# GLEN CANYON DAM INTERIM OPERATIONS

Estimated Net Expense
December 1992, January and February 1993



April 1993

Western Area Power Administration

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## 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**

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**