GLEN CANYON DAM INTERIM OPERATIONS

Estimated Net Expense

April 1994 through September 1994

October 1994

WESTERN
AREA POWER
ADMINISTRATION

232.00
FIN-6.00
6558
21685
V.6

ECO1001-0594

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I. EXECUTIVE SUMMARY

Power Scheduling and Real-time Operations

- In mid-August high temperatures across the region pushed the economy energy market to the 36-40 mills/kWh range. on August 18 the Montrose Power Control staff (Montrose) was forced to purchase energy at 46 mills/kWh, prompting them to advise the Bureau of Reclamation that Glen Canyon would be run at the maximum 20,000 cfs release rate due to the unavailability and expense of energy on the system.

Analysis of Ramping Events

- There were 114 deviations: "Control Area Regulation" accounted for most of the anomalies.

Expenses

- Net expense of interim releases:

April 1994	$281,420
May 1994	$328,093
June 1994	$421,262
July 1994	$510,924
August 1994	$574,955
September 1994	$489,742

Power Scheduling Concerns (Future)

- Coordination of a spike release from the Glen Canyon powerplant has posed uncertainties for power planning. Western has moved water from the upcoming winter season into April to accommodate the spike. It is expected there will be lower than normal releases from the Glen Canyon Dam for October 1994 through March 1995.

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 change in dam operations have 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.

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

III. SCHEDULING

A. Interim release restrictions have limited Western's ability to accommodate hourly changes in the pre-schedules. These restrictions have required Western to request customer pre-scheduling 3 days in advance in order to match firm loads to available project resources and substitute purchases for any hourly deficits. Hourly changes to pre-schedules 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 associated with their use.

B. Power Scheduling and Real-Time Operations

1. Power Scheduling and Purchases for April 1994

April water releases from Glen Canyon totaled 610,000 acre feet (AF). The weekday generation pattern was pre-scheduled at approximately 7,200 cfs (257 MW) during off-peak hours ramping up to a maximum of 13,200 cfs (472 MW) during on-peak hours for a majority of the month. this stayed within the daily maximum fluctuation restriction of 6,000 cfs per day (215 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

Firm purchase requirements in April were generally supplied through long-term purchase agreements.

2. Power Scheduling and Purchases for May 1994

May water releases from Glen Canyon totaled 599,000 AF. The weekday generation pattern was pre-scheduled at approximately 7,200 cfs (263 MW) during off-peak hours ramping up to a maximum of 13,200 cfs (482 MW) during on-peak hours for a majority of the month. This stayed within the daily fluctuation restriction of 6,000 cfs per day (219 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

On May 7 spring runoff increased releases from the Aspinall Unit. The U.S. Fish and Wildlife Service (FWS) requested a 3-day 4,000 cfs release from the Aspinall Unit to enhance flows on the Gunnison River for endangered fish.

3. Power Scheduling and Purchases for June 1994

June water releases from Glen Canyon totaled 624,000 AF. The weekday generation pattern was pre-scheduled at approximately

8,800 cfs (343 MW) during offpeak hours ramping up to a maximum of 14,800 cfs (578 MW) during onpeak hours for a majority of the month. This followed the maximum daily fluctuation limit of 6,000 cfs per day (235 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

Releases from Flaming Gorge and the Aspinall Unit were relatively high for the first week of the month. The Yampa River was supplying all water requirements for the endangered fish studies. The economy energy market tightened in the last week of June due to several unplanned unit outages.

4. Power Scheduling and Purchases for July 1994

Water releases from Glen Canyon powerplant totaled 846,000 AF for the month of July. The weekday generation pattern was pre-scheduled at approximately 10,800 cfs (427 MW) during off-peak hours ramping up to approximately 18,800 cfs (743 MW) during on-peak hours. Daily generation fluctuations were limited to 8,000 cfs (316 MW). Weekend releases were adjusted downward to follow reduced weekend loads.

July's weather was hot across the Western Region, however, the power grid was not affected. Flaming Gorge generation was increased to support endangered fish flows on the Green River at Jensen, providing generation flexibility. Due to reasonable energy prices and abundant energy on the economy energy market, Montrose was able to back down Glen Canyon water releases approximately 25,000 AF for later use in August and September.

5. Power Scheduling and Purchases for August 1994

Water releases from Glen Canyon powerplant totaled 860,000 AF for the month of August. For most of the month, weekday generation patterns were pre-scheduled at approximately 9,500 cfs (373 MW) during off-peak hours ramping up to approximately 17,500 cfs (688 MW) during on-peak hours. The daily generation fluctuation rate was limited to 8,000 cfs (315 MW) for the month. Weekend releases were adjusted downward to follow reductions in weekend loads.

In mid-August the temperatures were hot and the economy energy market tightened with very high prices (36-40 mills/kWh). Montrose began releasing water from Glen Canyon, which had been saved in July to avoid paying the high prices. On August 18 the cheapest energy available was 46 mills/kWh. Montrose contacted the Bureau to confirm system regulating capability at Glen Canyon and advise the Bureau that Glen Canyon would be run at the maximum 20,000 cfs release rate as defined in the exception criteria due to the unavailability and expense of energy on the system. Montrose interchanged available energy from the Loveland Area Office (LAO) and resulted in releases from Glen Canyon at 19,000 cfs maximum. In the last weeks of August energy remained tight and energy prices remained higher-than-normal until the long-term energy contractors returned to the market.

6. Power Scheduling and Purchases for September 1994

Water releases from the Glen Canyon powerplant totaled 623,000 AF for the month of September. Weekday generation patterns were pre-scheduled at approximately 8,000 cfs (311 MW) during off-peak periods and approximately 14,000 cfs (543 MW) during on-peak periods. The daily generation fluctuation rate was limited to 6,000 cfs (232 MW) all month. Weekend releases were adjusted downward to follow lower weekend demands.

September's weather turned cooler resulting in reduced irrigation demands and reduced Aspinall generation. Purchases were increased to supplement the lost generation.

C. Future Scheduling Concerns for October 1994-March 1995

Coordination of a spike release from the Glen Canyon powerplant has posed uncertainties for power planning. Western has moved water from the upcoming winter season into April to accommodate (the possibility) of the spike. As a result, there will be lower than normal releases from Glen Canyon Dam for October, November, December 1994, and January, February, and March 1995. In addition to this power reduction, the Aspinall Unit will be generating lower amounts of energy due to reduced runoff conditions in the basin, and Flaming Gorge generation will be reduced due to steady flow studies taking place this winter. This reduction in generation across the CRSP system will place a high demand on the winter economy energy market to support firm contract commitments. Most of Western's firm energy purchase requirements for the upcoming winter have been supported through contracts, and if these contracts remain reliable, there should be no problems supporting the system's firm load commitments.

The energy market in October is soft and is expected to remain unchanged in November. The extra water made available from the Aspinall Unit will be saved until it is needed by the end of November and into December, mitigating some of the lost generation from Glen Canyon. There is still a possibility that some additional generation will be made available from Flaming Gorge for December 1994, January and February 1995.

IV. ANALYSIS OF RAMPING EVENTS

A study was made to analyze hourly release rates which appeared to deviate from interim flow criteria. Operational records and logs kept during the study period, April 1, 1994, through September 30, 1994, were reviewed.

The operational records and logs are contained within the packet Glen Canyon Dam Interim Flows—Glen Canyon Power Plant Operations, for April 1994 through September 1994 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 Lee's 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, 114 instances of deviations were found. Most of the conditions were caused by more than one factor: (e.g., control area regulation and imports/exports different than pre-schedule), therefore, multiple variations can be explained by one anomaly.

The following table summarizes the causes and frequency of the 114 deviations:

Primary Cause(s) of Deviation	Number Of Instances	Percent Of Events
Control Area Regulation	49/114	43
Control Area Disturbance	4/114	4
CRSP Resource Availability	17/114	15
Aspinall Operations	8/114	7
Flaming Gorge Operations	1/114	1
Imports/Exports Different than Pre-schedule	13/114	11
Other	22/114	19

V. EXPENSES

A. Net Expense

The estimated net expense of interim releases for April through September 1994 are summarized below:

	Net Expense
April 1994	$281,420
May 1994	$328,093
June 1994	$421,262
July 1994	$510,924
August 1994	$574,955
September 1994	$489,742

Attached are Tables 1 through 6 detailing the net expense analysis by component for April through September 1994.

B. Purchases

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

Energy Purchase Comparison			
Months	Simulated Base Case Purchases	Actual Purchases	Differences
April 1994	87,739 MWh	83,757 MWh	3,982 MWh
May 1994	45,890 MWh	28,841 MWh	17,049 MWh
June 1994	93,530 MWh	92,709 MWh	821 MWh
July 1994	130,588 MWh	102,926 MWh	662 MWh
August 1994	109,615 MWh	107,849 MWh	1,766 MWh
September 1994	126,050 MWh	124,356 MWh	2,904 MWh

For April 1994 through September 1994, actual purchases were less than simulated 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 (Surplus)

For all months, actual nonfirm energy sales were less than projected for Base Case conditions. High water releases from Flaming Gorge and the Aspinall Unit, resulted in a surplus of energy to the economy energy market in the last half of May. This explains why May energy sales and revenues foregone, for Base Case and Actual, are significantly higher than the other 5 months. Revenues foregone are estimated below:

ENERGY SALES AND REVENUES FOREGONE			
Months	**Base Case**	**Actual**	**Revenues Foregone**
April 1994	$ 87,232	$ 8,249	$ 78,983
May 1994	867,160	355,937	511,223
June 1994	45,311	26,165	19,146
July 1994	35,928	22,536	13,392
August 1994	65,411	32,880	32,531
September 1994	30,390	0	30,390

D. Average Purchase Prices—Base Case and Actual

The average monthly purchase price estimates are derived from the actual nonfirm energy purchase prices. With the help of the Power Control staff (Montrose), some of the higher purchase prices for all months that are associated directly with interim release constraints, were excluded. As an example, June shows a $1.66/MWh difference from the Base Case offpeak and Actual offpeak prices. In consultation with Montrose, it was necessary to omit two high offpeak purchases that did not reflect the nonfirm energy market in June. 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:

ENERGY PURCHASE PRICES				
	Base Case		**Actual**	
Months	**Offpeak**	**Onpeak**	**Offpeak**	**Onpeak**
April 1994	$16.35/MWh	$23.78/MWh	$16.36/MWh	$23.78/MWh
May 1994	16.36/MWh	23.71/MWh	16.36/MWh	23.71/MWh
June 1994	14.94/MWh	23.55/MWh	16.60/MWh	23.70/MWh
July 1994	16.08/MWh	23.56/MWh	16.08/MWh	23.56/MWh
August 1994	16.47/MWh	24.65/MWh	16.51/MWh	24.83/MWh
September 1994	15.55/MWh	24.04/MWh	15.55/MWh	24.07/MWh

E. Economy Energy Sales Prices—Base Case and Actual

The sales price for the Base Case is determined with the help of the Montrose Power Control Staff (Montrose). 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, identification of those forced 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 energy sales during periods when the value is greatest. For all 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.

Presented below is a comparison of average monthly economy energy sales for Base Case prices to Actual prices. For the exception of May there are no differences between the Base Case prices and Actual prices, reflecting no forced sales for April and June through September.

The forced sale in May is attributed to the high water releases that occurred in the last half of the month from Flaming Gorge Dam and the Aspinall Unit, resulting in no daily purchase power requirements for the weeks of May 20 and 27 (Secretary's Report, May 27, 1994). Therefore, with a soft energy market, Western was forced to sell energy at $17.22/MWh to the nonfirm market.

ECONOMY ENERGY SALES PRICES BASE CASE & ACTUAL			
Months	**Base Case Prices**	**Actual Prices**	**Differences Between Base Case Prices and Actual Prices**
April 1994	$19.83/MWh	$19.83/MWh	$0.00/MWh
May 1994	22.99/MWh	17.22/MWh	5.77/MWh
June 1994	23.32/MWh	23.32/MWh	0.00/MWh
July 1994	20.23/MWh	20.23/MWh	0.00/MWh
August 1994	18.41/MWh	18.41/MWh	0.00/MWh
September 1994	17.94/MWh	17.94/MWh	0.00/MWh

Table 1
Glen Canyon Dam Interim Release
for April 1994
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	467,422 MWh	Firm Load & Losses:	467,422 MWh
GC Generation:	285,133 MWh	GC Generation:	285,133 MWh
Other CRSP/IP Generation:	98,948 MWh	Other CRSP/IP Generation:	98,948 MWh
Total Generation:	384,081 MWh	Total Generation:	384,081 MWh
Purchases:	87,739 MWh	Purchases:	83,757 MWh
Off Peak:	67,773 MWh	Off Peak:	27,820 MWh
On Peak:	19,966 MWh	On Peak:	55,937 MWh
Surplus:	4,399 MWh	Surplus:	416 MWh
Off Peak:	774 MWh	Off Peak:	284 MWh
On Peak:	3,625 MWh	On Peak:	132 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.35/MWh	Off Peak:	$16.36/MWh
On Peak:	$23.78/MWh	On Peak:	$23.78/MWh
Sales Price:	$19.83/MWh	Sales Price:	$19.83/MWh
Purchase Expense:	$1,582,880	Purchase Expense:	$1,785,317
Off Peak:	$1,108,089	Off Peak:	$455,135
On Peak:	$474,791	On Peak:	$1,330,182
Surplus Sales:	$87,232	Surplus Sales:	$8,249
Base Case Expense:	$1,495,648	Change Case Expense:	$1,777,068

Total Net Expense for April 1994 .... **$281,420**

Table 2
Glen Canyon Dam Interim Release
for May 1994
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	492,950 MWh	Firm Load & Losses:	492,950 MWh
GC Generation:	280,838 MWh	GC Generation:	280,838 MWh
Other CRSP/IP Generation:	203,941 MWh	Other CRSP/IP Generation:	203,941 MWh
Total Generation:	484,779 MWh	Total Generation:	484,779 MWh
Purchases:	45,890 MWh	Purchases:	28,841 MWh
Off Peak:	41,094 MWh	Off Peak:	11,012 MWh
On Peak:	4,796 MWh	On Peak:	17,829 MWh
Surplus:	37,719 MWh	Surplus:	20,670 MWh
Off Peak:	4,928 MWh	Off Peak:	12,480 MWh
On Peak:	32,791 MWh	On Peak:	8,190 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.36/MWh	Off Peak:	$16.36/MWh
On Peak:	$23.71/MWh	On Peak:	$23.71/MWh
Sales Price:	$22.99/MWh	Sales Price:	$17.22/MWh
Purchase Expense:	$786,011	Purchase Expense:	$602,882
Off Peak:	$672,298	Off Peak:	$180,156
On Peak:	$113,713	On Peak:	$422,726
Surplus Sales:	$867,160	Surplus Sales:	$355,937
Base Case Expense:	($81,149)	Change Case Expense:	$246,945

Total Net Expense for May 1994 .... **$328,093**

Table 3
Glen Canyon Dam Interim Release
for June 1994
Net Expense Analysis

Base Case (Without Interim Releases)		Actual (With Interim Release)	
Firm Load & Losses:	544,706 MWh	Firm Load & Losses:	544,706 MWh
GC Generation:	297,134 MWh	GC Generation:	297,134 MWh
Other CRSP/IP Generation:	155,984MWh	Other CRSP/IP Generation:	155,984 MWh
Total Generation:	453,118 MWh	Total Generation:	453,118 MWh
Purchases:	93,530 MWh	Purchases:	92,709 MWh
Off Peak:	60,715 MWh	Off Peak:	16,227 MWh
On Peak:	32,815 MWh	On Peak:	76,482 MWh
Surplus:	1,943 MWh	Surplus:	1,122 MWh
Off Peak:	103 MWh	Off Peak:	944 MWh
On Peak:	1,840 MWh	On Peak:	178 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$14.94/MWh	Off Peak:	$16.60/MWh
On Peak:	$23.55/MWh	On Peak:	$23.70/MWh
Sales Price:	$23.32/MWh	Sales Price:	$23.32/MWh
Purchase Expense:	$1,679,875	Purchase Expense:	$2,081,992
Off Peak:	$907,082	Off Peak:	$269,368
On Peak:	$772,793	On Peak:	$1,812,623
Surplus Sales:	$45,311	Surplus Sales:	$26,165
Base Case Expense:	$1,634,565	Change Case Expense:	$2,055,827

Total Net Expense for June 1994 .... $421,262

Table 4
Glen Canyon Dam Interim Release
for July 1994
Net Expense Analysis

Base Case (Without Interim Releases)		Actual (With Interim Release)	
Firm Load & Losses:	632,586 MWh	Firm Load & Losses:	632,586 MWh
GC Generation:	402,216 MWh	GC Generation:	402,217 MWh
Other CRSP/IP Generation:	128,557 MWh	Other CRSP/IP Generation:	128,557 MWh
Total Generation:	530,773 MWh	Total Generation:	530,774 MWh
Purchases:	103,588 MWh	Purchases:	102,926 MWh
Off Peak:	82,645 MWh	Off Peak:	14,045 MWh
On Peak:	20,943 MWh	On Peak:	88,881 MWh
Surplus:	1,776 MWh	Surplus:	1,114 MWh
Off Peak:	334 MWh	Off Peak:	1,114 MWh
On Peak:	1,442 MWh	On Peak:	0 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	\$16.08/MWh	Off Peak:	\$16.08/MWh
On Peak:	\$23.56/MWh	On Peak:	\$23.56/MWh
Sales Price:	\$20.23/MWh	Sales Price:	\$20.23/MWh
Purchase Expense:	\$1,822,349	Purchase Expense:	\$2,319,880
Off Peak:	\$1,328,932	Off Peak:	\$225,844
On Peak:	\$493,417	On Peak:	\$2,094,036
Surplus Sales:	\$35,928	Surplus Sales:	\$22,536
Base Case Expense:	\$1,786,420	Change Case Expense:	\$2,297,344

Total Net Expense for July 994 . . . . \$510,924

Table 5
Glen Canyon Dam Interim Release
for August 1994
Net Expense Analysis

Base Case (Without Interim Releases)		Actual (With Interim Release)	
Firm Load & Losses:	631,847 MWh	Firm Load & Losses:	631,847 MWh
GC Generation:	407,046 MWh	GC Generation:	407,046 MWh
Other CRSP/IP Generation:	118,738 MWh	Other CRSP/IP Generation:	118,738 MWh
Total Generation:	525,784 MWh	Total Generation:	525,784 MWh
Purchases:	109,615 MWh	Purchases:	107,849 MWh
Off Peak:	85,091 MWh	Off Peak:	15,565 MWh
On Peak:	24,524 MWh	On Peak:	92,284 MWh
Surplus:	3,553 MWh	Surplus:	1,786 MWh
Off Peak:	375 MWh	Off Peak:	1,636 MWh
On Peak:	3,178 MWh	On Peak:	150 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.47/MWh	Off Peak:	$16.51/MWh
On Peak:	$24.65/MWh	On Peak:	$24.83/MWh
Sales Price:	$18.41/MWh	Sales Price:	$18.41/MWh
Purchase Expense:	$2,005,965	Purchase Expense:	$2,548,390
Off Peak:	$1,401,449	Off Peak:	$256,978
On Peak:	$604,517	On Peak:	$2,291,412
Surplus Sales:	$65,411	Surplus Sales:	$32,880
Base Case Expense:	$1,940,555	Change Case Expense:	$2,515,510

Total Net Expense for August 1994 .... $574,955

Table 6
Glen Canyon Dam Interim Release
for September 1994
Net Expense Analysis

Base Case (Without Interim Releases)		Actual (With Interim Release)	
Firm Load & Losses:	520,076 MWh	Firm Load & Losses:	520,076 MWh
GC Generation:	292,222 MWh	GC Generation:	292,222 MWh
Other CRSP/IP Generation:	103,498 MWh	Other CRSP/IP Generation:	103,498 MWh
Total Generation:	395,720 MWh	Total Generation:	395,720 MWh
Purchases:	126,050 MWh	Purchases:	124,356 MWh
Off Peak:	93,037 MWh	Off Peak:	34,453 MWh
On Peak:	33,013 MWh	On Peak:	89,903 MWh
Surplus:	1,694 MWh	Surplus:	0 MWh
Off Peak:	302 MWh	Off Peak:	0 MWh
On Peak:	1,392 MWh	On Peak:	0 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$15.55/MWh	Off Peak:	$15.55/MWh
On Peak:	$24.04/MWh	On Peak:	$24.07/MWh
Sales Price:	$17.94/MWh	Sales Price:	$17.94/MWh
Purchase Expense:	$2,240,358	Purchase Expense:	$2,699,709
Off Peak:	$1,446,725	Off Peak:	$535,744
On Peak:	$793,633	On Peak:	$2,163,965
Surplus Sales:	$30,390	Surplus Sales:	$0
Base Case Expense:	$2,209,968	Change Case Expense:	$2,699,709

Total Net Expense for September 1994 .... $489,742

TABLE 7
GLEN CANYON DAM INTERIM RELEASE
Summary of Estimated Actual Net Expense
Associated With Interim Release

WY 1993 Cumulative Net Expense $10,523,219

Month/Yr	Estimated Actual Net Expense	Cumulative Estimated Actual Net Expense
October 1993	$387,899	$10,911,118
November 1993	$464,447	$11,375,565
December 1993	$551,942	$11,927,507
January 1994	$373,668	$12,301,175
February 1994	$465,858	$12,767,033
March 1994	$343,725	$13,110,758
April 1994	$281,420	$13,392,178
May 1994	$328,093	$13,720,271
June 1994	$421,262	$14,141,533
July 1994	$510,924	$14,652,457
August 1994	$574,955	$15,227,412
September 1994	$489,742	$15,717,154

WY 1994 Net Expense $5,193,935
Cumulative Net Expense $15,717,154