiment, weekend daily water release volumes were at least 85 percent of weekday releases. Under the MPF experiment, because of the low release requirement when conducting MPF operations, weekend daily release volumes typically dip below the 85% threshold.

In addition, from June through August 2019, operations allowed one cycle of raising and lowering GCD Powerplant output per day. In May 2019, operations allowed a maximum of two cycles as dictated by the hourly load pattern.

Changes in WAPA’s scheduling guidelines did not occur abruptly, but rather subtly, and over a period of months. These changes were not only the result of the operational constraints imposed by the ROD but also attributable to changing weather and market conditions, such as persistent drought, electricity market disruptions in 2000 and 2001, and extended experimental releases that had 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).

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3 Description of Experimental Releases

The MPF experimental release was conducted from the beginning of May through the end of August 2019. This section describes this experimental release and its characteristics.

3.1 Macroinvertebrate Production Flow

The MPF experiment is requested and described in the 2016 ROD (Reclamation 2016). These "macroinvertebrate production flows" maintain flat releases on the weekends and holidays to a level equal to the minimum hourly release rate made during weekdays plus an additional level. This additional level, called "flat flow adder", was set to 750 cfs during the 2019 MPF experiment. 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 if the flows increase the diversity and production of aquatic insects. The experiment was designed to test the hypothesis put forward in (Kennedy et al. 2016) while minimizing impacts to 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 minimum and maximum release rate and the range of water flow rates during the week.

Day-ahead scheduled flow pattern for the 2019 MPF experiment is shown graphically in Figure 3.1. For the sake of clarity, only one week is represented.

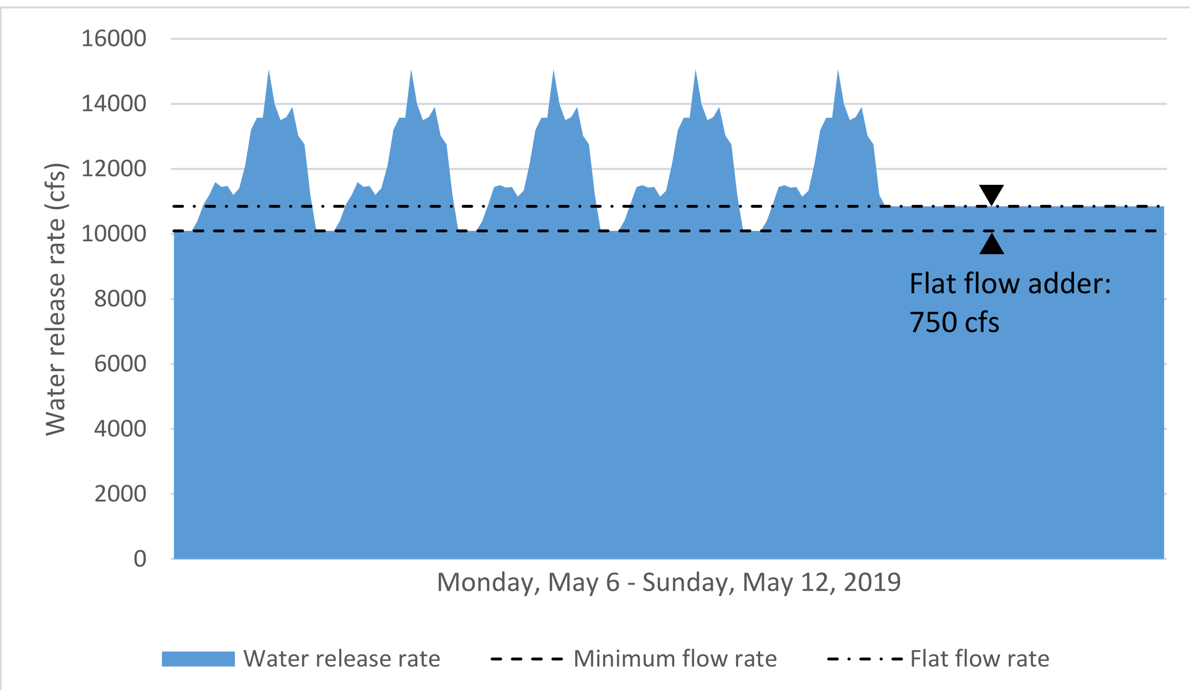

Figure 3.1: Release pattern of the MPF at GCD during a week in May 2019 according to day-ahead schedule

The 2019 MPF ran from May 1 to August 31. In practice, historical flow rates were slightly different from day-ahead scheduled flow rates because of adjustments for real-time energy transactions and regulation up and down services. Even though these deviations were significant in specific hours (reaching up to 5,600 cfs in absolute value), they were cancelling each other out, and their average value over the MPF period was negligible, representing less than 0.1% of the average flow rate. These hourly deviations are depicted in Figure 3.2 below.

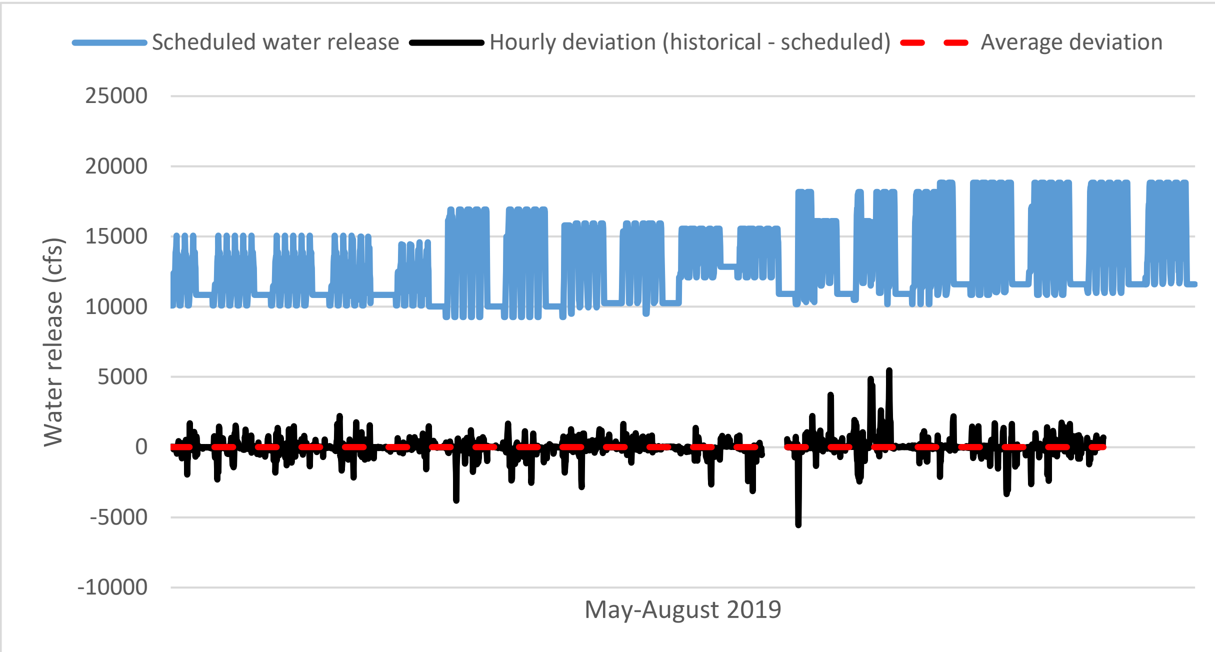

Figure 3.2: Hourly deviation profile and average deviation level during the 2019 MPF period

Because of the low average deviation level, the present financial analysis was performed based on day-ahead scheduled flow rates. This is based on the assumption that water releases that deviate from the day-ahead schedules due to regulation service deployments as driven automatic control generation signals at the Powerplant are not affected by the Bug flows. For example, WACM BA energy imbalances due to BA member load forecast errors would be identical under both the With and Without Experiment scenarios. Likewise, flow deviations from the pre-schedule due to hour-ahead and real-time financial transactions are not affected by the Bug flow experiment.

As explained in the next section, the Baseline and Counterfactual scenarios model the day-ahead scheduled generations at GCD with and without experimental release. From now on, for the sake of simplicity, we will simply refer to the day-ahead scheduled flow rate as "flow rate" and to the day-ahead scheduled generation as "generation".

For this analysis, we consider that all weeks start on Monday. This is because the flat flow adder is defined as the difference between the flat flow level during a weekend and the minimum flow level during the five preceding weekdays. This way, we can define a unique flat flow adder for each week.

There were 18 weeks during the MPF period. The flat flow target was met in 14 of the 18 weeks. The scheduled flat flow adder was higher than the target in June 17th to June 23rd timeframe, and lower than the target from both August 19th to 25th and August 26th to August 31st. During July 8th through July14th, the flat flow adder was negative, which means that the flat flow level was lower than the minimum flow rate by 1,179 cfs.

These weekly observations are summarized in Table 3.1 below.

Table 3.1: Observed flat flow adder for each week of the experiment

Week of the year	Month	Days of the month	Scheduled flat flow adder (cfs)
18	May	**1-5**	750
19	May	6-12	750
20	May	13-19	750
21	May	20-26	750
22	May	**27-31**	750
22	June	**1-2**	**N/A**
23	June	3-9	750
24	June	9-16	750
25	June	17-23	**975**
26	June	24-30	750
27	July	1-7	750
28	July	8-14	**-1,179**
29	July	15-21	750
30	July	22-28	750
31	July	**29-31**	**N/A**
31	August	**1-4**	750
32	August	5-11	750
33	August	12-18	750
34	August	19-25	**601**
35	August	**26-31**	**1**

3.2 Detailed reservoir operations

Operating rules at GCD were different between May-June and July-August. In May and June, GCD was operated in such a way that its hourly generation would closely following the variations of the net load (i.e. the contracted load minus the total generation from other CRSP hydropower plants). In this case, the Powerplant was in "load-following" operating mode. However, in July and August, the Powerplant was operated in such a way that it would maximize its revenue by producing at constant maximum level during on-peak hours and at constant minimum level during off-peak hours. In this case, the Powerplant was in "price-following" operating mode. The difference in generation profiles between these two operating modes is depicted in Figure 3.3 below.

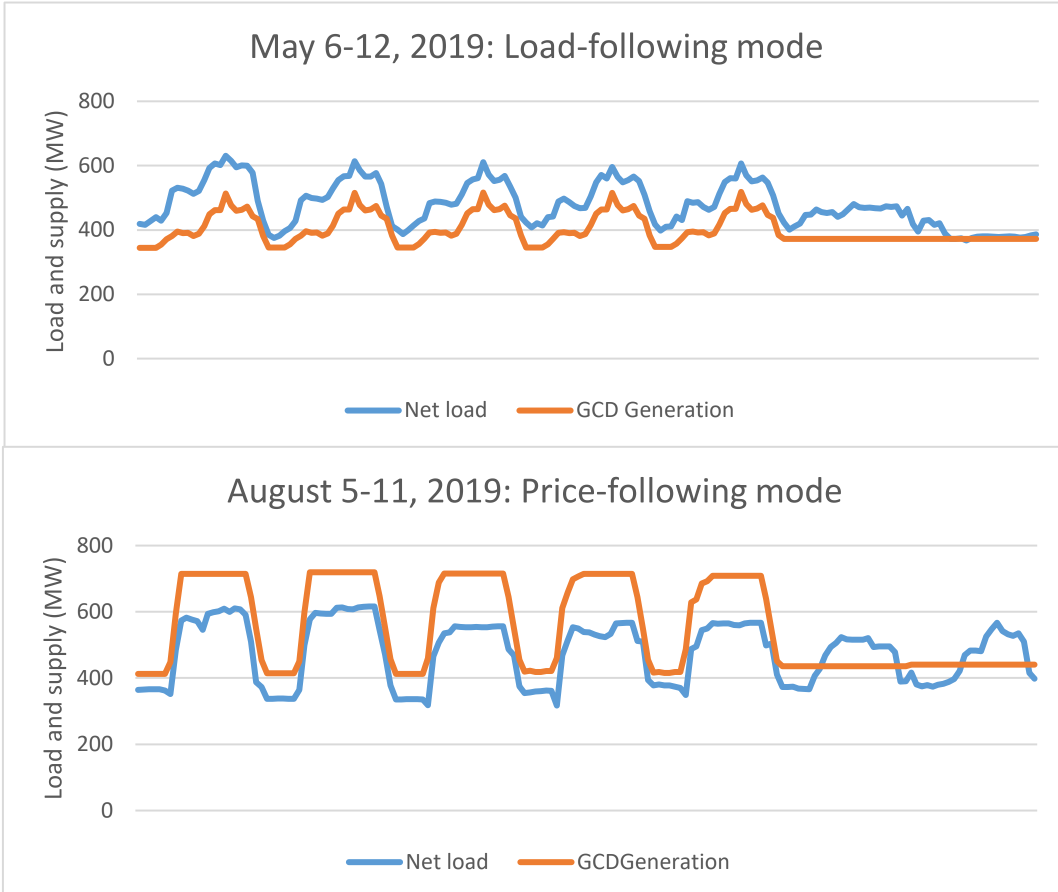

Figure 3.3: Comparison between a load-following generation pattern (upper graph) and a price-following generation patter (lower graph)

Despite the theoretical maximum daily fluctuations of 6,480 cfs/day (see Table 2.2), in practice, the flow rate at GCD in May 2019 was not fluctuating by more than 4,982 cfs/day. This is because of the low amount of water released during May and regulation down capacity requirements that were added to the minimum flow rate effectively increasing the minimum generation level. These May minimums were 5,000 cfs during off-peak hours and 8,000 cfs during on-peak hours. A summary of the operating modes and daily fluctuations in each month is provided in Table 3.2 below.

Table 4.2: Observed monthly operating modes and maximum daily change

Month	Operating mode	Maximum daily change (cfs/day)
May	Load-following	**4,982**
June	Load-following	7,650
July	Price-following	8,000
August	Price-following	8,000

From the operating perspective, federal holidays are considered by WAPA to be the same as a Sunday and, thus, flat flows were applied during May 27th, 2019. The flat flows were maintained at a constant level from Saturday, May 25th to Monday, May 27th. However, because July 4th 2019 occurred in the middle of the week (a Wednesday), flat flows were not applied and July 4th was considered to be a normal weekday for experimental flows.

In general, for a given month, the generation pattern at GCD looks the same from one week to another. This general rule was satisfied for all the months of the MPF period, except for the month of July. In July, the weekly generation pattern was altered several times. This is because of outages at several GCD turbines for extended periods and readjusted water availability forecasts. The changing generation pattern is illustrated in Figure 3.4 below that shows day-ahead scheduled hourly generation levels from the Powerplant.

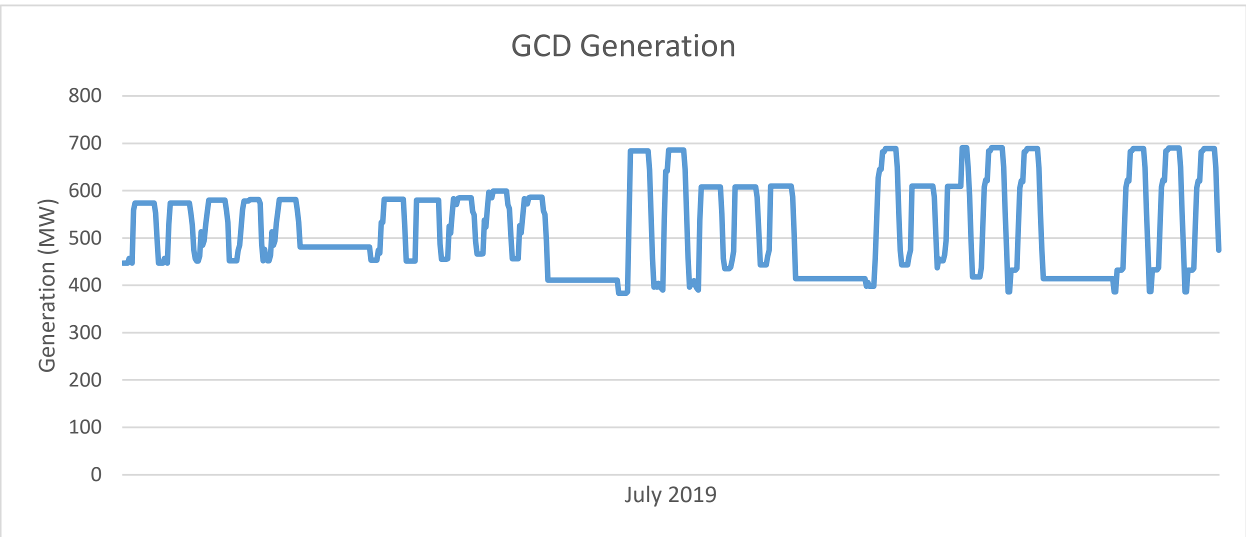

Figure 3.4: Changing weekly generation pattern at GCD during July 2019 according to day-ahead schedule

To account for this changing pattern, in this report, the GTMax SL model was used to simulate each individual week of the MPF period, as opposed to the previous report in which one typical week was run for each month (the typical week was then used/repeated to represent all weeks in each month).

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4 Methods and Models

For the 2019 MPF analysis, financial impacts were computed by comparing simulated results between two operating scenarios:

(1) The Baseline scenario**,** that assumes 2016 ROD operating criteria, the occurrence of the 2019 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. Weekly water releases, daily fluctuations, power conversion factors (PCF), and turbine availability 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 sales price profiles.

As explained previously in section 3.1, these two scenarios simulated the day-ahead pre-scheduled operations at GCD instead of the real-time operations. By doing so, complex deviations due to regulation up and down services and real-time market adjustments did not need to be represented. Simulating the day-ahead schedules (a.k.a., pre-schedule) is justified by the fact that real-time regulation service deployments are in responses to balancing authority energy imbalances (e.g., actual load that deviates from projected), which are not affected by the conduct of the experiment. Therefore, when applying a comparative analysis methodology, such as the one used in this study, the impacts of regulation services between the two scenarios cancel each other out because regulation services are assumed identical under both the Baseline and Counterfactual cases. It should also be noted that real-time deviations that increase generation tend to be cancelled out by deviations that decrease Powerplant generation resulting in a net average deviation that is, over the long-term, approximately equal to zero (Figure 3.2). Difference between day-ahead schedules and actual Powerplant operations is also impacted by hour-ahead and real-time market transactions that are largely unaffected by the conduct of the experiment. That is, an energy transaction that occurred under the Baseline scenario would have most likely occurred under the Counterfactual scenario.

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 it 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's scheduling guidelines and goals. The GTMax SL model is supported by several other tools and databases. These supporting tools include the SLCA/IP Contracts spreadsheet, Customer Scheduling algorithm, Market Price spreadsheet, Experimental Release spreadsheet, Price Shaping Algorithm spreadsheet, and a Financial Value Calculation spreadsheet.

In previous MPF report (Ploussard et al. 2019b), a typical week was used to represent each month in GTMax SL. For this analysis, because of the changing generation pattern that occurred in July 2019 (cf. section 3.2), the 18 weeks of the MPF period were individually simulated for both scenarios. 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, 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 hourly data contained in the pre-scheduled operations from EMMO (Dean 2020). This information is used to calculate, for each week of the MPF period, water release volume, PCF, average turbine availability, largest 24-hr fluctuation, and flat-flow adder.

Weekly water release volumes, PCFs, maximum output capacities, and daily constraint at GCD are assumed identical under both scenarios, and equal to the values calculated from EMMO data. The factor that relates the conversion of water releases to power production is the ratio between the weekly generation and the weekly water release. The maximum output capability (Output) at GCD is computed for each week. It is the minimum of (1) the physical capacity of the power plant turbines and (2) the maximum production level based on the weekly forebay elevation. Further details about the way the maximum output capability is computed can be found in the section 4.5.1 of (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 weekly 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 week, the maximum output was reduced by approximately 12.5% (i.e., 1/8). It is assumed that these outages are identical in the Baseline and Counterfactual scenarios.

The main differences in terms of operations between the Baseline scenario and the Counterfactual scenario are the flat flow constraints and the ratio of daily releases between a day of the weekend and a weekday. Under the Without Experiment scenario (Counterfactual scenario), it is assumed that the total water release on Saturday and Sunday is at least 85 percent of the average daily water release volume during weekdays (i.e., Monday through Friday inclusive). In contrast, for each week during the MPF experiment, water flows during weekends and holidays are required to be flat (i.e. constant) and 750 cfs higher than minimum flows during weekdays. Under the Baseline scenario, this flat flow requirement generally conflicts with the 85% rule, and it is therefore not applied.

The operating rules in both scenarios are summarized in Table 4.1 below. Note that only the last two table entries in bold differ between the two scenarios.

Table 4.1: Summary of the operating rules used in each scenario

Operating rule	Baseline scenario	Counterfactual scenario
Operating mode	Load-following in May and June, price-following in July and August	Load-following in May and June, price-following in July and August
Weekly water releases	Based on EMMO data	Based on EMMO data
Weekly PCFs	Derived from EMMO	Derived from EMMO
Weekly turbine availability	EMMO	EMMO
Largest daily change	Derived from EMMO (cf. Table 3.2)	Derived from EMMO (cf. Table 3.2)
Flat flow during weekend	**Required, at a level equal to the minimum flow rate during weekdays plus the weekly flat flow adder (cf. weekly table)**	**Not required**
Ratio between Saturday/Sunday and Weekday daily release	**Not constrained**	**Required to be greater or equal than 85%**

4.2 Model Input Data for Other SLCA/IP Hydropower Plants

For the sake of 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. 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
- Energy interchange into the SLCA/IP system

Power plant generation data are from pre-scheduled operations from EMMO (Dean 2020).

4.3 Model Input Data for Loads and Market Prices

Data for load input into GTMax SL are based on pre-scheduled operations from EMMO (Dean 2020). For the sake of 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 is composed of:

- Customer Available Hydropower (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 optimal generation profile at GCD computed by the model under the Baseline scenario conditions uses a blended price that is a weighted-average of pre-scheduled and real-time purchase and sale prices (Dean 2020). The resulting modeled hourly generation profile is very similar to the generation pattern from EMMO, validating the use of the blended price profile are a key model driver. A comparison between generation profiles at GCD, based on EMMO data and generated by the model, is shown in Appendix A, Figure A.1.

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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 Counterfactual scenarios. Both scenarios release identical amounts of water each week as shown in Figure 5.1, equal to identical to historical levels. However, modeled daily water release volumes during each day of the month differ. The flat flow constraint in the Baseline scenario generally leads to significantly smaller water releases, less than 85%, during weekends than during weekdays. Note that release volumes in weeks 18 and 35 are smaller than in other weeks from the same months. This is because part of these weeks is outside the study period and therefore account for less than seven days.

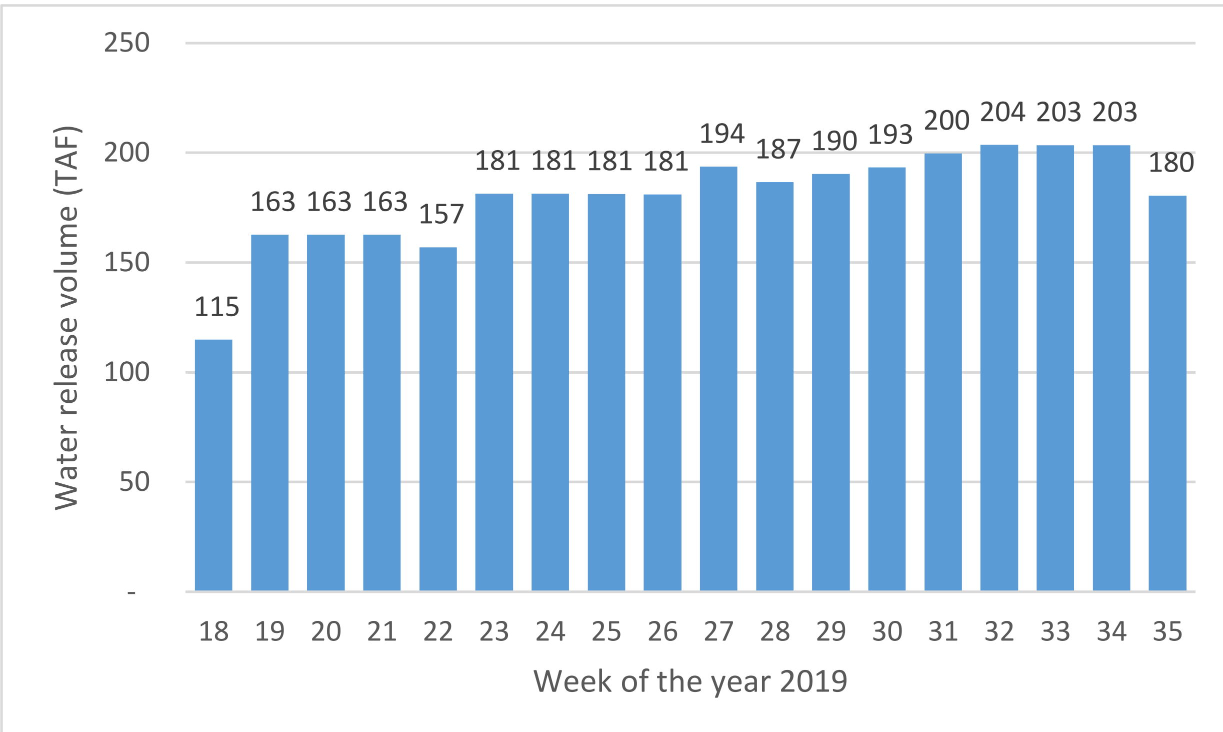

Figure 5.1: Weekly water releases from during the MPF period under both scenarios

The differences of modeled flow patterns during a typical week between the With (i.e. Baseline) and Without Experiment scenarios are illustrated in the hydrograph in Figure 5.2, from (GCDAM 2020). Note that the MPF (labeled "Bug Flow") weekend flat flow requirement under the Baseline scenario (With Experiment scenario) leads to maximum flows during weekdays significantly higher than under the Without Experiment scenario. This occurs because both scenarios are bound by identical daily change restrictions.

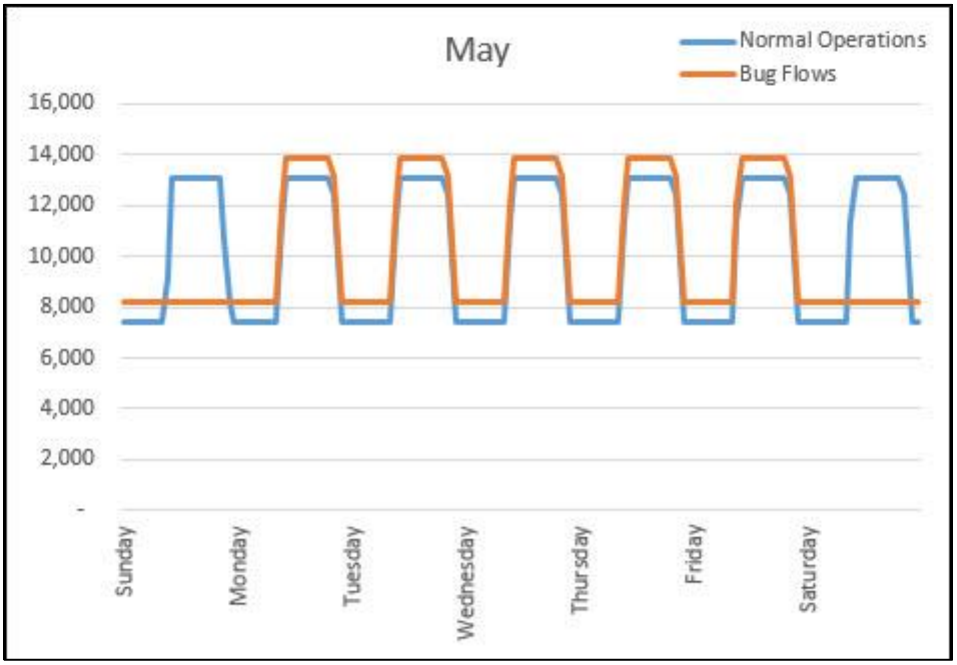

Figure 5.2: Modeled hydrograph in cfs at GCD under the With and Without MPF experiment scenarios (GCDAMP 2020)

5.1 Generation Profile at GCD

The hourly generation profile at GCD is calculated for each scenario and each week of the study period based on the operating rules summarized in Table 4.1. For each scenario, the weekly results are combined to build an hourly generation profile that covers the 4 months of the study period.

A figure of the detailed generation results under both scenarios is provided in Appendix A, Figure A.2.

5.2 Net Energy Purchases and Sales

Once the hourly generation profiles at GCD have been generated for each scenario, the hourly profile of net energy sales and purchase quantities are completed for the SLCA/IP system. For each hour of the entire study period, the following energy balance equation is satisfied by financial spreadsheet calculations.

SLCA/IP Generation + Net Purchases = SLCA/IP Load + Net Sales

In the equation above, SLCA/IP power plant generation resources were previously described in Section 4.2 and loads were described in Section 4.3. Consistently with our choice of modelling the day-ahead pre-schedule generation at GCD, energy purchases in the equation include only day-ahead pre-schedule purchases. Likewise, energy sales are only day-ahead sales. The energy balance equation is satisfied for each hour of the entire study period. Except for GCD Powerplant generation, all other SLCA/IP hydropower resources and loads are identical under both scenarios. Therefore, all financial differences between the two scenarios are directly attributed to a changed hourly generation pattern at GCD; that is, because net loads are fixed and identical under both scenarios, the changed MPF GCD generation profile directly affects 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

The sale price used for financial calculations was based on a monthly on-peak/off-peak price calculated by WAPA (Wilhite 2020). This monthly price is a modified version of the EMMO market price excluding the impact of energy arbitrage. Purchase price used for financial calculations was based on AHP purchase price from (EMMO 2019). Because the finest level of temporal granularity that both types of price were available at is monthly, it was necessary to generate an hourly price profile. The Price Shaping Algorithm, one of the supporting tools of GTMax SL, was used to generate the hourly sale price profile based on the monthly price data provided by WAPA and the shape of the Load profile. Similarly, the Price Shaping Algorithm was used to generate the hourly purchase price profile based on the monthly AHP purchase price. For more details, the generated hourly profiles of the sale and purchase prices are shown in Appendix, Figure A.3.

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

(1) an incremental <u>increase</u> in net **purchase** expenses under the Bug Flow scenario due to a relatively <u>lower</u> generation level than the counterfactual scenario is based on the historical day-ahead purchase prices and quantities;
(2) an incremental <u>decrease</u> in net **purchase** expenses under the Bug Flow scenario due to a relatively <u>higher</u> generation level than the counterfactual scenario is based on the historical day-ahead purchase prices and quantities;
(3) an incremental <u>increase</u> in net **sales** revenues under the Bug Flow scenario due to a relatively <u>higher</u> generation level than the counterfactual scenario is based on the historical day-ahead sale prices and quantities;

(4) an incremental <u>decrease</u> in net **sales** revenue under the Bug Flow scenario due to a relatively <u>lower</u> generation level than the counterfactual scenario is based on the historical day-ahead 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; and,
(6) all historical non-FES energy sales that are 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 is a reasonable approximation of the financial impacts of the MPF experiment because it is based on the change in finances not absolute financial levels. It also circumvents the need for computation of non-hydropower energy arbitrage transactions that is assumed to be unaffected by the MPF.

5.4 Water Release Model Results

The optimal water release profiles at GCD modeled by GTMax SL have been computed under the With and Without experiment scenarios. Modeled water release profiles of a week in June under both scenarios are illustrated in Figure 5.3. Results are consistent with the hydrograph depicted in Figure 5.2.

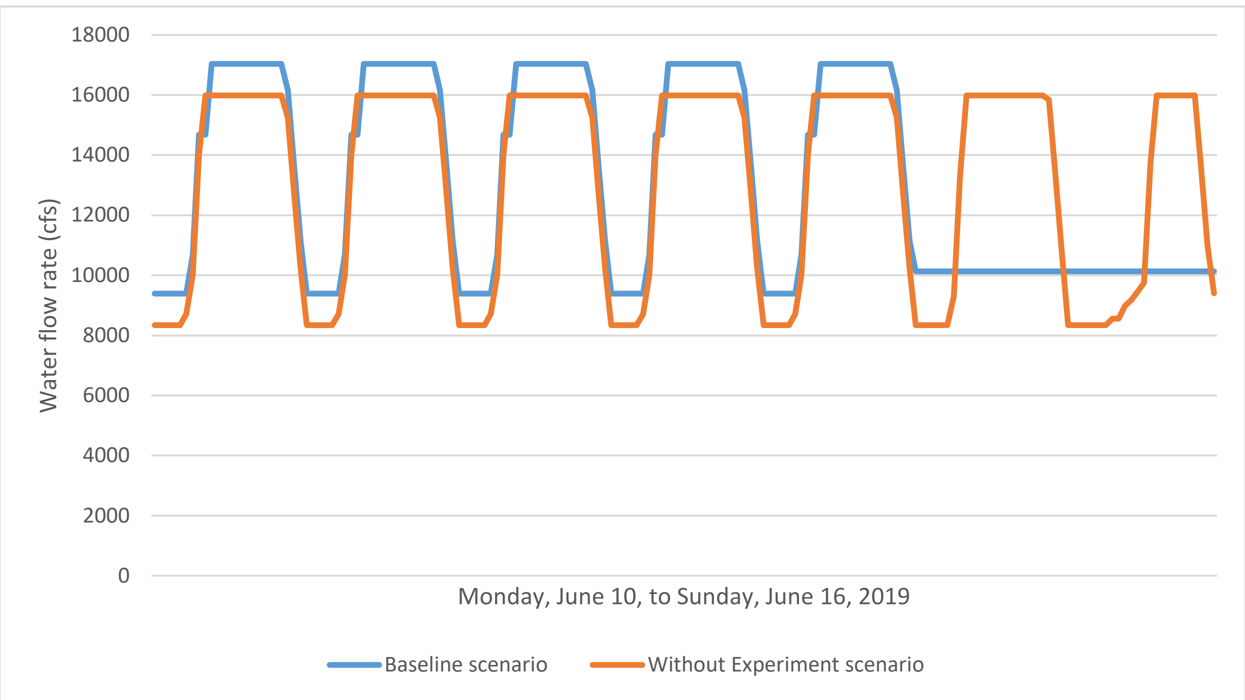

Figure 5.3: Modeled hourly water release profiles during a typical week in May 2019 under the With and Without Experiment scenarios

Water release ranges during weekends and weekdays, under both scenarios, are depicted in Figure 5.4. As can be seen in the figure, under the Baseline scenario (red rectangles), water release ranges during weekends are relatively small due to flat flow constraints. They are not null because the flat flow level is not exactly the same from one weekend to another within a given month. Especially, during the month of July, the range of weekend water releases is higher than in other months because of the changing weekly pattern that occurred. Moreover, because the flat flow level is required to be only 750 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 under the Without Experiment scenario (blue rectangles), especially for the months of June, July and August.

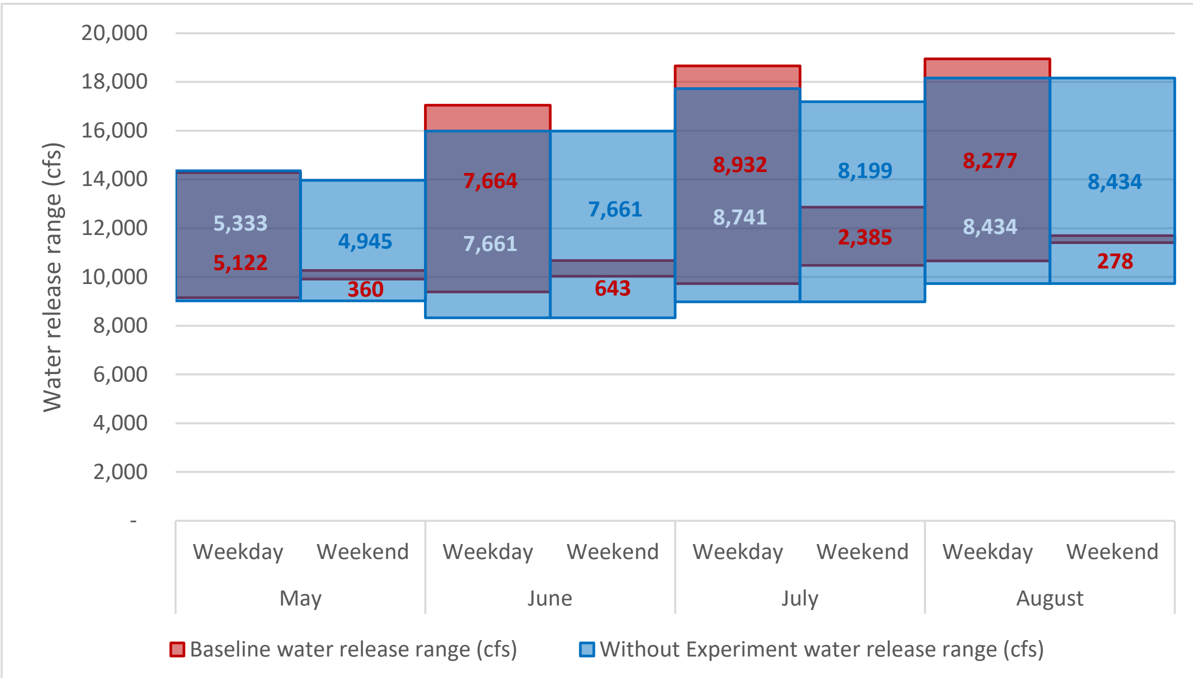

Figure 5.4: Model results of water release range in weekends and weekdays from May to August 2019 under the With and Without Experiment scenarios

5.5 Net Revenues from Energy Transactions

Bug flows shift water release volumes and therefore energy production from weekends to weekdays. From Figure 5.5, we can see that this generation shift is equal to 6, 14, 14, and 17 GWh in May, June, July, and August, respectively.

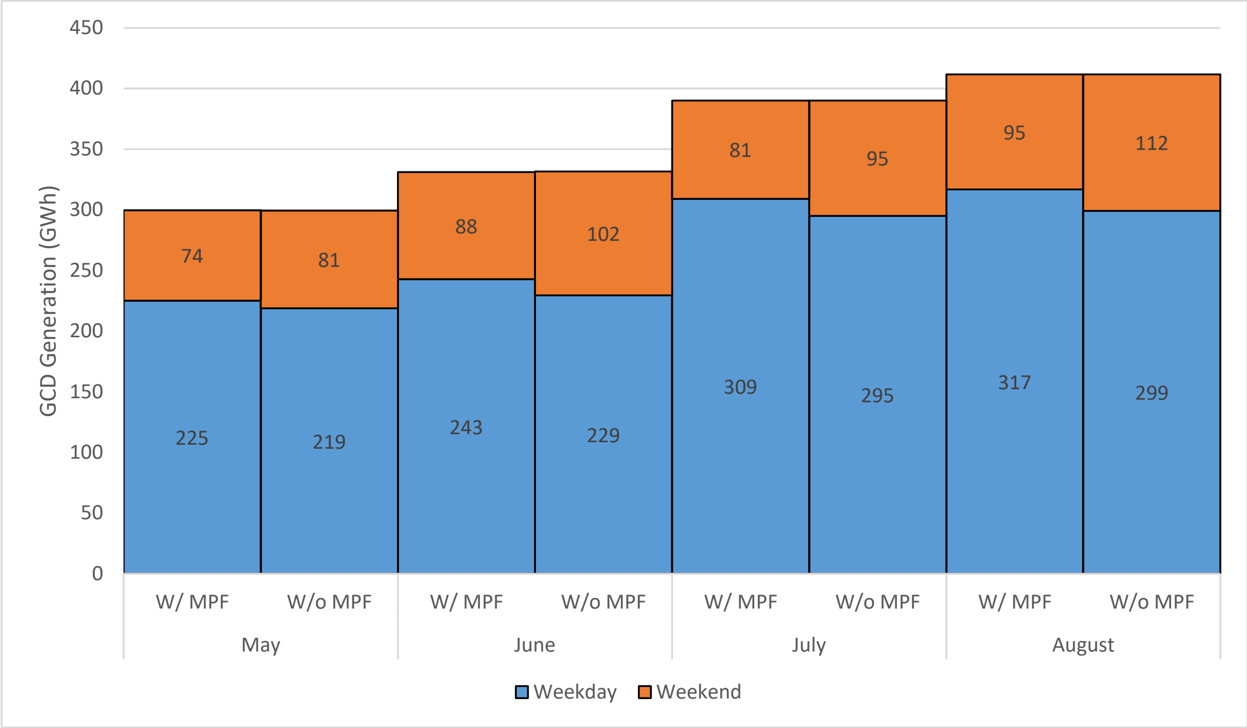

Figure 5.5: Comparison of With and Without Experiment GCD production for weekdays and weekends

This shifting result in lower net energy position during the weekends under the MPF experiment (Baseline scenario) compared to the Counterfactual scenario. In addition, the MPF flat flow requirement does not allow WAPA schedulers to follow/respond to market prices during the weekends. Lower releases and less power production therefore lower WAPA's net financial position during the weekend during an MPF experiment.

On the other hand, during weekdays both net energy and financial positions are higher under the Baseline (MPF) scenario because of higher water release volumes in combination with peak releases that are higher under Bug Flow scenario (cf. Figure 5.4).

Figure 5.6 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 tradeoffs weekday net revenues against weekend net costs.

The results of this tradeoff are depicted in the waterfall chart shown in Figure 5.7 that depicts cumulative financial impacts at the end of each month. Conducting the MPF experiment during May resulted in an estimated WAPA financial gain of $10,000. On the other hand, it resulted in financial losses in June, July, and August of $52,000, $61,000, and $224,000, respectively, for a total loss of $337,000. The net MPF financial costs over the 4-month experimental period is estimated to be about $327,000.

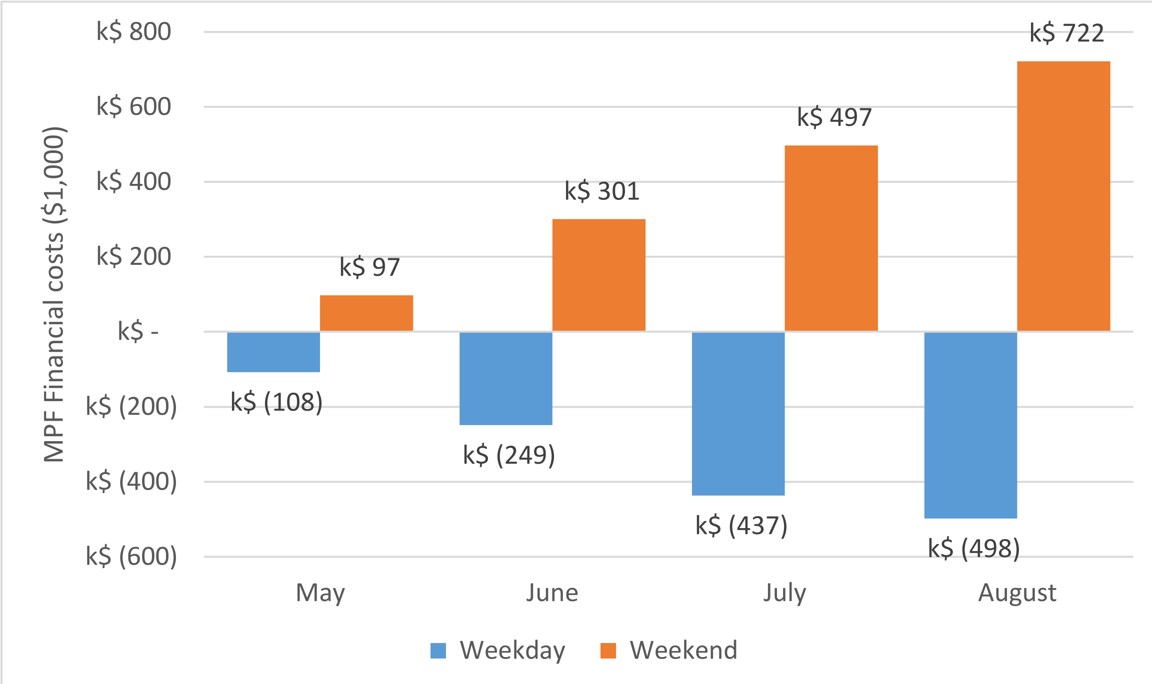

Figure 5.6: Cost of the MPF experiment conducted from May to August 2019: comparison of the MPF financial costs between weekdays and weekdends

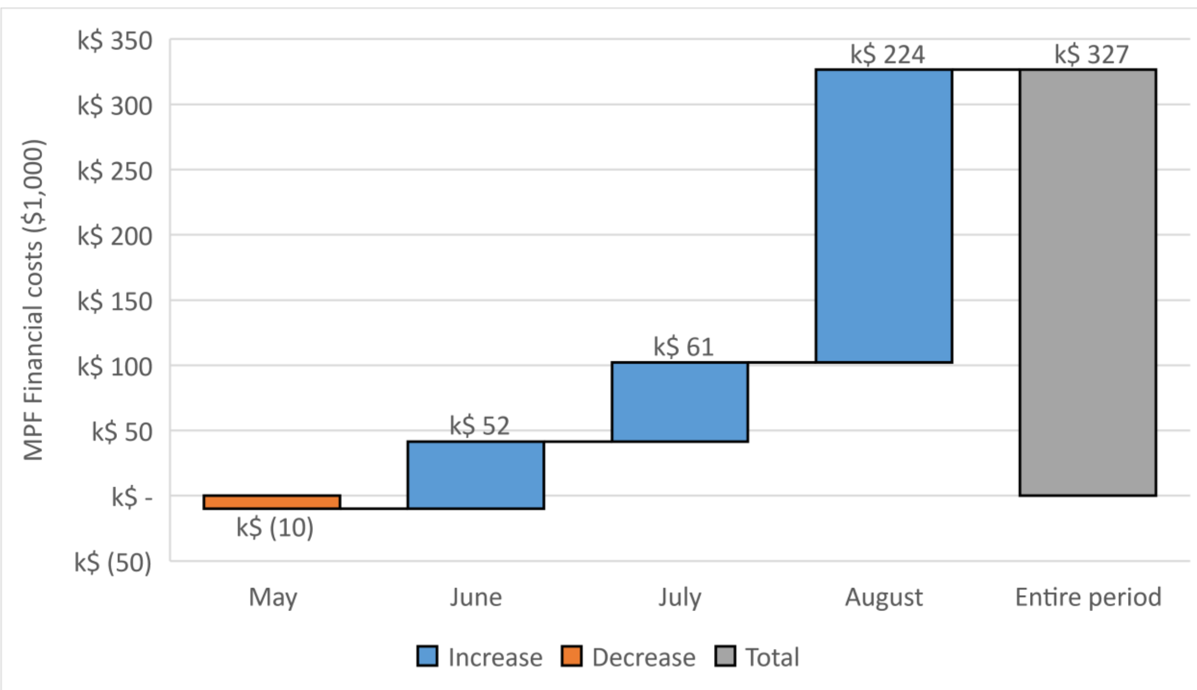

Figure 5.7: Waterfall chart illustrating the cumulative monthly cost of the MPF experiment conducted from May to August 2019

The 2019 MPF experiment resulted in a net financial loss. Most of this financial loss occurred during August, when the generation shift between weekend and weekdays was the largest (see Figure 5.5). In comparison to the overall financial cost, the financial gain that occurred in May, when the generation shift was the lowest, was negligible. For more details, the hourly profile of the cumulative cost can be found in Appendix A.4.

The pattern of monthly net costs is driven largely by the spread and direction of weekend energy prices versus weekday prices in combination with WAPA's net energy position (see Appendix A, Figure A.3). At times, the cost of the Bug Flow experiment is driven primarily by the temporal shift in purchases when, during a week, WAPA has a significant energy short position and must, therefore, buy power throughout the week. Under these conditions, sale price is of little to no importance because financial results are primarily driven by relative weekend versus weekday purchase prices. The opposite occurs if WAPA is consistently energy long during a week in which case the financial outcome is mainly driven by the sales price pattern. Both energy purchases and sales play a role in the financial equation when lower generation levels during the weekend under the Baseline scenario require WAPA to buy relatively more energy on Saturday and Sunday and then sell it at either a higher or lower price during the weekdays.

- **<u>May Bug Flow Financial Result</u>**

As shown by the orange bars in Figure 5.8, during the month of May the weekend flat flow requirement under the Baseline scenario (with experiment) required WAPA to buy relatively higher amounts of energy during the weekend compared to the Counterfactual scenario (without experiment). This occurs because relatively low generation levels produced by flat flows on Saturday and Sunday exacerbates daytime short energy positions. On the other hand, low flows during weekend allowed WAPA to produce more energy during the weekdays compared to the Counterfactual scenario, requiring WAPA to sell more power (blue bars). However, relative to changes in purchase, increases in sales due to the conduct of Bug flows is small.

During May, financial impacts are primarily driven by the shifting of WAPA energy purchases from weekdays to the weekend when purchase prices are lower. Note on Figure A.3 that during the weekend purchase prices are about \$1 to \$4 per MWh less expensive during the weekend daytime hours. The result is a \$10,000 financial benefit of conducting Bug flow in May while at the same time yielding the environmental benefits of an increased bug population.

- **<u>June Bug Flow Financial Results</u>**

In contrast to May, WAPA has primarily a long energy position during the month of June. Changes in generation patterns due to Bug flows therefore result in a shifting of energy sales such that sales are higher during the weekdays and lower during weekends (see blue bars during June in Figure 5.8). Because the energy sale prices are about \$1 to \$3 more expensive during weekdays compared to weekend, and because WAPA has relatively higher weekday energy sales, WAPA should financially benefit by conducting a Bug flow experiment in this month. However, Figure 5.7 shows that the Bug flow experiment cost WAPA an estimated \$52,000. This result is partially because during June there are five full weekends (10 days) during which time WAPA loses money due to lower energy sales. On the other hand, there are only 4 weekday periods when WAPA financially gains from bug flows. Figure A.4 shows that at the end of the first full 4 week (28 days) the cumulative Bug flow costs (red line) are negative (positive net financial benefit). However, during the last two days of the month, which are weekend days, the flat flow requirement incurs costs that exceed the preceding cumulative benefit.

In general, for there to be a net financial benefit to WAPA, weekday on-peak generation levels need to be significantly higher under the Counterfactual scenario to overcome losses due to inflexible weekend operations during Bug flow experiment. Figure A.4 shows that weekday benefits are the greatest when, under the Counterfactual scenario, there is higher daytime generation and lower nighttime generation. During the first two weeks of the month, when there is significantly higher on peak generation, the downward slope of net cumulative costs (red line) is steeper than during the last two full weeks. Based on the above observations, as a general rule of thumb, WAPA financial benefits increase with higher generation shifts from weekends to weekdays and with a higher concentration of these weekday energy shifts to on-peak hours.

The financial outcomes for May and June were primarily driven by a single price vector; that is the purchase price vector for May and the sales price vector for June. However, as described below, when the shifting of Powerplant generation requires a shift of increased weekend purchases to higher weekday sales, both price vectors are important and the general of thumb described above is not applicable when the price vectors differ.

- **July and August Bug Flow Financial Results**

The financial cost of Bug flows during July and August are driven by the same key factors. That is, Bug flows necessitate expensive weekend purchases that are shifted to the weekday for higher sales at a lower price. Note in Figure 5.8 that the purchase price is about $2 to $3 per MWh more expensive than the sale price during July and August. The higher the price difference and the greater the level of Powerplant energy shift, the greater the financial cost to WAPA. On the other hand, if weekend purchase prices had been less expensive as compared to weekday sales prices, WAPA financial outcomes would have been driven in the opposite direction.

Figure 5.8: Difference in purchase and sales levels between the Baseline (MPF) and Counterfacual scenarios energy transaction prices

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 tradeoff 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 that resulted in a MPF financial benefit was in May 2019. However, this financial benefit was negligible in comparison to the overall financial cost of the experiment.

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Appendix A: GTMax SL Simulations for the 2019 MPF Experiment: Generation profiles, price profiles, and cumulative costs

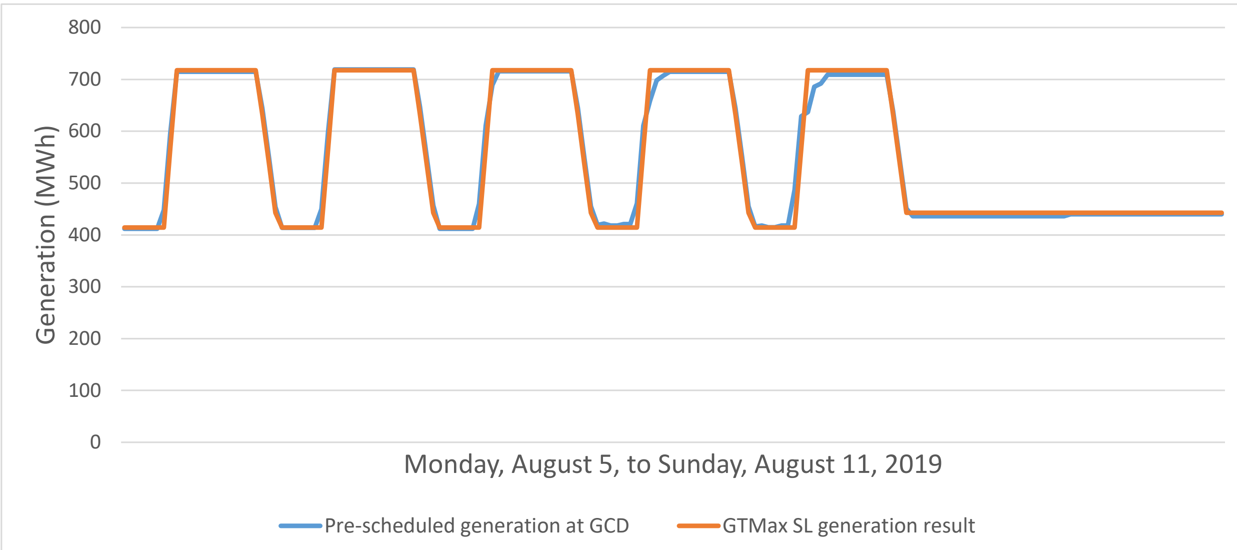
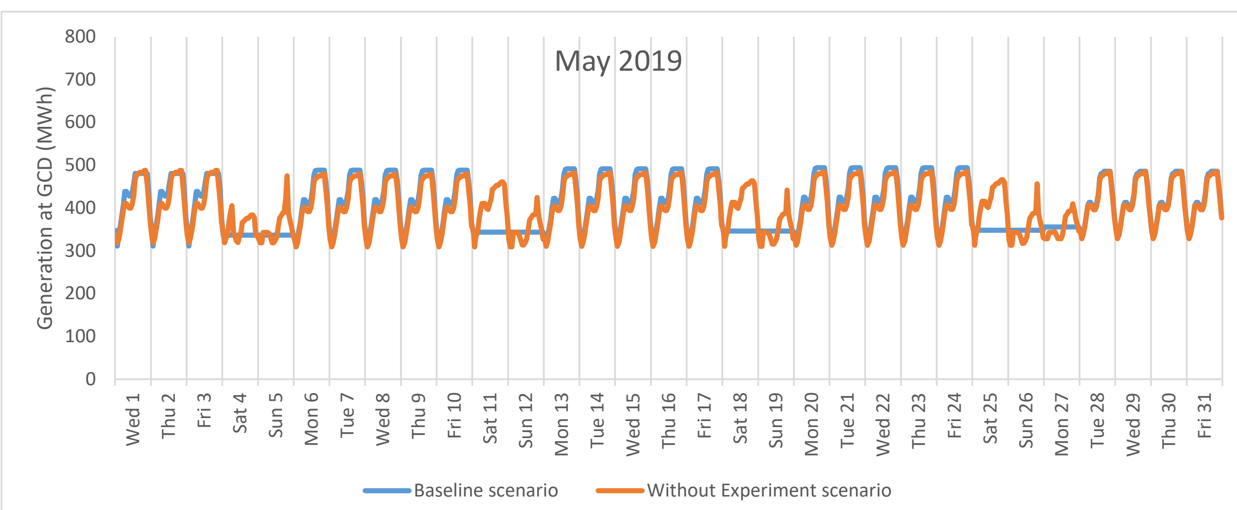


Figure A.1: Generation profile at GCD during a week of August 2019: comparison between pre-scheduled values and optimized results output from the GTMax SL Model



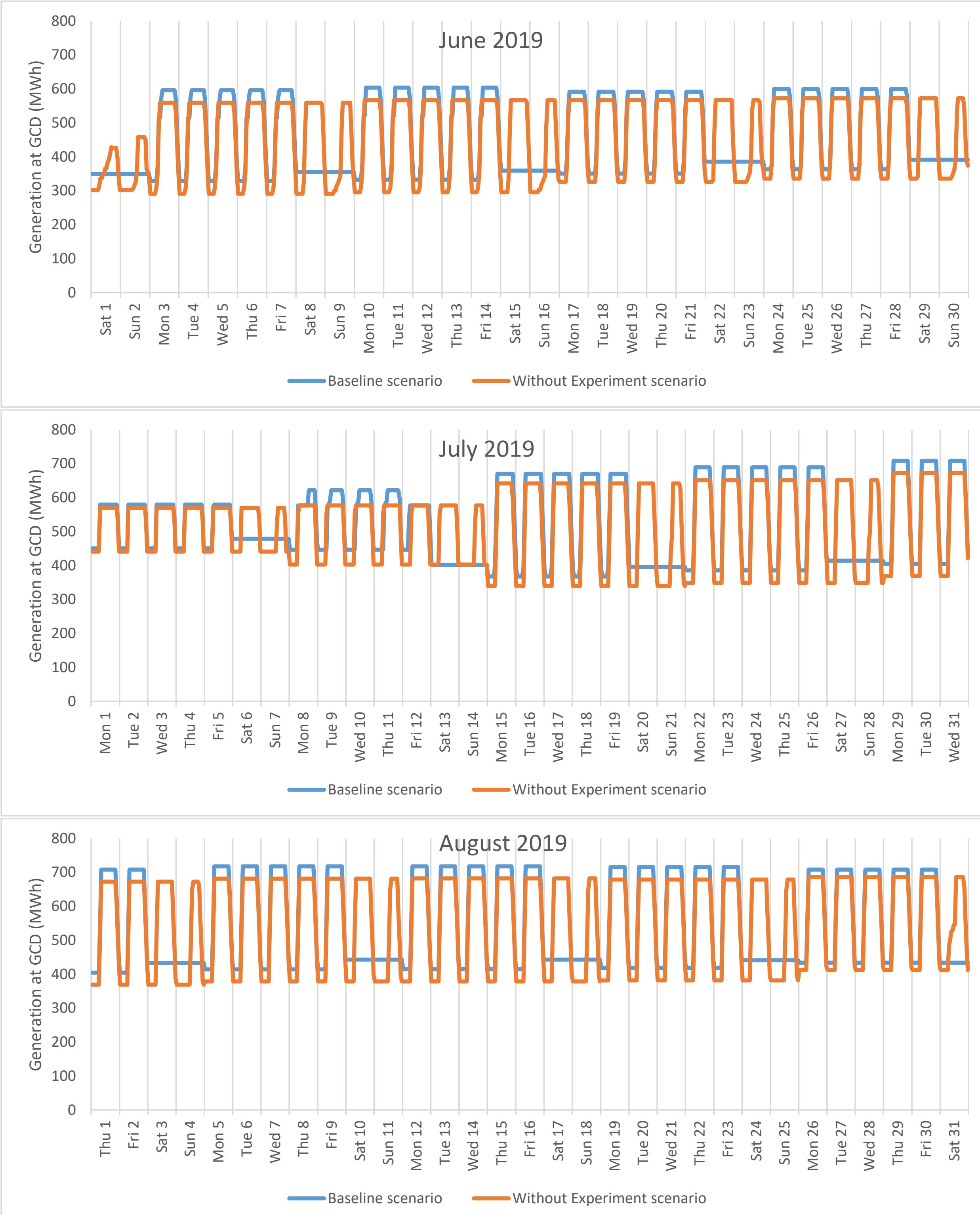
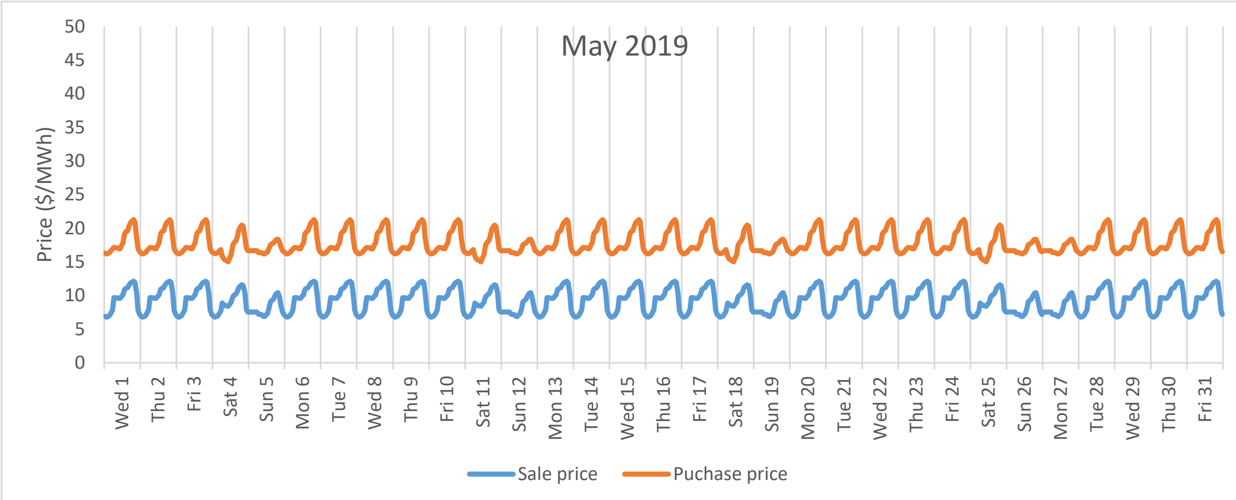
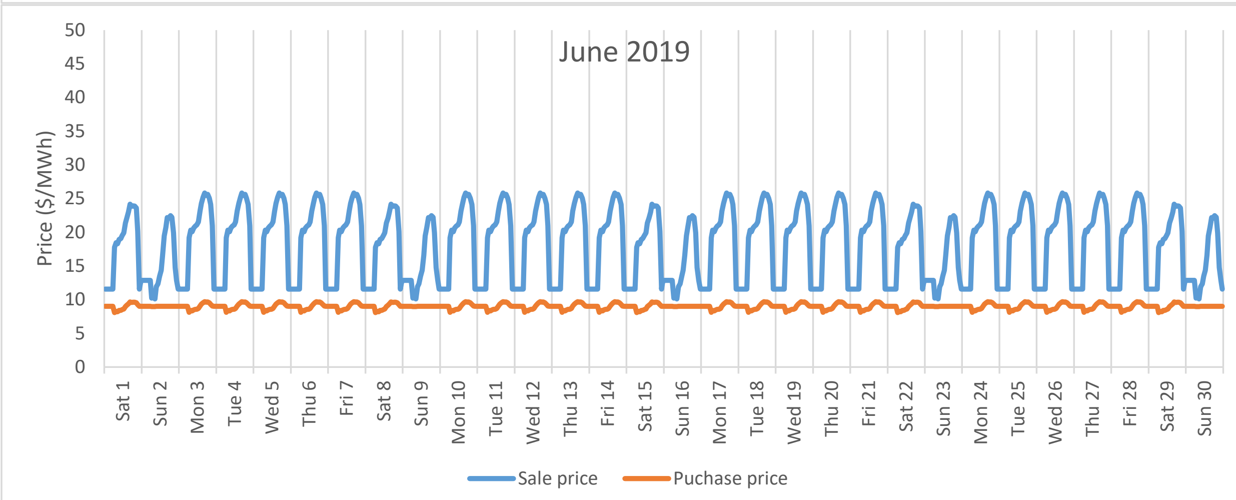
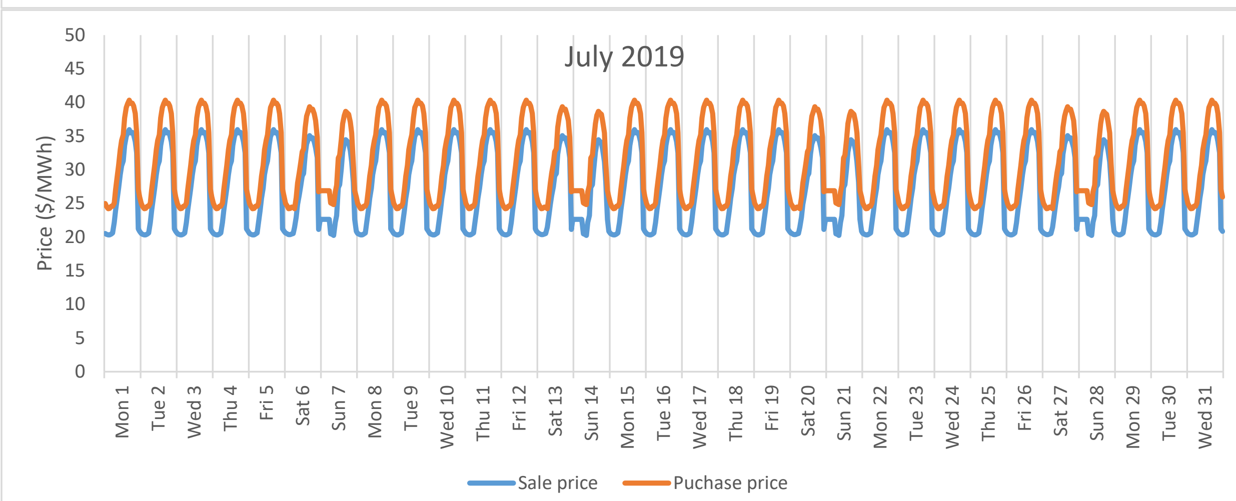


Figure A.2: Modeled hourly generation at GCD under the Baseline scenario and the Without Experiment scenario during May, June, July, and August 2019


May 2019
Price ($/MWh)
Sale price
Puchase price


June 2019
Price ($/MWh)
Sale price
Puchase price


July 2019
Price ($/MWh)
Sale price
Puchase price

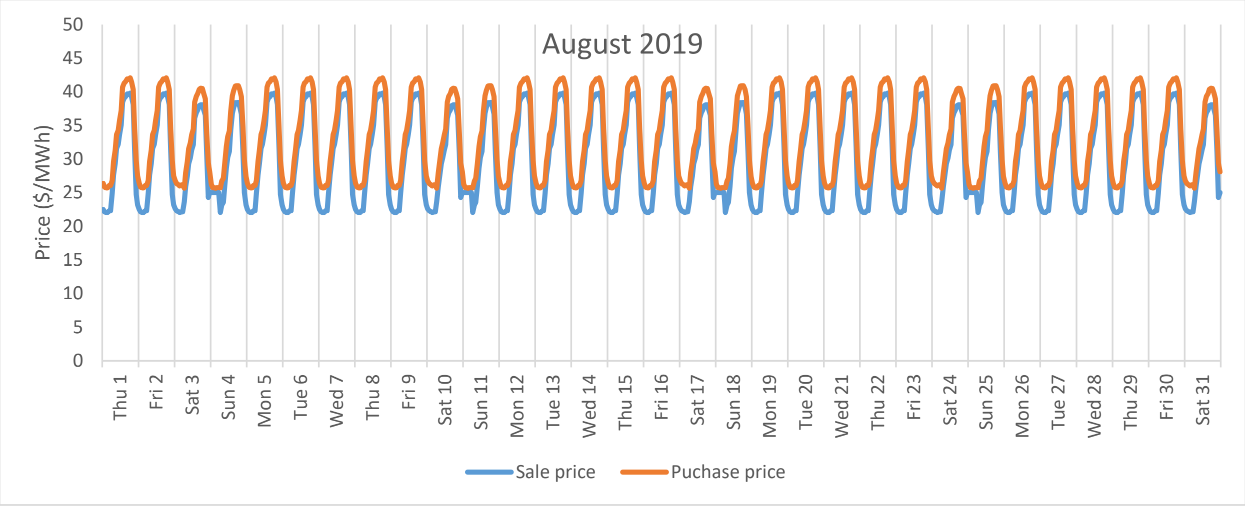
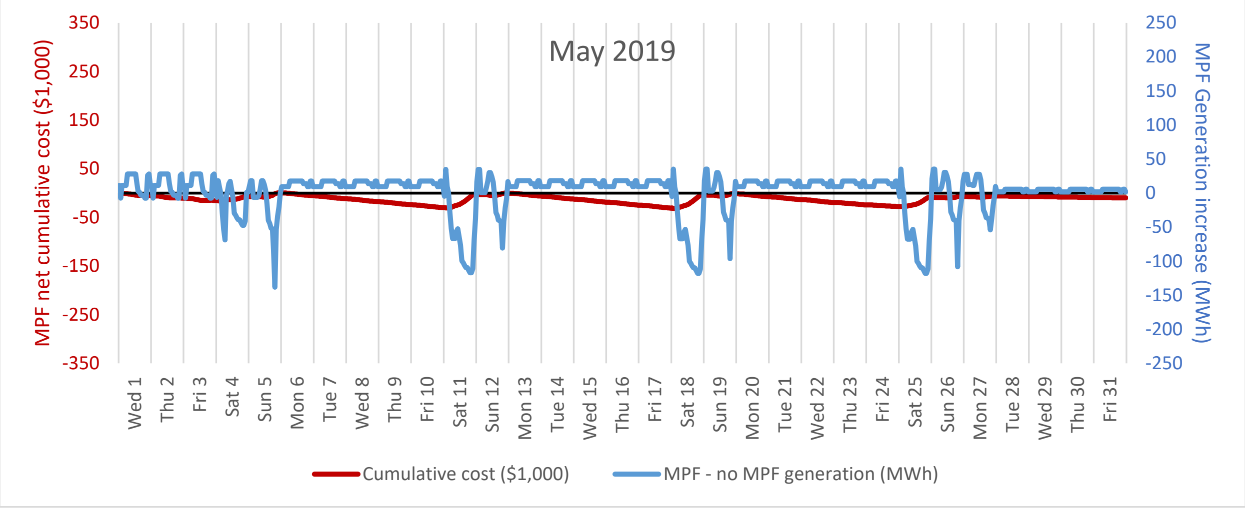
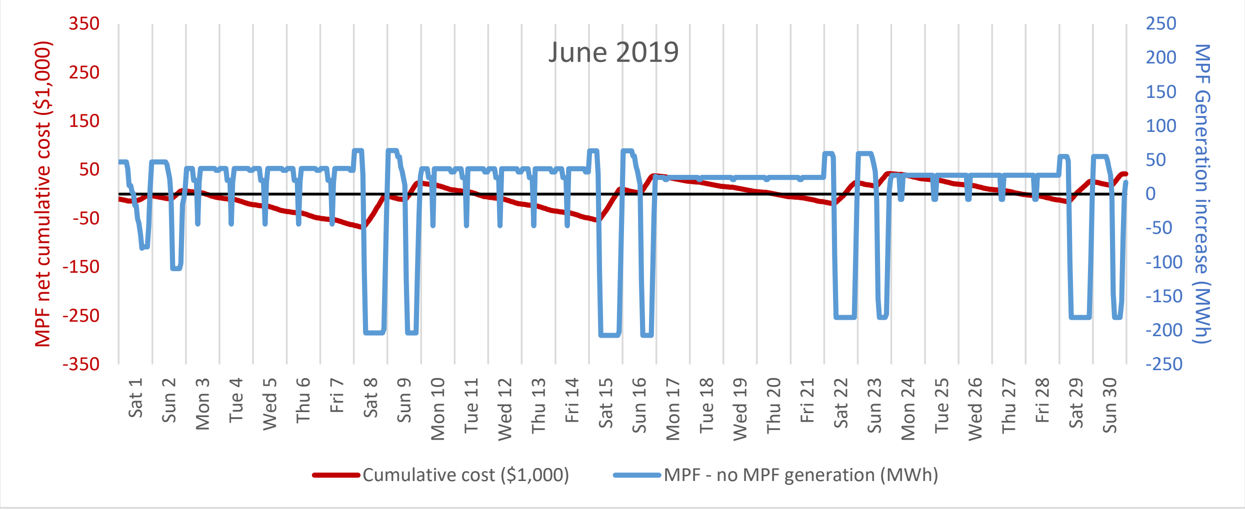


Figure A.3: Price Shaping Alogorithm generated purchase and sale profiles used for financial calculations for the month of May, June, July, and August 2019





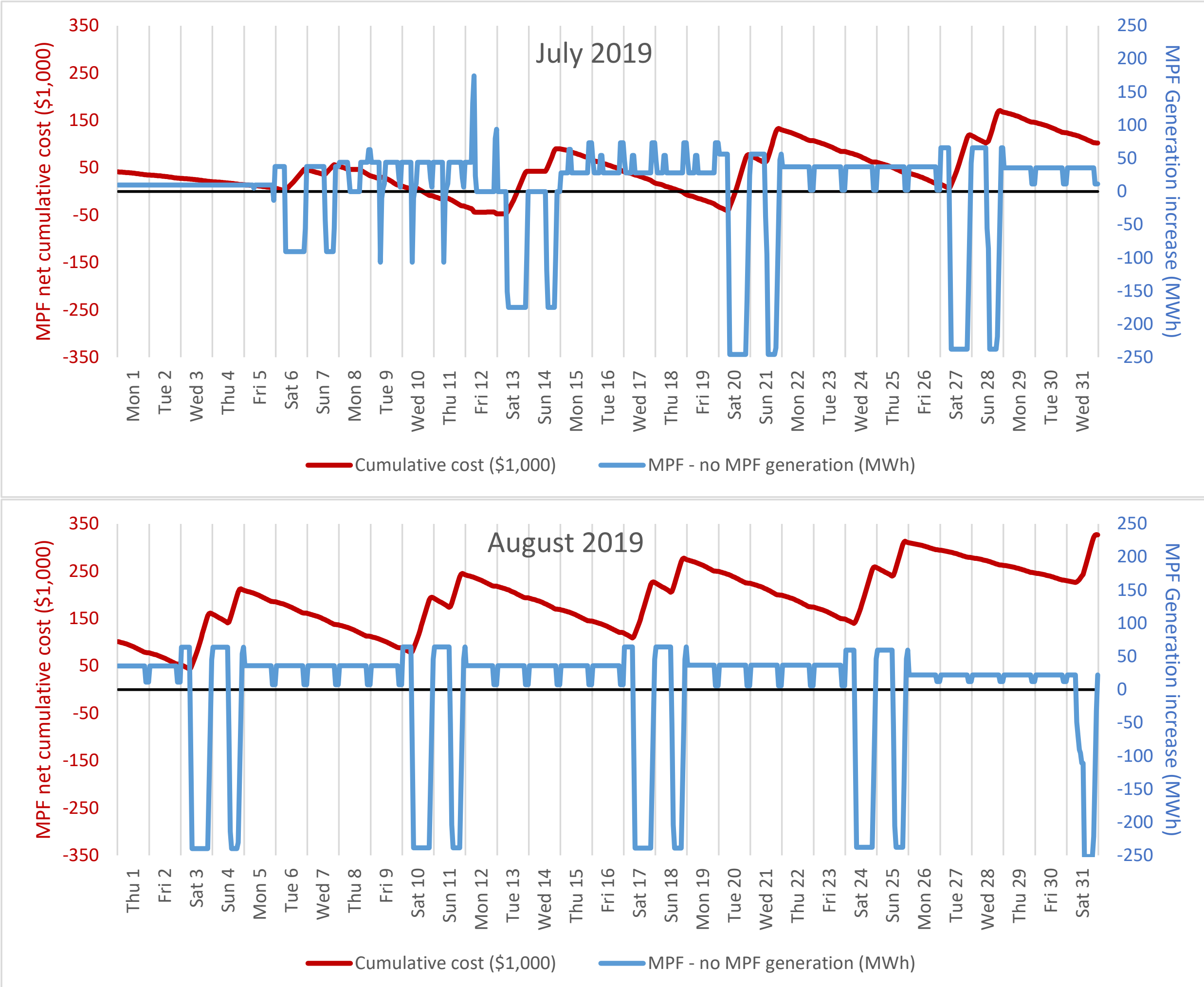


Figure A.4: Modeled hourly GCD power production difference between both scenarios and MPF cumulative cost in May, June, July, and August 2019

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