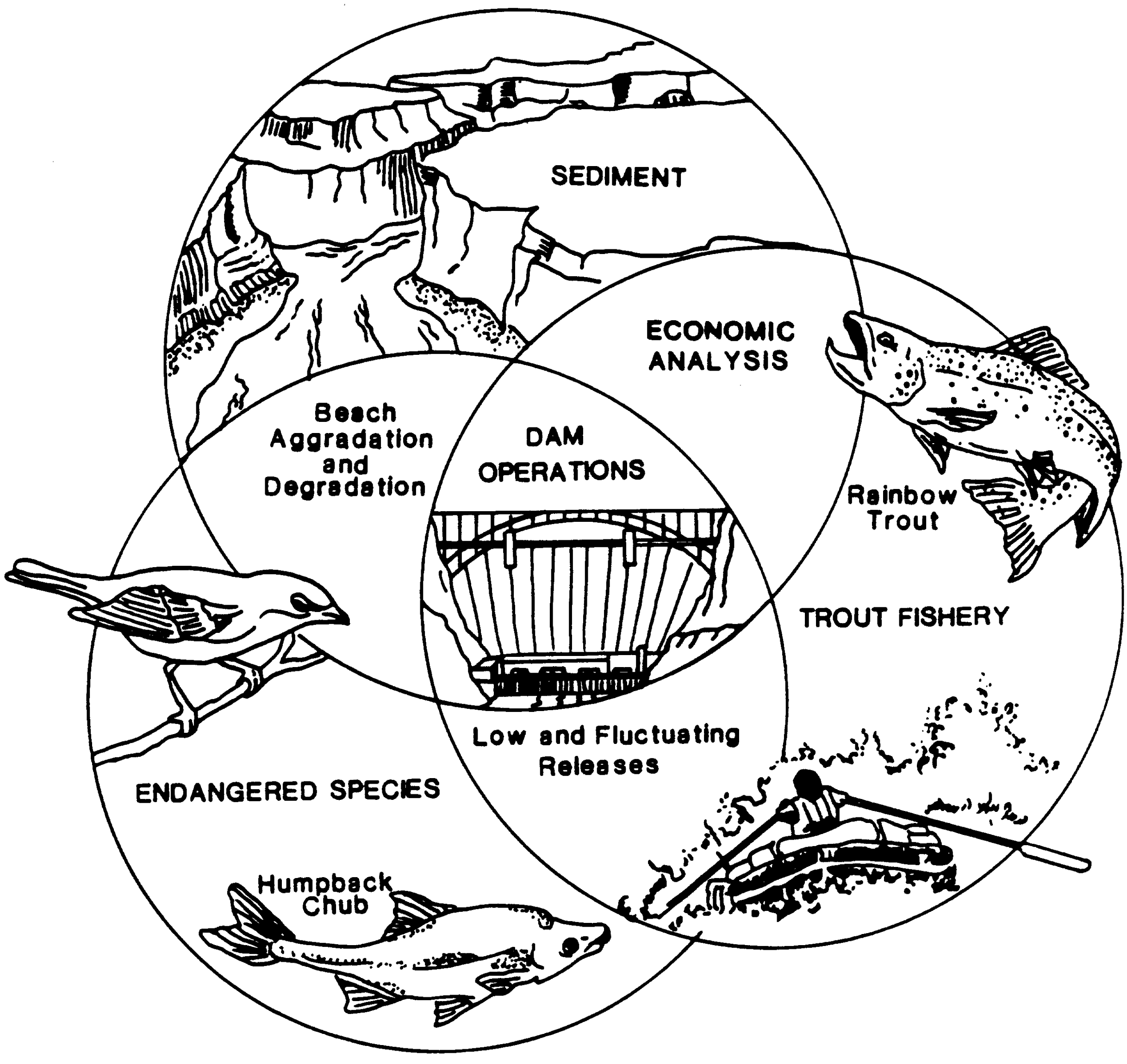
GLEN CANYON DAM

MONITORING OF INTERIM OPERATING CRITERIA



JANUARY - APRIL 1992

BUREAU OF RECLAMATIION

GLEN CANYON DAM

MONITORING
OF
INTERIM OPERATING CRITERIA

January through April 1992

Bureau of Reclamation

This document summarizes the monitoring of Interim Operating Criteria for Glen Canyon Dam for January through April 1992. This is the second report of monitoring of operations, the first report having covered August through December 1991. Summaries will be published quarterly throughout the interim operation period.

GENERAL

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

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

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 the 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 FLOWS - January through April 1992

MONITORING OF INTERIM FLOW CRITERIA

The operating criteria parameters are: maximum daily flows, minimum daily flows, daily fluctuation, and ramp rates. Parameters 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 gaging 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 January 1 through April, 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 were met throughout the period (see Attachment A).

The ramping rates were exceeded periodically as a result of system disturbances and regulation responses to power demands. Ramping rates may be exceeded under the criteria for system disturbances, regulation, and other emergency situations to allow for power system operation adjustments. As operators have become more experienced with projecting power system adjustments, the number of times ramping rates are exceeded is being reduced.

Attachment B shows the traces of discharge and river stages for the Lees Ferry and Grand Canyon gaging stations for January through April 1992.

MONITORING OF EXCEPTION CRITERIA

The exception criteria are monitored at Glen Canyon Dam using Reclamation's Supervisory Control and Data Acquisition System. Exception criteria for system regulation, specifically for ramping rates, were utilized frequently in the first few months after interim flows began primarily due to the "learning curve," as operators and dispatchers became familiar with the criteria. But, in the instances when exception criteria were used, the deviations were not reflected in river stage fluctuations at downstream gaging stations because of the short duration of the occurrences (see Attachment B).

Deviations from the ramp rate criteria have occurred periodically, particularly when Glen Canyon Dam is following the power load under system regulation. Such deviations are allowed under the generator regulation exception criteria.

Emergency Exception Criteria. Exception criteria for emergencies were invoked once for a 1-hour duration to fill in a demand which could not be met elsewhere in the power system.

Financial Exception Criteria. To date, financial exception criteria have not been used.

INTERIM FLOW MONITORING PROGRAM - RESOURCES AND RESPONSES

The interim flow monitoring program development is undergoing further development and implementation through the Glen Canyon Environmental Studies (GCES) staff and the cooperating agencies. The program focuses on the evaluation of critical resources 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 monitoring program has been designed utilizing: ongoing GCES research, critical ecosystem elements, and representative ecosystem elements. The program is built around specific elements and is flexible enough to allow for specific resource evaluation.

During development of this program, a limited monitoring effort was accomplished in conjunction with ongoing GCES research. This includes endangered species, seepage sites at beaches, cultural resources, remote camera monitoring, and monthy video flights.

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

Sediment - The interim flows are designed to lessen impacts to sediment resources by reducing the fluctuations in riverflow below Glen Canyon Dam and to allow new channel sediment storage to occur. Overall erosion rates at many beaches in the Grand Canyon have been reduced as a result of interim flows. Many beach areas are experiencing a redistribution of existing sediments.

Marshes have been reestablishing themselves in the canyon after the high flows of 1983-85. Marshes above the 20,000 cfs level are tending to dry out; however, some are being established at lower levels. Selected beaches and sediment movement will be monitored to determine the effectiveness of interim flows.

Endangered Species - The interim flows are designed to stabilize flow levels to enhance habitat in backwaters, side channels, and along channel margins. Interim flows have not been in effect long enough to document specific impacts, but monitoring will continue.

Trout - Three broad categories are being monitored: biological processes, food resources, and physical habitat. While the interim flows have not been in effect long enough to document specific impacts on trout or their food base in the Colorado River, it appears that *Gammarus* are increasing in the Lees Ferry area. Continued monitoring will help to identify changes and trends.

Cultural Resources - These resources, including Spencer Steamboat above Lees Ferry, are being monitored. The interim flows are designed to reduce sediment erosion and therefore reduce erosion of cultural resource sites. Continuous evaluations of the most sensitive locations are planned.

Recreation - Reduced fluctuations and higher minimum flows under the interim flows have provided safer passage for river trips through the Grand Canyon.

Attachments

Attachment A - Glen Canyon Dam Releases
- Integrated Hourly Values - January 1992
- Hourly Ramping Rates (cfs/hour) - January 1992

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

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

- Integrated Hourly Values - April 1992
- Hourly Ramping Rates (CFS/Hour) - April 1992

Attachment B - Gaging Stations
- Lees Ferry - Flow Rate - January 1992
- Lees Ferry - Gage Height - January 1992
- Near Grand Canyon Village - Flow Rate - January 1992
- Near Grand Canyon Village - Gage Height - January 1992

- Lees Ferry - Flow Rate - February 1992
- Lees Ferry - Gage Height - February 1992
- Near Grand Canyon Village - Flow Rate - February 1992
- Near Grand Canyon Village - Gage Height - February 1992

- Lees Ferry - Flow Rate - March 1992
- Lees Ferry - Gage Height - March 1992
- Near Grand Canyon Village - Flow Rate - March 1992
- Near Grand Canyon Village - Gage Height - March 1992

- Lees Ferry - Flow Rate - April 1992
- Lees Ferry - Gage Height - April 1992
- Near Grand Canyon Village - Flow Rate - April 1992
- Near Grand Canyon Village - Gage Height - April 1992

Attachment C - Glen Canyon Dam Interim Operations - January and February 1992 and March and April 1992 - Western Area Power Administration

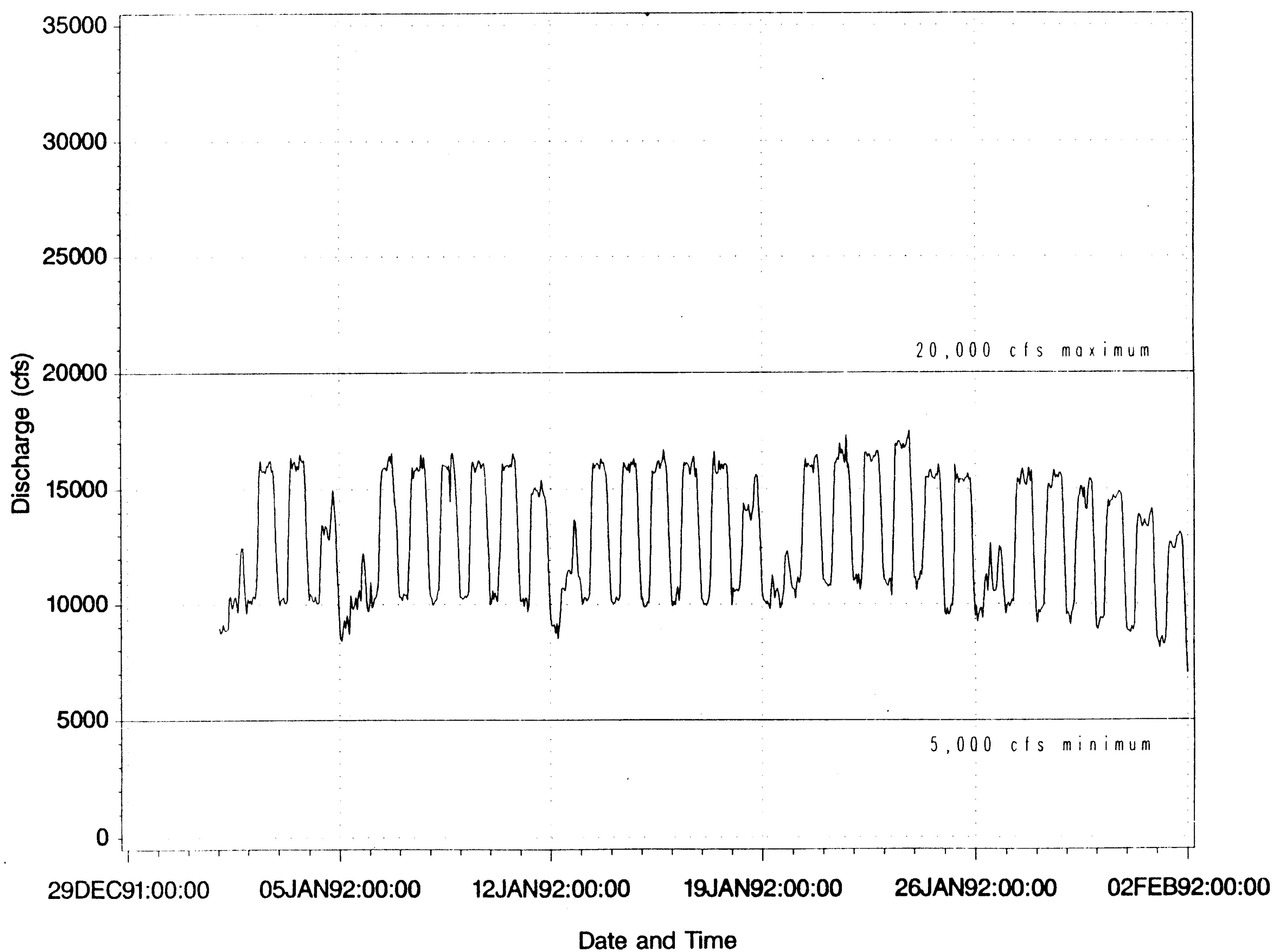
Attachment A

Glen Canyon Dam Releases

Glen Canyon Dam Releases

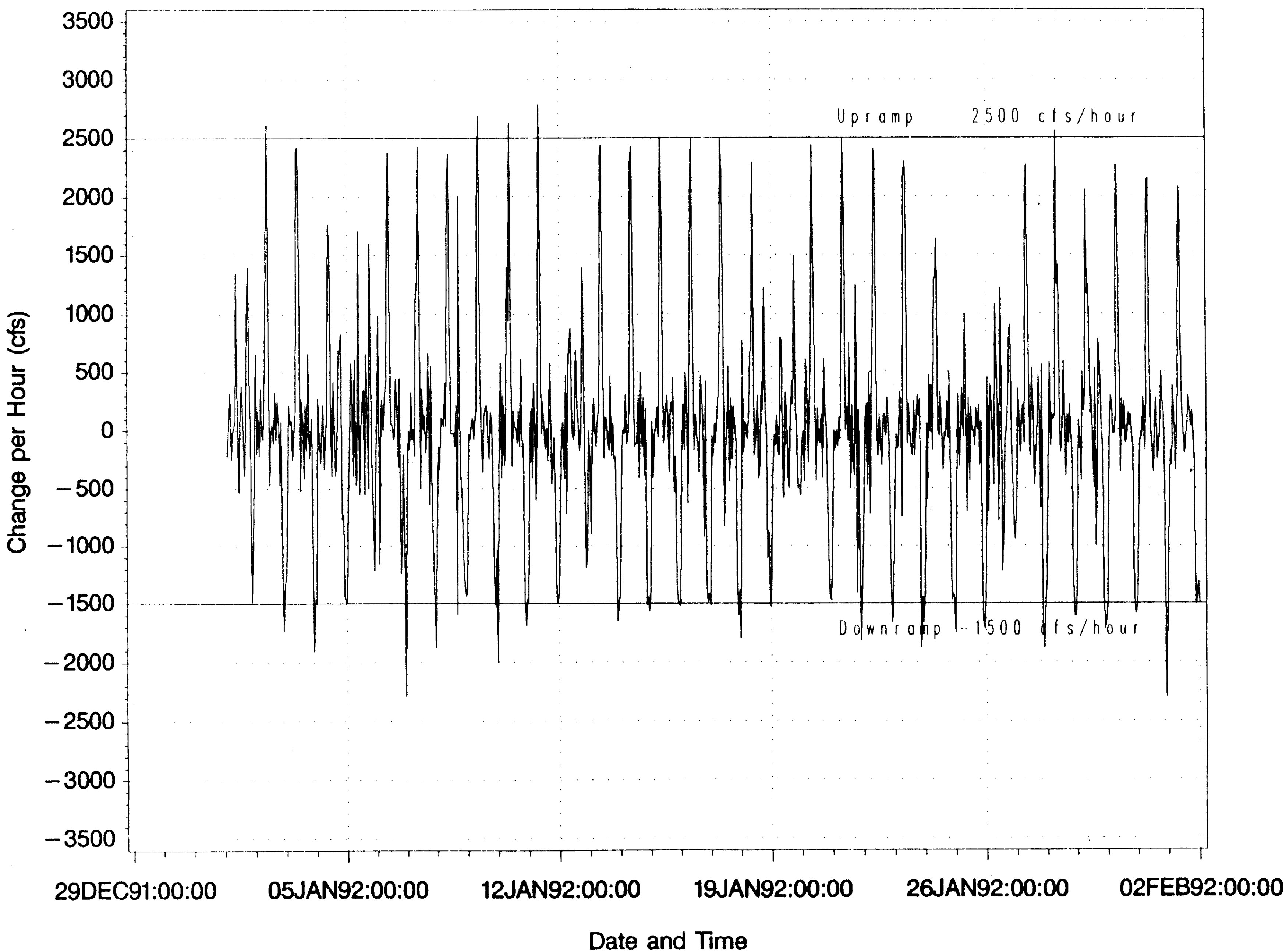
Glen Canyon Dam Releases

Integrated Hourly Values – January 1992



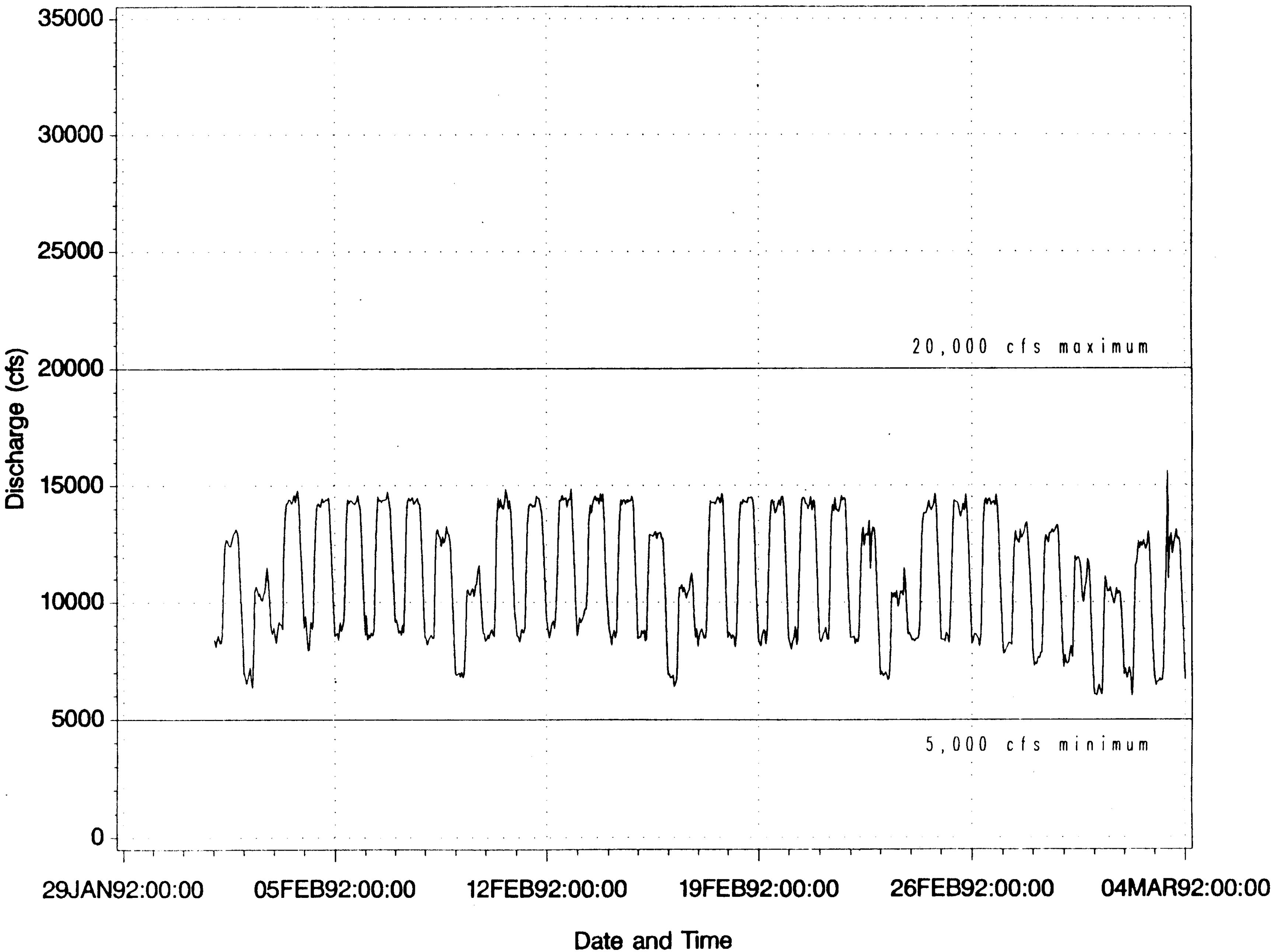
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – January 1992



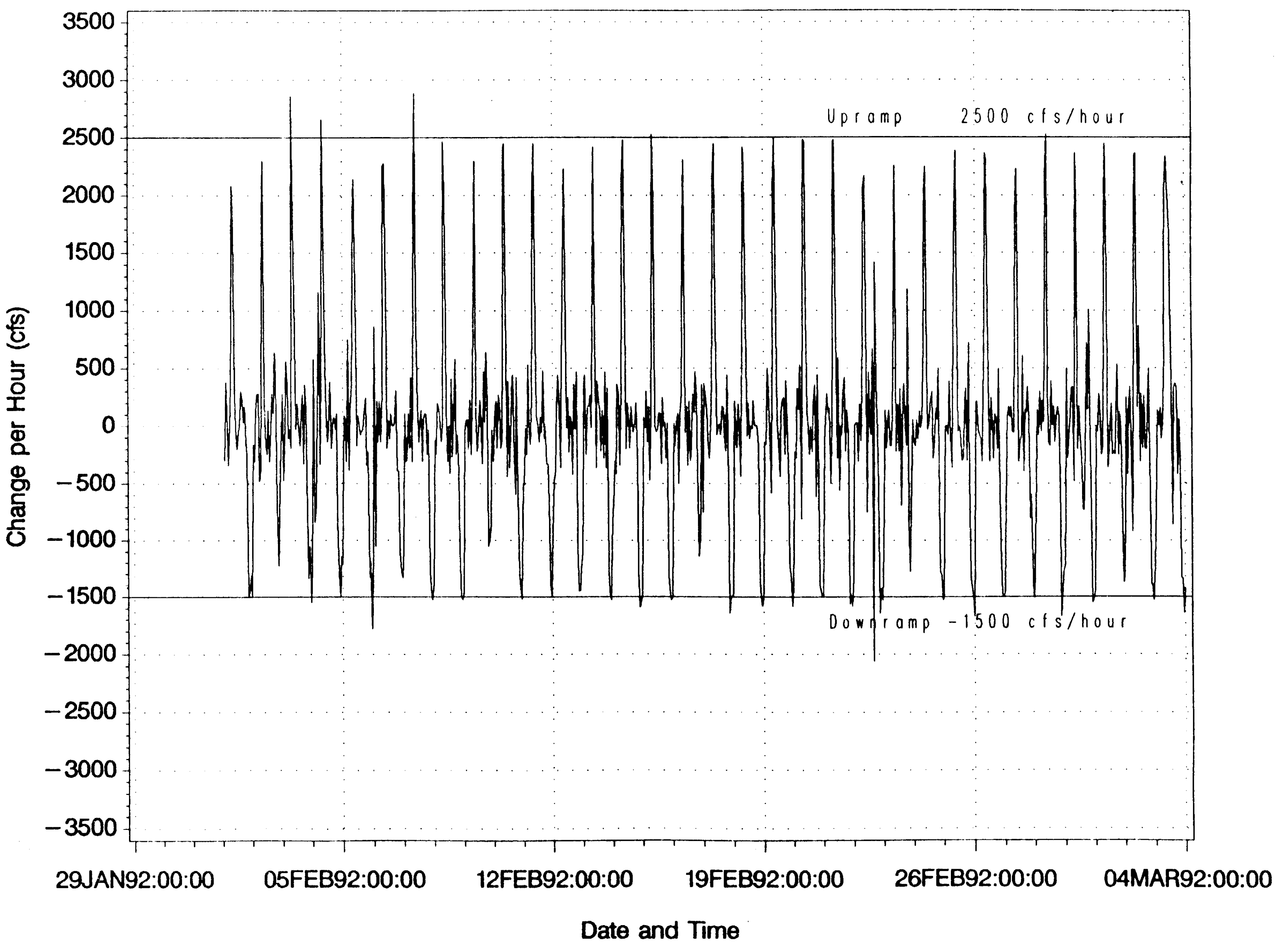
Glen Canyon Dam Releases

Integrated Hourly Values – February 1992



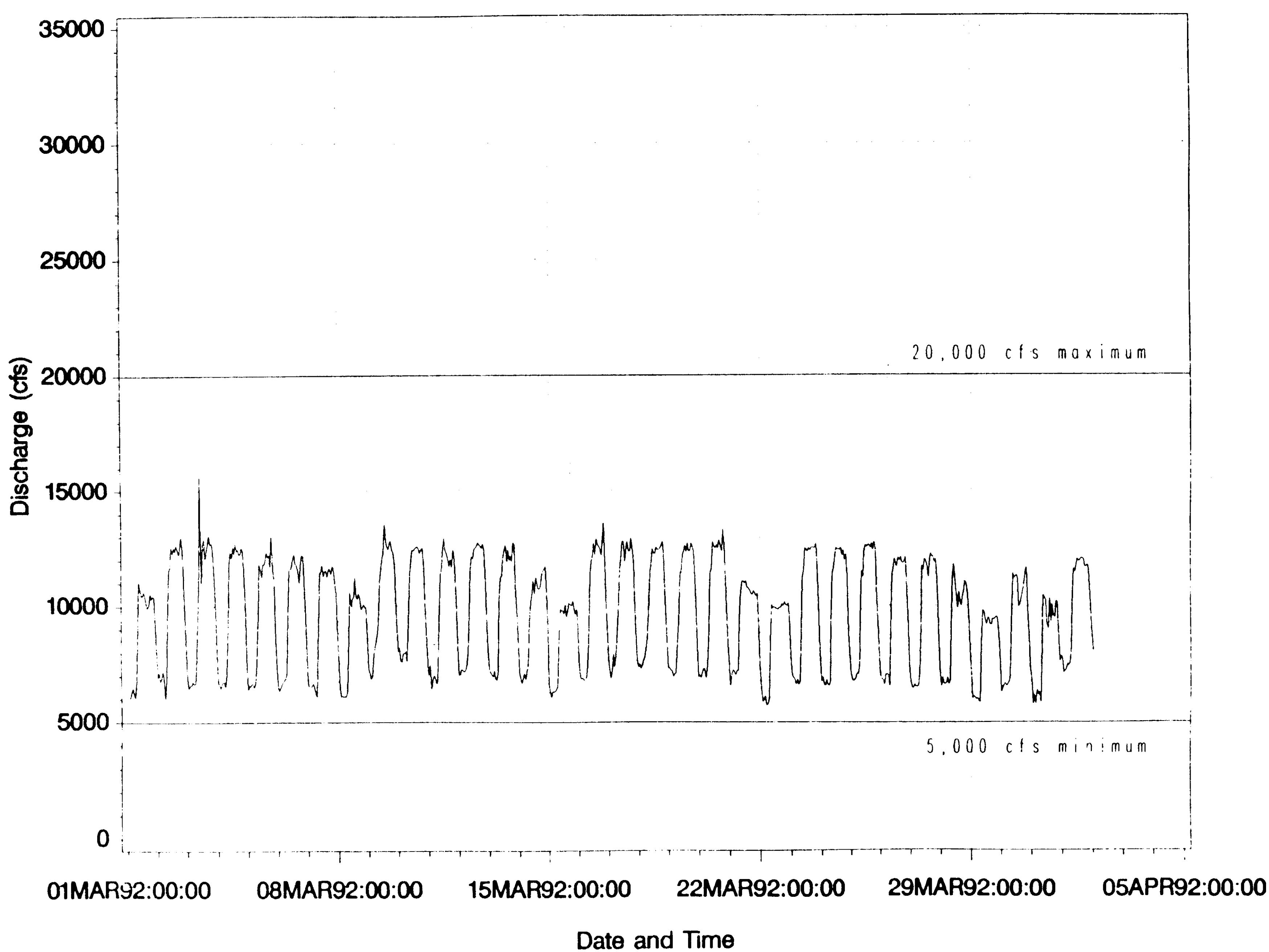
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – February 1992



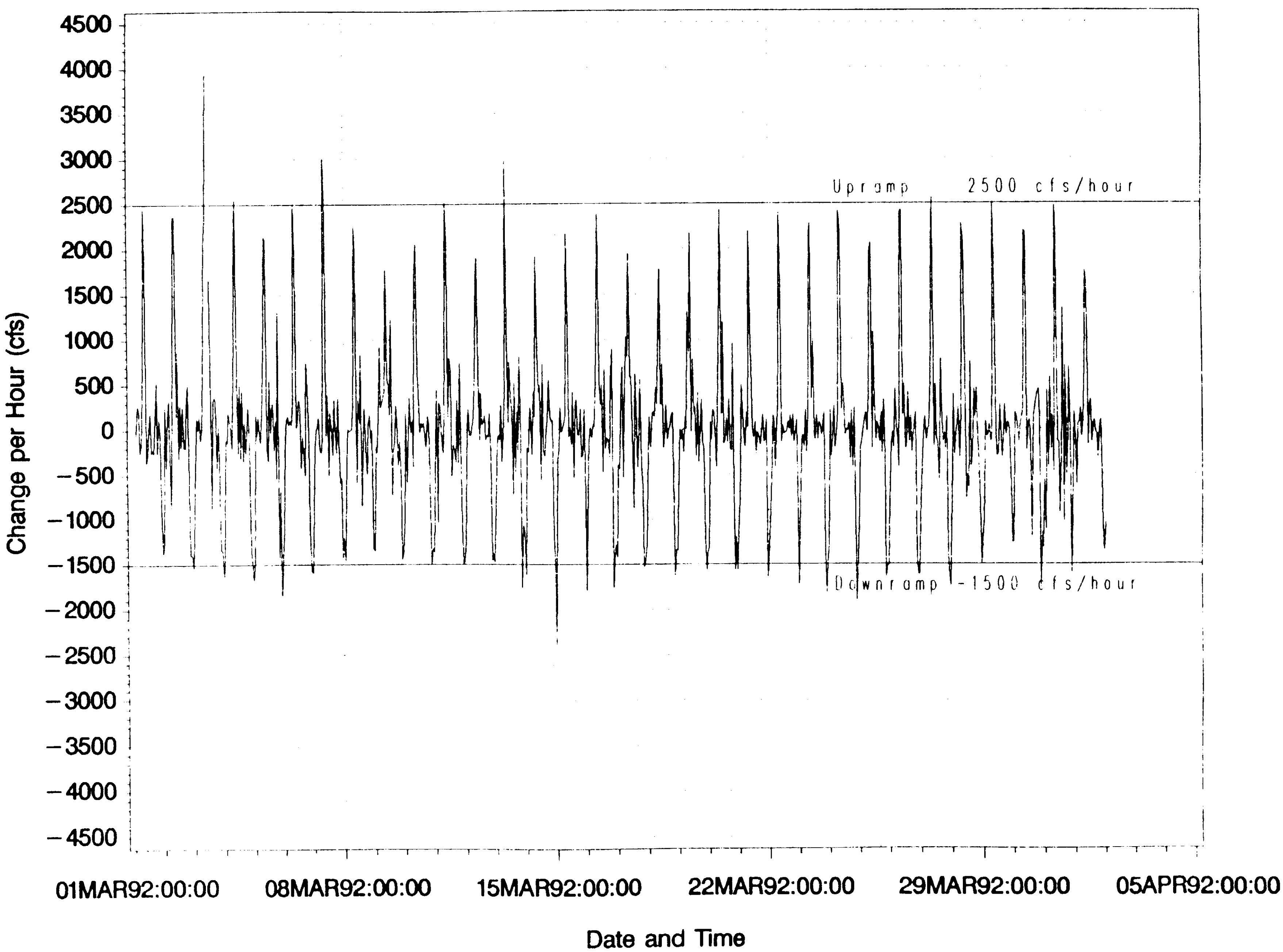
Glen Canyon Dam Releases

Integrated Hourly Values – March 1992



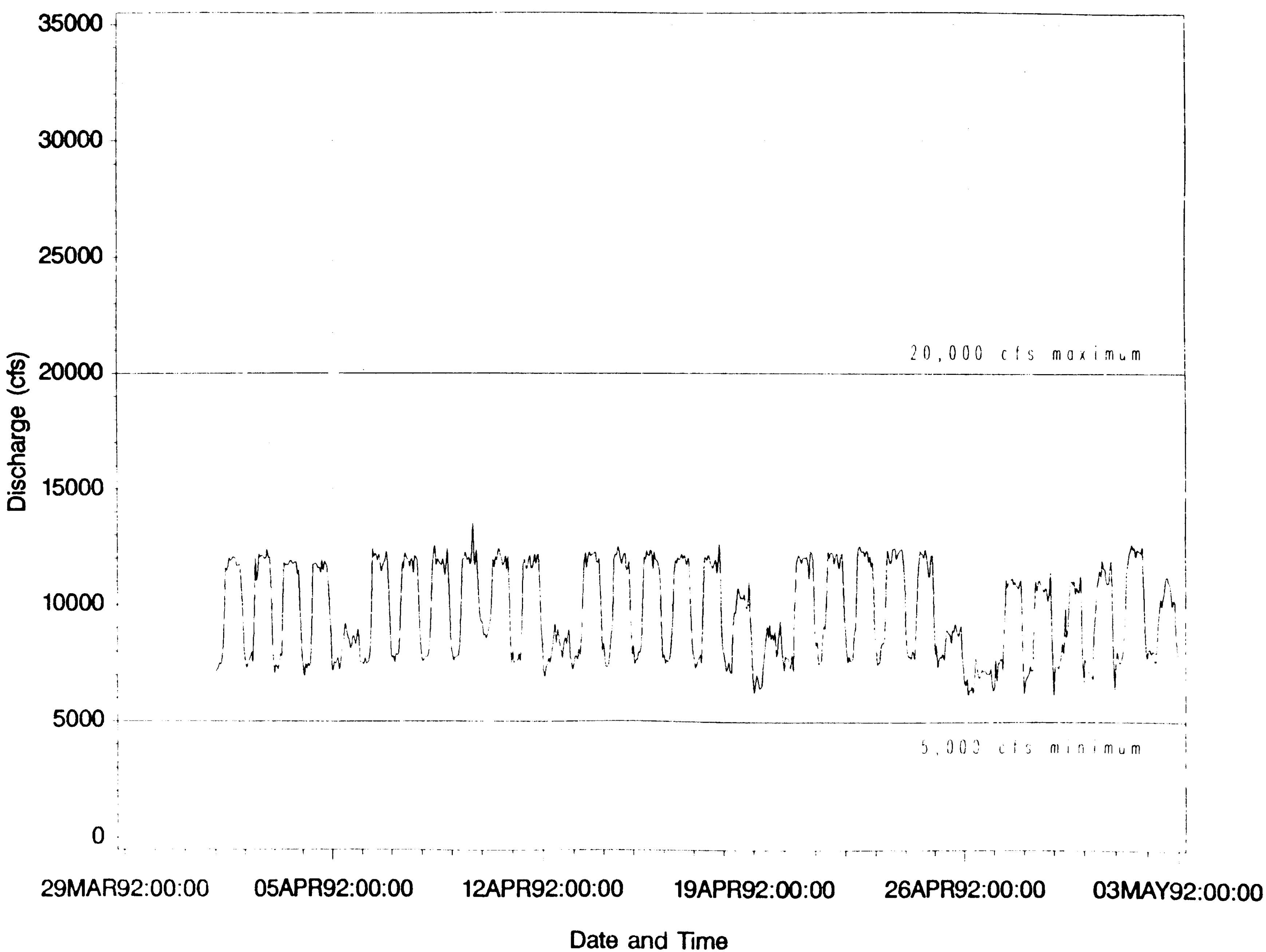
Glen Canyon Dam Releases

Hourly Ramping Rates (cfs/hour) – March 1992



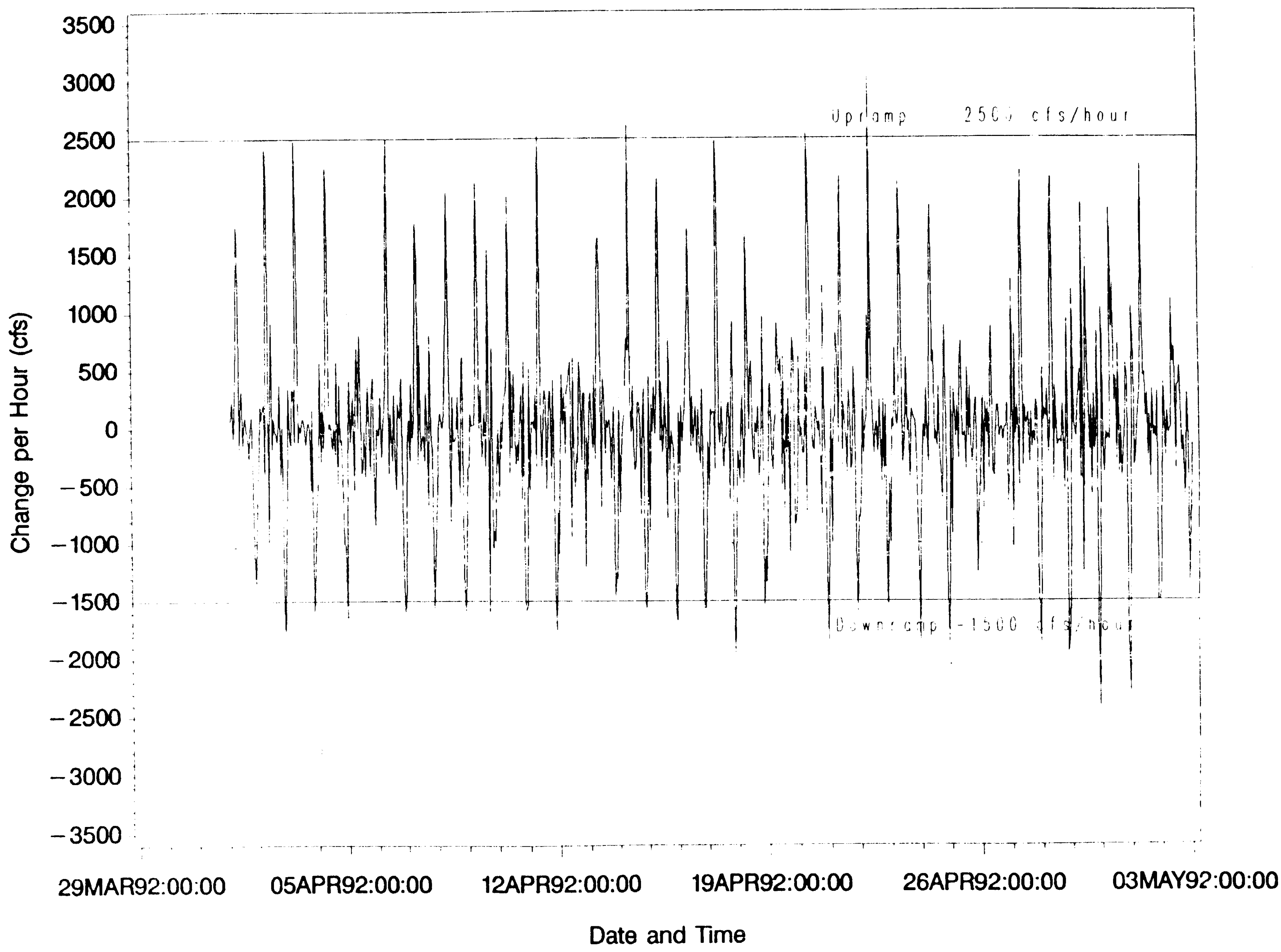
Glen Canyon Dam Releases

Integrated Hourly Values – April 92



Glen Canyon Dam Releases

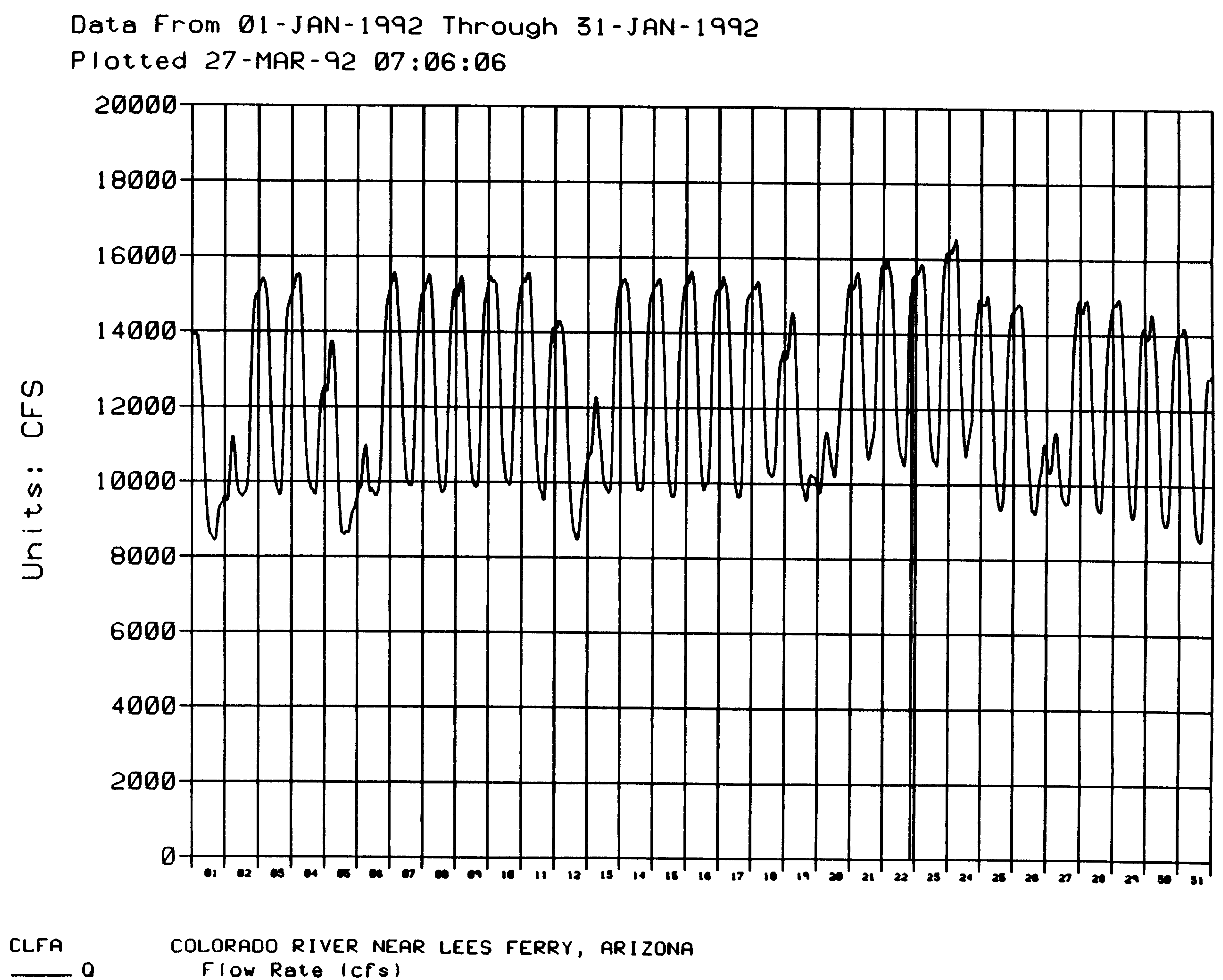
Hourly Ramping Rates (cfs/hour) – ~~February~~ April 1992



Attachment B

Gaging Stations

Gaging Stations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Plotted 27-MAR-92 07:06:06
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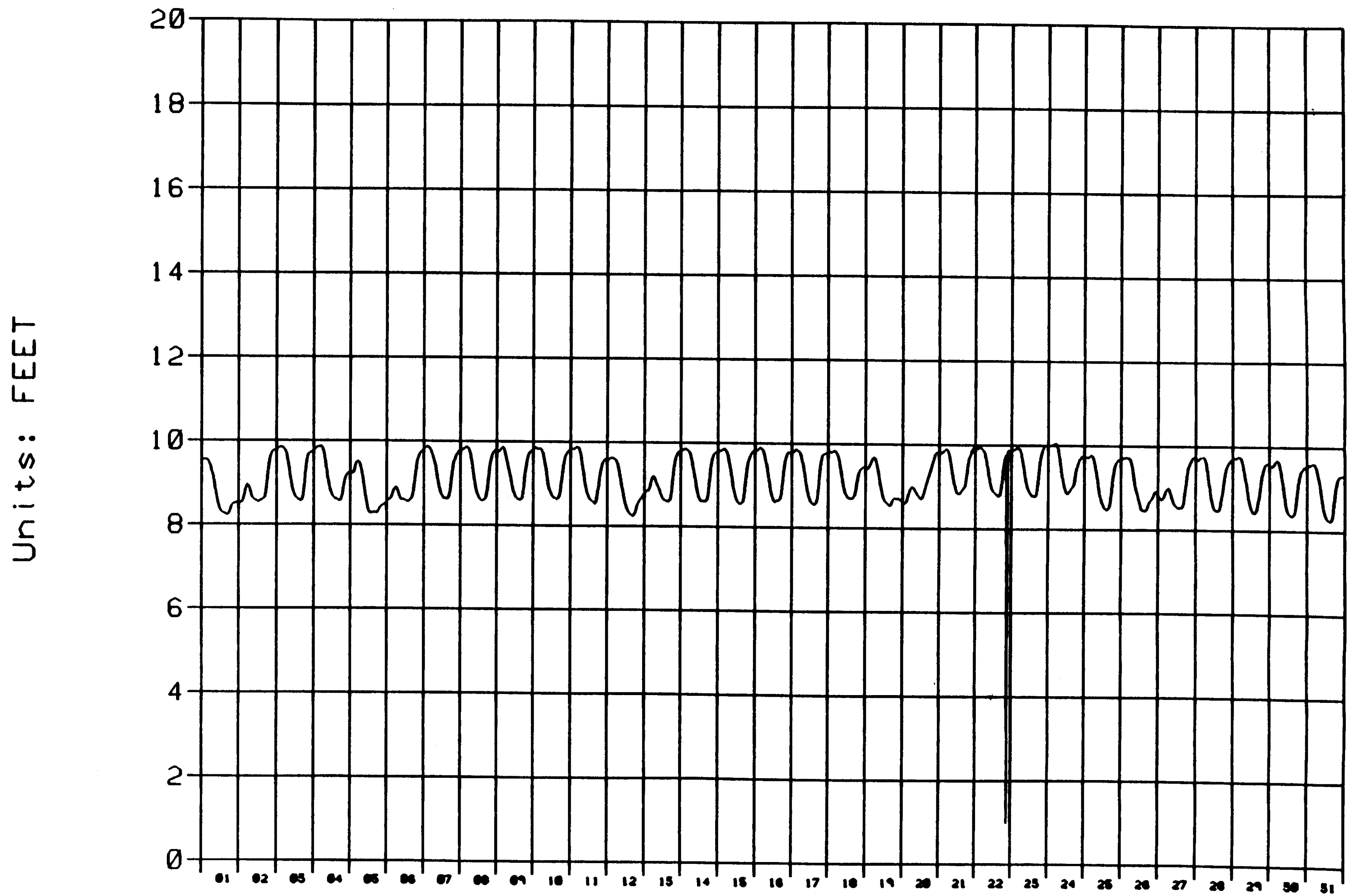
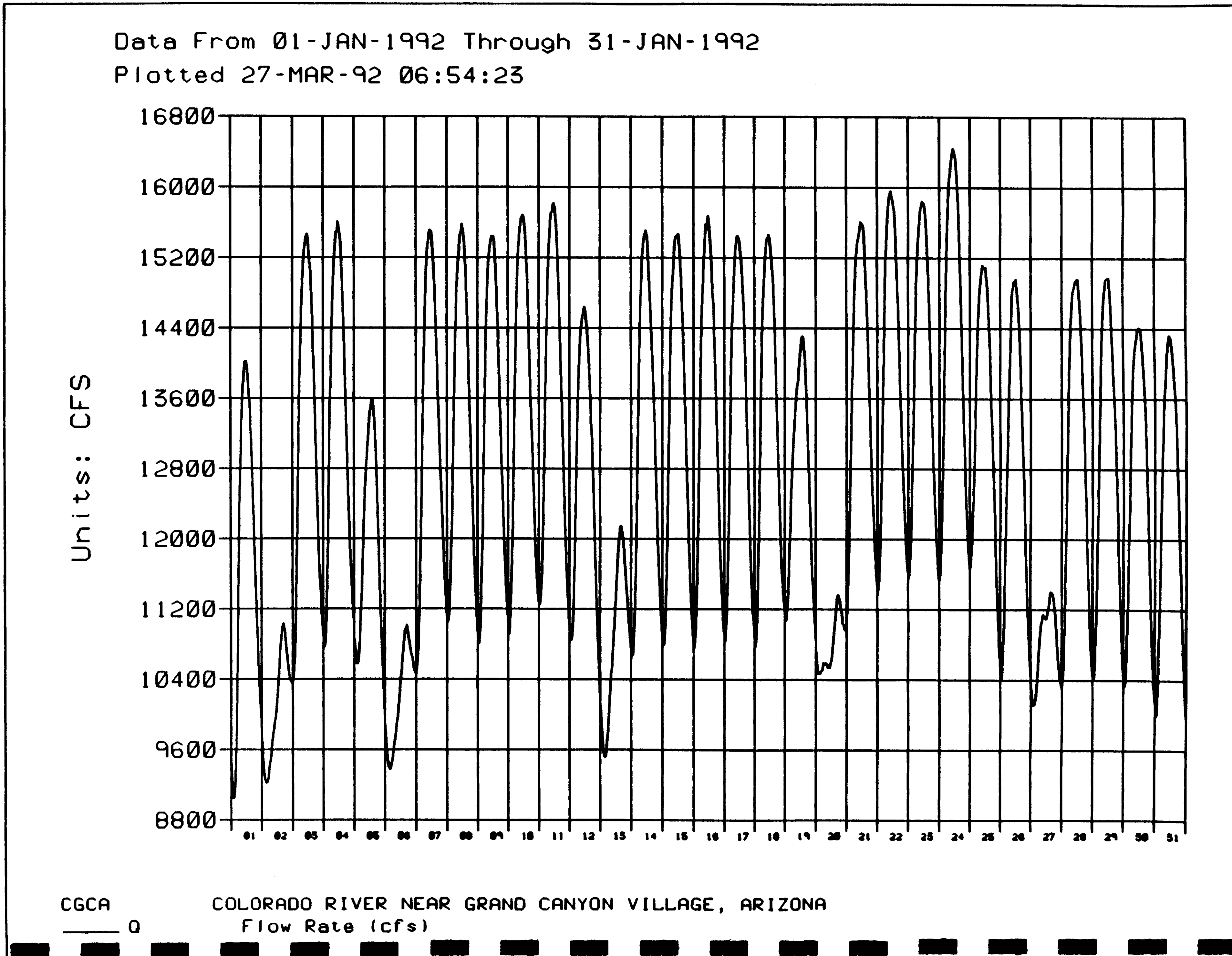
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From 01-JAN-1992 Through 31-JAN-1992
Plotted 27-MAR-92 07:07:45



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



Data From 01-JAN-1992 Through 31-JAN-1992
Plotted 27-MAR-92 06:54:23
Units: CFS
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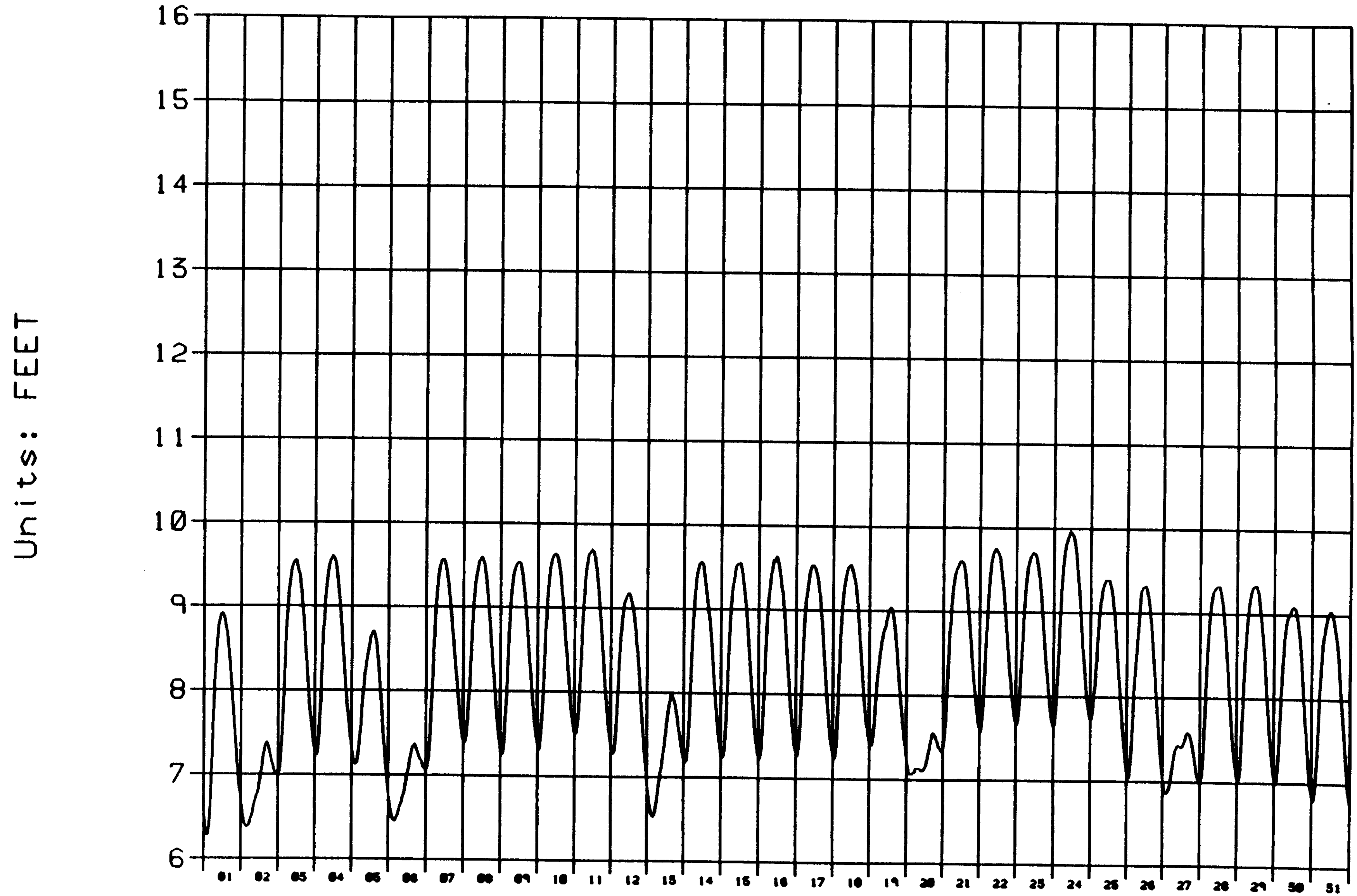
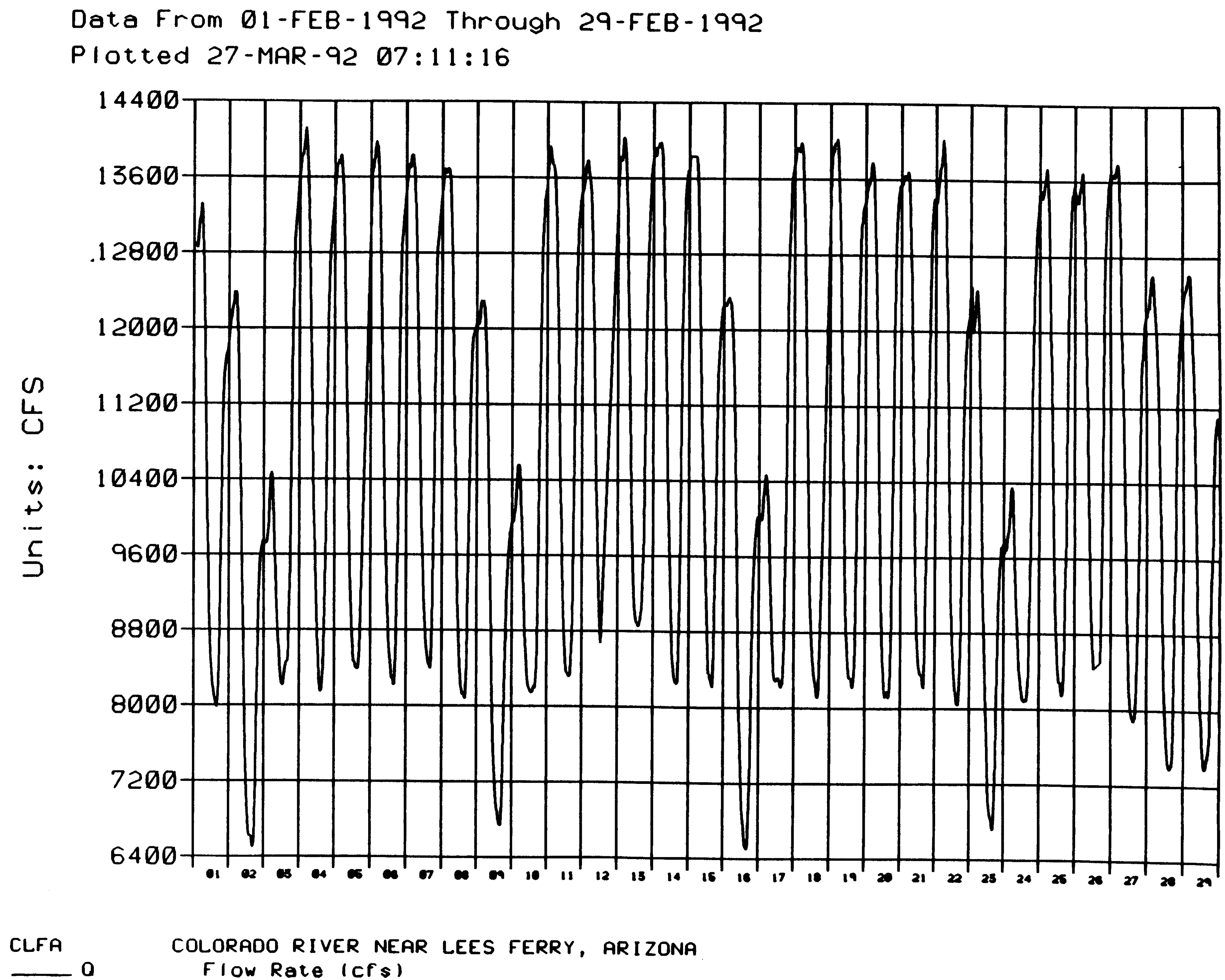
16000
15200
14400
13600
12800
12000
11200
10400
9600
8800
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
CGCA
Q
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-JAN-1992 Through 31-JAN-1992
Plotted 27-MAR-92 06:56:25



CGCA
—— GH

COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Gage Height (feet)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Plotted 27-MAR-92 07:11:16
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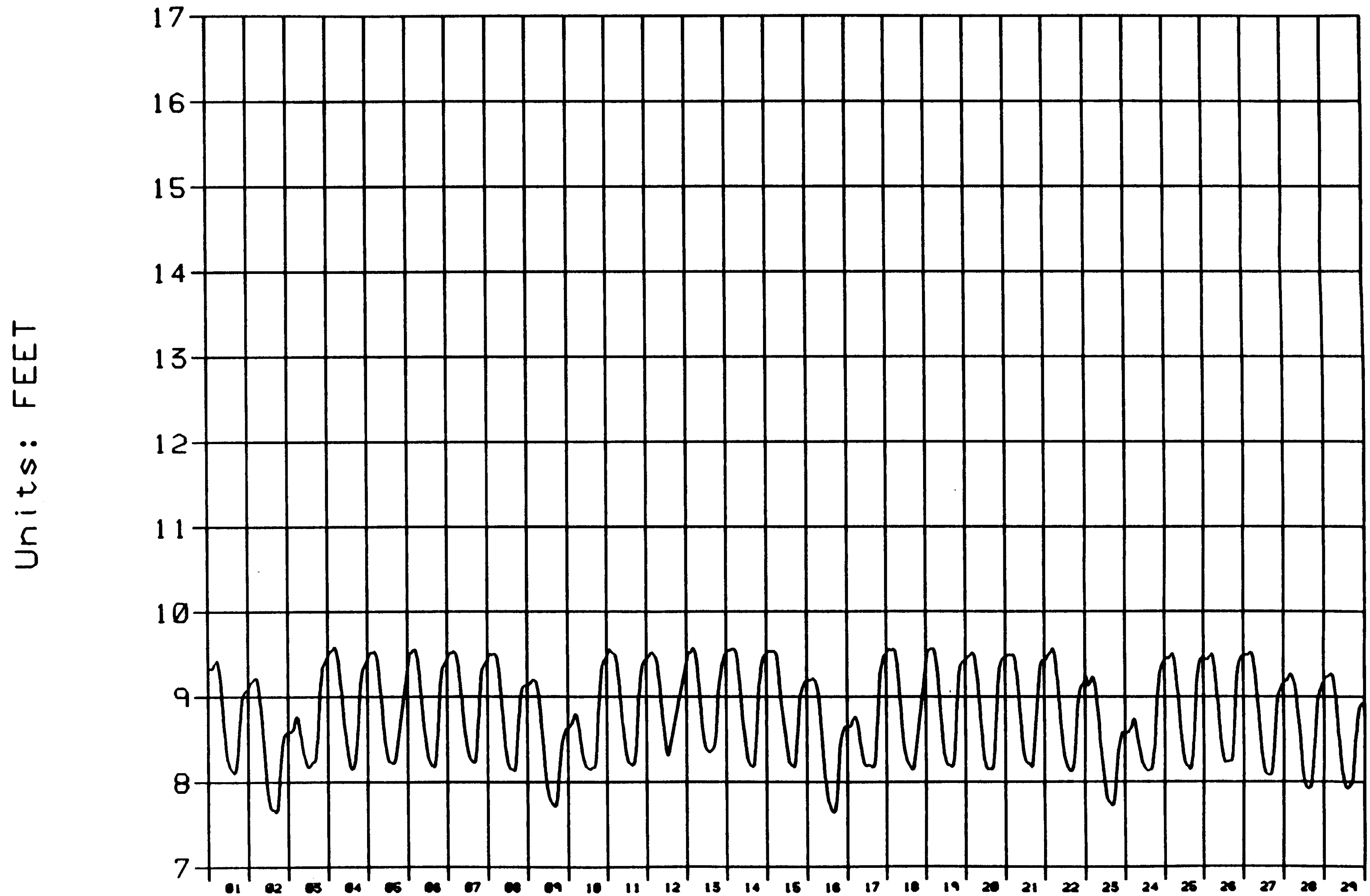
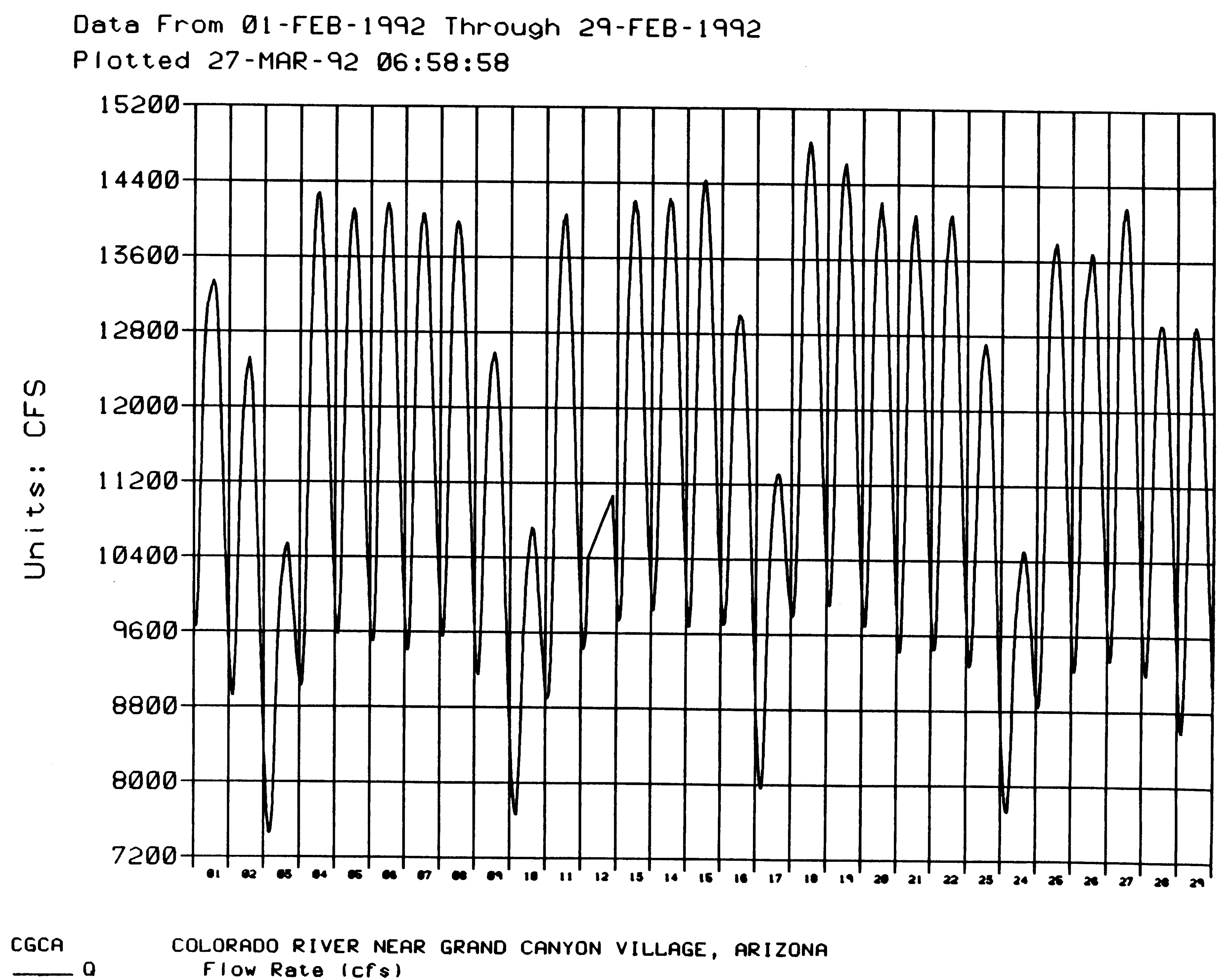
12800
12000
11200
10400
9600
8800
8000
7200
6400
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From 01-FEB-1992 Through 29-FEB-1992
Plotted 27-MAR-92 07:14:03



CLFA
—— GH

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



Data From 01-FEB-1992 Through 29-FEB-1992
Plotted 27-MAR-92 06:58:58
Units: CFS
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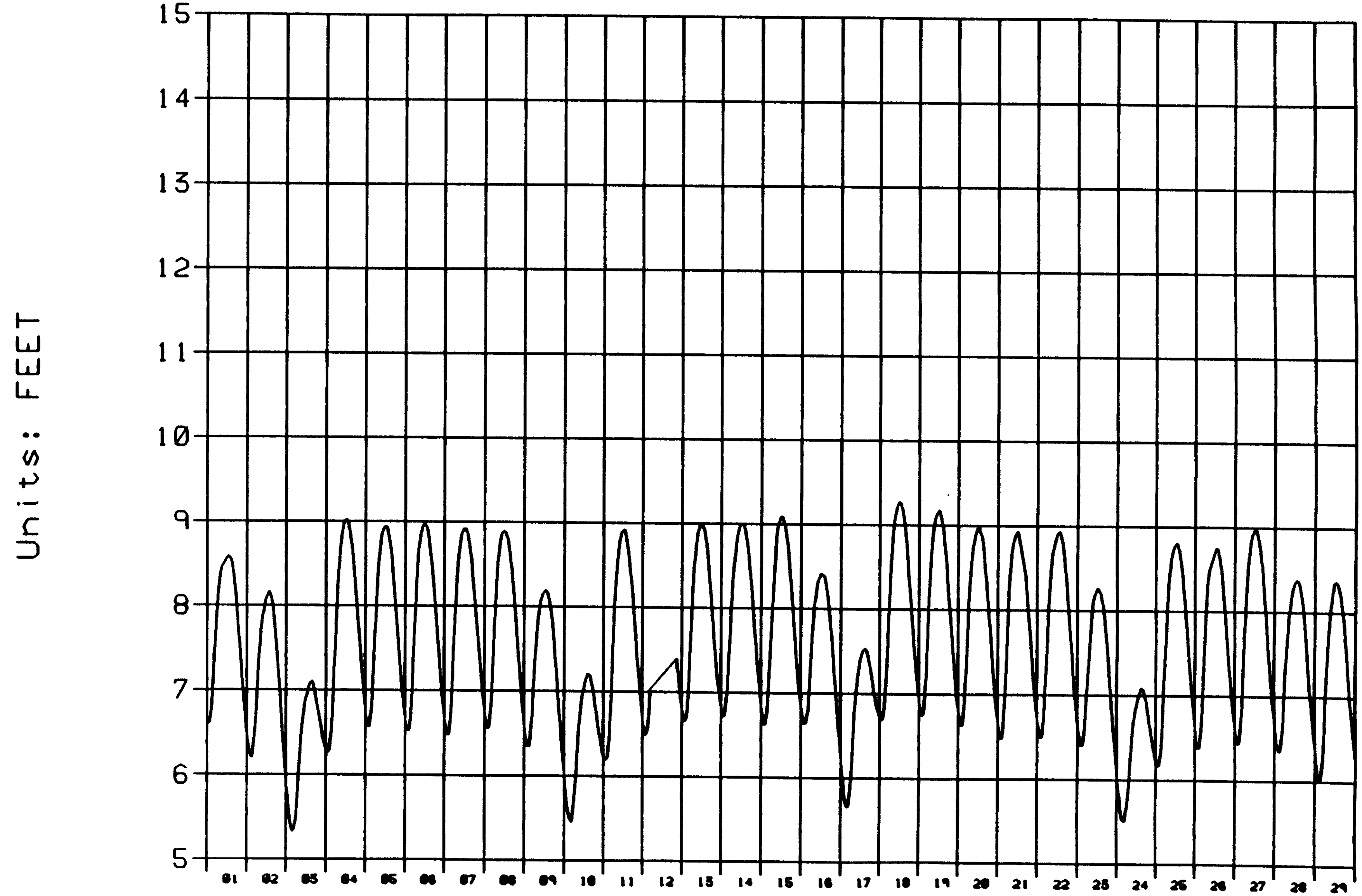
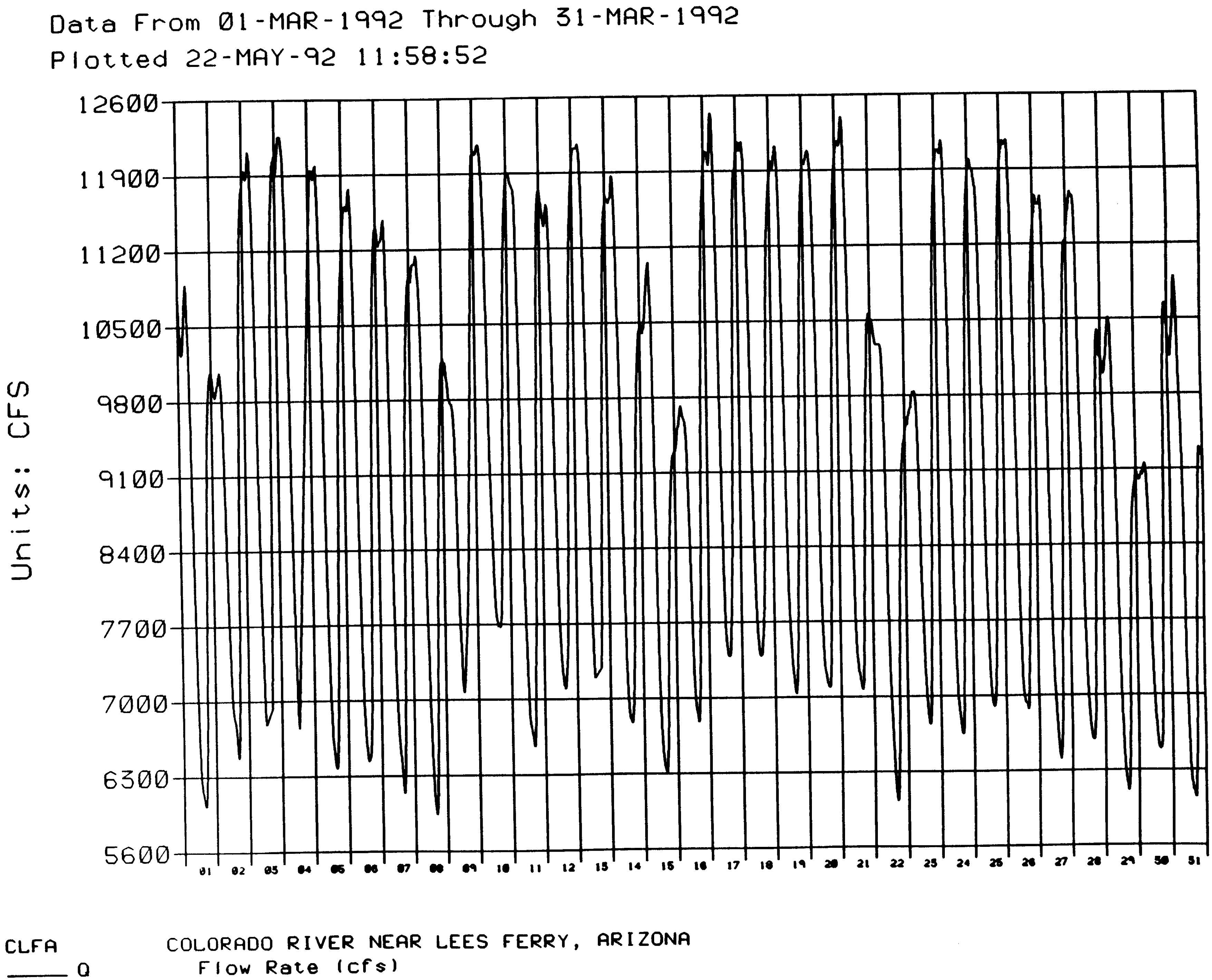
12800
12000
11200
10400
9600
8800
8000
7200
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29
CGCA
Q
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-FEB-1992 Through 29-FEB-1992
Plotted 27-MAR-92 07:00:58



CGCA
—— GH

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


Data From 01-MAR-1992 Through 31-MAR-1992
Plotted 22-MAY-92 11:58:52
Units: CFS
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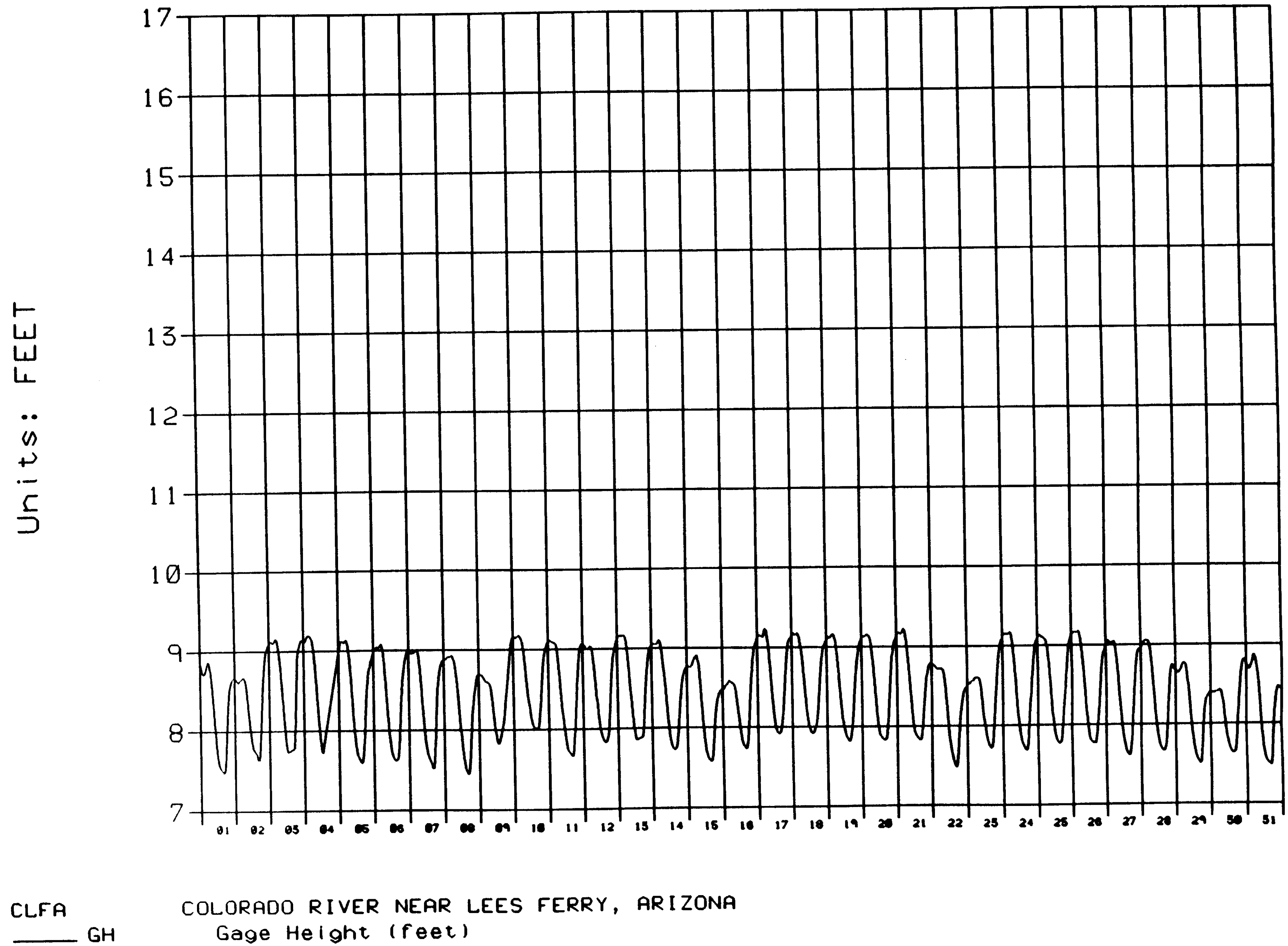
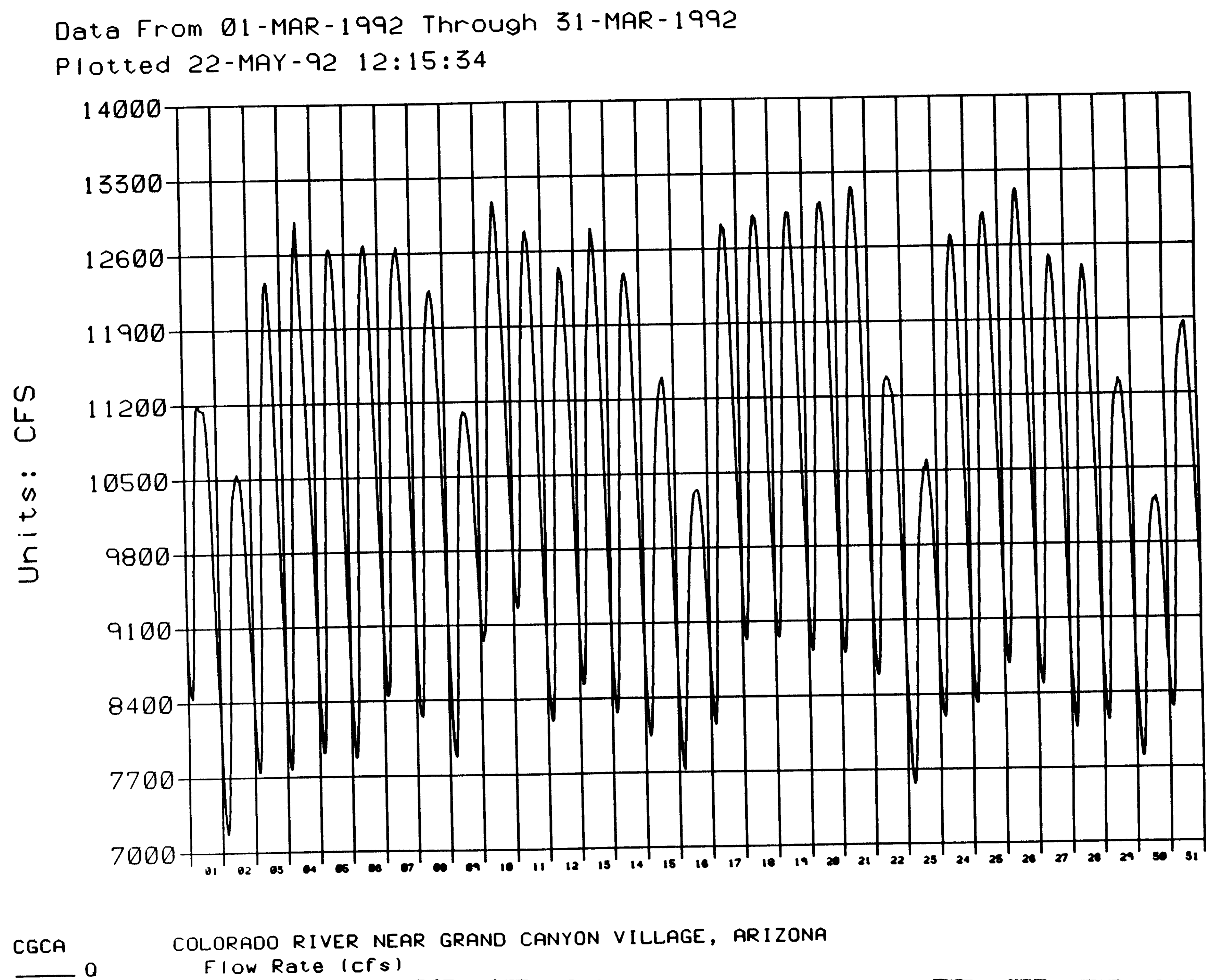
11900
11200
10500
9800
9100
8400
7700
7000
6300
5600
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From 01-MAR-1992 Through 31-MAR-1992
Plotted 22-MAY-92 11:49:51



COLORADO RIVER NEAR LEES FERRY, ARIZONA
Gage Height (feet)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Plotted 22-MAY-92 12:15:34
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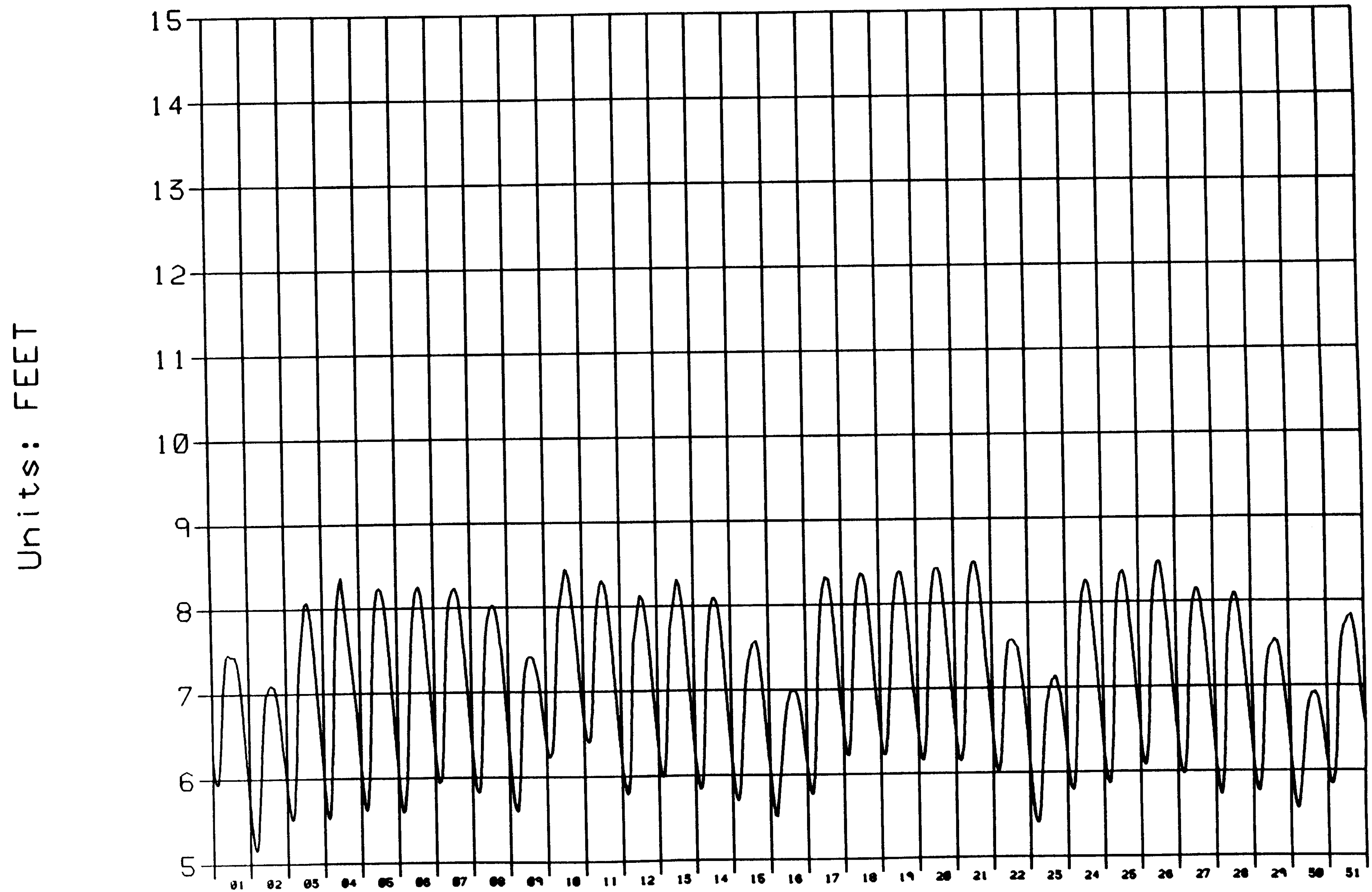
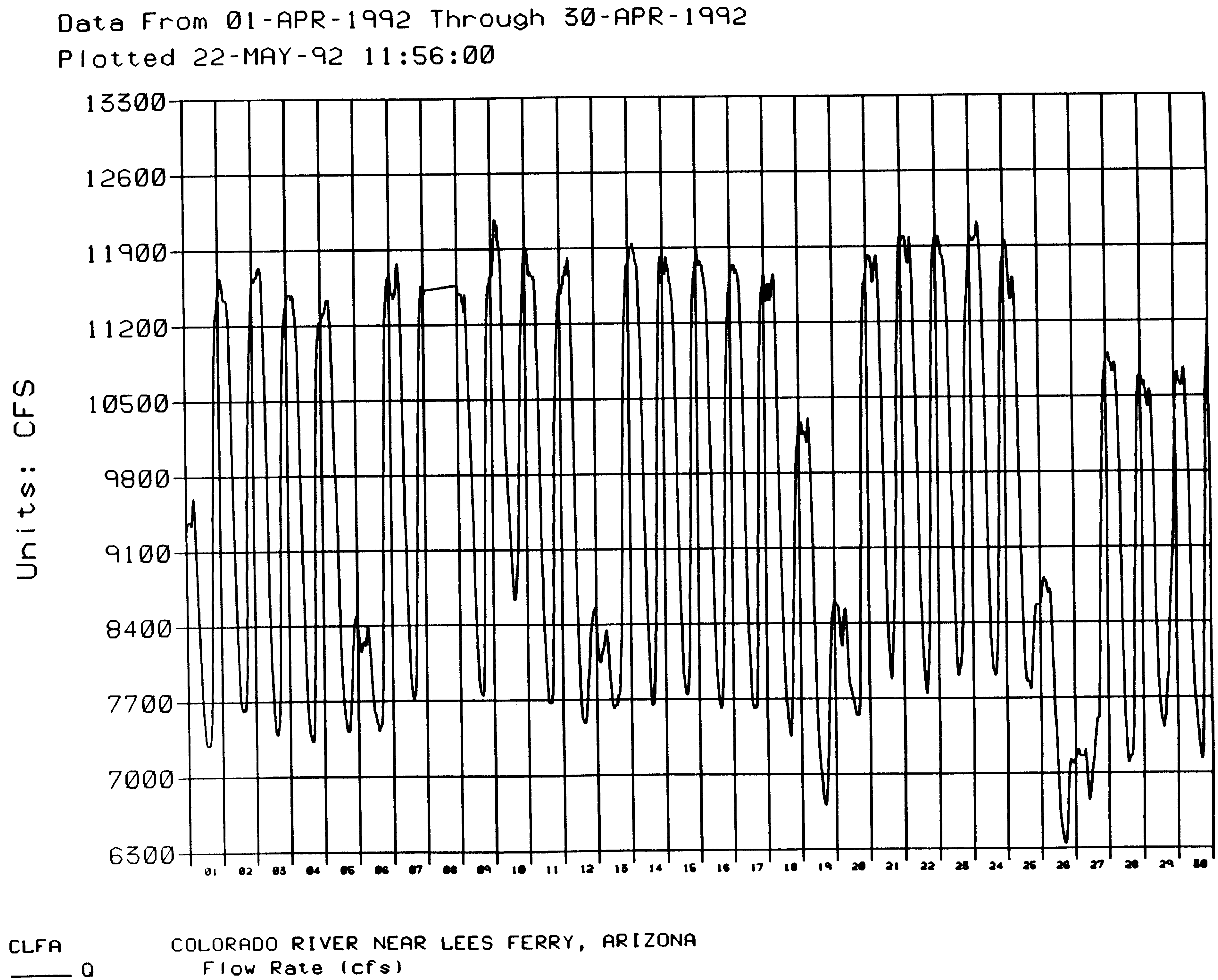
11900
11200
10500
9800
9100
8400
7700
7000
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
CGCA
0
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-MAR-1992 Through 31-MAR-1992
Plotted 22-MAY-92 12:07:05



CGCA
—— GH

COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Gage Height (feet)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Plotted 22-MAY-92 11:56:00
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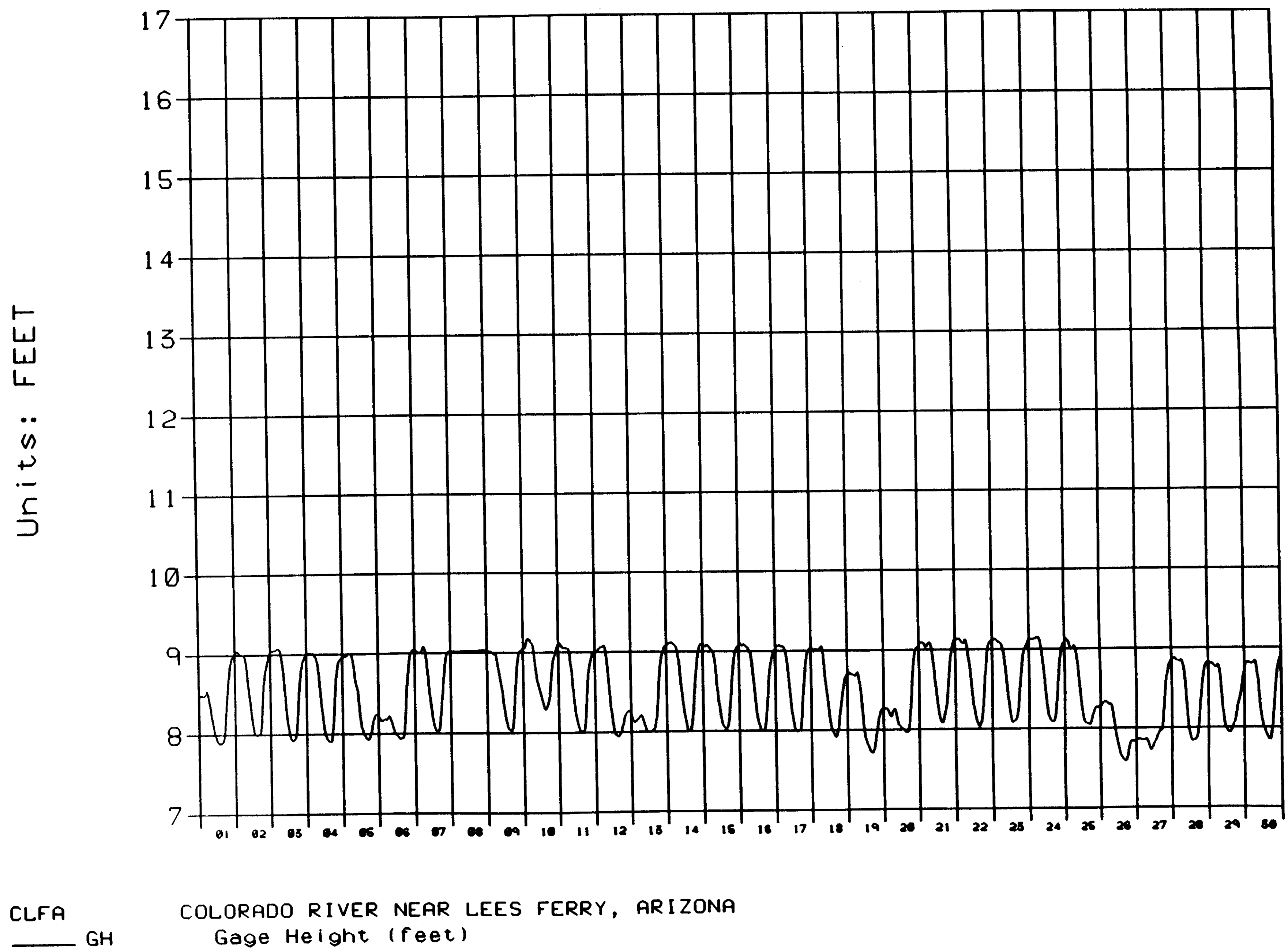
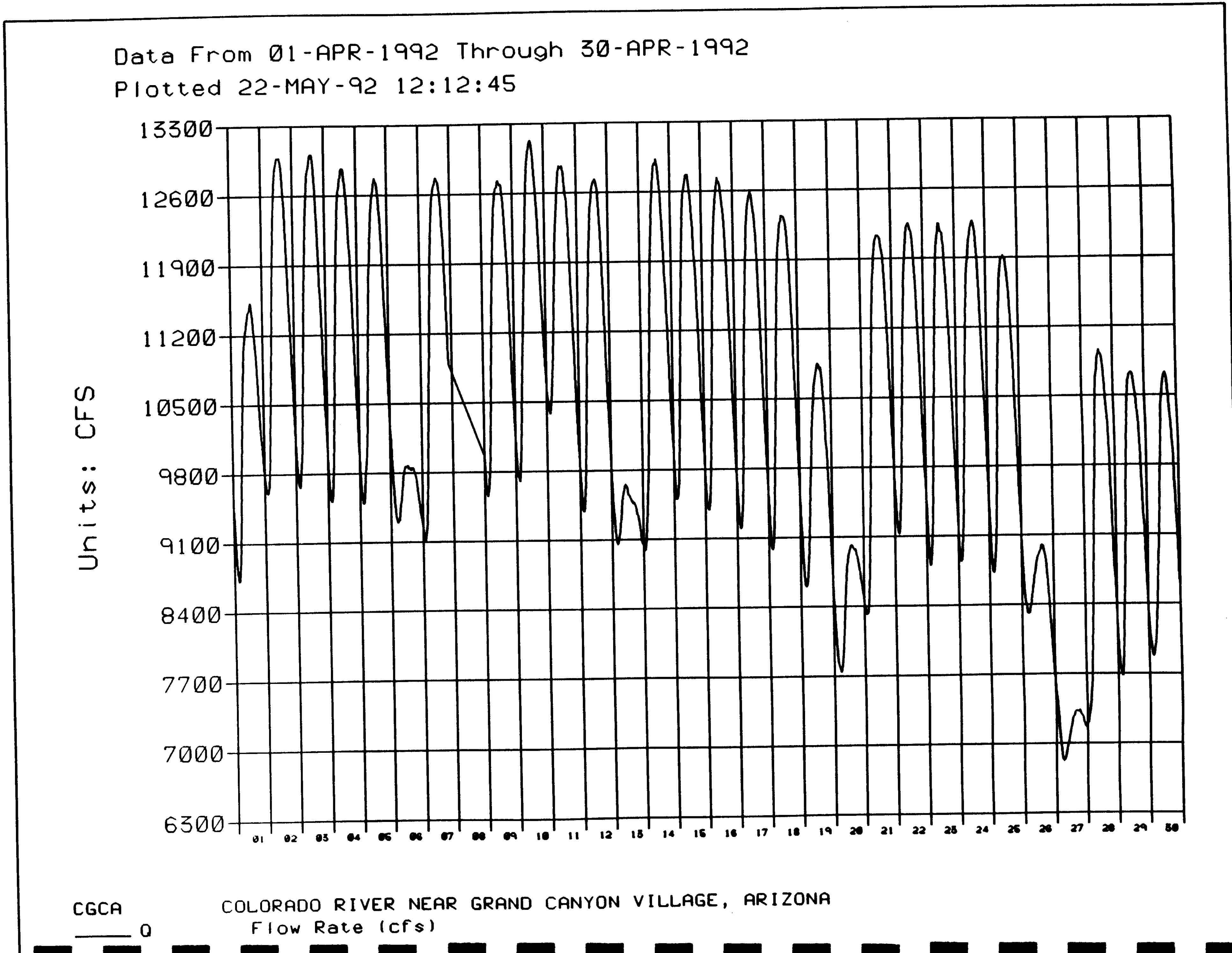
12600
11900
11200
10500
9800
9100
8400
7700
7000
6300
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
CLFA
Q
COLORADO RIVER NEAR LEES FERRY, ARIZONA
Flow Rate (cfs)

Data From 01-APR-1992 Through 30-APR-1992

Plotted 22-MAY-92 11:46:32



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



Data From 01-APR-1992 Through 30-APR-1992
Plotted 22-MAY-92 12:12:45
Units: CFS
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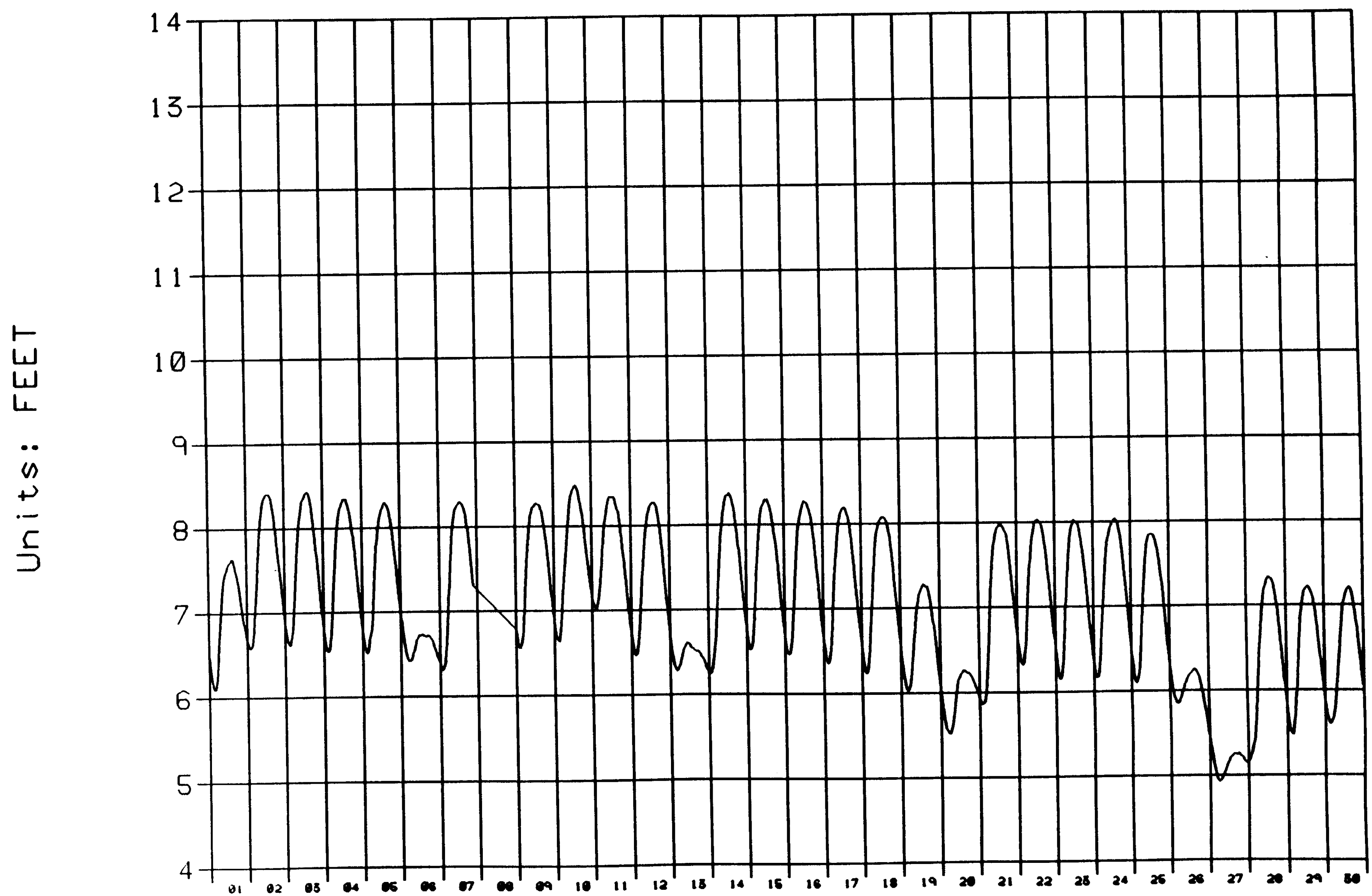
12600
11900
11200
10500
9800
9100
8400
7700
7000
6300
01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
CGCA
Q
COLORADO RIVER NEAR GRAND CANYON VILLAGE, ARIZONA
Flow Rate (cfs)

Data From 01-APR-1992 Through 30-APR-1992
Plotted 22-MAY-92 12:04:40



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

QUARTERLY REPORT

(January, and February 1992)

WESTERN AREA POWER ADMINISTRATION

I. **SUMMARY**

Scheduling and Real-Time Operations:
Power Scheduling Concerns:
Analysis of Ramping Events:
Expenses:

II. **POWER SCHEDULING AND REAL-TIME OPERATIONS**

A. Power Scheduling and Purchases for the Month of January 1992

Releases from Glen Canyon for the month of January were scheduled at 800,000 A.F. To accommodate this monthly release, the weekday release pattern from Glen Canyon was set at 10,100 c.f.s. (365 MW/hr.) during off-peak periods, ramping up to a maximum release level of 16,100 c.f.s. (582 MW/hr.), or a daily maximum fluctuation restriction of 6,000 c.f.s./day (217 MW). Daily release levels were adjusted within the month to meet the monthly release target. Weekend (Sat.& Sun.) release levels were adjusted to follow a lower load pattern and avoid off-peak sales. Actual January water releases from Glen Canyon were 801,346 A.F.

Releases from Flaming Gorge were scheduled at 140,000 A.F. To accommodate this release level, the powerplant was base loaded near maximum during all on-peak hours requiring all regulation assistance to be transferred to the Curecanti (CCI) units, specifically Blue Mesa and Morrow Point.

Energy availability during the first week of January was very good. Prices on the economy energy market were approximately 21-22 mills/kWh on-peak. Although energy availability was high, we did not pursue purchases from the non-firm market. Firm loads were served through available project generation and seasonal purchase agreements. Any additional energy required to cover deficits across peak hours was acquired through interchange payback. On January 7th, prices on the economy energy market took an extreme jump. There was approximately 2,500 MW of capacity off-line across the region. Prices rose from 22-23 mills/kWh to around 28 mills/kWh. Even though energy availability decreased and prices jumped, we were still able to serve our commitments through seasonal purchases. The market did not affect our ability to serve firm load.

On January 14th, the Bureau of Reclamation (Reclamation) notified our office that the Gunnison River Basin runoff forecast had been reduced by 100,000 A.F. Consequently, Reclamation reduced Crystal powerplant releases from 1,200 c.f.s. (18 MW) to 800 c.f.s. (12 MW) on that day without advance warning. Due to the reduced flows from Crystal, Western lost approximately 700 MWh/day of generation capability from the Curecanti units. The purchase program was adjusted to pick up the additional energy at a cost of approximately $14,000 per day. We were fortunate to have had the energy available through the non-firm energy market. Glen Canyon would have had to react to the energy/capacity deficit if Western were unable to acquire the additional energy on such short notice. Although the additional energy cost was an unplanned factor, the major impact of the action was the lost capability to use the Curecanti units for regulation assistance and load following across peaks. The release reduction cut in half the number of hours Blue Mesa and Morrow Point could be operated. With Flaming Gorge base loaded, regulation responsibility was moved entirely to Glen Canyon when the Curecanti units were turned off. This unplanned situation continued until February when releases from Flaming Gorge were reduced and the units were backed down to allowing some regulation movement.

No other problems were encountered in January. Glen Canyon daily generation patterns were adjusted from time to time in order to meet monthly release levels. Non-firm energy availability was good and prices reasonably low. We began ramping Glen Canyon down on January 30th to accommodate the transition between January and February release levels. Off-peak releases were cut back from 9,500 c.f.s. (343 MW) to 8,350 c.f.s. (302 MW) for February.

B. <u>Power Scheduling and Purchases for the Month of February 1992</u>

Releases from Glen Canyon for the month of February were scheduled at 650,000 A.F. The weekday generation pattern was scheduled at 8,350 c.f.s. (302 MW) during off-peak hours ramping up to 14,350 c.f.s. (518 MW) during on-peak hours. This followed the daily maximum fluctuation restriction of 6,000 c.f.s. (216 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

The Bureau revised snowpack forecasts downward during the first week in February. Crystal generation was revised from 800 c.f.s. (12 MW) to 650 c.f.s. (10 MW). This reduction reduced available generation capability from the Curecanti units a total of 120 MWh/day and reduced the time the units were able to operate for load following and regulation assistance. Flaming Gorge releases were reduced from 100,000 A.F./Mo. to 75,000 A.F. This reduced energy availability from Flaming Gorge by approximately 280 MWh/day (approx. $5,800/day) but also reduced expected unit loading during on-peak hours. This allowed Western room on the Flaming Gorge units to move regulation assistance from Curecanti to Flaming Gorge so Glen Canyon would not be responsible for all the regulation swings.

The non-firm energy market was very soft the entire month. Prices were extremely good at 18-19 mills/kWh. Availability was high all hours. No major scheduling problems were encountered the entire month.

C. Power Scheduling and Purchases for the Month of March 1992

March releases from Glen Canyon were scheduled at 600,000 A.F. The weekday generation pattern was pre-scheduled at 6,640 c.f.s. (238 MW) during offpeak hours ramping up to a maximum of 12,640 c.f.s. (454 MW) during onpeak hours for a majority of the month. This followed the daily maximum fluctuation restriction of 6,000 c.f.s. (215 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

The month of March has gone quite well from a pre-schedule point of view. Energy availability was very high the entire month and prices very reasonable. The economy energy market remained around 11-14 mills/kWh during offpeak hours and between 17-19 mills/kWh onpeak the entire month. A Palo Verde unit tripped towards the end of the month and drove prices up approximately 1 mill/kWh during onpeak periods. There was a snow storm in eastern Colorado in the middle of the month which created some line outages but they did not affect our operations.

The diversion tunnel below Crystal power plant was opened for irrigation purposes. Power scheduling was not notified by the Bureau. This did not create any problems this time since there no generation adjustments, but it reinforces the concern we have been voicing about lack of communication and coordination for special releases and/or water release changes on the system.

III. POWER SCHEDULING CONCERNS FOR THE NEXT QUARTER

A. Power Scheduling Concerns for the Month of April 1992

As side flows increase into Crystal due to runoff, generation at Crystal also will be increased, but releases from Morrow Point and Blue Mesa will be decreased accordingly to accommodate those same side flows. This will reduce generation availability from Morrow Point and Blue Mesa for load following and regulation assistance. Scheduled releases from Flaming Gorge have been increased somewhat in April to adjust for this problem so regulation assistance from Flaming Gorge should be available. Any maintenance or special releases from Flaming Gorge should be avoided while Curecanti unit availability is restricted due to side flows into Crystal. If Flaming Gorge availability is interrupted, Glen Canyon will not be able to rely on the Curecanti units for much regulation assistance.

Energy availability from the non-firm energy market should be good the entire month of April.

B. Power Scheduling Concerns for the Month of May 1992

May is a transition month for the Curecanti units. Irrigation diversions below Crystal will gradually increase. As a result, Morrow Point and Blue Mesa generation will gradually become available for load following and regulation assistance. We will have to watch the proposed peak flows which are scheduled to be released from Flaming Gorge very closely. These flows have yet to be scheduled. If they occur before generation becomes available from Blue Mesa and Morrow Point, Flaming Gorge will be fully loaded and unavailable for regulation assistance and there will be no water to release from Blue Mesa and Morrow Point for generation. If this happens, Glen Canyon will have to take the burden of regulation on its own. Once the high flows begin at Flaming Gorge, scheduled outages on the Curecanti units must be limited or closely coordinated.

C. Power Scheduling Concerns for the Month of June 1992

No major problems are anticipated on the system. There should be sufficient operating capacity available to serve firm commitments barring any unforeseen problems. Depending on restrictions at Flaming Gorge (not yet imposed), the Curecanti units will be used for regulation assistance. Maintenance activities should be closely coordinated.

IV. ANALYSIS OF RAMPING EVENTS

There were 26 incidences between January 1, 1992 and February 29, 1992. There were 35 explanations for these 26 incidences, as more than one factor explained some incidences.

The following is a tabulation of these factors which caused these incidences:

Limitations by Aspinall/Flaming Gorge Operations:	4	(11%)
Actual Load not Following Prescheduled:	1	(3%)
Error in Glen Canyon AGC & Operations:	4	(11%)
Control Area Regulation/Disturbance/Internal Load:	13	(37%)
Unanticipated Imports/Exports:	3	(9%)
CRSP Resource Availability:	7	(20%)
Prescheduling Error:	2	(6%)
Plant Scheduling Error:	1	(3%)

V. EXPENSES

- Net Expense -- The total net expense, January and February = $346,689. Includes additional cost associated with opportunity (economy energy) sales foregone. The March analysis is not available yet.

- Purchases -- Deficits are slightly higher than projected for Base Case conditions. In the change case, the deficits are met by both purchases and the interchange received. But in the base case all the deficits are assumed to be met by purchases. The purchases in the base case, for both January and February, are higher than that of the change case. There is a significant shift of purchases from offpeak to onpeak in the change case for both months.

- Economy Energy Sales -- Economy (non-firm) energy sales were significantly less than projected for Base Case conditions. A statistical analysis has been applied to calculate the nonfirm sales for the base case. Revenues foregone were estimated as $848,241 (base case less actual sales) for the month of January, and $721,640 for the month of February. There were no economy energy sales in February.

- Purchase Prices - Base Case - Generally, purchase prices offpeak and onpeak would remain unchanged with interim release constraints. Average monthly purchase prices for January are estimated to be $15.26 per MWh offpeak and $21.40 per MWh onpeak. Average monthly purchase prices for February were estimated to be $14.79 per MWh offpeak and $21.09 per MWh onpeak.

  The average monthly purchase price estimates were derived from the actual non-firm energy purchase prices. With the help of the Power Control staff, some of the higher price purchases in any month which were associated directly with interim release constraints were excluded. An adjusted weighted average of remaining purchase amounts and prices render the Base Case offpeak and onpeak purchase prices used in the net expense assessment. For the months of January and February the base case average offpeak and onpeak purchase prices are the same as the actual average offpeak and onpeak purchase prices.

- Purchase Price - Actual -- Average monthly purchase prices for actual purchases from all sources have been $15.26 per MWh offpeak, and $21.40 per MWh onpeak for the month of January and $14.79 per MWh offpeak, and $21.09 per MWh onpeak for the month of February.

- Economy Energy Sales Prices - Base Case -- Average monthly economy energy sales price for Base Case conditions was estimated to be $23.50 per MWh for January and $20.00 for February.

  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; and,

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

In most cases, since Western would have had the flexibility of making all or most of the non-firm 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.

- Economy Energy Sales - Actual -- The actual consummated average monthly economy energy sales price is $21.61 per MWh for January. There are no economy energy sales in February.

- Comparison, Average Purchase Prices vs Economy Energy Sales Prices -- When looking at the sales prices and average purchase prices for base case and actual, we can see overall the purchase and sales prices have been consistent between the base case and actual. In January, in the base case, 37,542 MWh of sales are estimated to be made with a price differential of approximately 5 mills/KWh between the average estimated purchase price and the average sales price, whereas in the actual operations, the price differential is approximately 2 mills/KWh due to some forced sales. In February, there were no economy energy sales made since the market was soft. The nonfirm sales were estimated to be 36,082 MWh in the base case. Western would have had the flexibility of making all or most of the non-firm sales during the time the market had been high. 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 price was determined to be $20.00 per MWh.

GCES Interim Release
Net Expense Analysis for January 1992
File Name: JAN92EXP.WQ!
CREATE 27-Mar-92
PRINTED 01-Apr-92

January 1992 Summary
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	521,816 MWh	Firm Load & Losses:	521,816 MWh
GC Generation:	348,598 MWh	GC Generation:	348,600 MWh
Other CRSP/IP Generation:	108,702 MWh	Other CRSP/IP Generation:	108,702 MWh
Purchases:	65,483 MWh	Purchases:	55,084 MWh
Off Peak:	31,629 MWh	Off Peak:	15,196 MWh
On Peak:	33,855 MWh	On Peak:	39,888 MWh
Other Imports:	36,575 MWh	Other Imports:	11,003 MWh
Other Sales:	37,542 MWh	Other Sales:	1,573 MWh
Purchase Prices :		Purchase Prices :	
Off Peak:	$15.26 /MWh	Off Peak:	$15.26 /MWh
On Peak:	$21.40 /MWh	On Peak:	$21.40 /MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$18.43 /MWh	Other Imports Price: (Avg.Purchase Price)	$19.71 /MWh
Sales Price:	$23.50 /MWh	Sales Price:	$21.61 /MWh
Purchase Expense:	$1,207,156	Purchase Expense:	$1,085,441
Off Peak:	$482,659	Off Peak:	$231,963
On Peak:	$724,497	On Peak:	$853,478
Other Imports Expense:	$674,247	Other Imports Expense:	$216,816
Other Sales:	$882,237	Other Sales:	$33,996
Net Expense:	$999,166	Net Expense:	$1,268,261

Total Net Expense for January 1992: $269,096

GCES Interim Release
Net Expense Analysis for February 1992
File Name: FEB92EXP.WQ!
CREATE 01-Apr-92

February 1992 Summary
Net Expense Analysis

	Base Case (Without Interim Release)		Actual (With Interim Release)
Firm Load & Losses:	448,891 MWh	Firm Load & Losses:	448,891 MWh
GC Generation:	281,277 MWh	GC Generation:	281,276 MWh
Other CRSP/IP Generation:	65,203 MWh	Other CRSP/IP Generation:	65,203 MWh
Purchases:	102,411 MWh	Purchases:	94,310 MWh
Off Peak:	40,195 MWh	Off Peak:	32,923 MWh
On Peak:	62,215 MWh	On Peak:	61,387 MWh
Other Imports:	36,083 MWh	Other Imports:	8,102 MWh
Other Sales:	36,082 MWh	Other Sales:	0 MWh
Purchase Prices :		Purchase Prices :	
Off Peak:	$14.79 /MWh	Off Peak:	$14.79 /MWh
On Peak:	$21.09 /MWh	On Peak:	$21.09 /MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$18.62 /MWh	Other Imports Price: (Avg.Purchase Price)	$18.89 /MWh
Sales Price:	$20.00 /MWh		
Purchase Expense:	$1,906,611	Purchase Expense:	$1,781,304
Off Peak:	$594,487	Off Peak:	$486,925
On Peak:	$1,312,123	On Peak:	$1,294,379
Other Imports Expense:	$671,768	Other Imports Expense:	$153,029
Other Sales:	$721,640	Other Sales:	$0
Net Expense:	$1,856,739	Net Expense:	$1,934,332

Total Net Expense for February 1992: $77,593

GLEN CANYON DAM INTERIM OPERATIONS

March and April 1992

WESTERN
AREA POWER
ADMINISTRATION

GLEN CANYON DAM INTERIM OPERATIONS

Western Area Power Administration

March and April 1992

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GLEN CANYON DAM INTERIM OPERATIONS

Western Area Power Administration

March and April 1992

I. EXECUTIVE SUMMARY

A. General Scheduling Under Interim Releases

B. Power Scheduling and Real-Time Operations

C. Power Scheduling Concerns

D. Analysis of Ramping Events

E. Expenses

II. INTRODUCTION

On August 1, 1992, 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 on-peak 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 the inception of interim flows, Western and the Bureau of Reclamation (Reclamation) have been successful in meeting the operational parameters of the interim flows. Several refinements such as the 24-hour rolling period, the 30-day rolling period, and regulation caused minor problems, but they were resolved.

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 allocation 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 entitlement as defined in Exhibit A of their electric service contract. 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 and 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 has 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 resource 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 on and off-peak 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, off-peak generation has been increased and energy, normally purchased off-peak when generation was low, is purchased during higher priced on-peak 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 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 complicates "normal" Glen Canyon operations.

B. Power Scheduling and Real-Time Operations

1. Power Scheduling and Purchases for the Month of March 1992

March releases from Glen Canyon were scheduled at 600,000 acre-feet. The weekday generation pattern was prescheduled at 6,640 cfs (238 MW) during off-peak hours ramping up to a maximum of 12,640 cfs (454 MW) during on-peak hours for a majority of the month. This follows the daily maximum fluctuation restriction of 6,000 cfs (215 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

March went quite well from a preschedule perspective: energy availability was very high for the entire month and prices remained reasonable. The economy energy market remained around 11-14 mills/kWh during off-peak hours and between 17-19 mills/kWh onpeak during the entire month. A Palo Verde unit tripped towards the end of March and raised prices up approximately 1 mill/kWh during on-peak periods. There was a snow storm in eastern Colorado in mid-March, which created some line outages but did not appreciably affect Western's dispatch operations.

The diversion tunnel below Crystal Powerplant was opened for irrigation purposes. Power scheduling was not notified by Reclamation. This did not create any problems this time since there were no generation adjustments needed to be made. However, it reinforces the concern about the occasional lack of communication and coordination for special releases and/or water release changes on the system.

2. Power Scheduling and Purchases for the Month of April 1992

April releases from Glen Canyon were scheduled at 585,000 acre-feet. The weekday generation pattern was prescheduled to follow a 7,325 cfs

(263 MW) off-peak release ramping up to a maximum-release level of 12,325 cfs (442 MW) during daytime hours for a majority of the month. The maximum daily fluctuation limit was set at 5,000 cfs (179 MW). Weekend releases were adjusted downward within criteria to follow reduced weekend loads.

Energy availability on the economy energy market was very good in April. On-peak energy prices remained between 16-18 mills/kWh for the first 3 weeks of the month and escalated to 21 mills/kWh during the last week of April. Off-peak energy prices were between 13 and 14 mills/KWh.

No major prescheduling difficulties which could have threatened Glen Canyon release restrictions were encountered in April. However, there were a few events that occurred during April 25-27 which should have been anticipated by Reclamation and by the Forest Service in advance, causing real time problems over a 3-day period and could have affected Glen Canyon releases.

3. Coordination Problem With Special Releases

There were no restrictions in effect at Flaming Gorge or on the Aspinall Unit, but there was a limited amount of water available for release from Flaming Gorge due to the upcoming schedule for high spring flows. Also, side flows into Crystal and Morrow Point reservoirs were extremely high, which severely limited the generation capability from Blue Mesa and Morrow Point (approximately 180 MWh/day). Flaming Gorge was being used for regulation assistance because of the limited availability of the Aspinall Unit.

On Saturday, April 25, Reclamation requested a unit acceptance test of the newly uprated Morrow Point Unit No. 1. Western dispatchers accommodated the unit test request, but filled Crystal Reservoir in the process. Because Crystal generation was very low (13 MW/hr) and side flows very high, it was difficult to reduce lake elevation after the tests to restore Morrow Point generation capability. Complicating the problem further was the fact that Crystal Reservoir elevation was already high before April 25 due to problems encountered during the week.

On April 27, Crystal Lake elevation was not sufficiently reduced to allow significant generation from Morrow Point. That morning the Forest Service contacted Flaming Gorge for a special release. The request from the Forest Service was for a steady 800-cfs flow all day to clean out a stream (Red Creek) that is below the Dam. Western accommodated the special release.

The special releases from Flaming Gorge, requested by the Forest Service and the Morrow Point unit acceptance tests placed much stress on Western to accommodate Glen Canyon Interim Releases. The system had no flexibility with Flaming Gorge generation at minimum levels and with Crystal Reservoir at full elevation, which limited Morrow Point and Blue Mesa generation. On April 27, Western dispatchers requested the interconnected system for energy to avoid violations. Reclamation is working with Western to develop criteria/policy for special releases.

C. Power Scheduling Concerns for the Next Quarter

Power Scheduling Concerns for June-August 1992

All units on the SLCA/IP system will be available for generation during the summer months: capacity commitments should not be a problem unless there are unit outages at Glen Canyon. Flaming Gorge will be restricted to minimum generation (800 cfs or 25 MWh) until the Yampa River flows drop below 800 cfs. After that time, releases from Flaming Gorge will be increased to maintain a constant flow of approximately 1,600 cfs at the confluence of the Yampa and Green Rivers. The 800 cfs flow from Flaming Gorge is restricted, the only units available to provide regulation assistance and/or follows peaks will be Morrow Point and Blue Mesa. These units will have to be closely scheduled, or Glen Canyon will take all system swings related to regulation. All maintenance and/or special work on the Aspinall Unit should be coordinated well in advance with Western.

Western dispatchers will be purchasing a great deal of firming energy over the summer months during on-peak periods. It appears that there will be sufficient energy available on the interconnected system to meet our needs if the system remains healthy. Due to the low-water conditions in the Northwest, anticipated surpluses from Bonneville Power Administration (BPA) did not materialize. Energy will be available, but at higher prices.

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, March 1, 1992 to April 30, 1992.

The operational records and logs are contained within the packet Glen Canyon Dam Interim Flows—Glen Canyon Power Plant Operations, March 1992 through April 1992 containing 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, 33 instances of deviations were found. Most of the conditions were caused by more than one factor; for example, control area regulation and Flaming Gorge operational limitations; therefore, multiple variations can be explained by one antecedent.

The following table summarizes the causes and frequency of the 33 deviations:

	Number Of Events	Percent Of Events
Control Area Regulation or Disturbance	17/33	52
CRSP Resource Availability	14/33	42
Flaming Gorge/Aspinal Operational Limitations	14/33	42
Imports/Exports Different than Preschedule	12/33	36
Computer Trouble/Time Error Correction	1/33	3
SCADA/System Regulation	1/33	3
Glen Canyon Plant Operator Error	1/33	3
Real Time Interchange Scheduling Changes	1/33	3

V. EXPENSES

A. Net Expense

The net expense of interim releases for the months March and April of 1992 are summarized below:

March 1992 . . . . $41,944
April 1992 . . . . $143,858

This analysis includes additional cost associated with opportunity (economy energy) sales foregone. Attached are two spreadsheets of net expense analysis for March and April, 1992.

B. Purchases

In the change case (with interim-release restrictions), the deficits are met by both purchases and the interchange received. In the base case (without interim-release restrictions), all the deficits are assumed to be met by purchases. The purchases in the base case for March are higher than that of the change case; but in the month of April, the purchases are about 18 GWh higher in the change case than in the base case. The reason for the shift is Western was returning "pay back" that was carried over from FY 1991 to the Loveland Area Office. There is a significant shift of purchases from offpeak to onpeak in the change case for both months.

C. Economy Energy Sales

Economy (nonfirm) energy sales were significantly less than projected for base case conditions. A statistical analysis has been applied to calculate the nonfirm sales for the base case. Revenues foregone were estimated as $606,060 for both March and April. Actual economy energy sales revenues for March is $19,492 and $10,385 for April.

D. Purchase Prices—Base Case

Generally, purchase prices offpeak and onpeak would remain unchanged with interim-release constraints. Average monthly purchase prices for March are estimated to be $14.48/MWh offpeak and $19.40/MWh onpeak. Average monthly purchase prices for April were estimated to be $14.43/MWh offpeak and $19.58/MWh onpeak.

The average monthly purchase price estimates were derived from the actual non-firm energy purchase prices. With the help of the Power Control staff, some of the higher price purchases in any month which were associated directly with interim-release constraints were excluded. An adjusted weighted average of remaining purchase amounts and prices render the base case off-peak and on-peak purchase prices used in the net expense assessment. For the month of March, the base case average off-peak and on-peak purchase prices are the same as the actual average off-peak and on-peak purchase prices.

E. Purchase Price—Actual

Average monthly purchase prices for actual purchases from all sources have been $14.48/MWh offpeak, and $19.40/MWh onpeak for the month of March and $14.54/MWh offpeak, and $19.57/MWh onpeak for the month of April.

F. Economy Energy Sales Prices—Base Case

Average monthly economy energy sales price for base case conditions was estimated to be $18/MWh for March and $22.22/MWh for April.

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 cases, 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.

G. Economy Energy Sales—Actual

The actual consummated average monthly economy energy sales price is $16.66/MWh for March and $22.22/MWh for April.

H. Comparison, Average Purchase Prices vs Economy Energy Sales Prices

When looking at the sales prices and average purchase prices for base case and actual, we can see 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 March, in the base case, 33,670 MWh of sales are estimated to be made. Whereas in the actual operations, there were some forced sales made which resulted in an average sales price of 16.66 mills/kWh and an average purchase price of 17.75 mills/kWh. In April, nonfirm sales are estimated to be 33,670 MWh in the base case; whereas the actual sales are 483 MWh. The base case sales price is estimated to be $22.22/MWh, which is the same as the actual average consummated economy energy sales price for April 1992.

Glen Canyon Dam Interim Release

March 1992
Net Expense Analysis

	Base Case (Without Interim Release)	Actual (With Interim Release)
Firm Load & Losses:	461,930 MWh	461,930 MWh
GC Generation:	259,384 MWh	259,384 MWh
Other CRSP/IP Generation:	83,168 MWh	83,168 MWh
Total Generation:	342,552 MWh	342,552 MWh
Deficits:	119,380 MWh	119,424 MWh
Off Peak:	46,624 MWh	40,544 MWh
On Peak:	72,756 MWh	78,880 MWh
Purchases:	119,380 MWh	116,063 MWh
Off Peak:	46,624 MWh	39,018 MWh
On Peak:	72,756 MWh	77,045 MWh
Surplus:	0 MWh	46 MWh
Off Peak:	0 MWh	0 MWh
On Peak:	2 MWh	46 MWh
Other Imports:	33,668 MWh	4,485 MWh
Other Sales:	33,670 MWh	1,170 MWh
Purchase Prices:		
Off Peak:	$14.48/MWh	$14.48/MWh
On Peak:	$19.40/MWh	$19.40/MWh
Other Imports Price: (Avg.Estimated Purchase Price) / (Avg.Purchase Price)	$17.75/MWh	$17.75/MWh
Sales Price:	$18/MWh	$16.66/MWh
Purchase Expense:	$2,086,582	$2,059,957
Off Peak:	$675,116	$565,047
On Peak:	$1,411,466	$1,494,910
Other Imports Expense:	$597,607	$79,609
Other Sales:	$606,060	$19,492
Net Expense:	$2,078,129	$2,120,073

Total Net Expense for March 1992 .... **$41,944**

Glen Canyon Dam Interim Release
April 1992
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	470,946 MWh	Firm Load & Losses:	470,946 MWh
GC Generation:	253,024 MWh	GC Generation:	253,060 MWh
Other CRSP/IP Generation:	80,542 MWh	Other CRSP/IP Generation:	80,542 MWh
Total Generation:	333,566 MWh	Total Generation:	333,602 MWh
Deficits:	137,381 MWh	Deficits:	137,346 MWh
Off Peak:	54,026 MWh	Off Peak:	36,379 MWh
On Peak:	83,355 MWh	On Peak:	100,967 MWh
Purchases:	137,379 MWh	Purchases:	155,571 MWh
Off Peak:	54,024 MWh	Off Peak:	47,484 MWh
On Peak:	83,355 MWh	On Peak:	108,087 MWh
Surplus:	2 MWh	Surplus:	2 MWh
Off Peak:	2 MWh	Off Peak:	2 MWh
On Peak:	0 MWh	On Peak:	0 MWh
Other Imports:	33,035 MWh	Other Imports:	
		Other Exports:	17,744 MWh
Other Sales:	33,670 MWh	Other Sales:	483 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$14.43/MWh	Off Peak:	$14.54 /MWh
On Peak:	$19.58/MWh	On Peak:	$19.57/MWh
Other Imports Price: (Avg.Estimated Purchase Price)	$17.96 /MWh	Other Imports Price: (Avg.Purchase Price)	$18.03 /MWh
Sales Price:	$22.22/MWh	Sales Price:	$22.22/MWh
		Other Exports Price: (Average Sales Price)	$22.22/MWh
Purchase Expense:	$2,411,657	Purchase Expense:	$2,805,680
Off Peak:	$779,566	Off Peak:	$690,417
On Peak:	$1,632,091	On Peak:	$2,115,263
Other Imports Expense:	$593,309	Other Imports Expense:	$0
Other Sales:	$748,147	Other Sales:	$10,732
		Other Exports:	$394,272
Net Expense:	$2,256,818	Net Expense:	$2,400,676

Total Net Expense for April 1992 .... $143,858