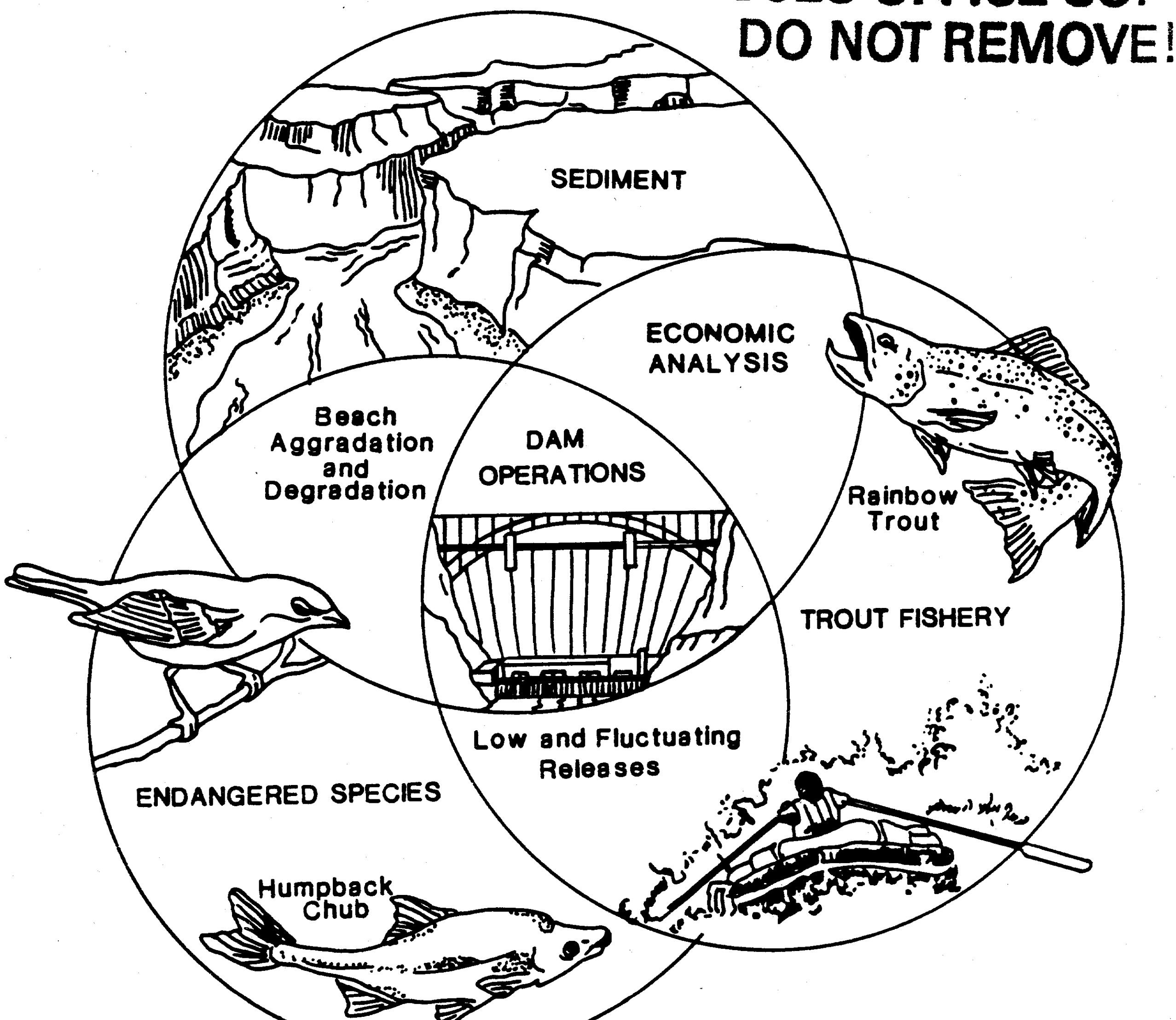
GLEN CANYON DAM

MONITORING OF INTERIM OPERATING CRITERIA



OCTOBER 1992 - FEBRUARY 1993

BUREAU OF RECLAMATION

GLEN CANYON DAM

MONITORING
OF
INTERIM OPERATING CRITERIA

October 1992 through February 1993

Bureau of Reclamation

This document summarizes the monitoring of Interim Operating Criteria for Glen Canyon Dam from October 1992 through February 1993. This is the fourth report of monitoring of operating criteria, with the first report covering August through December 1991, the second report covering January through April 1992, and the third report covering May through September 1992. Summaries will be published periodically throughout the interim operation period.

BACKGROUND

The Glen Canyon Dam Interim Operating Criteria were implemented on November 1, 1991, following a 3-month testing of the proposed interim flow criteria. An Environmental Assessment was completed in October 1991 with a Finding of No Significant Impact. The Interim Operating Criteria will remain in effect until completion of the Glen Canyon Dam Environmental Impact Statement, scheduled for completion in October 1994, and Record of Decision scheduled shortly thereafter.

Exception Criteria. The Western Area Power Administration and the Bureau of Reclamation signed an interagency agreement on October 21, 1991, implementing exception and associated interim operating criteria, including financial exception criteria.

The exception criteria allow deviation from the interim flow criteria for response to power system disturbances or other emergency situations and for power system regulation. The agreement incorporates emergency and system regulation provisions which were in place during research flows and, in addition, includes "financial criteria" as a means of avoiding the expense of purchasing replacement firm capacity and energy during the interim period. The financial criteria element is conditional and the primary conditions include:

- limiting the use of financial criteria to not more than 3 percent of the time (22 hours) in any consecutive 30-day period
- periodic review and renewal
- reporting the use and costs associated with the financial criteria

MONITORING OF INTERIM FLOW CRITERIA

The operating criteria parameters--maximum daily flows, minimum daily flows, daily fluctuation, and ramp rates--are monitored at the Glen Canyon Dam using Reclamation's Supervisory Control and Data Acquisition (SCADA) system. The discharge and river stage changes are monitored at downstream gauging stations near Lees Ferry and Grand Canyon Village. The SCADA data at Glen Canyon Dam is recorded in megawatts of energy and require conversion to flow--cubic feet per second (cfs).

From October 1, 1992, through February 28, 1993, the maximum flow of 20,000 cfs was adhered to as shown on the charts in Attachment A. The minimum flow of 5,000 cfs at night and 8,000 cfs between 7 am and 7 pm was also met throughout the period.

Ramp Rates - The ramp rates were exceeded periodically as a result of system disturbances and regulation responses to power demands. Ramp rates may be exceeded under the criteria for system disturbances, regulation, and other emergency situations to allow for power system operation adjustments. The number of times ramp rates were exceeded has been consistently reduced as operators have become more experienced with projecting power system adjustments.

Attachment B shows the traces of discharge and river stages for the Lees Ferry for October 1992 through February 1993 and Grand Canyon Viggage gauging stations for February 1993 (due to equipment malfunction, the gauging stations at Grand Canyon Village for October 1992 through January 1993 are not available at this time).

MONITORING OF EXCEPTION CRITERIA

The exception criteria are monitored at Glen Canyon Dam using Reclamation's SCADA system. Several deviations from the interim flow criteria occurred, primarily due to electrical system emergencies caused by electrical transmission system and generation capability. None of the system deviations lasted longer than 1 hour (see Attachment B).

Deviations from the ramp rate criteria have occurred periodically, particularly when the dam is following the power load under system regulation and generally occurs during the upramp. Such deviations are allowed under the generator regulation exception criteria.

The estimated net expenses of interim operations are included in Appendix C. Sumary of estimated costs by month is shown in the following tabulation:

Month	Net Expense
October 1992	$193,938
November 1992	152,373
December 1992	471,698
January 1993	466,684
February 1993	380,314

To date, financial exception criteria have not been used.

INTERIM FLOW MONITORING PROGRAM - RESOURCES AND RESPONSES

The program focuses on the evaluation of critical resources and ecosystem processes relative to the interim flow regime to determine natural changes in the ecosystem, changes as a result of interim flows, and effects on power generation.

The interim flow monitoring programs have been implemented and results will be integrated into the long-term monitoring program.

Additional work was conducted from September through December 1992 on the impacts of the low Lake Powell levels on temperature and nutrient balances downstream of Glen Canyon Dam.

High Spring Flows - During January and February of 1993, high tributary inflows from the Little Colorado River (LCR), the Paria River, and several of the drainages into the mainstem Colorado River transported high compositions of silts and clays. The tributary flows augmented the releases from Glen Canyon Dam and resulted in flows up to 30,000 cfs in the Grand Canyon.

Resource Response - Resources included in the monitoring program and responses to interim flows to date are:

Sediment - The high January and February tributary flows resulted in silt and clay covering to many of the sediment deposits below the Paria River. The majority of the impact was the filling in of backwaters, which added sediment to beach faces and covering the marshes. Aerial video records were immediately collected as were remote camera shots. A beach survey trip and scaled aerial photography is scheduled over Memorial Day weekend (May 29-31) to provide additional information. The majority of the beaches are rapidly reassuming their pre-January angle of repose and the gained sediment is being reworked into the main channel.

Riparian Ecosystem - The increase in sediment has provided additional substrate for the riparian vegetation to colonize in the river corridor. It is too early to identify the specific impacts of the interim and high flows but initial indication is that the riparian community has maintained itself. A riparian trip is in the Canyon documenting changes that have occurred since October 1992.

Aquatic Ecosystem - Juvenile chub from the 1991 spawn continue to show up in the mainstem river below the LCR. During 1992, the LCR flooded repeatedly as a result of local precipitation during what turned out to be a very wet year in Arizona. There is little direct evidence to suggest that 1992 was a very good spawn. The factors that contributed to the reduced spawn are related to local flooding events in the LCR drainage during the spawning period.

The success of the 1993 year class is still unknown. Adult chub have massed at the mouth of the LCR and have made several spawning runs into the river. Additional adults have been located around springs in the lower Grand Canyon.

Natural spawning of trout has also apparently benefitted from the interim operations. This is due to maintaining water over the spawning bars and in the near shore habitat areas. Significant numbers of unstocked fry and fingerling fish have appeared in Lees Ferry sampling activities by the Arizona Game and Fish Department and GCES. Of the young of year fish collected recently, as many as two-thirds appear to be naturally reproduced.

Cladophora and *gammarus* (foodbase for the trout population) continue to reestablish in areas throughout the Lees Ferry reach. Blue green algae species have begun to be established in selected locations in the Canyon and in the Lee's Ferry areas. Blue green algae do not support the extensive diatom food base that the green algae, *Cladophora*, does.

Endangered Species - The interim flows have been designed to restrict fluctuating flow levels to enhance and maintain backwaters, side channels, and channel margin habitats. Interim flows have not been in effect long enough to document specific impacts, but monitoring continues.

A population of Kanab Amber Snails has been documented above the interim flow line at Vassey's Paradise. The impact of the interim flow levels on this population is thought to be minimal.

Cultural Resources - These resources, including Spencer Steamboat above Lees Ferry and Native American sites, are being monitored. The interim flows are designed to reduce sediment erosion at cultural resource sites. Continuous evaluations of the most sensitive locations are planned. The National Park Service has been documenting affects. Recently a Paiute trip has evaluated the cultural resources in the Grand Canyon and a Zuni Pueblo trip is planned in the near future.

Economic Resources - The past 5 months have had limited power emergencies. Much of the Western power grid has been at full operating levels resulting in substantial capacity and energy being available on the market and reduced strain on the Glen Canyon Dam electrical contractors.

Several deviations have occurred as related to power production in the rest of the Western grid and due to consolidation of the Loveland and Montrose offices. It is anticipated that the number of deviations will be reduced as the operators define their specific duties.

Recreation - Restricted fluctuations and higher minimum flows under the interim flows have provided safer passage for river trips through the Grand Canyon. Access to the Lee's Ferry fishing area has been adequate due to the higher minimum flow releases from Glen Canyon Dam. This time period is typically low for downstream travel.

Attachments

Attachment A - Glen Canyon Dam Releases

- Integrated Hourly Values - October 1992
- Hourly Ramping Rates (cfs/hour) - October 1992

- Integrated Hourly Values - November 1992
- Hourly Ramping Rates (cfs/hour) - November 1992

- Integrated Hourly Values - December 1992
- Hourly Ramping Rates (cfs/hour) - December 1992

- Integrated Hourly Values - January 1993
- Hourly Ramping Rates (cfs/hour) - January 1993

- Integrated Hourly Values - February 1993
- Hourly Ramping Rates (cfs/hour) - February 1993

Attachment B - Gaging Stations

- Lees Ferry - Flow Rate - October 1992
- Lees Ferry - Gage Height - October 1992

- Lees Ferry - Flow Rate - November 1992
- Lees Ferry - Gage Height - November 1992

- Lees Ferry - Flow Rate - December 1992
- Lees Ferry - Gage Height - December 1992

- Lees Ferry - Flow Rate - January 1993
- Lees Ferry - Gage Height - January 1993

- Lees Ferry - Flow Rate - February 1993
- Lees Ferry - Gage Height - February 1993
- Near Grand Canyon Village - Flow Rate - February 1993
- Near Grand Canyon Village - Gage Height - February 1993

Attachment C - Glen Canyon Dam Interim Operations - Western Area Power Administration

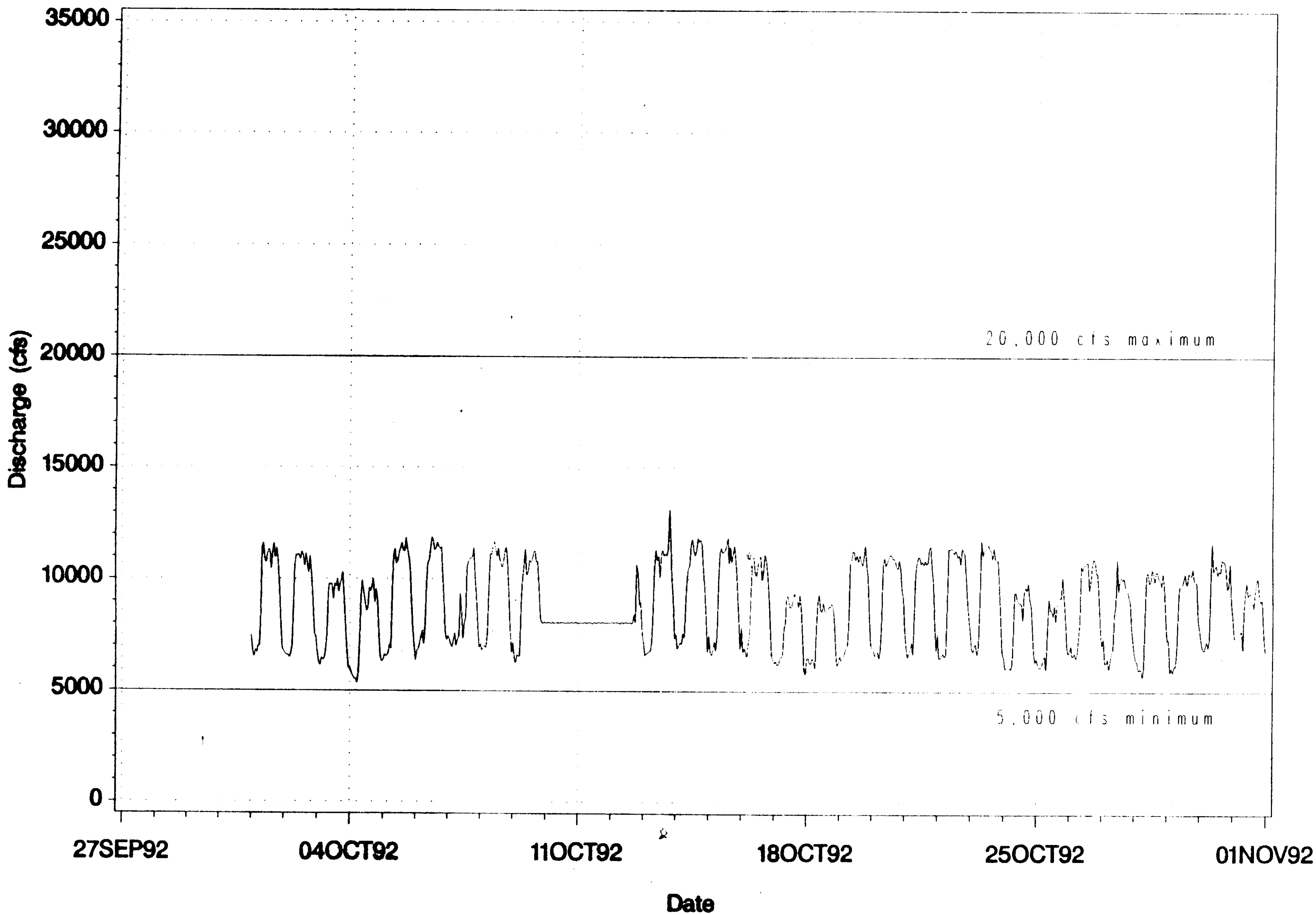
- October and November 1992
- December 1992 and January and February 1993

Attachment A

Glen Canyon Dam Releases

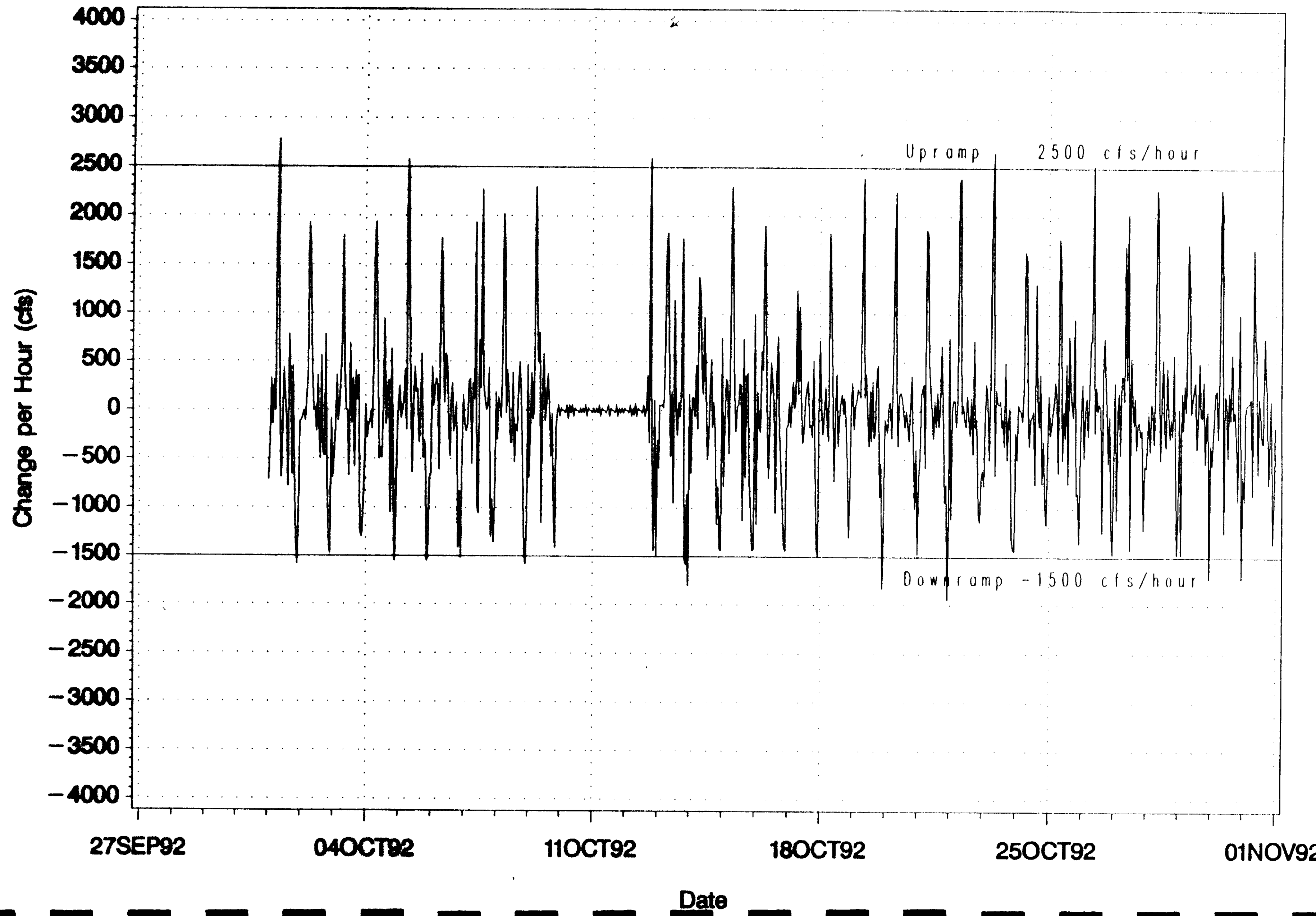
Glen Canyon Dam Releases

Integrated Hourly Values – October 92



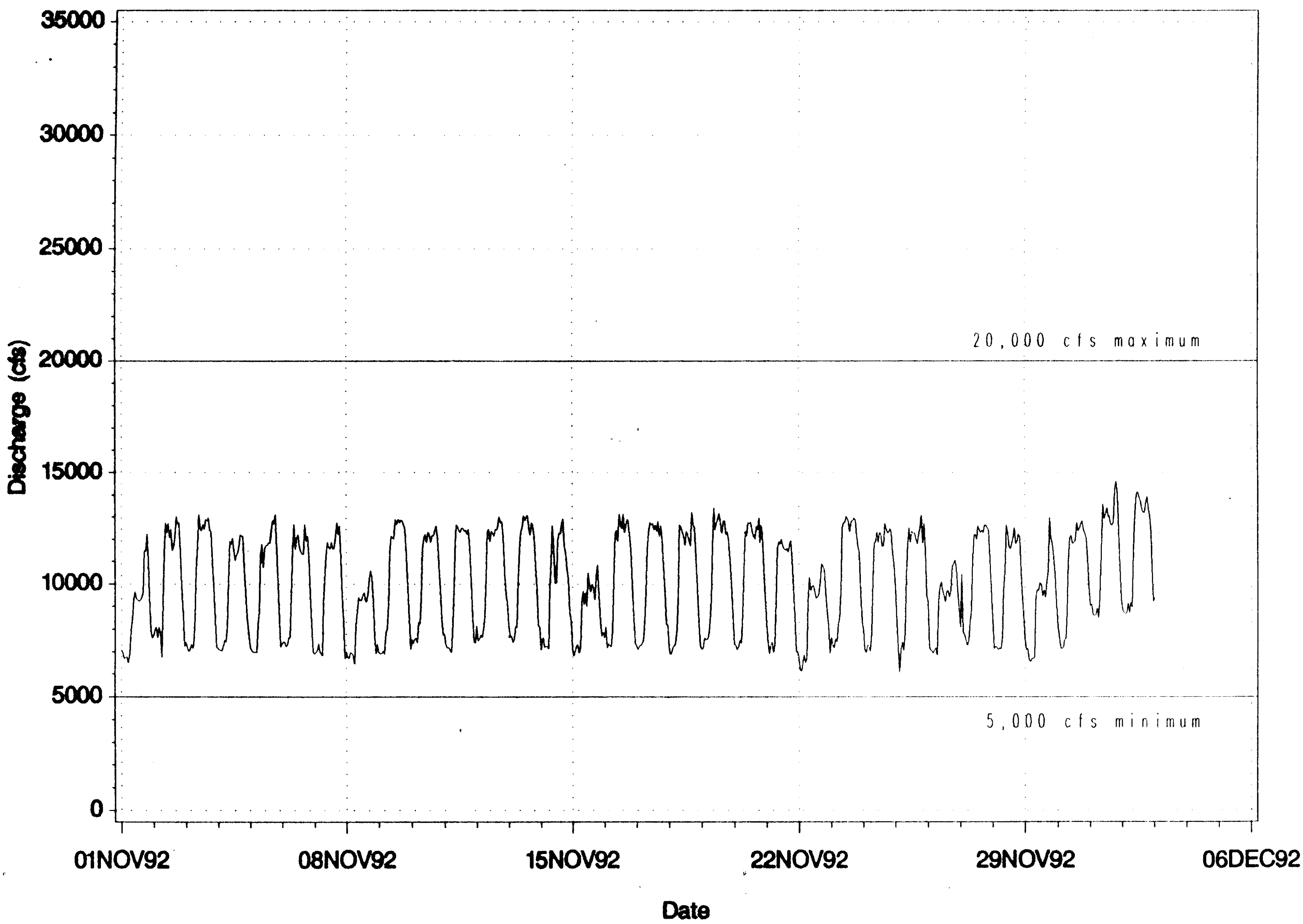
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – October 1992



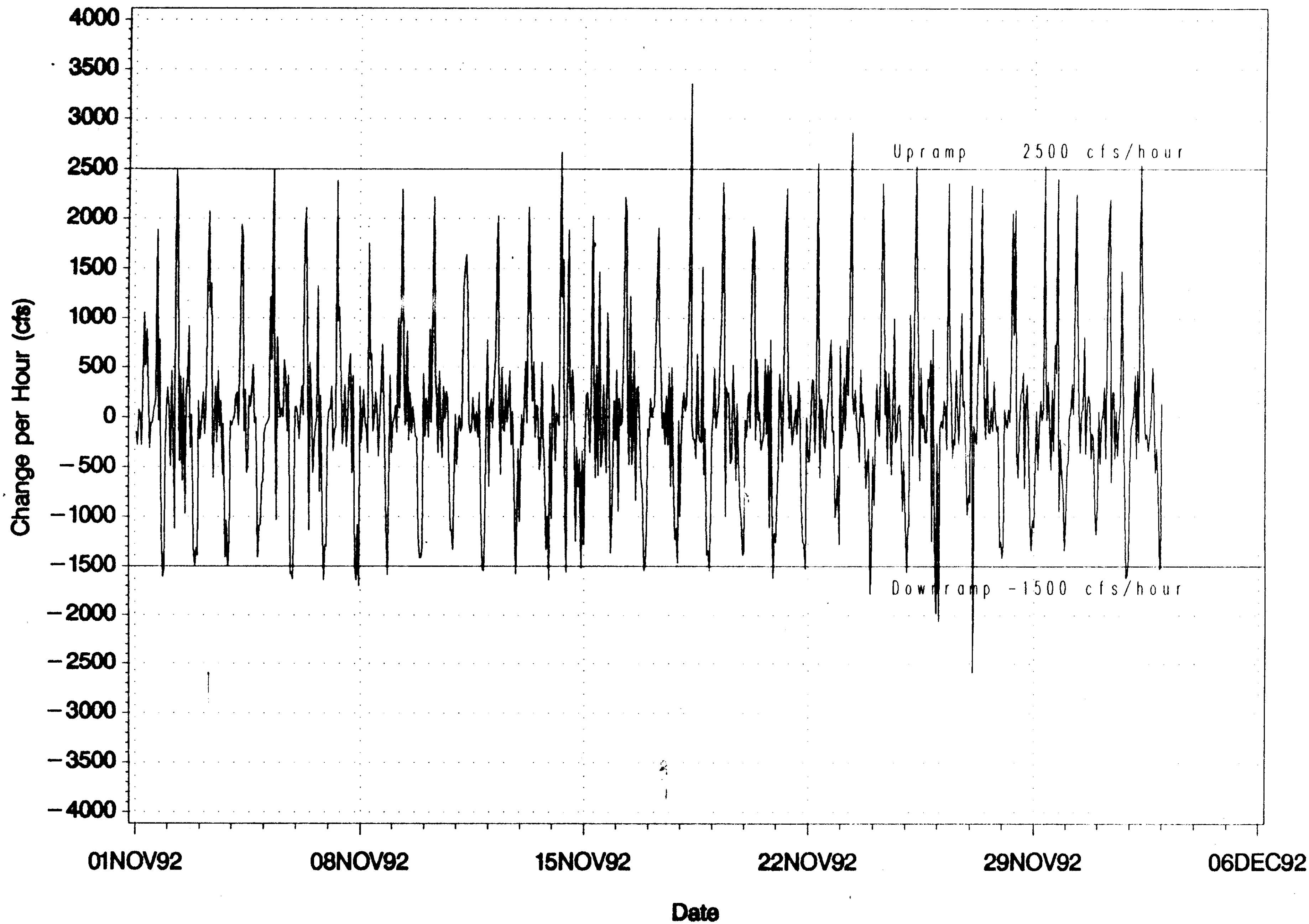
Glen Canyon Dam Releases

Integrated Hourly Values – November 92



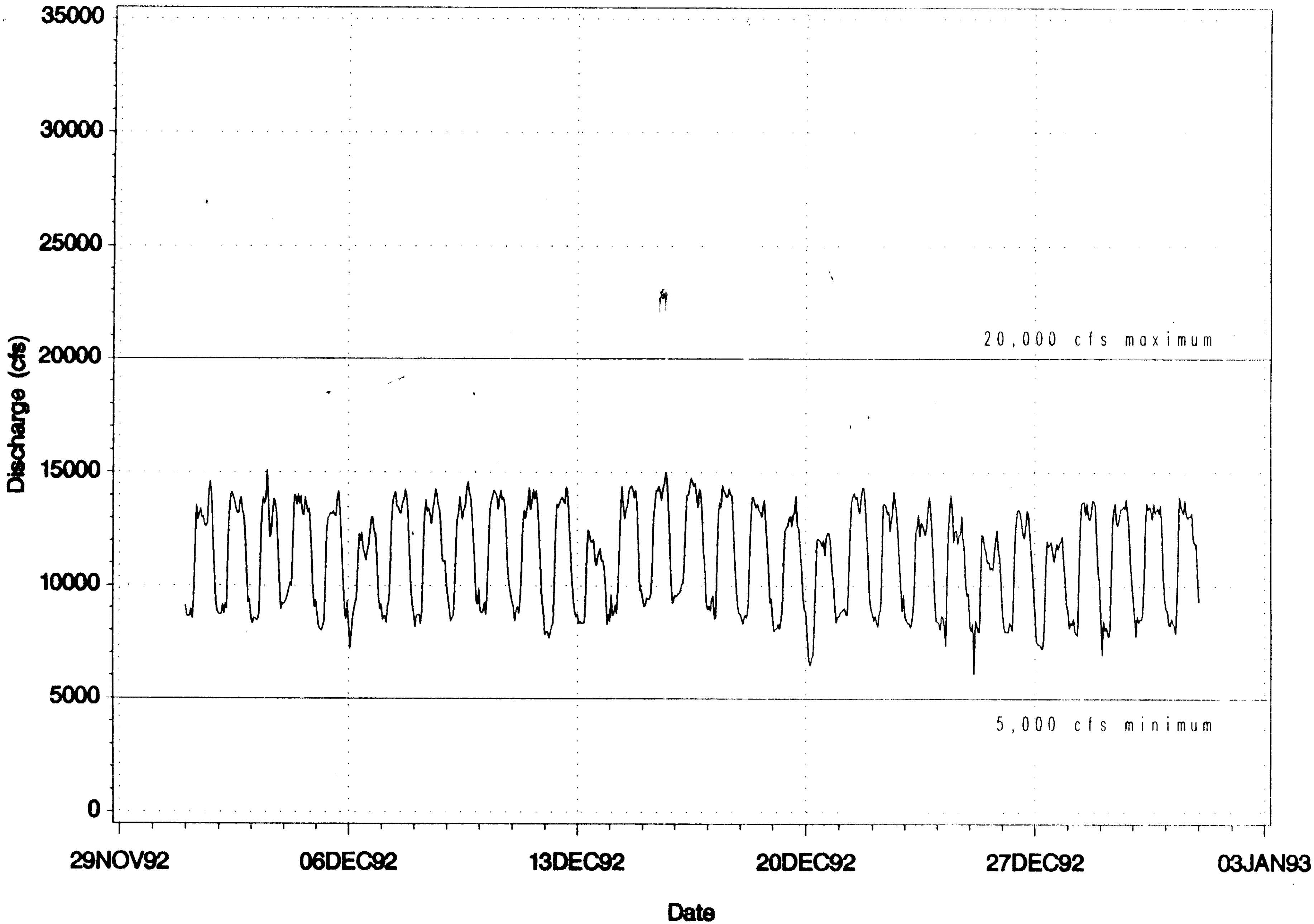
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – November 1992



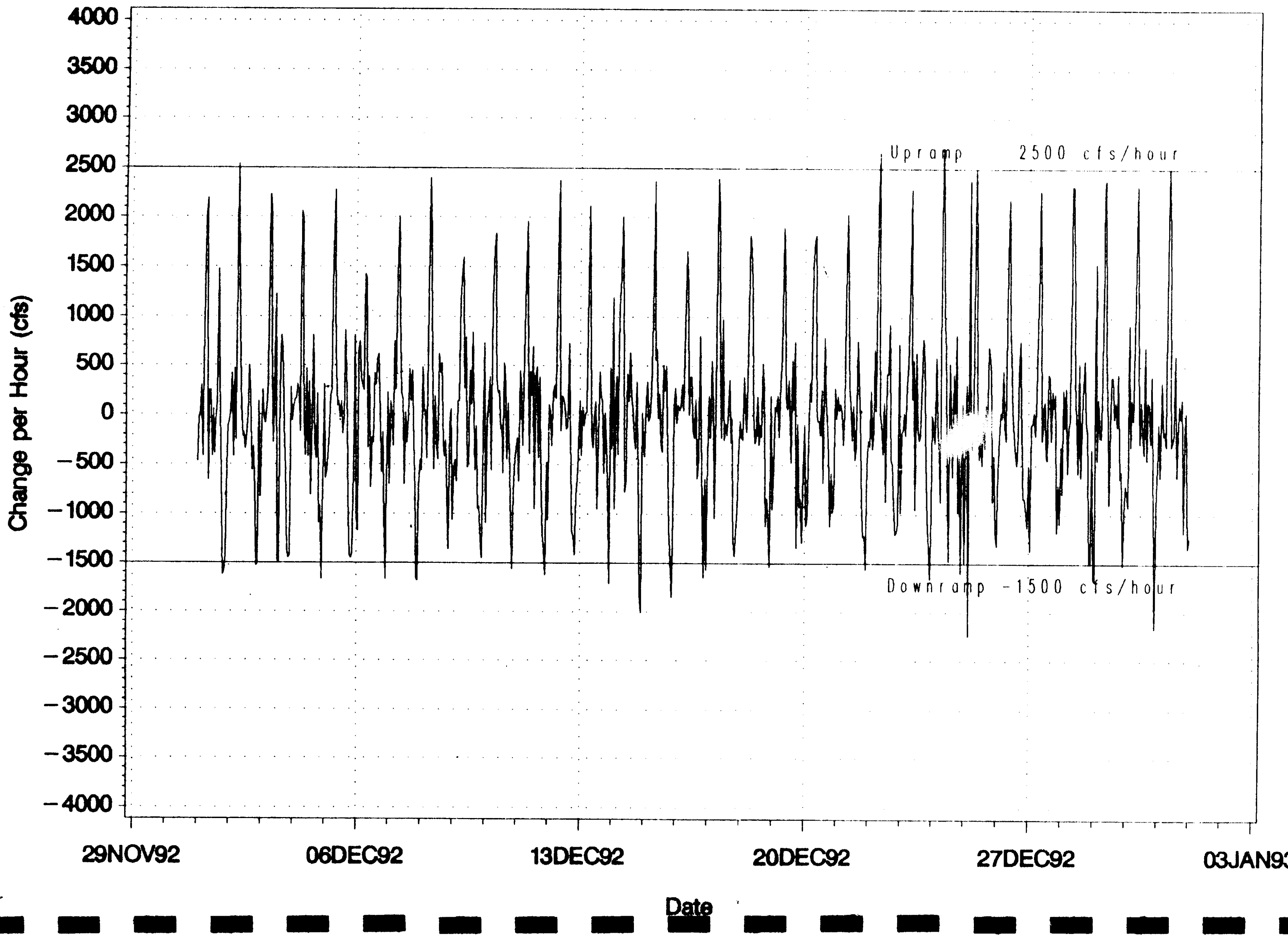
Glen Canyon Dam Releases

Integrated Hourly Values – December 92



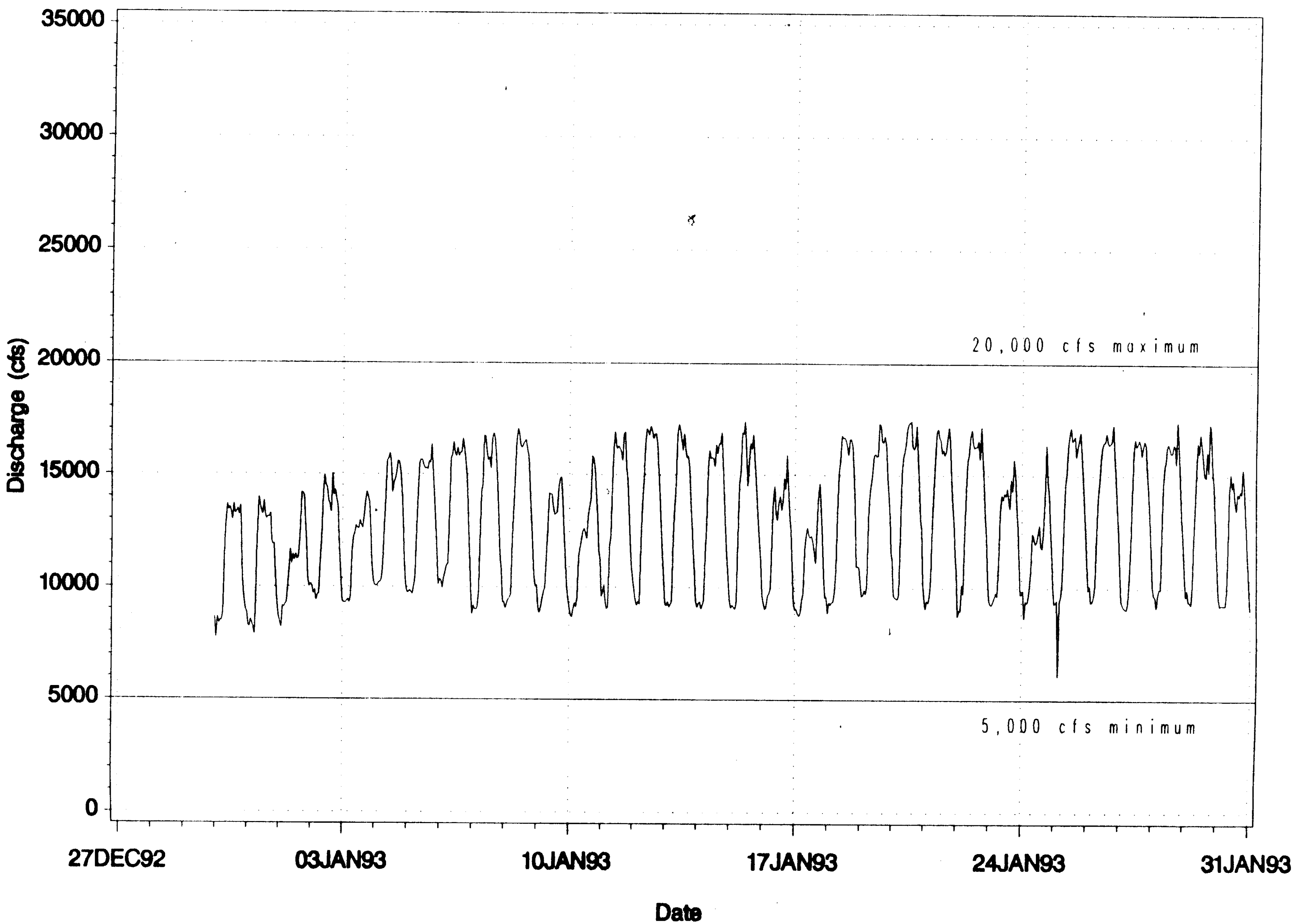
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – December 1992



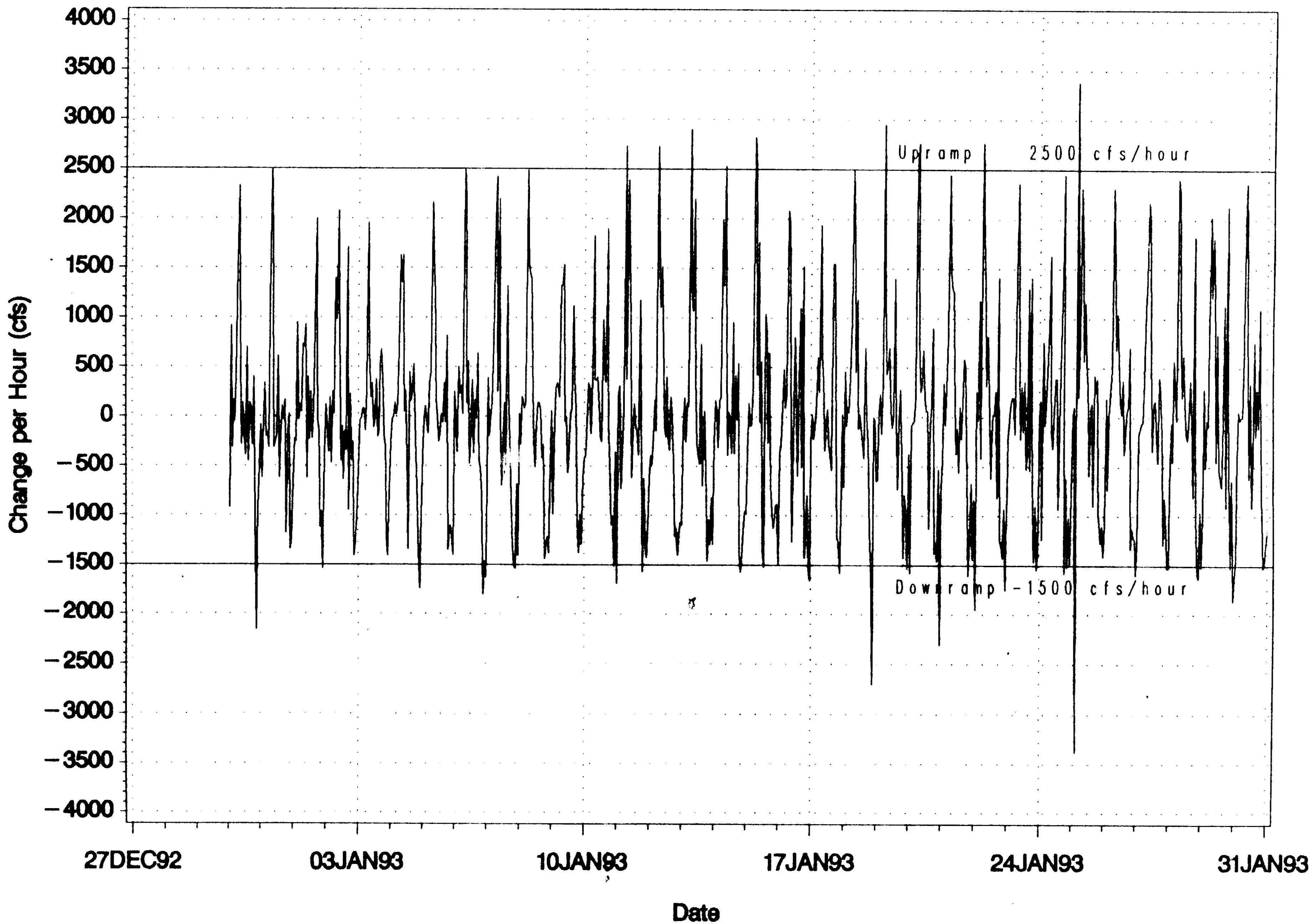
Glen Canyon Dam Releases

Integrated Hourly Values — January 93



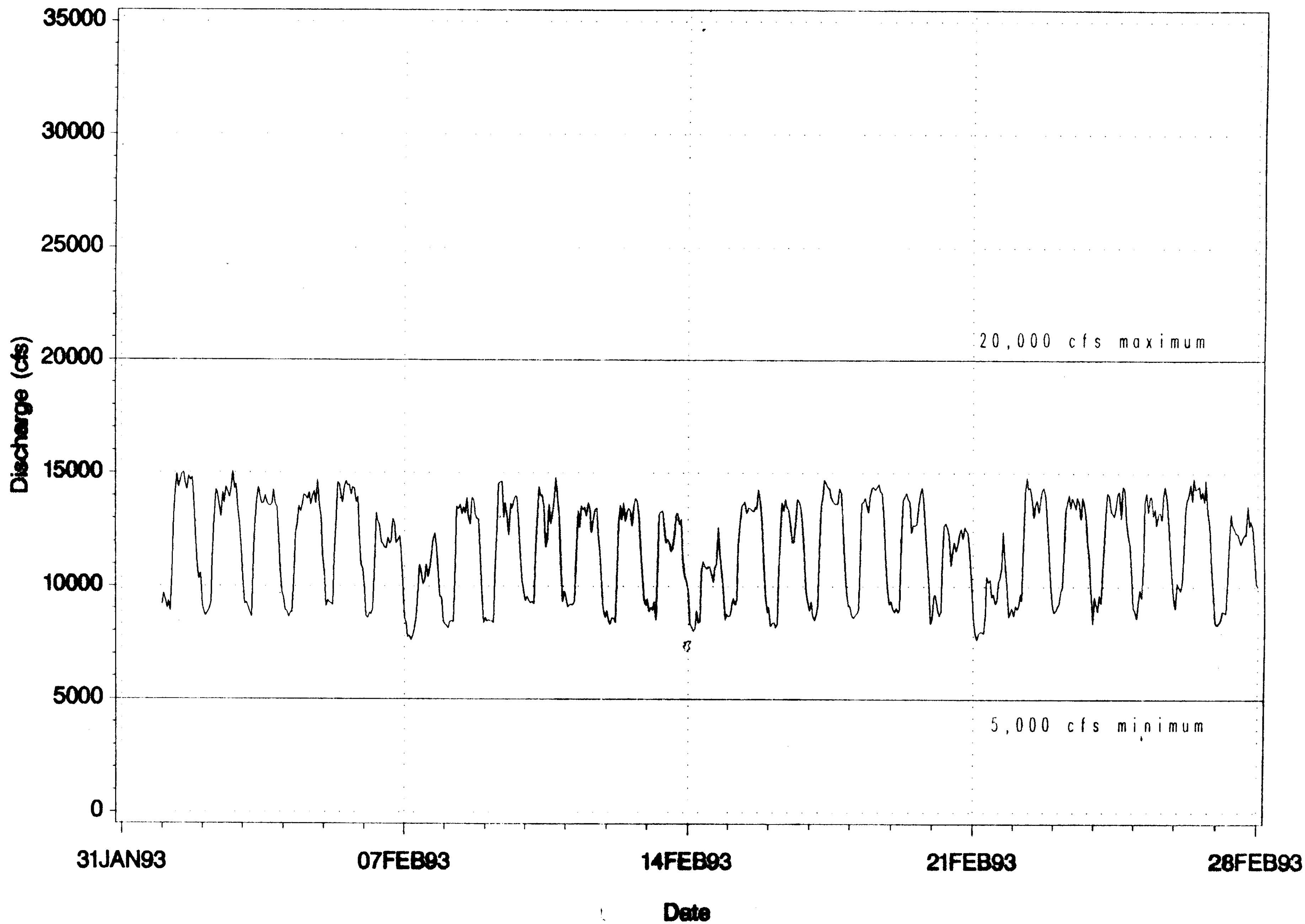
Glen C. .iyon Dam Releases

Hourly Ramping Rates (cfs/hour) – January 1993



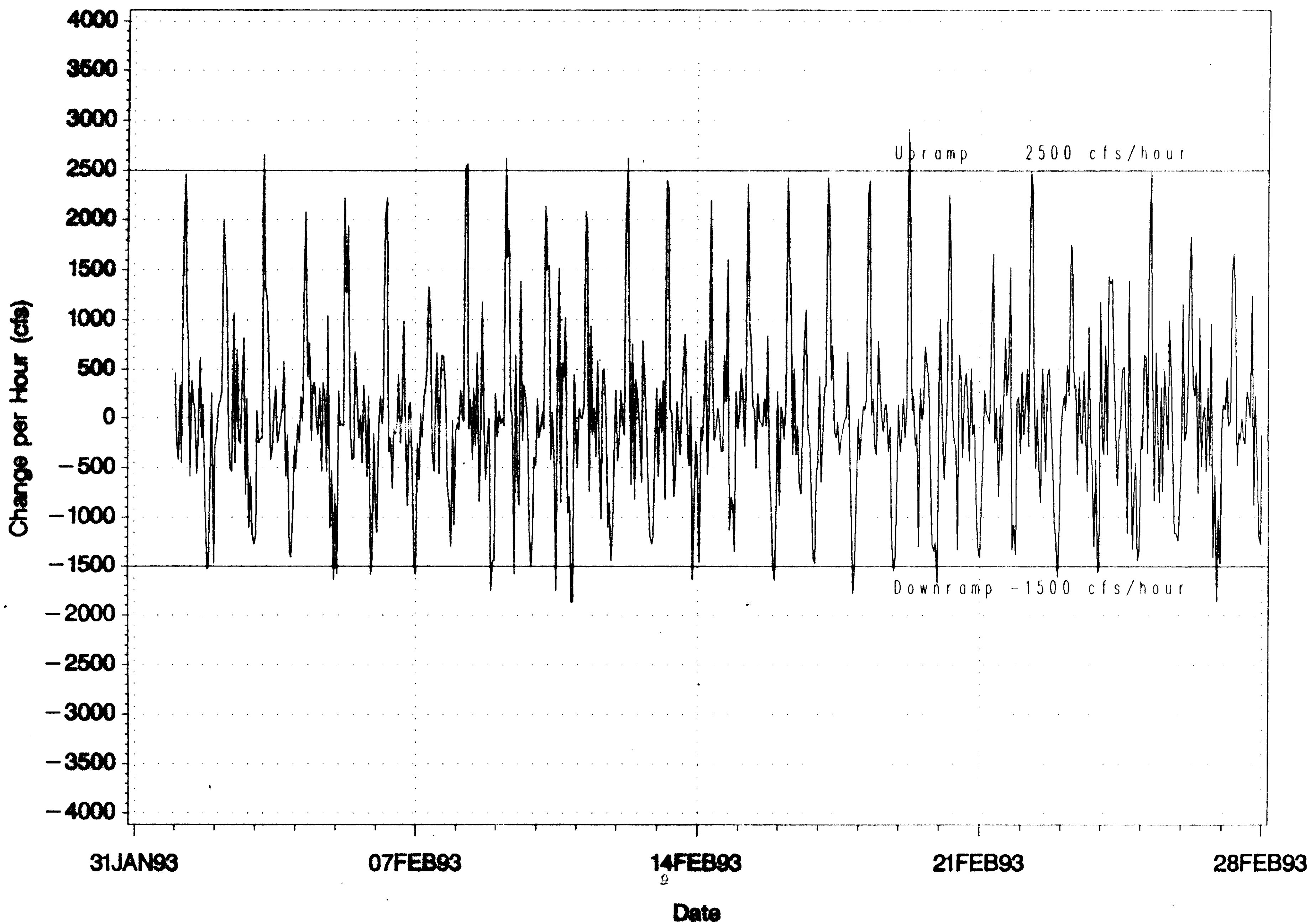
Glen Canyon Dam Releases

Integrated Hourly Values – February 93



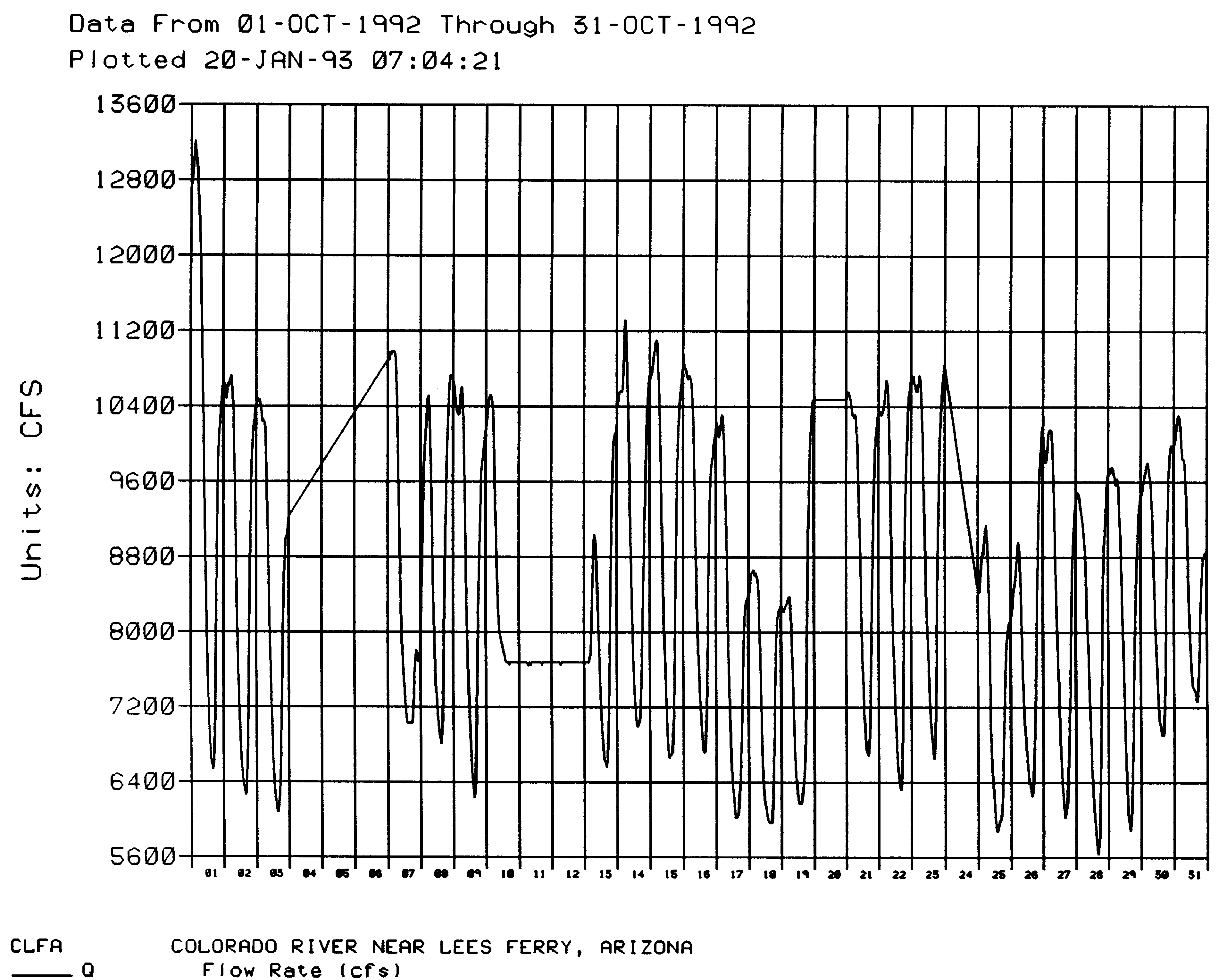
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – February 1993



Attachment B

Gaging Stations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Units: CFS
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12800
12000
11200
10400
9600
8800
8000
7200
6400
5600
CLFA
Q
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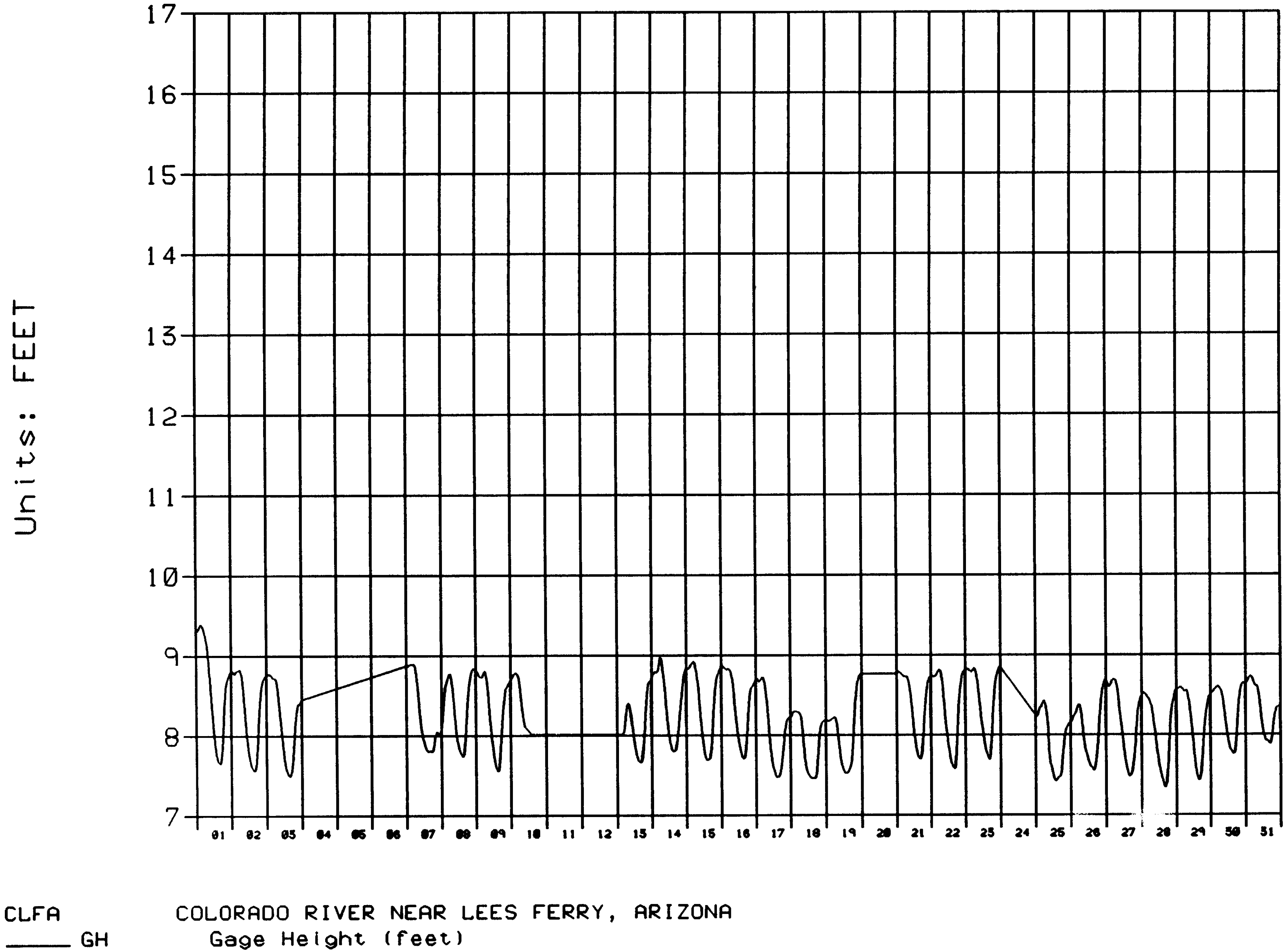
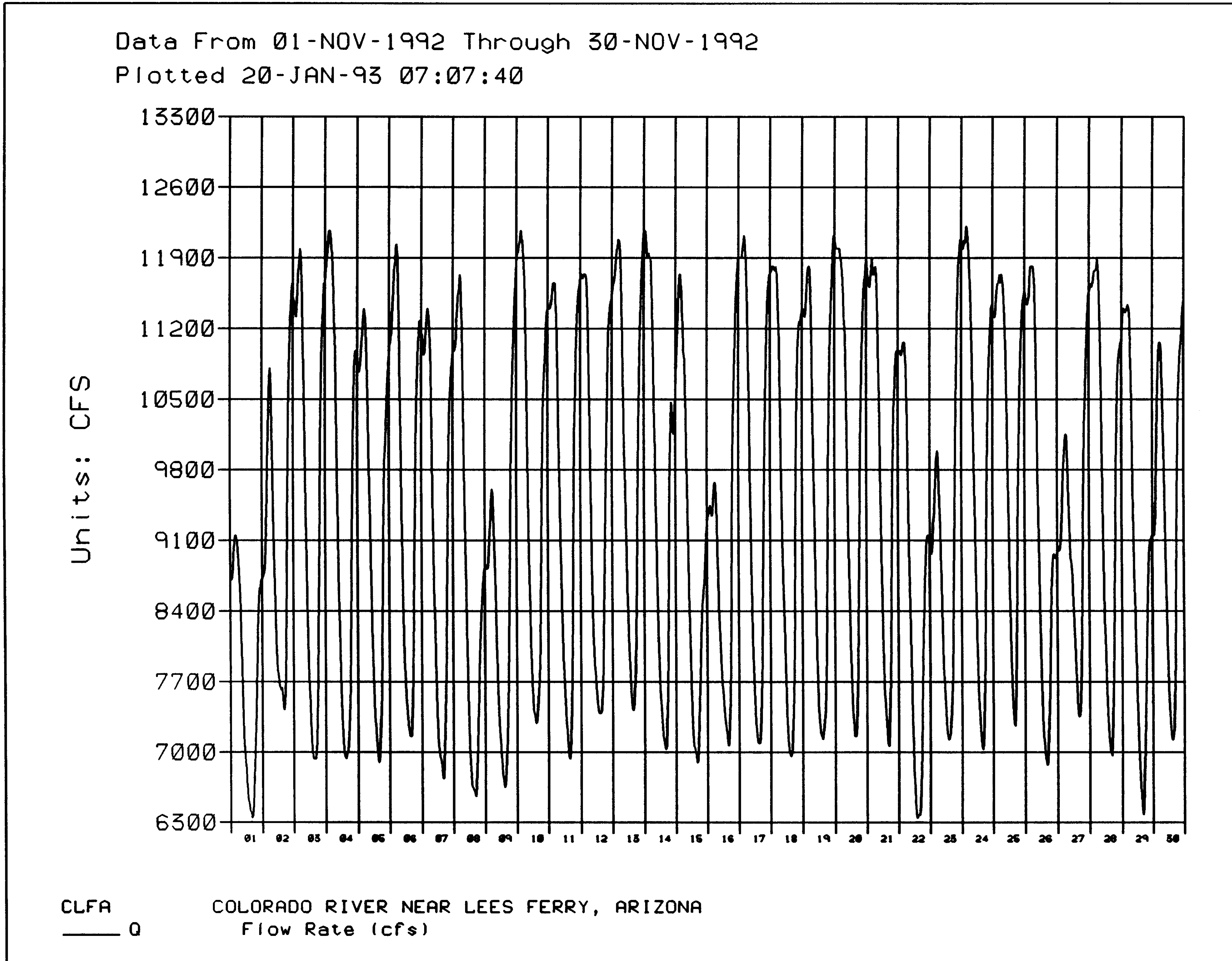
Flow Rate (cfs)

Data From 01-OCT-1992 Through 31-OCT-1992
Plotted 20-JAN-93 07:03:15



COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)



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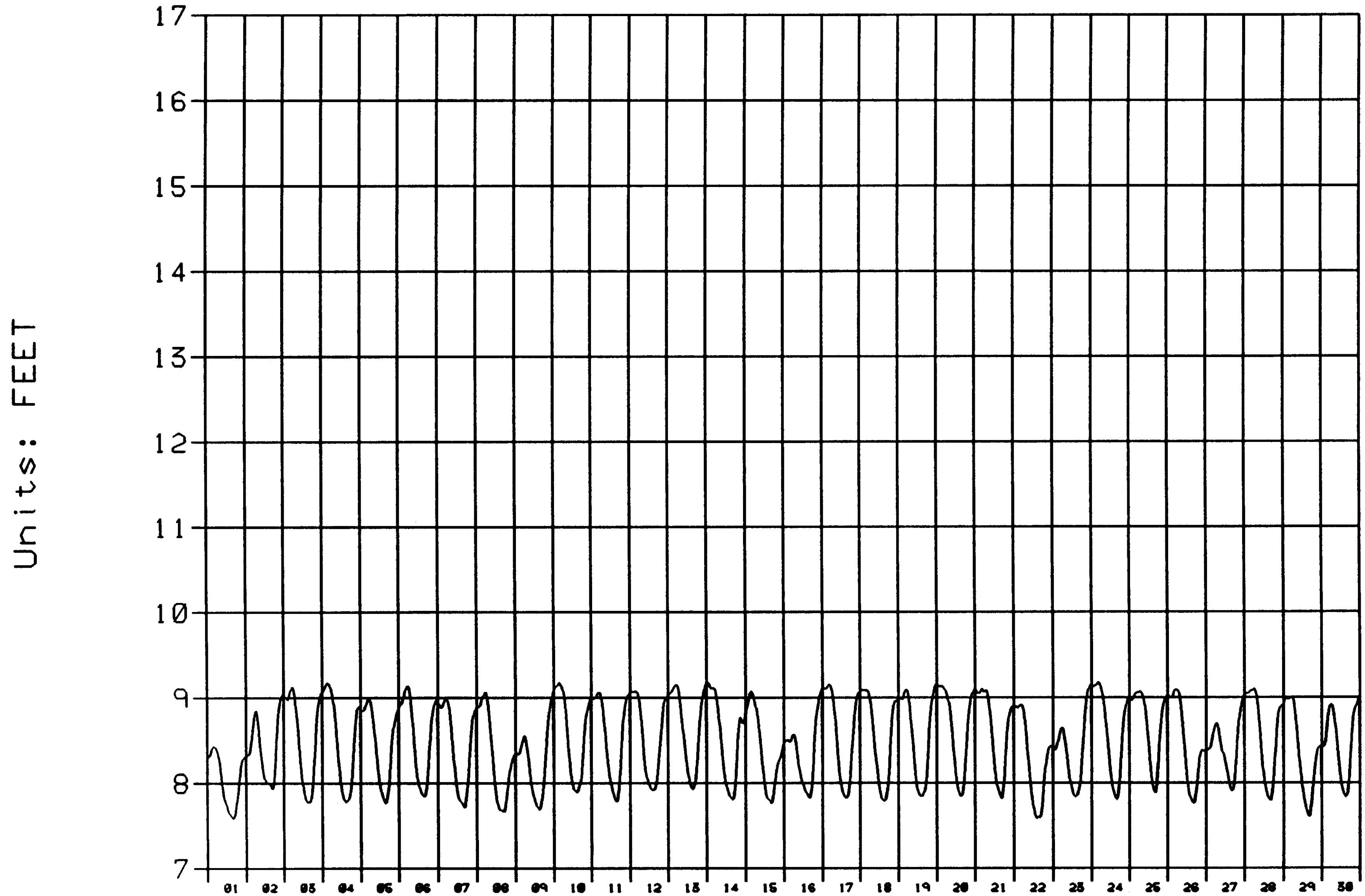
12600
11900
11200
10500
9800
9100
8400
7700
7000
6300
01
02
03
04
05
06
07
08
09
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From 01-NOV-1992 Through 30-NOV-1992
Plotted 20-JAN-93 07:06:09



CLFA COLORADO RIVER NEAR LEES FERRY, ARIZONA
—— GH Gage Height (feet)

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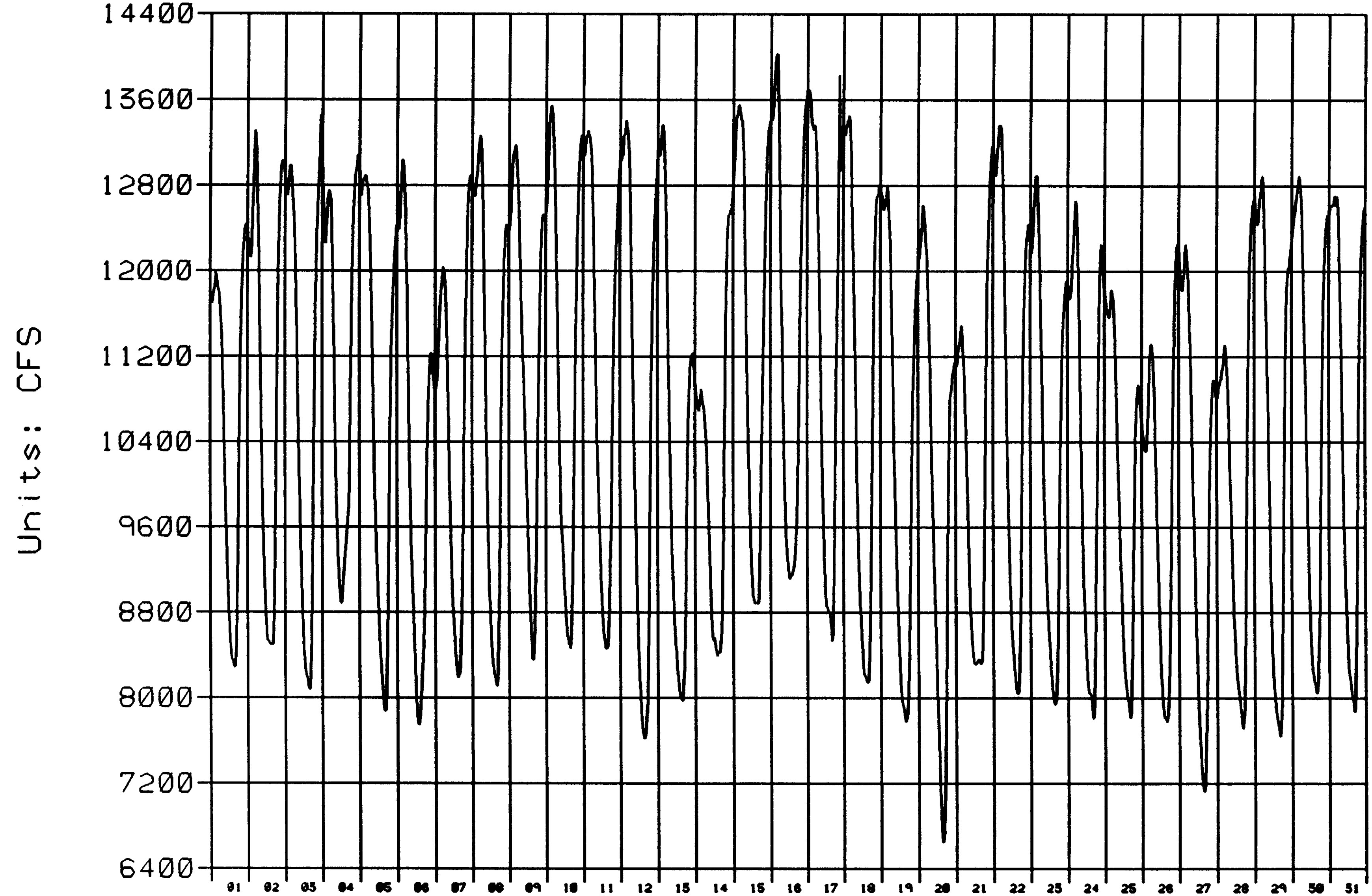
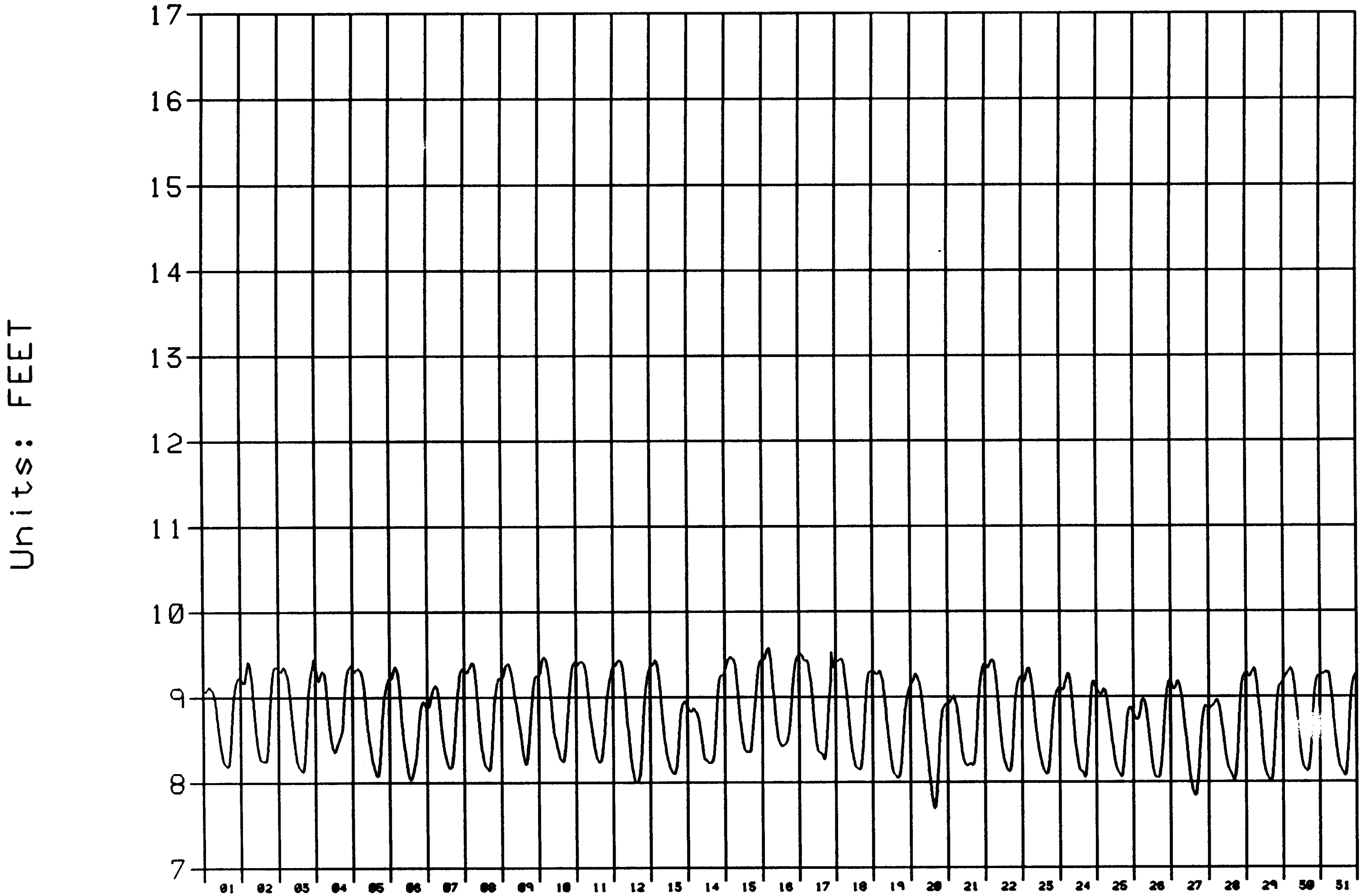
Plotted 20-JAN-93 07:10:39



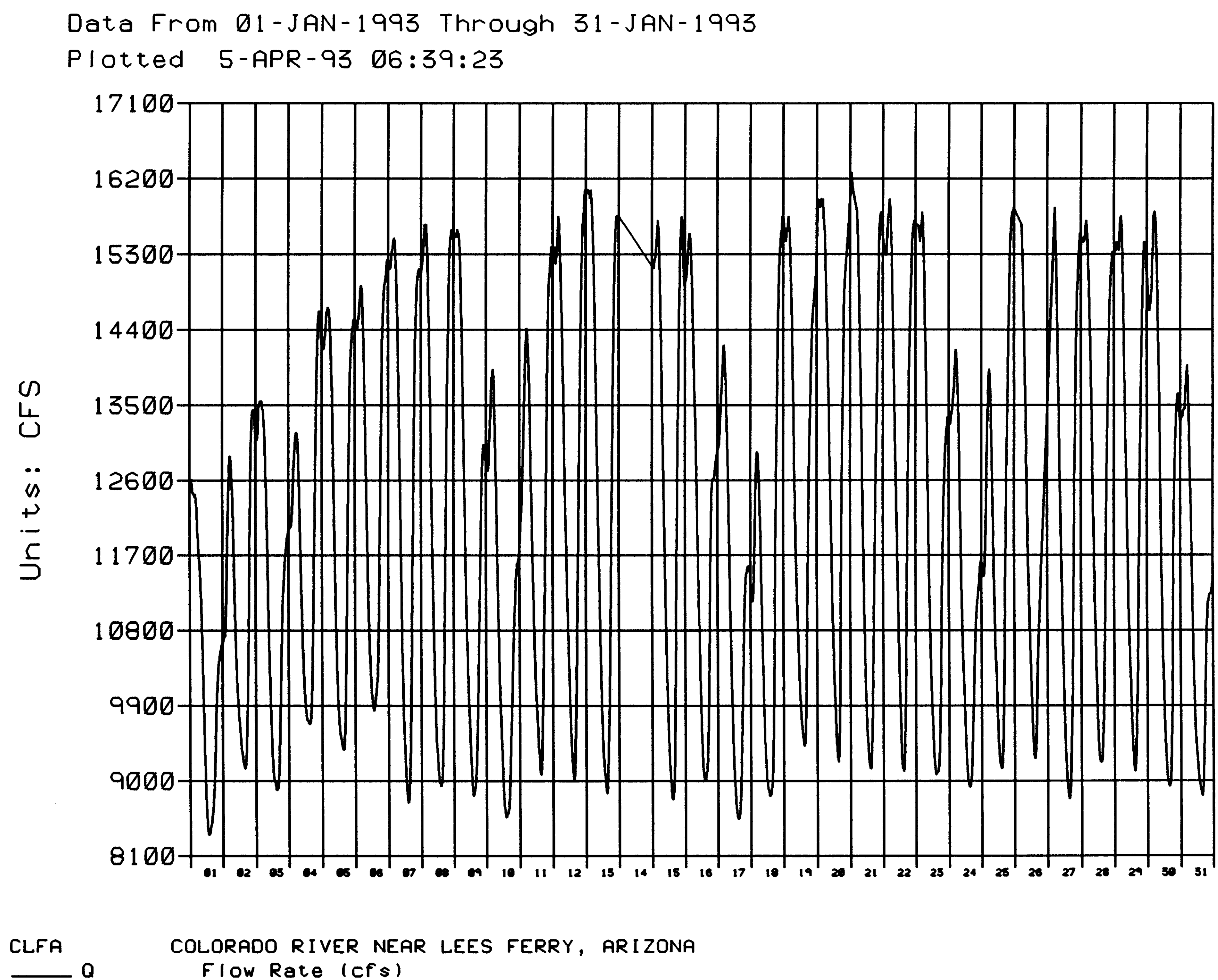
CLFA
—— Q

COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From 01-DEC-1992 Through 31-DEC-1992
Plotted 20-JAN-93 07:09:07



CLFA COLORADO RIVER NEAR LEES FERRY, ARIZONA
GH Gage Height (feet)



Data From 01-JAN-1993 Through 31-JAN-1993
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15300
14400
13500
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11700
10800
9900
9000
8100
01
02
03
04
05
06
07
08
09
10
11
12
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14
15
16
17
18
19
20
21
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CLFA
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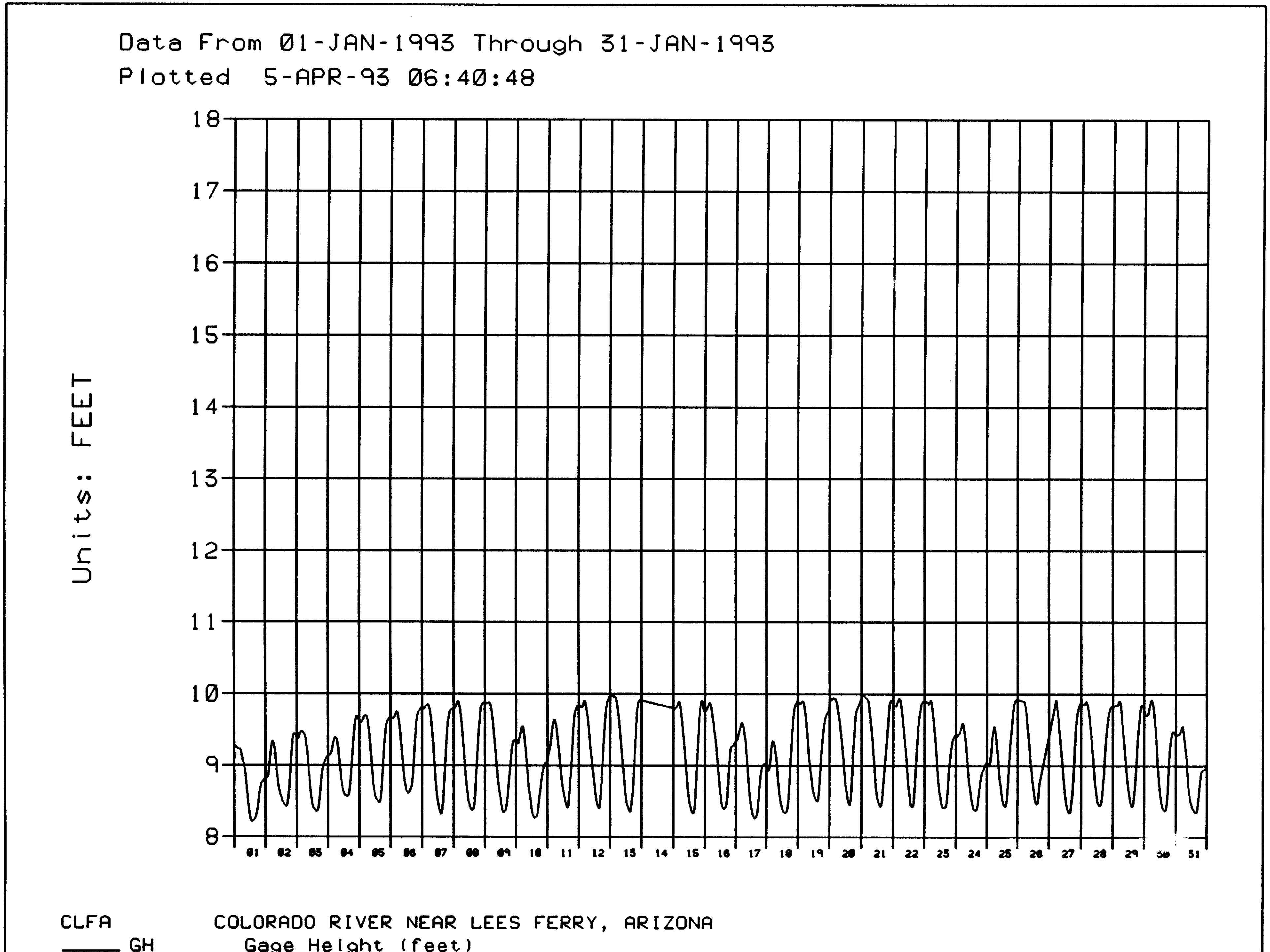
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)



Data From 01-JAN-1993 Through 31-JAN-1993
Plotted 5-APR-93 06:40:48
Units: FEET
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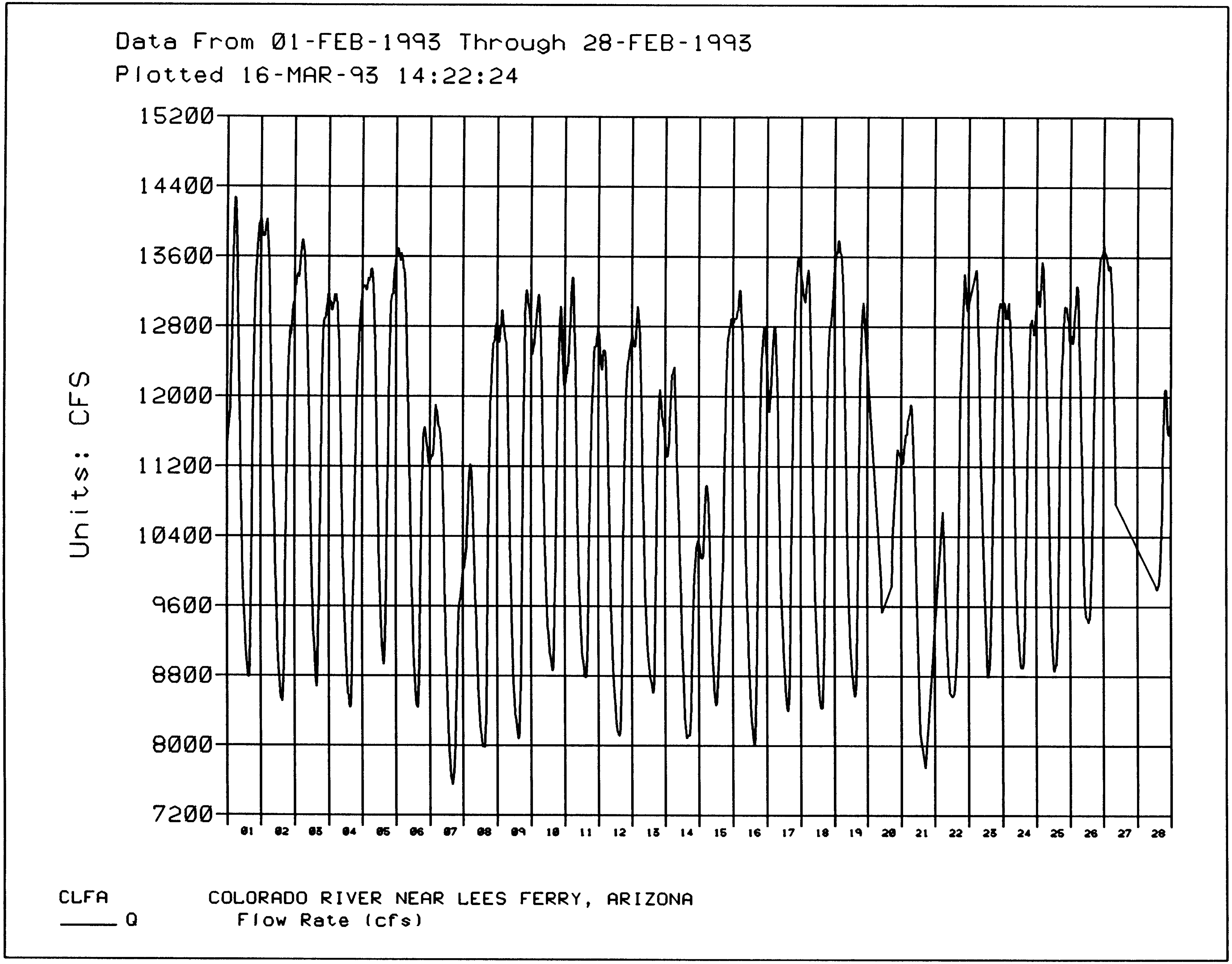
17
16
15
14
13
12
11
10
9
8
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
CLFA
GH
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)



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Plotted 16-MAR-93 14:22:24
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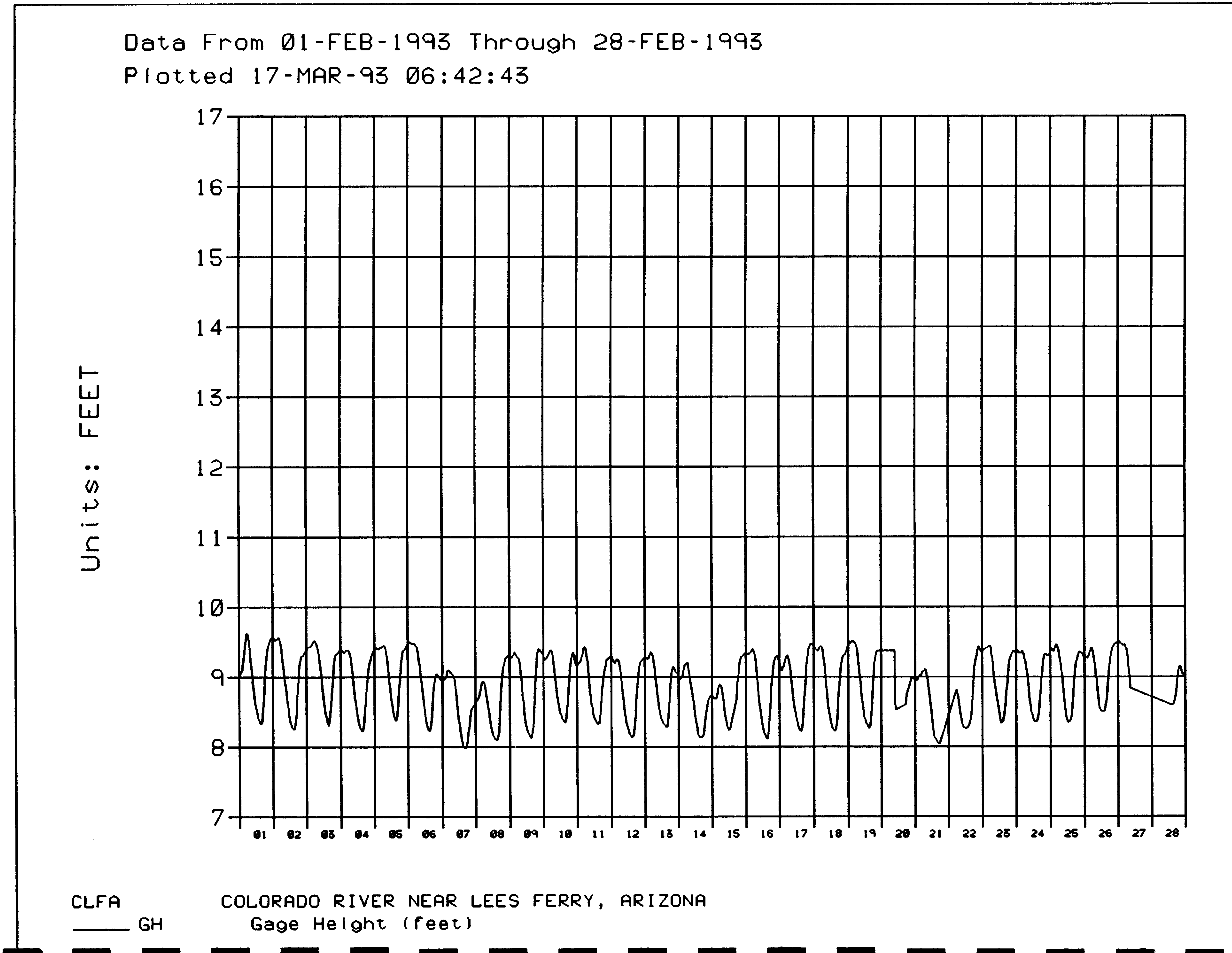
13600
12800
12000
11200
10400
9600
8800
8000
7200
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)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Units: FEET
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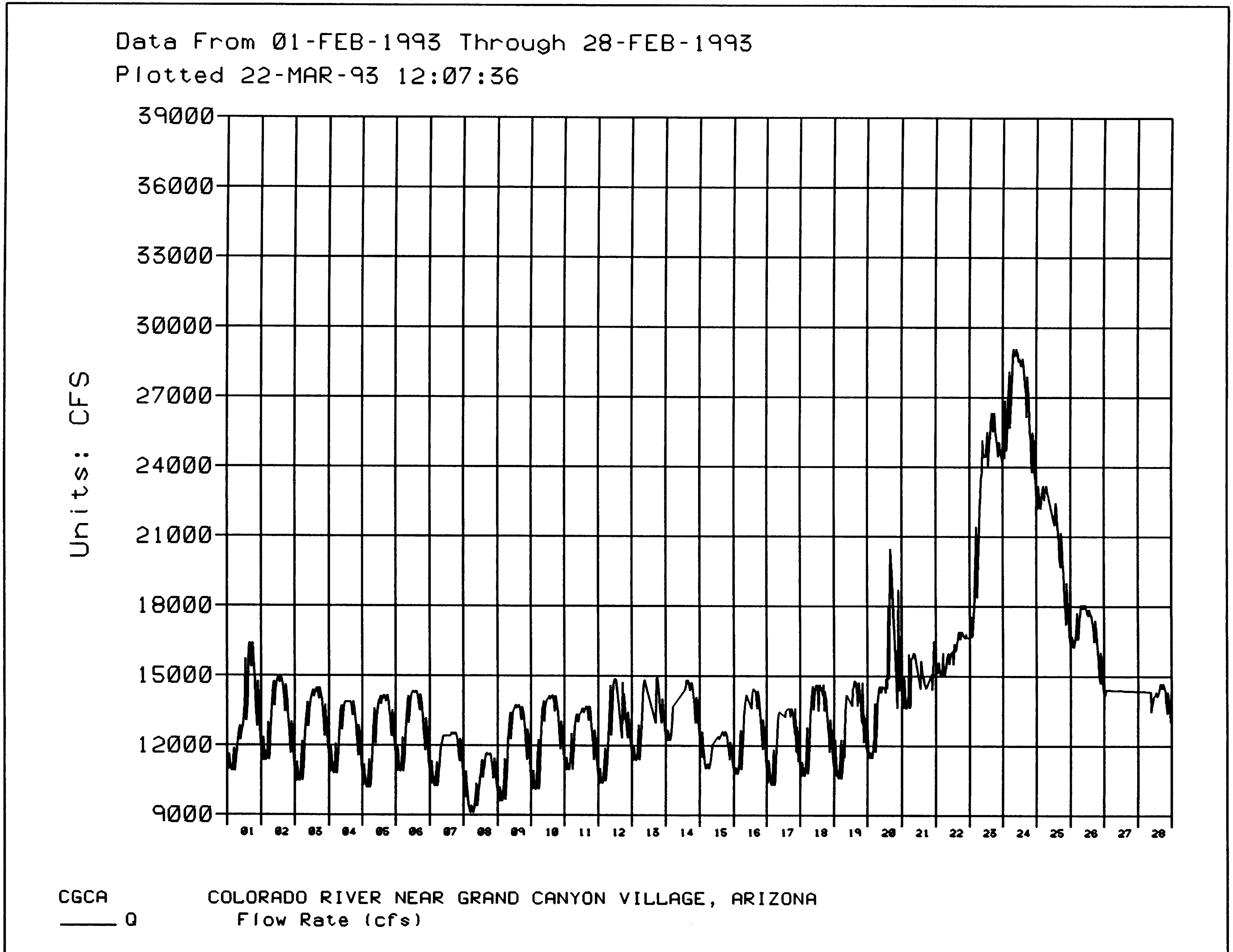
16
15
14
13
12
11
10
9
8
7
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28
CLFA
GH
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)



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Plotted 22-MAR-93 12:07:36
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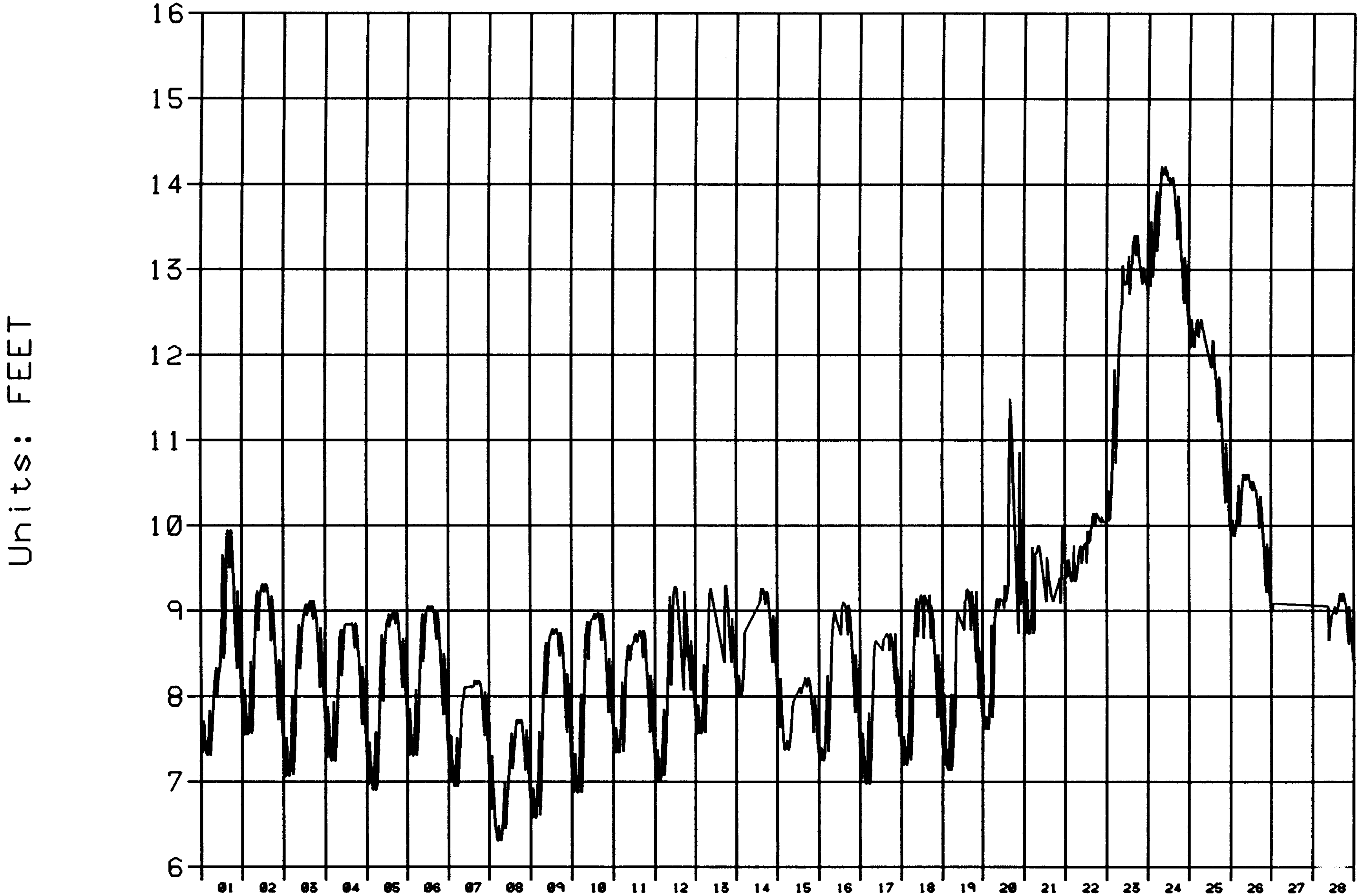
36000
33000
30000
27000
24000
21000
18000
15000
12000
9000
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28
CGCA
Q
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-FEB-1993 Through 28-FEB-1993
Plotted 22-MAR-93 12:08:37



CGCA — GH
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Gage Height (feet)

Attachment C

Glen Canyon Dam Interim Operations
Western Area Power Administration

GLEN CANYON DAM INTERIM OPERATIONS

Estimated Net Expense
October and November 1992

January 1993

WESTERN
AREA POWER
ADMINISTRATION

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GLEN CANYON DAM INTERIM OPERATIONS
Estimated Net Expense
October and November 1992

I. EXECUTIVE SUMMARY

Power Scheduling and Real-Time Operations

- From October through November energy availability was tight due to down time for unit maintenance and colder temperatures across the region.

Analysis of Ramping Events

- There were 25 deviations: "Control Area Regulation" accounted for most of the anomalies.

Expenses

- Net expense of interim releases:

  October 1992 . . . . $191,188
  November 1992 . . . . $137,853

Power Scheduling Concerns (Future)

- Morrow Point Unit No. 2 is out of service through March 1993 for uprating activities. This is a reduction of 73 MW in operating capacity.

- It is anticipated that 850 GWh of energy will be purchased for the 1992-1993 winter season.

- Glen Canyon will be the only generation sources available for system regulation this winter due to low release levels elsewhere on Western's system. Hence, capacity commitments will be tight this winter.

- Energy availability has been tight due to significant purchases by Bonneville Power Administration.

II. INTRODUCTION

On August 1, 1991, Interior Secretary Manual Lujan implemented interim flows at Glen Canyon Dam. These interim flows were a considerable departure from previous operation of the dam and have had a significant impact on the daily operation of Western Area Power Administration's (Western) Upper Colorado Control Area.

The impacts of this sudden change in dam operations required Western to implement new scheduling procedures for its customers, develop interim release guidelines for real-time operations, purchase higher-priced energy during onpeak periods, and increase the firm-power rates to its customers to cover the additional costs.

Because these operational modifications have occurred within a brief time period, Western and its customers and the utilities interconnected within the Western network have been jolted from predictability in Western's power operations. The familiarity of daily operations established during the past 20 years has been replaced with uncertainty; however, maintaining a stable and reliable power system operating within the constraints of the Upper Colorado River Basin Fund remains unchanged.

Since their inception, Western and the Bureau of Reclamation (Reclamation) have been successful in meeting the operational parameters of interim flows. Several refinements such as the 24-hour rolling period, the 30-day rolling period, and regulation caused minor problems. Once these issues were resolved by the Cooperating Agencies, Western and Reclamation responded in kind.

The following sections are a review of Power Operations for the reporting period.

III. SCHEDULING

A. General Scheduling Procedures Under Interim Release Operations

Scheduling procedures associated with the delivery of Salt Lake City Area Integrated Projects (SLCA/IP) firm capacity and energy have been modified to accommodate the release restrictions imposed on Glen Canyon Powerplant with interim release constraints.

Under previous scheduling procedures, SLCA/IP contractors were allowed to preschedule their monthly capacity allocations on an hourly basis, within established minimum and/or maximum schedule limits set by contract. Energy is delivered under the capacity up to the contractors' monthly energy entitlements as defined in Exhibit A of their electric service contracts. Capacity and associated energy schedules could have been changed (real-time) to adjust to changes in system load.

Interim release restrictions have limited Western's ability to accommodate hourly changes in the preschedules. These restrictions have required Western to request customer prescheduling 3 days in advance in order to match firm loads to available project resources and substitute purchases for any hourly deficits. Hourly changes to preschedules have been restricted by the lack of system flexibility. The burden to adjust to changes in real-time load has shifted from the contractors' use of their SLCA/IP resources to the contractors' alternate resources. A majority of these other resources are thermal and have higher costs in their use.

After Western receives the contractors' advance firm schedules, project generation is patterned hourly to optimize system capacity. During times of surplus generation, the surplus is scheduled when the energy reaches its greatest value. In times of hourly deficiencies, unit capacity is scheduled over system peaks to the maximum available, and hourly shortages are met through nonfirm energy purchases.

During periods of normal operations, there were no hourly deficiencies due to restricted flows from Glen Canyon. System energy shortages were supplied through nonfirm purchases scheduled in equal amounts across all hours, divided into onpeak and offpeak periods. Hourly peaks were covered with available project capacity.

Under interim operations, Western must determine when the system peak loads will occur and purchase nonfirm energy to cover shortages during specific hours, requiring advance scheduling of both project generation and nonfirm purchases. Due to the very narrow ramping restrictions at Glen Canyon, offpeak generation has been increased and energy, normally purchased offpeak when generation was low, is purchased during higher priced onpeak periods.

Interim release conditions have forced scheduling and dispatch personnel to monitor projected water releases and hourly generation levels very carefully.

With interim release conditions, Glen Canyon Dam Powerplant must operate within very specific daily fluctuation limits. Peaking capacity required to serve firm load obligations unavailable at Glen Canyon must be obtained from other project resources. These resources have daily water limitations which must be maintained. Any large deviations from anticipated generation levels which may occur on a real-time basis could affect prescheduling for several days. To avoid this, a very comprehensive set of interim release guidelines have been developed for dispatchers to use when running the power system during real-time operations. One individual is solely devoted to coordinate prescheduling with dispatch. Not surprisingly, this new set of procedures brought on by Interim Flow restrictions complicate "normal" Glen Canyon operations.

B. Power Scheduling and Real-Time Operations

1. Power Scheduling and Purchases for October 1992

October water releases from Glen Canyon totaled 549,000 A.F. The weekday generation pattern was prescheduled at approximately 6,500 cfs (235 MW) during offpeak hours ramping up to a maximum of 11,500 cfs (415 MW) during onpeak hours for a majority of the month. This followed the daily maximum fluctuation restriction of 5,000 cfs (180 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

Weather in October was relatively moderate, but unit maintenance work kept the economy energy market tight. The tight market had no effect on prescheduling activities; all purchase requirements were met with newly negotiated 1992-93 winter season purchase agreements.

According to the October Secretary's Report, the first week of October began with onpeak energy prices at a month high of 34/kWH and offpeak energy prices at 23.5/kWH. However, as temperatures began to moderate, the onpeak energy prices for the remainder of October hovered around 24/kWH and offpeak energy prices at 16/kWH.

From October 10-12, Western provided the Glen Canyon environmental studies, a 3-day 8,000 cfs constant release from Glen Canyon Dam. Weekend purchases for the special release did not increase (1,000 MWh for Monday, October 12) significantly. Additional energy was available for this special release from seasonal contractors, and releases from the Aspinall Unit were moderately high, allowing for some system flexibility. No real problems were encountered from the preschedule side during the special release.

There was a Glen Canyon exceedence late Monday, October 12, due to several unassociated events within Western's control area. The Bonanza Unit fell off line due to a tube leak and both Blue Mesa units were lost (490 MW) due to heating problems.

Flaming Gorge generation was restricted to 800 cfs, or 25 MW of generation throughout the entire month due to endangered fish research. This restriction limited Western's ability to respond to unanticipated events since only the Aspinall Unit was available for "load-following" requirements.

2. Power Scheduling and Purchases for November 1992

November water releases from Glen Canyon totaled 600,000 A.F. The weekday generation pattern was prescheduled at approximately 7,000 cfs (252 MW) during offpeak hours ramping up to a maximum of 13,000 cfs (468 MW) during onpeak hours for a majority of the month. This followed the maximum daily fluctuation limit of 6,000 cfs per day (216 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

The month of November began cold and wet which tightened the economy market; energy prices on the system were above winter season contract amounts. During the first week, the Laramie River Station fell off line which reduced contract imports, forcing Western to purchase energy over system peaks for 28 mills/KWh, or 4 mill/KWh more than the purchase agreement prices. The Montrose Power Control staff interchanged with Western's Loveland Area office during the first half of November. Later in the month, when loads increased, Loveland returned the energy and Western was able to avoid purchasing higher-priced energy.

Flaming Gorge generation was limited to 800 cfs (25 MW) for the entire month. This prevented Western from using this unit for any regulation assistance. In giving dispatchers some flexibility, the Montrose Power Control staff did not preschedule any hourly generation from the Morrow Point and Blue Mesa powerplants (only approximately 300-400 MWh of available daily generation). This allowed dispatchers to respond to limited system problems and avoid as many Glen Canyon exceedences as possible. Difficulties occurred during the last few hours of each day when Crystal reservoir was full, and generation from Morrow Point and Blue Mesa was unavailable. Crystal was only generating 3 MW/hr and it was difficult to lower the reservoir very fast to produce additional generation during those times.

3. Scheduling Concerns for January 1993 through March 1993

Flaming Gorge generation will be limited to a minimum (800 cfs, or 26 MW) all winter with Aspinall generation available to the extent water is released from Crystal for Gunnison River flows (projected to be 500 cfs). This should give Western about 7 hours of operation from Morrow Point and Blue Mesa. These units will be used to follow load and flatten out firming purchases from other interconnected utilities. Capacity commitments will be tight, but should not be a problem unless Western loses a unit or two at Glen Canyon. Some unit maintenance was moved around to accommodate some capacity shortages in January and February. Morrow Point unit No. 2 is out of service for uprating activities, reducing 73 MW by changing operating capacity. If current system conditions continue, this should not present an operational problem.

Western will be purchasing a great deal of firming energy during onpeak periods over the winter months. Due to the extended renewal of the operating criteria, Western was able to enter into some longer term purchase commitments which will help stabilize energy imports. The Montrose Power Control staff is anticipating the need to purchase approximately 850 GWh of energy this winter season. Prices will be much higher this winter because most of the energy will be contracted far in advance for the 6 month period and due to less energy purchased on the economy energy market to help prevent violation of release restrictions at Glen Canyon.

Purchases will be shaped in a "double humped peak" configuration which is normal for a winter season. Onpeak purchases over high load hours will be as large as 350 MW/hr. Unless there are significant problems with the system, there will be sufficient energy available to support contractual commitments without risking the violation of release restrictions at Glen Canyon. Glen Canyon will be the only generation source available for system regulation this winter due to low release levels elsewhere on the system.

Western and Reclamation have agreed to operate reservoir elevations behind Crystal and Morrow Point, a few feet lower than normal, to accommodate system emergencies because of the unavailability of Flaming Gorge. This operation will help avoid higher priced energy if Western loses a contract purchase for a day. In trying to avoid using Flaming Gorge and risking ice breakups, Western agreed to purchase generation from a combustion turbine, if available, before ramping Glen Canyon.

Energy availability has been tight all winter due to significant purchases by Bonneville Power Administration and other hydro generators. If energy contractors maintain energy deliveries, Western should have the resources available to serve load requirements for the remainder of the winter.

IV. ANALYSIS OF RAMPING EVENTS

This study was made to analyze hourly ramping rates which appeared to deviate from interim flow criteria. This research was facilitated by reviewing operational records and logs kept during the study period, October 1, 1992, through November 30, 1992.

The operational records and logs are contained within the packet Glen Canyon Dam Interim Flows—Glen Canyon Power Plant Operations, for October through November 1992 and provide specific explanations for each ramping event.

Each page within the packet contains (1) a strip chart of real-time Glen Canyon Dam operations during the ramping event, (2) a graph of the USGS Lees Ferry Gauge showing river elevation during the ramping event, (3) a graph of hourly integrated Glen Canyon Dam generation during the ramping event, and (4) a brief written explanation of the ramping event.

For the study period, 25 instances of deviations were found. Most of the conditions were caused by more than one factor: for example, control area regulation and CRSP resource availability; therefore, multiple variations can be explained by one anomaly.

The following table summarizes the causes and frequency of the 25 deviations:

Primary Cause(s) of Deviation	Number Of Instances	Percent Of Events
Control Area Regulation	9/25	36
CRSP Resource Availability	4/25	16
Aspinall Operations	2/25	8
Imports/Exports Different than Preschedule	4/25	16
Other	6/25	24

V. EXPENSES

A. Net Expense

The net expense of interim releases for October and November 1992 are summarized below:

	Net Expense
October 1992	$191,188
November 1992	$137,853

This includes additional cost associated with opportunity (economy energy) sales foregone. Attached are Tables 1 and 2 Net Expense Analysis for October and November 1992.

B. Purchases

In the base case (without interim release restrictions), all the deficits are assumed to be met by purchases. In the change case (with interim release restrictions), the deficits are met by both purchases and interchange received. The purchases in the base case for October are approximately 3 GWh higher than that of the change case. In November, the base case purchases are nearly 10 GWh less than that of the change case. Since the load and resource balance was not in deficit in November, interchange out was 3.8 GWh more than interchange in. Therefore, the 3.8 GWh of export (interchange out), along with 6.4 GWh of other sales, account for nearly 10 GWh of base case purchases less than the change case.

C. Economy Energy Sales

Economy (nonfirm) energy sales were less than projected for base case conditions. A regression analysis has been applied to calculate the nonfirm sales for the base case. Revenues foregone were estimated at $759,304 for October and $681,272 for November. Actual economy energy sales revenues were $288,592 for October and $135,976 for November.

D. Purchase Prices—Base Case

Generally, purchase prices offpeak and onpeak would remain unchanged with interim release constraints. Average monthly purchase prices are estimated as follows:

Months	Offpeak	Onpeak
October 1992	$16.06/MWh	$23.69/MWh
November 1992	$15.94/MWh	$23.40/MWh

The average monthly purchase price estimates are derived from the actual nonfirm energy purchase prices. With the help of the Power Control staff, some of the higher price purchases in October and November are associated directly with interim release constraints and were excluded. An adjusted weighted average of remaining purchase amounts and prices are rendered to calculate the base case offpeak and onpeak purchase prices.

E. Purchase Price—Actual

Average actual monthly purchase prices from all sources are as follows:

Months	Offpeak	Onpeak
October 1992	$16.07/MWh	$23.71/MWh
November 1992	$16.17/MWh	$23.47/MWh

F. Economy Energy Sales Prices—Base Case

Average monthly economy energy sales price for base case conditions is estimated to be $23.84/MWh for October, and $21.39/MWh for November which is the same as the actual sales price in this month.

The estimate of economy energy sales prices involve three steps:

1. Identification of the range of market prices through review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, as reflected in Western's Weekly Reports to the Secretary.

2. Review of the actual monthly economy energy sales summary and, with the help of the Power Control staff, identify those sales directly associated with interim release constraints.

3. Assumption of expected sales price based on then-current market conditions for that portion of sales identified in step 2.

In most instances, since Western would have had the flexibility of making all or most of the nonfirm sales during the time the market has been high, with the help of the Power Control staff, the sales price for the base case is determined. For October, the actual and base case sales prices differ due to the deletion of some nonfirm sales that were deemed too low by the Power Control staff. For November there were no forced sales so the base case sales price is the same as the actual sales price ($21.39/MWh).

G. Economy Energy Sales—Actual

The actual consummated average monthly economy energy sales price is:

October 1992 . . . . $22.04/MWh
November 1992 . . . . $21.39/MWh

1. Comparison, Average Purchase Prices versus Economy Energy Sales Prices

When looking at the sales prices and average purchase prices for base case and actual, overall, the purchase and sales prices have been consistent between the base case and actual. With the help of the Power Control staff and review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, the base case sales prices are determined.

In the October base case, 31,850 MWh of sales are estimated to be made with a price differential of approximately 3.88 mills/kWh between the average estimated purchase price and the average estimated sales price. In actual operations, 13,094 MWh of sales were made with the price differential of 1.32 mills/kWh.

In the November base case, 31,850 MWh of sales are estimated to be made with a price differential of 1.37 mills/kWh between the average estimated purchase price and the average estimated sales price. In actual operations, 6,357 MWh of sales were made with a price differential of 0.67 mills/kWh.

January 1993
Revised 3/93

Table 1 [1]
Glen Canyon Dam Interim Release
for October 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	434,567 MWh	Firm Load & Losses:	434,567 MWh
GC Generation:	238,838 MWh	GC Generation:	238,837 MWh
Other CRSP/IP Generation:	84,130 MWh	Other CRSP/IP Generation:	84,130 MWh
Total Generation:	322,967 MWh	Total Generation:	322,967 MWh
Deficits:	111,599 MWh	Deficits:	111,672 MWh
Off Peak:	54,625 MWh	Off Peak:	41,559 MWh
On Peak:	56,974 MWh	On Peak:	70,113 MWh
Purchases:	111,599 MWh	Purchases:	108,610 MWh
Off Peak:	54,625 MWh	Off Peak:	42,575 MWh
On Peak:	56,974 MWh	On Peak:	66,035 MWh
Surplus:	0 MWh	Surplus:	72 MWh
Off Peak:	0 MWh	Off Peak:	72 MWh
On Peak:	0 MWh	On Peak:	0 MWh
Other Imports:	31,850 MWh	Other Imports:	16,084 MWh
Other Sales:	31,850 MWh	Other Sales:	13,094 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.06/MWh	Off Peak:	$16.07/MWh
On Peak:	$23.69/MWh	On Peak:	$23.71/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$19.96/MWh	Other Imports Price: (Avg.Purchase Price)	$20.72/MWh
Sales Price:	$23.84/MWh	Sales Price:	$21.83/MWh
		Other Exports Price:	$21.83/MWh
Purchase Expense:	$2,227,000	Purchase Expense:	$2,249,870
Off Peak:	$877,278	Off Peak:	$684,180
On Peak:	$1,349,721	On Peak:	$1,565,690
Other Imports Expense:	$635,577	Other Imports:	$333,182
Other Sales:	$759,304	Other Sales:	$285,842
Base Case Expense:	$2,103,272	Change Case Expense:	$2,297,210

Total Net Expense for October 1992 .... $193,938

(1) Revised Net Expense due to correction in sales price calculation.

January 1993
Revised 3/93

Table 2 [1]
Glen Canyon Dam Interim Release
for November 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	443,818 MWh	Firm Load & Losses:	443,818 MWh
GC Generation:	259,931 MWh	GC Generation:	259,930 MWh
Other CRSP/IP Generation:	39,446 MWh	Other CRSP/IP Generation:	39,446 MWh
Total Generation:	299,377 MWh	Total Generation:	299,376 MWh
Deficits:	144,441 MWh	Deficits:	144,756 MWh
Off Peak:	65,439 MWh	Off Peak:	51,081 MWh
On Peak:	79,001 MWh	On Peak:	93,675 MWh
Purchases:	144,441 MWh	Purchases:	154,620 MWh
Off Peak:	65,439 MWh	Off Peak:	58,255 MWh
On Peak:	79,001 MWh	On Peak:	96,365 MWh
Surplus:	0 MWh	Surplus:	314 MWh
Off Peak:	0 MWh	Off Peak:	314 MWh
On Peak:	0 MWh	On Peak:	0 MWh
Other Imports:	31,850 MWh	Other Exports:	3,821 MWh
Other Sales:	31,850 MWh	Other Sales:	6,357 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$15.94/MWh	Off Peak:	$16.17/MWh
On Peak:	$23.40/MWh	On Peak:	$23.47/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$20.02/MWh	Other Imports Price: (Avg.Purchase Price)	$20.72/MWh
Sales Price:	$22.06/MWh	Sales Price:	$22.06/MWh
		Other Exports Price:	$22.06/MWh
Purchase Expense:	$2,891,737	Purchase Expense:	$3,203,670
Off Peak:	$1,043,105	Off Peak:	$941,983
On Peak:	$1,848,632	On Peak:	$2,261,687
Other Imports Expense:	$637,644	Other Exports:	$0
Other Sales:	$702,611	Other Sales:	$140,235
Base Case Expense:	$2,826,770	Change Case Expense:	$2,979,143

Total Net Expense for November 1992 .... $152,373

(1) Revised Net Expense due to correction in sales price calculation.

GLEN CANYON DAM INTERIM OPERATIONS

Estimated Net Expense
December 1992, January and February 1993

April 1993

WESTERN AREA POWER ADMINISTRATION

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GLEN CANYON DAM INTERIM OPERATIONS
Estimated Net Expense
December 1992, January and February 1993

I. EXECUTIVE SUMMARY

Power Scheduling and Real-Time Operations

- From December 1992 through February 1993 energy availability was tight due to down time for unit maintenance and colder temperatures across the region.

- The economy energy market price for January rose into the mid $30 mill/KWh range. For the week of January 14, onpeak purchases jumped to $38 mill/KWh.

Analysis of Ramping Events

- There were 51 deviations: "Imports/Exports Different than Pre-schedule" accounted for most of the anomalies.

Expenses

- Net expense of interim releases:

December 1992	$471,698
January 1993	$466,684
February 1993	$380,314

- A refinement in valuating interim release expenses is introduced with a table comparing the differences from earlier reported net expense for October and November 1992.

Power Scheduling Concerns (Future)

- Morrow Point Unit No. 2 is out of service through April 1993 for uprating activities. This is a reduction of 73 MW in operating capacity.

- It is expected that May and June will be difficult to schedule due to the high Spring releases from Flaming Gorge and from the Aspinall Units.

- June will be critical because energy import needs will be high due to low Glen Canyon releases.

- The period from July through September is anticipated to look good for power control operations, because Glen Canyon generation will be high and all Aspinall Units are expected to be available.

II. INTRODUCTION

On August 1, 1991, former Interior Secretary Manual Lujan implemented interim flows at Glen Canyon Dam. These interim flows were a considerable departure from previous operation of the dam and have had a significant impact on the daily operation of Western Area Power Administration's (Western) Upper Colorado Control Area.

The impacts of this sudden change in dam operations required Western to implement new scheduling procedures for its customers, develop interim release guidelines for real-time operations, purchase higher-priced energy during onpeak periods, and increase the firm-power rates to its customers to cover the additional costs.

Because these operational modifications have occurred within a brief time period, Western and its customers and the utilities interconnected within the Western network have been jolted from predictability in Western's power operations. The familiarity of daily operations established during the past 20 years has been replaced with uncertainty; however, maintaining a stable and reliable power system operating within the constraints of the Upper Colorado River Basin Fund remains unchanged.

Since their inception, Western and the Bureau of Reclamation (Reclamation) have been successful in meeting the operational parameters of interim flows. Several refinements such as the 24-hour rolling period, the 30-day rolling period, and regulation caused minor problems. Once these issues were resolved by the Cooperating Agencies, Western and Reclamation responded in kind.

The following sections are a review of Power Operations for the reporting period.

III. SCHEDULING

A. General Scheduling Procedures Under Interim Release Operations

Scheduling procedures associated with the delivery of Salt Lake City Area Integrated Projects (SLCA/IP) firm capacity and energy have been modified to accommodate the release restrictions imposed on Glen Canyon Powerplant with interim release constraints.

Under previous scheduling procedures, SLCA/IP contractors were allowed to preschedule their monthly capacity allocations on an hourly basis, within established minimum and/or maximum schedule limits set by contract. Energy is delivered under the capacity up to the contractors' monthly energy entitlements as defined in Exhibit A of their electric service contracts. Capacity and associated energy schedules could have been changed (real-time) to adjust to changes in system load.

Interim release restrictions have limited Western's ability to accommodate hourly changes in the preschedules. These restrictions have required Western to request customer prescheduling 3 days in advance in order to match firm loads to available project resources and substitute purchases for any hourly deficits. Hourly changes to preschedules have been restricted by the lack of system flexibility. The burden to adjust to changes in real-time load has shifted from the contractors' use of their SLCA/IP resources to the contractors' alternate resources. A majority of these other resources are thermal and have higher costs in their use.

After Western receives the contractors' advance firm schedules, project generation is patterned hourly to optimize system capacity. During times of surplus generation, the surplus is scheduled when the energy reaches its greatest value. In times of hourly deficiencies, unit capacity is scheduled over system peaks to the maximum available, and hourly shortages are met through nonfirm energy purchases.

During periods of normal operations, there were no hourly deficiencies due to restricted flows from Glen Canyon. System energy shortages were supplied through nonfirm purchases scheduled in equal amounts across all hours, divided into onpeak and offpeak periods. Hourly peaks were covered with available project capacity.

Under interim operations, Western must determine when the system peak loads will occur and purchase nonfirm energy to cover shortages during specific hours, requiring advance scheduling of both project generation and nonfirm purchases. Due to the very narrow ramping restrictions at Glen Canyon, offpeak generation has been increased and energy, normally purchased offpeak when generation was low, is purchased during higher priced onpeak periods.

Interim release conditions have forced scheduling and dispatch personnel to monitor projected water releases and hourly generation levels very carefully.

With interim release conditions, Glen Canyon Dam Powerplant must operate within very specific daily fluctuation limits. Peaking capacity required to serve firm load obligations unavailable at Glen Canyon must be obtained from other project resources. These resources have daily water limitations which must be maintained. Any large deviations from anticipated generation levels which may occur on a real-time basis could affect prescheduling for several days. To avoid this, a very comprehensive set of interim release guidelines have been developed for dispatchers to use when running the power system during real-time operations. One individual is solely devoted to coordinate prescheduling with dispatch. Not surprisingly, this new set of procedures brought on by Interim Flow restrictions complicate "normal" Glen Canyon operations.

B. Power Scheduling and Real-Time Operations

1. Power Scheduling and Purchases for December 1992

December water releases from Glen Canyon totaled 693,000 acre feet (A.F.) The weekday generation pattern was prescheduled at approximately 8,300 cfs (298 MW) during onpeak hours ramping up to a maximum of 14,000 cfs (502 MW) during onpeak hours for a majority of the month. This followed the daily maximum fluctuation restriction of 6,000 cfs (215 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

December's weather was moderate at the beginning of the month then turning cold for the last week of the month. The cold weather and unplanned unit outages caused the economy energy market to tighten towards the end of December. Because firming energy purchases were obtained either through Western's long-term (or 6 month) winter season contractual agreements, the weather and unit outages did not have an appreciable effect on energy prices.

The Power Control staff encountered problems coordinating Flaming Gorge winter releases with the U.S. Fish and Wildlife Service (F&WS). Flaming Gorge generation was restricted to 800 cfs (25 MW) of generation for endangered fish research; however, the "Final Biological Opinion", submitted November 28, 1992 did not address winter flows. It was difficult to obtain co-operation from F&WS when Western requested to increase flows at Flaming Gorge. This was a problem because Western encountered "a tight resource situation." After consulting with the F&WS, Western decided not to risk breaking up the ice cap on the Green River, providing the F&WS with a baseline of "low flat flows" for their research. In lieu of ramping up Flaming Gorge, Western committed to purchase energy to avoid a high flow on the Green River. However, this verbal agreement did not cover system emergencies.

The Aspinall Units were the only units available for load-following requirements for December. This generation was left unscheduled for Western dispatchers to use (real time) in order to respond to unanticipated system problems.

2. Power Scheduling and Purchases for January 1993

Actual January water releases from Glen Canyon totaled 797,000 A.F. The weekday generation pattern was prescheduled at approximately 9,250 cfs (329 MW) during offpeak hours ramping up to a maximum of 17,250 cfs (613 MW) during onpeak hours for the month. This followed the maximum daily fluctuation limit of 8,000 cfs per day (284 MW); weekend releases were adjusted downward to follow reduced loads.

January's weather was frigid and stormy with cold temperatures pushing the economy energy market prices into the mid-30 mill/KWh range (i.e. The Secretary's Report, January 14, 1993 reported a high onpeak purchase of 38 mill/KWh). The Navajo and Laramie Power Station units dropped off for 2 weeks. When these events are coupled with Bonneville Power Administration (BPA) purchases, it forced Power Marketing into purchasing higher priced energy for about 50 MW/hr. Western's firm loads increased towards the middle of the month. Glen Canyon releases were increased within ramping restrictions to accommodate the change to reach the monthly target release level. As the weather warmed up near the end of January, prices stabilized to 24 mill/KWh (The Secretary's Report, January 28, 1993).

Flaming Gorge generation was limited to 800 cfs (25 MW) for January. Because generation from the Aspinall Units was not pre-scheduled, this allowed Western's dispatchers some system flexibility. Hourly generation from Morrow Point and Blue Mesa was limited to approximately 300-400 MWh daily due to reduced water releases.

3. Power Scheduling and Purchases for February 1993

Water releases from Glen Canyon powerplant totaled 646,000 A.F. for February. Daily fluctuation rate was limited to 6,000 cfs. The weekday generation pattern was prescheduled at approximately 8,500 cfs (301 MW) during offpeak hours ramping up to approximately 14,500 cfs (513 MW) during onpeak hours for a daily generation fluctuation limit of 213 MW. Weekend releases were adjusted downward to follow reduced weekend loads.

The economy energy market was tight during the first week in February due to two units going off-line, affecting two contract purchase sources. The Montrose Power Control Staff was able to pick up additional resources from other contractors which prevented a rise in energy prices. In late February, Winter season purchase agreements, with Tucson Electric Power Company, (TEPCO) was disrupted for 3 days due to unit problems. However, energy prices were unaffected due to the availability of energy from other sources.

Flaming Gorge generation was limited to 800 cfs (25 MW) for February. Aspinall generation remained unscheduled to give Western dispatchers' some flexibility.

4. Scheduling Concerns for April 1993 through September 1993

April begins the 1993 Summer Season. With increases in the availability of water from the Aspinall Units, firm purchase requirements will be minimal. Generation from the Aspinall Units will be (practically) base-loaded providing no system flexibility if problems arise; however, Flaming Gorge could provide assistance if necessary. Morrow Point Unit No. 2 will begin uprating tests in April, which will reduce operating capacity by 73 MW.

May and June will be difficult to schedule due to the high Spring releases scheduled to take place from Flaming Gorge and the Aspinall Units. Because of the uncertainty of when these high releases will take place, it was difficult to coordinate firm purchase requirements. June will be critical because energy import needs will be high due to low Glen Canyon releases. It is difficult to estimate when these high Spring releases will occur.

There could be operational problems during May and June if all Flaming Gorge and Aspinall Units are base loaded with no flexibility to respond to system distress. Contract purchases in June are short because of the uncertainty of high releases. "If the (economy energy) market gets tight, prices could jump through the roof", according to the Montrose Power Control Staff.

The period from July through September is anticipated to look good for Power Control Operations, because Glen Canyon generation will be high and all firm purchase requirements will have been arranged. All Aspinall Units are expected to be available allowing for some system response capability. In addition, Flaming Gorge resources will be available, albeit limited.

IV. ANALYSIS OF RAMPING EVENTS

This study was made to analyze hourly ramping rates which appeared to deviate from interim flow criteria. This research was facilitated by reviewing operational records and logs kept during the study period, December 1, 1992, through February 28, 1993.

The operational records and logs are contained within the packet Glen Canyon Dam Interim Flows—Glen Canyon Power Plant Operations, for December 1992 through February 1993 and provide specific explanations for each ramping event.

Each page within the packet contains (1) a strip chart of real-time Glen Canyon Dam operations during the ramping event, (2) a graph of the USGS Lees Ferry Gauge showing river elevation during the ramping event, (3) a graph of hourly integrated Glen Canyon Dam generation during the ramping event, and (4) a brief written explanation of the ramping event.

For the study period, 51 instances of deviations were found. Most of the conditions were caused by more than one factor: for example, control area regulation and CRSP resource availability; therefore, multiple variations can be explained by one anomaly.

The following table summarizes the causes and frequency of the 51 deviations:

Primary Cause(s) of Deviation	Number Of Instances	Percent Of Events
Control Area Regulation	14/51	27
CRSP Resource Availability	4/51	8
Aspinall Operations	1/51	2
Morrow Point Operations Limitations	5/51	10
Imports/Exports Different than Preschedule	17/51	33
Computer Trouble/time Error Correction	1/51	2
Other	9/51	18

V. EXPENSES

Beginning with the April 1993 "Glen Canyon Dam Interim Operations" report, Power Marketing, Salt Lake City Area Office made improvements in the method of calculating the monthly net expense. With the previous method, the base case scenario simulated hourly Glen Canyon generation with the peak-shaving algorithm. The peak-shaving algorithm basically follows the firm load by minimizing distance between the load and the generation for any particular hour.

However, it does not reflect the economic factors which are considered during normal operations when Western tries to minimize purchases during onpeak hours and maximizes purchases during offpeak hours. The peak-shaving algorithm neglects consideration of this objective.

The refinement addresses the dynamics of hydropower operations by making all offpeak hours (hours ending 2400 through 0700) constrained to minimum releases Glen Canyon generation plus a "buffer" component which reflects approximately the 5 percent cumulative frequency levels of historic offpeak hourly generation/power release (1,929 cfs/winter, 3,714 cfs/summer).

For onpeak hours, the peak-shaving algorithm is applied to generate the hourly Glen Canyon generation. With this new option, the Glen Canyon generation during offpeak hours is decreased and purchases during these hours are increased. Conversely, during onpeak hours, the Glen Canyon generation has increased, purchases have decreased, and surplus sales have increased.

Also, in previous analyses for the base case (without interim release restrictions), all deficits are assumed to be met by purchases. In the change case (with interim release restrictions), all deficits are met by both purchases and interchange received. With the refinement, the deficits are assumed to be met by purchases in the base case and in the change case.

It is believed that these refinements to the methodology for base case expense calculation more accurately describe normal operations without interim releases, and for the treatment of offpeak generation, are consistent with methods in using the peak-shaving algorithm for large system modeling used by the GCES Power Resources Committee.

A recalculation of the net expense valuation utilizing the old and new methods for WY 1993, October and November, is provided in the table below. Power Marketing is anticipating to have all WY 1992 monthly net expenses recalculated using the refined method for the next Glen Canyon Dam Interim Operations report.

A Comparison of Net Expense Analysis with Refinements to Existing Methodology		
MONTH/YEAR	NET EXPENSE (GLEN CANYON DAM INTERIM OPERATIONS REPORT JANUARY 1993)	NET EXPENSE (GLEN CANYON DAM INTERIM OPERATIONS REPORT APRIL 1993)
October 1992	$191,188	$336,662
November 1992	$137,853	$375,274

A. Net Expense

The net expense of interim releases for December 1992, January, and February 1993 are summarized below:

	Net Expense
December 1992	$471,698
January 1993	$466,684
February 1993	$380,314

Attached are Tables 1, 2, and 3 summarizing the net expense analysis for December 1992, January 1993, and February 1993.

B. Purchases

A comparison of Base Case purchases to Actual purchases are summarized below:

Months	Base Case Purchases	Actual Purchases	Differences
December 1992	163,234 MWh	163,332 MWh	<98> MWh
January 1993	118,172 MWh	117,374 MWh	798 MWh
February 1993	116,647 MWh	115,384 MWh	1,263 MWh

As shown, December Base Case purchases are 98 MWh lower than actual purchases due to a low surplus of 11 MWh (offpeak 0 MWh, onpeak 11 MWh). January and February have the highest Base Case purchases. This is due to a shift in deficits from onpeak to offpeak hours in the base case, resulting in higher purchases during offpeak hours.

C. Economy Energy Sales

For the exception of December 1992, economy (nonfirm) energy sales were less than projected for Base Case conditions. Revenues foregone are estimated below:

	Energy Sales		
Months	Base Case	Actual	Revenues Foregone
December 1992	$245	$2,404	$2,159
January 1993	$28,273	$10,437	($17,836)
February 1993	$50,468	$21,063	($29,405)

D. Average Purchase Prices—Base Case

The average monthly purchase price estimates are derived from the actual nonfirm energy purchase prices. With the help of the Power Control staff, some of the higher purchase prices for December, January and February that are associated directly with interim release constraints, were excluded. An adjusted weighted average of remaining purchase amounts and prices are rendered to calculate the base case offpeak and onpeak purchase prices.

Average Base Case monthly purchase prices are estimated as follows:

Months	Offpeak	Onpeak
December 1992	$15.95/MWh	$23.28/MWh
January 1993	$16.59/MWh	$23.67/MWh
February 1993	$16.30/MWh	$22.76/MWh

E. Purchase Price—Actual

Average actual monthly purchase prices from all sources are as follows:

Months	Offpeak	Onpeak
December 1992	$16.38/MWh	$23.28/MWh
January 1993	$16.59/MWh	$23.71/MWh
February 1993	$16.68/MWh	$22.80/MWh

F. Economy Energy Sales Prices—Base Case

The sales price for the Base Case is determined with the help of the Montrose Power Control Staff. The estimate of economy energy sales prices involve three steps:

1. Identification of the range of market prices through review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, as reflected in Western's Weekly Reports to the Secretary.

2. Review of the actual monthly economy energy sales summary and, with the help of the Power Control staff, identify those sales directly associated with interim release constraints.

3. Assumption of expected sales price based on then-current market conditions for that portion of sales identified in step 2.

   In most instances Western would have had the flexibility of making all or most of the nonfirm sales during the time the market has been high. For all 3 months, the economy energy sales prices under the base case is the same as the actual sales price, reflecting no forced sales within this period.

Average monthly economy energy sales prices for Base Case conditions are as follows:

Months	Prices
December 1992	\$22.26/MWh
January 1993	\$22.35/MWh
February 1993	\$23.30/MWh

G. Economy Energy Sales Prices—Actual

The actual consummated average monthly economy energy sales prices are as follows:

Months	Prices
December 1992	\$22.26/MWh
January 1993	\$22.35/MWh
February 1993	\$23.30/MWh

Table 1
Glen Canyon Dam Interim Release
for December 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	506,748 MWh	Firm Load & Losses:	506,748 MWh
GC Generation:	300,640 MWh	GC Generation:	300,640 MWh
Other CRSP/IP Generation:	42,884 MWh	Other CRSP/IP Generation:	42,884 MWh
Total Generation:	343,524 MWh	Total Generation:	343,524 MWh
Deficits:	163,234 MWh	Deficits:	163,332 MWh
Off Peak:	108,976 MWh	Off Peak:	47,423 MWh
On Peak:	54,258 MWh	On Peak:	115,909 MWh
Purchases:	163,234 MWh	Purchases:	163,332 MWh
Off Peak:	108,976 MWh	Off Peak:	47,423 MWh
On Peak:	54,258 MWh	On Peak:	115,909 MWh
Surplus:	11 MWh	Surplus:	108 MWh
Off Peak:	0 MWh	Off Peak:	60 MWh
On Peak:	11 MWh	On Peak:	48 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$15.95/MWh	Off Peak:	$16.38/MWh
On Peak:	$23.28/MWh	On Peak:	$23.28/MWh
Sales Price:	$22.26/MWh	Sales Price:	$22.26/MWh
Purchase Expense:	$3,001,293	Purchase Expense:	$3,475,150
Off Peak:	$1,738,167	Off Peak:	$776,789
On Peak:	$1,263,126	On Peak:	$2,698,362
Surplus Sales:	$245	Surplus Sales:	$2,404
Base Case Expense:	$3,001,049	Change Case Expense:	$3,472,746

Total Net Expense for December 1992 .... $471,698

Table 2
Glen Canyon Dam Interim Release
for January 1993
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	507,602 MWh	Firm Load & Losses:	507,602 MWh
GC Generation:	343,810 MWh	GC Generation:	343,810 MWh
Other CRSP/IP Generation:	46,885 MWh	Other CRSP/IP Generation:	46,885 MWh
Total Generation:	390,695 MWh	Total Generation:	390,695 MWh
Deficits:	118,172 MWh	Deficits:	117,374 MWh
Off Peak:	101,451 MWh	Off Peak:	35,847 MWh
On Peak:	16,721 MWh	On Peak:	81,527 MWh
Purchases:	118,172 MWh	Purchases:	117,374 MWh
Off Peak:	101,451 MWh	Off Peak:	35,847 MWh
On Peak:	16,721 MWh	On Peak:	81,527 MWh
Surplus:	1,265 MWh	Surplus:	467 MWh
Off Peak:	555 MWh	Off Peak:	315 MWh
On Peak:	710 MWh	On Peak:	152 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.59/MWh	Off Peak:	$16.59/MWh
On Peak:	$23.67/MWh	On Peak:	$23.71/MWh
Sales Price:	$22.35/MWh	Sales Price:	$22.35/MWh
Purchase Expense:	$2,078,858	Purchase Expense:	$2,527,707
Off Peak:	$1,683,072	Off Peak:	$594,702
On Peak:	$395,786	On Peak:	$1,933,005
Surplus Sales:	$28,273	Surplus Sales:	$10,437
Base Case Expense:	$2,050,585	Change Case Expense:	$2,517,269

Total Net Expense for January 1993 .... $466,684

April 1993

Table 3
Glen Canyon Dam Interim Release
for February 1993
Net Expense Analysis

Base Case (Without Interim Releases)		Actual (With Interim Release)	
Firm Load & Losses:	465,653 MWh	Firm Load & Losses:	465,653 MWh
GC Generation:	277,622 MWh	GC Generation:	277,622 MWh
Other CRSP/IP Generation:	73,551 MWh	Other CRSP/IP Generation:	73,551 MWh
Total Generation:	351,173 MWh	Total Generation:	351,173 MWh
Deficits:	116,647 MWh	Deficits:	115,384 MWh
Off Peak:	92,144 MWh	Off Peak:	35,982 MWh
On Peak:	24,503 MWh	On Peak:	79,402 MWh
Purchases:	116,647 MWh	Purchases:	115,384 MWh
Off Peak:	92,144 MWh	Off Peak:	35,982 MWh
On Peak:	24,503 MWh	On Peak:	79,402 MWh
Surplus:	2,166 MWh	Surplus:	904 MWh
Off Peak:	218 MWh	Off Peak:	698 MWh
On Peak:	1,948 MWh	On Peak:	206 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.30/MWh	Off Peak:	$16.68/MWh
On Peak:	$22.76/MWh	On Peak:	$22.80 MWh
Sales Price:	$23.30/MWh	Sales Price:	$23.30/MWh
Purchase Expense:	$2,059,635	Purchase Expense:	$2,410,545
Off Peak:	$1,501,947	Off Peak:	$600,180
On Peak:	$ 557,688	On Peak:	$1,810,366
Surplus Sales:	$ 50,468	Surplus Sales:	$21,063
Base Case Expense:	$2,009,168	Change Case Expense:	$2,389,482

Total Net Expense for February 1993 .... $380,314