UNDERSTANDING HOURLY OPERATIONS AT GLEN CANYON DAM
Colorado River Storage Project, Arizona

GCPSE95 version 2.0

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David A. Harpman

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Bureau of Reclamation
Denver Federal Center
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13. ABSTRACT ***(Maximum 200 words)***

GCPSE95 is a modeling tool for simulating the pattern of hourly generation and water releases from Glen Canyon Dam under various operational constraints and conditions. This program is primarily an experiential learning tool. It is designed to help the user understand hydropower operations at Glen Canyon Dam and to illustrate the manner in which environmental constraints and ancillary services affect those operations and the economic value of the electricity produced.

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by

David A. Harpman

Economics Group
Technical Service Center
Bureau of Reclamation
Denver, Colorado

September 2002

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Purpose

The GCPSE95 program and this documentation are tools for experiential learning. They were designed to help the user understand hourly hydropower operations at Glen Canyon Dam and to illustrate how physical constraints, environmental constraints and the provision of ancillary services affect power production, economic value and downstream releases.

Obtaining the Program

The GCPSE95 program, required data files and additional electronic copies of this manual are available for public download at the following sites:

http://www.usbr.gov/tsc/tsc8270.html
http://www.du.edu/~dharpman

Disclaimer

The GCPSE95 program was designed for educational use. We make no warranties, express or implied, that this program or documentation are free of error, are consistent with any particular standard, or that they will meet your requirements for any particular application. This program should not be relied on for solving a problem when an incorrect solution could result in injury to a person or loss of property, whether material or monetary. If you do use the program in such a manner, it is at your own risk. Neither the United States Government, nor any agency thereof, nor any of its employees make any warranty express or implied, nor assume any legal liability or responsibility for the accuracy, completeness or usefulness of this program. Mention of any product, process or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by the United States Government or any agency thereof. The views and opinions of the authors expressed herein do not necessarily reflect those of the United States Government, the Department of the Interior or the Bureau of Reclamation.

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Introduction

About Glen Canyon Dam. Glen Canyon Dam was completed by the U.S. Bureau of Reclamation in 1963. It is located on the Colorado River, upstream from the Grand Canyon. This 710-foot-high concrete arch dam controls a drainage basin of approximately 108,335 square miles. There are eight hydroelectric generators at the dam, which can produce up to 1,296 MW of electric power at a 95 percent power factor.

Glen Canyon Dam is an integral part of the Colorado River Storage Project (CRSP), which was authorized in 1956. The energy and capacity from CRSP is marketed by the Western Area Power Administration (Western). Appendix 1 contains a relatively detailed description of this facility and recent environmental studies.

About this program. The GCPSE95 model is an easy to use educational version of the model described in Harpman (1999a). This hourly simulation model was used to estimate the short-run impacts of the modified low fluctuating flow (MLFF) operations now used at Glen Canyon Dam and a subsequent experimental flood event, which is described in Collier, Webb and Andrews (1997) and Harpman (1999b). This model allows for the rapid simulation of a wide variety of environmental constraints for policy analysis and experiential learning. This program is designed as an educational tool to help users understand the potential effects of operational constraints on river flows, hydropower generation, and economic value.

To simulate hourly operations at Glen Canyon Dam, the user first chooses a month for the analysis and then supplies values for the input data and parameters which characterize the environmental and operational constraints on hydropower generation. Using the peakshaving approach (Environmental Defense Fund 1996), GCPSE95 optimally dispatches the hydroelectric generation units at the dam to meet the chronological load subject to the specified constraint set. This produces an optimal hourly pattern of generation and water release. Finally, the economic value of this hourly pattern of generation is calculated.

Logistics. The GCPSE95 program is designed for use in a Windows 9x or NT operating system environment.

Hardware required. A graphics card is required to run this program. A printer is required to print out the numerical results. A graphics capable printer is required to print out graphs.

Caution. GCPSE95 contains a number of input error checking routines. These routines do not and cannot check for all possible logical or factual inconsistencies. For this reason, common sense and logic must be used to obtain meaningful results with this program.

Program Installation

Using Windows Explorer, create a folder (directory) on your hard drive. Download the GCPSE95 program and data files or copy them from the CD-ROM disk to the directory you created on your hard drive. Using PKZip or similar program, unpack the program and the data files. Ensure the program and all of the files supplied with it are in the same folder on the same drive.

Quick Start

First, ensure that GCPSE95, the parameter and data files supplied with the program are "unzipped" and placed in the same directory on the same drive. Using Windows Explorer, locate the icon for the executable program and double-click on it. This should start the program. Figure 1 illustrates the opening screen of the GCPSE95 hourly simulation model.

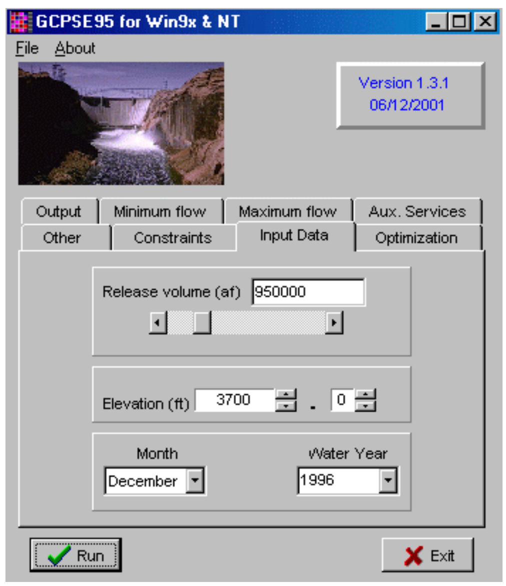

Figure 1. GCPSE95 Opening screen.

As shown, there are eight tabbed input pages entitled, "Output", "Other," "Minimum flow," "Maximum flow," "Constraints," "Input Data", "Aux (Auxiliary) Services," and "Optimization." When the program is started, the "Input Data" page should be visible.

Select a month from the pull-down list on the Input Data page. Then click on the "Run" button. Using the default values of the parameters, the program will simulate hourly operations for the selected month and water year.

Summary Results

The summary results screen is displayed by default. As shown in Figure 2, the summary results include both graphical and numerical results for the simulation.

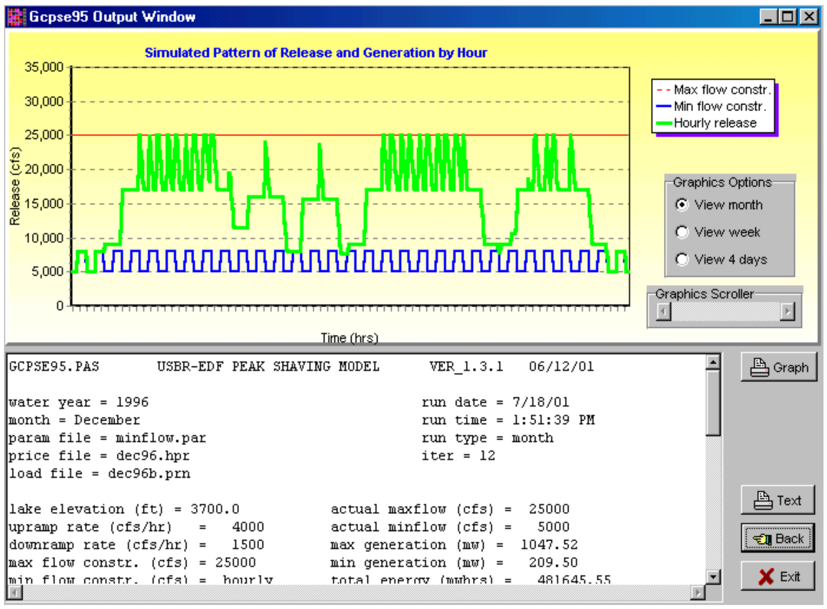

Figure 2. Summary output for the month of December using a monthly release volume of 950,000 acre-feet and the default values for the other parameters and constraints. The monthly graphical view is shown.

Graphical Results

Graphics options. Three different "Graphics options" or views are available. By selecting the appropriate radio button, the user can view a plot of the entire month, one week, or four days at a glance. By using the graphics scroll bar, the user can scroll across the weeks or days as needed. The graphics scroll bar is disabled when the entire month is displayed.

Interpretation. The red horizontal line in Figure 2, shown at a flow level of 25,000 cfs, indicates the position of the user specified maximum flow constraint. Hourly releases will exceed this amount only if monthly release volumes are quite large. The blue line represents the user-specified minimum flow constraint. The minimum flow constraint may appear as a horizontal line or an hourly pattern as specified by the user.

The simulated hourly release pattern, or hydrograph, is shown in green. Under most circumstances, the pattern of hourly releases (and generation) will vary on an hourly basis in a relatively complex manner. The hourly hydrograph will be a horizontal line when the powerplant is baseloaded (See Appendix 10 for definitions of terms).

The rate of increase in flow from one hour to the next is often determined by the user-specified upramp rate. The rate of decrease in flow from one hour to the next is often determined by the user-specified downramp rate.

The maximum daily flow and capacity attained during the day is determined by the interactions of the user-specified parameters and water volume. The difference between the highest and lowest flow is often limited by the maximum daily change constraint. For example, if the maximum daily change constraint is 8,000 cfs, the difference between the highest and lowest flow, during any 24-hour period, will often be 8,000 cfs or less.

Graphics printing. The graphical output can be printed by any graphics-capable printer. To print the graph, click on the "Print Graphics" button. A graphics dialog box will then appear allowing the user to select a variety of plotting options.

Numerical Results

The summary numerical results produced by the program are illustrated in Text Box 1. Much of the information shown in the summary numerical results documents the values of the parameters used for the analysis. The use and effect of these user specified parameters are described under the heading for the appropriate tabbed page. The results calculated by the GCPSE95 program and displayed on the summary output screen are briefly described below.

Iteration. "Iter" is an abbreviation for the number of major iterations made by the peakshaving algorithm. Under most circumstances, the number of iterations required to reach convergence ranges from 12 to 19. Convergence is obtained when the difference between the monthly volume of water released, as calculated by the program, and the available volume of water specified by the user is less than 0.001% of the available release volume. When the powerplant is baseloaded, no peakshaving is required and the number of iterations will be equal to 0. The maximum allowable number of iterations is 50. Should the algorithm fail to converge, an error message will be displayed (see section on fatal errors).

Actual maxflow. Actual maximum flow is the highest flow that can be attained given the physical parameters and logical constraints specified by the user. If the monthly release volume is sufficiently large, the actual maximum flow may necessarily exceed the maximum flow constraint. If the specified monthly volume requires it, the jet tubes and/or spillways may be used to pass the required monthly volume. In this event, the user may wish to examine the specified monthly volume for accuracy and realism.

```
PROGRAM GCPSE95.PAS      USBR-EDF PEAK SHAVING MODEL       VER_1.3.1   06/12/01

water year = 1996                          run date = 7/18/01
month = December                           run time = 1:51:43 PM
parameter file =  minflow.par              run type = month
price file =    dec96.hpr                  iter =  12
load file =   dec96b.prn

lake elevation (ft) = 3700.0                 actual maxflow (cfs) =   25000
upramp rate (cfs/hr)   =   4000              actual minflow (cfs) =    5000
downramp rate (cfs/hr) =   1500              max generation (MW) =  1047.52
max flow constr. (cfs) = 25000               min generation (MW) =   209.50
min flow constr. (cfs) = hourly              total energy (MWhrs) =   481645.55
maximum daily change (cfs) =   8000          dump energy (MWhrs)  =        0.00

spinning reserves (MW) =   0.0               area load control (MW) =   0.0
value spin reserv ($/MWhr) =  0.00           value area LC ($/MWhr) =  0.00

available volume (af) =  950000.00           price factor = 1.00000
volume released (af) =   949993.43           hydro varcost ($/MWhr) =  1.80
turbine release (af) =   949993.43


Economic Value
--------------------------------------
spinning reserves ($) =        0.00
area load control ($) =        0.00
generation ($)        =  4317544.06
--------------------------------------
Total ($)             =  4317544.06


WARNING: none
```

Text Box 1. Summary Numerical Output

Actual minflow. Actual minimum flow is the lowest flow reached during the simulation period. In low release volume simulations, the actual minimum flow may be equal to the minimum flow constraint specified by the user for some or all of the hours in the day. In higher volume situations, the minimum flow is generally higher than the specified minimum flow constraint.

Volume released. The volume released is the total amount of water released in acre-feet (af) during the simulation. Generally, this volume should be very close to the available volume. Small differences (<0.001%) between the volume released and the available volume are an artifact of the iterative technique used to obtain a solution under certain combinations of constraints and monthly volumes.

Turbine release. The turbine release is the amount of water which is released through the turbines during the simulation. In most circumstances, this will be identical to the volume released. However, if the specified monthly release volume is sufficiently high, the use of the outlet works (jet tubes or spillways) is required. In this event, the turbine release will be less than the total volume released. This is important because only water released through the turbines generates electricity.

Min generation Minimum generation is the lowest level of electrical generation during the month, measured in megawatts (MW).

Max generation. Maximum generation is the highest level of electrical generation (a.k.a., the capacity) during the month, measured in megawatts (MW). Note only flows that pass through the generators are used to produce power. Releases made through the jet tubes or the spillways do not produce electrical power. It is assumed that all eight generators are available for use.

Total energy. Total energy is the number of megawatt hours (MWhrs) of electrical energy generated during the month.

Dump energy. Dump energy is defined as the number of megawatt hours (MWhrs) of energy generated during the day in excess of aggregate load. Under most circumstances, no dump energy will be produced. A non-zero value for dump energy is an indication that generation exceeds aggregate load during at least one hour of the day. This may occur if minimum flows are high relative to aggregate load or may indicate another analysis problem which requires consideration. Also see, "Warning Messages— Minimum flow constraint exceeds some loads."

Economic value. The economic value of the electricity produced and the ancillary services supplied during the simulation are calculated and displayed. Note that economic value is measured in nominal dollars for the user-specified water year. Appendix 3 describes the economic value of hydropower and the factors which influence it.

> *Spinning reserves*. The economic value of the spinning reserves supplied is the user-specified price of the spinning reserves times the user-specified quantity supplied. For further information about spinning reserves, see the description of the tabbed page entitled, “Aux. Services.”
>
> *Area load control.* The economic value of the area load control services supplied is measured by the user-specified price of the services times the user-specified quantity supplied. See the description of the tabbed page entitled, “Aux. Services” for further information.
>
> *Generation*. The economic value of the electrical energy produced is the sum, over all of the hours in the simulation, of the hourly avoided cost times the amount of energy generated in that hour. The hourly avoided cost is the hourly price of electricity minus the user-specified variable cost of operating the powerplant. See Appendix 7 for a further description.

Warning. Under certain conditions a warning message will be displayed in the summary numerical output. Ordinarily, these will also be preceded by the appearance of a warning message dialog box. For further information consult the section entitled "Warning Messages."

Input Data

The "Input data" tabbed page, shown in Figure 1, contains an interface for setting the monthly volume of water released at Glen Canyon Dam, the elevation of Lake Powell, the month of the analysis and the water year of the analysis.

Monthly release volume. All other things being equal, the amount of water available for release during any given month determines the maximum release (or capacity) and the minimum release from Glen Canyon Dam.

The user can enter a wide range of monthly release volumes for analysis purposes. Typically, Glen Canyon releases range from about 500,000 to about 2,500,000 af per month. Appendix 6 contains representative monthly release volumes which can be employed in the absence of more specific hydrologic information.

Monthly release volumes entered by the user are tested to ensure that they are sufficient to allow the specified minimum flow to be met. If not, a warning message will appear prompting the user to increase the monthly volume (or reduce the minimum flow constraint).

Note: monthly release volume, reservoir elevation, and maximum daily change are not independent parameters. It is up to the user to determine realistic combinations of these parameters.

Reservoir elevation. The elevation of Lake Powell determines the amount of head available to run the generators. The reservoir is full at 3,700 feet above mean sea level, and the maximum amount of water that can be released through the powerplant when the reservoir is full is 33,200 cfs. As the level of the reservoir decreases, the distance from the surface of the lake to the tailwater falls— reducing the gross head. Correspondingly less water can physically be released from the dam as the reservoir elevation falls.

The elevations of the generator penstocks (intakes) and the outlet works (the spillways and hollow jet tubes) constrain monthly release volumes in certain elevation ranges. Power cannot be generated if the reservoir surface elevation falls below 3,490 feet. The jet tubes are located at elevation 3,500 feet. If lake elevations fall below this level, water cannot be released through the jet tubes. The spillways are located at elevation 3,648 feet. The spillways cannot be used if the reservoir falls below that elevation.

A warning message will appear if the user specifies a lake elevation that is incompatible with a specified release volume. For example, if the user specifies a lake elevation of 3,495 feet and a monthly release volume that exceeds powerplant capacity, a warning message will appear. If this message appears, the user should re-examine the monthly volume specified and the lake level specified. Appropriate adjustments must be made.

Again, it cannot be overemphasized that reservoir elevation is not independent of monthly release volume. For instance, high discharges are unlikely to occur under low reservoir conditions. Spills will never occur under low reservoir conditions. Thus, the user must make realistic and informed choices for reservoir elevation in combination with other related parameters. Appendix 6 contains representative monthly release volumes and reservoir elevations which can be employed in the absence of more specific hydrologic information.

Month. The month of the analysis can be selected by the user with the drop-down combination box. Selection of a particular month automatically determines the number of hours in the simulation period as well as the appropriate load and price data for the analysis.

Water year. In the Western United States, a water year is defined as the period October 1 through September 30 and spans parts of two calender years. The water year used for the analysis can be selected using the drop down combination box. The user-specified water year used for the analysis is shown in the numerical output. The user-specified month in the water year is shown in the numerical output.

Constraints

The “Constraints” tabbed page contains a user interface for setting three of the environmental constraints used in the hourly simulation.

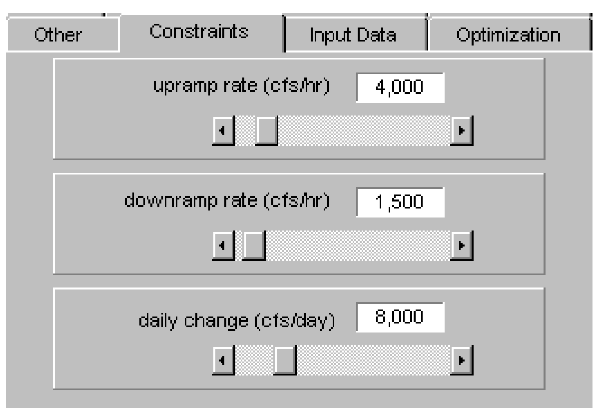

Figure 3. The Constraints Tabbed Page

Upramp rate. The upramp rate is the maximum rate at which the flow can be increased from one level to a higher level measured over an hour. Historically, the upramp rate ranged from

1,000 cfs/hr to 31,500 cfs/hr. All other things being equal, the greater the upramp rate, the higher the maximum release that can be achieved. Conversely, a lower or more restrictive upramp rate will result in lower maximum releases.

Downramp rate. The downramp rate is the maximum rate at which the flow can be decreased from one level to a lower level measured over an hour. Historically, the downramp rate ranged from 1,000 cfs/hr to 31,500 cfs/hr. All other things being equal, the greater the downramp rate, the higher the maximum release that can be achieved. Conversely, a lower, or more restrictive, downramp rate will result in a lower maximum release.

Maximum daily change constraint. The maximum daily change constraint limits the amount of flow fluctuation in any rolling 24-hour period. In practice, this constraint is often the limiting constraint (in a mathematical programming sense). When there is a restrictive maximum daily change constraint, the difference between the maximum flow and the minimum flow is often limited by the magnitude of this constraint. For example, if the maximum daily change constraint is 8,000 cfs, the difference between the maximum flow and the minimum flow in any 24-hour period is always 8,000 cfs or less.

For the analysis of steady flow alternatives, the maximum daily change should be set to 0.

Minimum flow

The "Minimum flow" tabbed page contains an interface for setting the minimum flow constraint used in the hourly simulation. The user can select either a constant minimum flow or an hourly varying minimum flow. The default hourly varying minimum flow file contains the pattern of minimum flows specified in MLFF.

The minimum flow parameter places a lower limit on the amount of water (in cfs) that can be released from the dam under normal operating conditions. The minimum flow constraint can differ for each hour of the day. This program requires the user to input monthly release volumes which are at least large enough to meet this constraint. If the user-specified monthly release volume is insufficient to meet this constraint, the program will calculate the volume required to meet the indicated minimum flow and an error message will appear.

Maximum flow

The maximum flow parameter places an upper limit on the amount of water (in cfs) that can be released from the dam under normal operating conditions. Under conditions of very high monthly release volumes, this constraint may be exceeded to achieve the monthly release volume specified by the user. In the event that the indicated monthly volume requires the powerplant to be baseloaded, a warning message will be displayed. In the event that the monthly release volumes are so large that the jet tubes or spillways must be opened, appropriate warning messages are displayed.

In cases in which the reservoir elevation is sufficiently low and the maximum flow constraint is sufficiently large, the physical capacity to release water may be less than the maximum flow constraint.

In version 2.0 of GCPSE95, only a constant maximum flow can be specified.

Other

The "Other" tabbed page contains user options for setting the variable cost of hydropower production and a scale factor for hourly energy price.

Varcost. The variable cost of hydropower production is the incremental cost of producing one additional megawatt-hour of electricity. In practice, this cost is often estimated by using the average "production cost" at a facility.

Price scale factor. The user-specified scale factor is applied to each hourly price to scale it upwards or downwards based on information available to the analyst.

Optimization

The "Optimization" tabbed page contains user options for setting the length of the optimization horizon used by the program. In the GCPSE95 version 2.0 program there are two options. These are a monthly time horizon or a typical week approach. The optimization approach selected by the user is reported in the output as "run type = month," or "run type = week."

Month. When the monthly optimization approach is selected by the user, the solution algorithm optimizes over all the loads for the month. This "perfect foresight" approach is subject to criticism on the grounds that human operators of the facility cannot anticipate hourly demand over a month.

Typical week. If the typical week approach is employed, the hourly varying prices and loads which occur chronologically are reduced to a "typical week." In a typical week, each hour for each day of the week is represented by the mean value for that hour for the month. For example, the value for hour 5 on a Monday is the mean value calculated for hour 5 over all Mondays in the month. This approach is subject to criticism because simulated release and generation is identical for, for example—all Mondays in the month, a condition not observed in the data.

Output

The "Output" tabbed page contains a user interface for selecting the type of output(s) produced by the model.

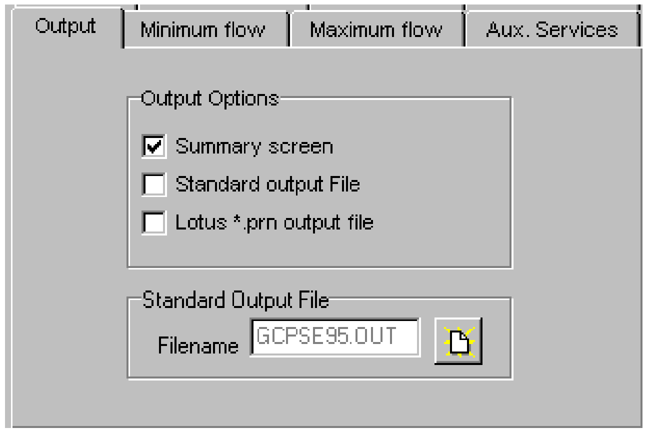

Figure 4. The Output Tabbed Page

Summary results screen. The summary results screen is the default output option. When the program is run for the month of December using the default parameter and constraint settings, the graphical and numerical outputs shown in Figure 2 are produced.

Standard output file. If the user "checks" the option for a standard output file, a voluminous results file will be written to the specified file. This file contains not only the summary output information but also the simulated release and generation for each hour of the month. A standard two-record-per-day data format is used.

Lotus *.prn file. If the user "checks" the option for a Lotus *.prn file, a Lotus 1-2-3 print file will be generated. This text file can be read directly by most common spreadsheet programs. This file format is particularly useful for post-processing and additional analyses.

Auxiliary Services

The "Aux. Services" tabbed page allows the user to specify the amount and value of the auxiliary services furnished by the hydropower plant.

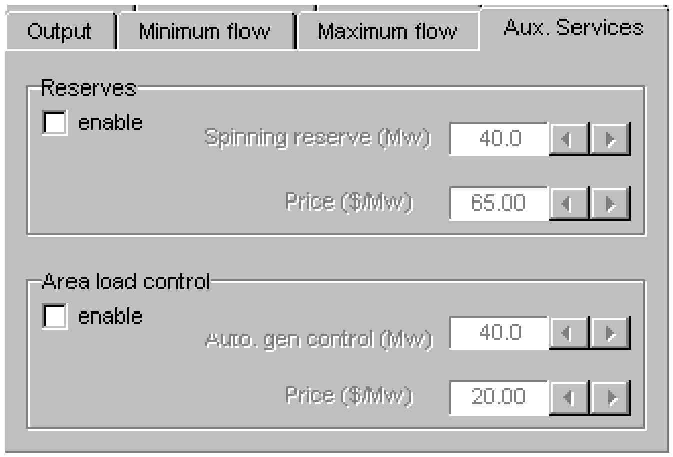

Figure 5. The Auxiliary Services Tabbed Page.

Spinning reserves. Spinning reserves are deliberately idled generation capabilities which are electrically synchronized (spinning) and available for instant use should a system emergency, such as a unit outage or transmission line failure, occur. In addition to good business practice, provision of spinning reserves is necessary for the reliability of the interconnected electricity system and each utility is required to share in their provision by regional reliability councils such as the Western System Coordinating Council (WSCC). In the model, spinning reserves are characterized as purposeful reductions in generation capabilities. The increment between what is generated and what could be generated without the reservation is then available for sale as an auxiliary service to other utilities. The provision of spinning reserves may be limited by high or low release volumes and/or may conflict with user-specified minimum and maximum release constraints. In these cases, appropriate warning messages will appear.

Spinning reserve price. By using the appropriate spinner button, the user can increase or decrease the amount of spinning reserves used in the analysis. The spinning reserve price is applied to each unit of spinning reserves sold for each hour in the month.

Area load control. Area load control (ALC) services are the provision of frequency and voltage control, dispatch, load balancing and reactive power supply. Like spinning reserves, these are required for the functioning and stability of the interconnected utility system. The provision of ALC is often computerized or "automatic" and is manifested by second to second fluctuations in generation and release. These second to second changes in generation (a) occur within an hourly time-step, and, (b) are assumed to have a mean of zero over an hour. Therefore in many situations, they will have no apparent effect on the modeled output. The provision of ALC services, may be limited by the minimum and maximum flow constraints and release volumes. When these limitations occur, appropriate warning or information messages are issued by the model.

Area load control price. By using the spinner buttons, the user can increase or decrease the amount of area load control used in the analysis. The area load control price is applied to each unit of area load control sold for each hour in the month.

Warning Messages

Powerplant baseloaded This message indicates that releases (and power generation) are constant across all hours of the day. This condition can occur in three situations: (1) the maximum daily change constraint is set to 0.0, (2) the monthly volume specified by the user produces an average daily flow within 25 cfs of the maximum release constraint specified, or, (3) the specified monthly release volume produces an average daily flow within 25 cfs of the maximum release physically possible.

Opening jet tubes. The outlet works at Glen Canyon Dam consist of two spillways and four hollow jet tubes. These four tubes have a combined release capacity of 15,000 cfs. This message indicates that the user-specified monthly release volume produces average flows exceeding powerplant capacity (33,200 cfs) but less than the combined capacity of the generators and the hollow jet tubes (33,200 cfs + 15,000 cfs = 48,200 cfs). This necessitates opening the jet tubes. Water released through the jet tubes is "spilled" and does not generate electricity. From a power production standpoint, this is undesirable. If this warning message appears, the user may wish to re-examine the monthly volume specified and verify that it is realistic.

Opening spillways. This message indicates the user-specified monthly volume produces average flows exceeding the combined capacity of the generators and the hollow jet tubes (48,200 cfs) which necessitates opening the spillways. Since this condition has occurred only a few times since the dam was constructed, the user may wish to re-examine the monthly release volume specified.

Flashboards in use. This message indicates the user-specified lake elevation exceeds the current full pool level of 3,700 feet above mean sea level. Elevations in excess of 3,700 feet would require the installation of flashboards on the spillways. Actual installation of these flashboards would require National Environmental Policy Act (NEPA) compliance due to potential impacts on natural and cultural resources around Lake Powell.

Minimum flow constraint exceeds some loads. This message indicates that the user supplied aggregate load curve is exceeded by the minimum flow constraint for at least one hour. A non-zero value for dump energy will appear in the results following this message. While it may be the case that the minimum flow constraint is sufficiently high that dump energy results, this message is more likely to indicate an inconsistency in the analysis. In particular, careful consideration should be given to the nature of the load curves being used for the simulation.

Information Messages

Software license expired. The use of the GCPSE95 program is limited to a particular date range by a relatively sophisticated copyright protection algorithm. The appearance of this message indicates the useful life of the program has passed. Contact the author (see "Technical Assistance) or check the download site for program updates.

Month not specified. The appearance of this message indicates the user has failed to specify a month for the analysis. Select a month from the drop down list to proceed.

Area load control and minimum flow constraints may conflict. Under certain conditions where the specified monthly release volume is relatively low and the user has enabled area load control, there may be conflicts between the ability to provide ALC and the minimum flow constraints. These conflicts cannot be detected before a simulation. The user is advised to examine the output, particularly the graphical output, to ensure no such conflicts occurred.

Invalid release volume. The appearance of this message indicates a non-numeric character (such as a comma) has been entered in the monthly release volume edit box. Review the entry in this field and correct it as appropriate.

Error Messages

Load, price or minflow file not found. The appearance of this error message indicates the program is unable to find the indicated file in the current directory. There are two possible causes for this. First, it is possible the file is not present because it was not copied to the directory or was inadvertently deleted. Using Windows Explorer, ensure the file is present before continuing with the analysis. If it is not, you will need to restore the file to the correct location or reinstall GCPSE95.

Max and min flow constraints conflict. This message indicates that either the user-specified maximum and minimum flow constraints cannot be satisfied simultaneously (usually because they overlap) or they are within 2,000 cfs of each other. This problem must be corrected before the simulation can proceed.

Spinning reserves cannot be sustained. In the event there is insufficient water release to attain the amount of generation implied by the user-specified level of spinning reserves, this message will appear. Either the monthly release volume must be increased or the specified level of spinning reserves must be decreased before the simulation can proceed.

Spinning reserves, max, minflow constraints conflict. If there is a logical conflict between the user-specified level of spinning reserves and the maximum or minimum flows, this message will appear. Either the maximum flow constraint will need to be increased or the spinning reserves or minimum flows, or both, will need to be decreased before the simulation can proceed.

ALC conflicts with release volume. If the user-specified level of area load control (ALC) and the average monthly release are too high relative to the maximum amount of water which could be released at the specified reservoir elevation, the required generation could not be achieved and this message will appear. It is recommended that the level of ALC be reduced in order to proceed with the analysis.

Minflow cannot be sustained with monthly volume. If the monthly release volume is too low to allow the user-specified minimum flow to be achieved, this message will appear. Either increase the monthly release volume or decrease the minimum flow to continue with the simulation.

Monthly release incompatible with lake elevation. The monthly release volume and reservoir elevation level are not independent of each other. It is the user's responsibility to ensure these are logically consistent with each other. In the event that the user-specified release volume exceeds the physically attainable release, at the specified reservoir elevation, this message will appear followed by "**(Error 1)**". In the event the user-specified release volume exceeds the amount which can physically be released through both the turbines and the jet-tubes, at the specified reservoir elevation, this message will appear followed by "**(Error 2)**". In either case, the user must reduce the monthly release volume or increase the reservoir elevation to proceed with the simulation.

Fatal Error Messages

PS algorithm failure. In some extremely rare circumstances, the peakshaving algorithm may fail to converge. Should this occur, this error message will be issued and all subsequent output, if any, is meaningless. If this condition can be replicated, please record the values of all parameters and call for technical assistance.

Logic error abort. The area under the aggregate load curve is equal to the total amount of energy demanded during a day. This area can be converted from an energy measure to an equivalent water volume. If the user supplied water volume exceeds the water volume implied by the aggregate load curve, (a) it is likely that the analyst has made a logic error, (b) the peakshaving model cannot converge to a unique solution, (c) this error message appears, and (d) the program halts.

Other Topics

Program failures. Although this program has been tested extensively, it is possible that some unforeseen runtime errors may occur during use. If a runtime error or other failure occurs, (1) record the error message and the runtime error code number, (2) record the values of all parameters at the time of the mishap, and (3) see if you can consistently cause this error to occur.

If you have faithfully completed steps 1, 2, and 3, above, without resolution of the problem, please call for technical assistance.

Known program deficiencies. The following are currently known deficiencies in GCPSE95.

1. Entry of non-numeric characters (such as commas) when numerical entries are required may result in various implicit or explicit errors. Most of these errors are trapped and corrected by the program, but others are not. For example, entry of the string '5,000,000' may cause an error message. Where a numeric response is requested, enter only numeric characters.

2. Because the graphical results are plotted to the nearest hour, they may not correspond exactly with the numerical results. The numerical results should be used for any subsequent analyses.

Technical Assistance

To report errors or obtain technical assistance contact:

David A. Harpman
Economics Group
U.S. Bureau of Reclamation
P.O. Box 25007 (D-8270)
Denver, CO 80225
(303) 445-2733 [voice]
(303) 445-9438 [FAX]
dharpman@do.usbr.gov [e-mail]

Limitations

The short-run estimates of economic value estimated by the GCPSE95 model are sensitive to the quantity and pattern of water release across the year, the reservoir elevations used, and conditions in the electric power market which are reflected by spot market prices. The GCPSE95 modeling framework simulates the operation of Glen Canyon Dam in isolation from the other CRSP units. Admittedly, the opportunity to manage other CRSP units in a discretionary manner is limited. However, to the extent that operational flexibility exists, these units could be used to partially offset the power system impacts of changes in operations at Glen Canyon Dam. Finally, this analysis is restricted to direct power system impacts. Although releases from Glen Canyon Dam have been shown to affect economic use value (Bishop et al 1987), total economic value (Welsh et al 1995) and emissions in the region (Bureau of Reclamation 1995, Power Resources Committee 1995), these topics are not addressed here.

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Appendix 1. Glen Canyon Dam and Lake Powell

Location

Glen Canyon Dam and Lake Powell are located on the Colorado River in Arizona. Electricity produced at the powerplant is sold predominantly in a six-state region comprised of Nevada, Utah, Arizona, Wyoming, Colorado and New Mexico. Figure 6 illustrates the location of this facility within the region.

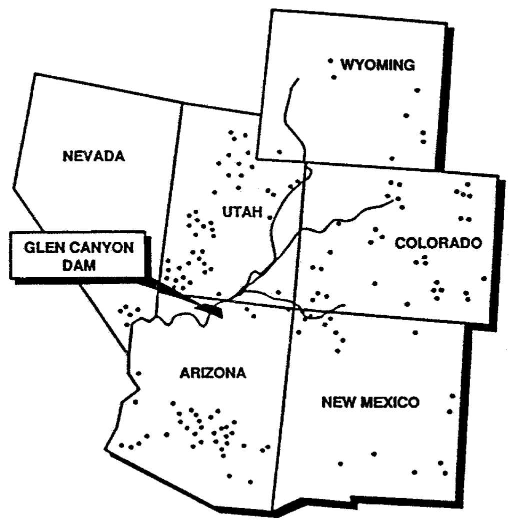

Figure 6. Location of Glen Canyon Dam within the six-state region.

Lake Powell

Glen Canyon Dam creates a reservoir named Lake Powell, after John Wesley Powell the Civil War Veteran and first person of European descent to travel through the Grand Canyon. When full (when the water level is 3,700 feet above mean sea level), Lake Powell is approximately 186 miles long and has a shoreline of approximately 1,960 miles. The principal tributaries into the lake are the Colorado, Escalante and the San Juan Rivers. The average (regulated) annual inflow into Lake Powell from all sources is approximately 11,500,000 acre-feet.

Lake Powell was first filled on June 22,1980, 17 years after the closure of outlet works. The total storage capacity is 26,215,000 acre-feet. The "live" capacity (volume above the intake elevation of the jet tubes) of the lake is 24,400,000 acre-feet or approximately 2.1 times the average annual inflow. The average annual evaporation loss from the lake is approximately 2.5% of the volume.

Glen Canyon Dam

Glen Canyon Dam, shown in Figure 7, is a 710-foot-high concrete thick arch dam. It is the second highest dam in the United States (Hoover Dam is 16 feet higher). Construction of the Glen Canyon Dam began on October 1, 1956; the reservoir started filling on March 13, 1963; and the first electric power was generated on September 4, 1964.

Figure 7. Aerial view of Glen Canyon Dam showing the jet-tubes and the spillways in use.

The outlet works at Glen Canyon Dam are composed of four hollow “jet tubes” and two spillways. These outlet works are used only under special conditions, primarily to accommodate releases from the dam that exceed the amount of water which can be released through the powerplant. Such releases may occur when the reservoir is full and tributary inflows exceed the powerplant’s capacity, or they may be ordered for environmental purposes such as the 1996 Beach-Building/Habitat-Maintenance flow.

The hollow jet tubes consist of four 96-inch-diameter pipes. Each outlet pipe is controlled by one 96-inch ring follower gate and one 96-inch hollow jet valve. The combined release capacity of the four hollow jet tubes is 15,000 cfs. The intake elevation of the jet tubes is approximately 3,374 feet or 326 feet below the surface when the reservoir is full. The jet tubes cannot be used to release water when the reservoir elevation falls below 3,374 feet. These elevations are illustrated in Figure 8.

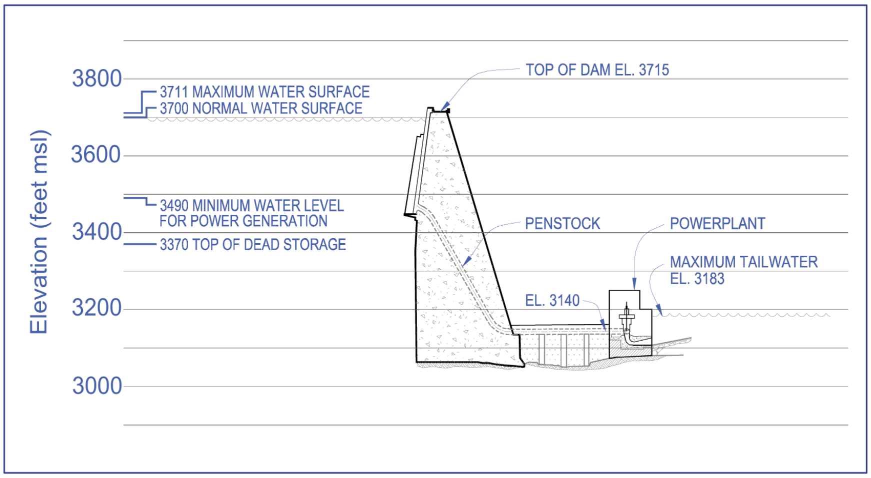

Figure 8. Lake Powell and Glen Canyon Dam Important Operating Elevations.

Each of the two spillways consists of an intake structure with two 40- by 52.5-foot radial gates and a concrete-lined spillway tunnel. These are located on both sides of the dam. Each spillway is capable of releasing 104,000 cfs when the reservoir is full (3,700'). Their combined release capacity is approximately 208,000 cfs. The elevation of the spillway crest is 3,648 feet. The spillways cannot be used to release water from the reservoir when the lake elevation falls below 3,648 feet.

Powerplant

The powerplant at Glen Canyon Dam is made up of eight hydro-generation units. Five of these units are rated at 165 MW and 3 are rated at 157 MW. The combined nameplate or installed generation capability of the powerplant is 1,296 MW (at a 95% power factor). A separate penstock feeds each of the eight Francis type turbines which produce approximately 155,000 horsepower. Current operating rules require at least 40 feet of submergence to prevent the entrainment of air into the penstocks with subsequent damage to the turbines. As a result, the powerplant cannot be operated at lake elevations below 3,490 feet. Each turbine has a release capacity of approximately 4,150 cfs generating when the reservoir is full. The nominal powerplant release capacity is 33,200 cfs. At the Glen Canyon Dam substation there are four large step-up transformers, one for each pair of generation units. The capacity of these transformers is 300 megavolt amperes (MVA) at 50 degrees Fahrenheit. These transformer constraints effectively limit the sustained generation capacity of the powerplant to approximately 1,200 MW. This generation level is equivalent to a release of approximately 30,000 cfs when the reservoir is full.

Monthly operations

Glen Canyon Dam is an integral part of the Colorado River Storage Project (CRSP). Based on projected hydrologic conditions, monthly and annual release volumes for all major CRSP facilities are established by the Annual Operating Plan at the beginning of the water year, which runs from October to September. Releases are then adjusted during the water year to reflect actual inflow conditions. Hydropower production at CRSP facilities is “incidental” to all other purposes including international treaty obligations, basin storage, municipal and industrial uses, agriculture, flood control, and fish and wildlife uses. CRSP operations, pertinent treaties, decrees and regulations which comprise the “Law of the River” are described in Nathanson (1980).

Environmental considerations

During the period 1963 through 1991, Glen Canyon Dam was operated primarily to produce power during on-peak periods while meeting minimum flows during the remaining hours. These operations are referred to as “historical operations.” Historical operations caused 7 to 12 foot fluctuations in the elevation of the river below the dam (Bureau of Reclamation 1994, Appendix D). These fluctuations have been shown to affect the quality of the recreation (Bishop et al 1987), aquatic resources (Maddux et al 1988) and riparian resources (Stevens et al 1995).

The Operation of Glen Canyon Dam Environmental Impact Statement (GCDEIS) was initiated in 1989 to examine options which, “...minimize—consistent with law—adverse impacts on downstream environmental and cultural resources and Native American interests...”. The environmental impacts of nine operational alternatives, ranging from unrestricted operations to baseloading of the powerplant, were examined in the final GCDEIS (Bureau of Reclamation 1995).

On October 9, 1996, the Secretary of the Interior, Bruce Babbitt, issued a Record of Decision (ROD) on future operations at Glen Canyon Dam. Based largely on Endangered Species Act considerations, the Secretary announced the facility will be operated according to the Modified Low Fluctuating Flow (MLFF) alternative. Under MLFF new restrictions were imposed on maximum flows, minimum flows and the daily change in flow. Table A8.1 in Appendix 8 compares the historical and MLFF operating criteria.

The MLFF operating criteria were designed to reduce fluctuations in river elevations to a range of from 1 to 3 feet (Bureau of Reclamation 1994, Appendix D). Minimum flows, maximum flows, ramping rates and allowable daily fluctuations were established with the goal of protecting downstream resources while allowing limited flexibility for power operations. As shown in Figure 9, operations under MLFF are considerably different than historical operations.

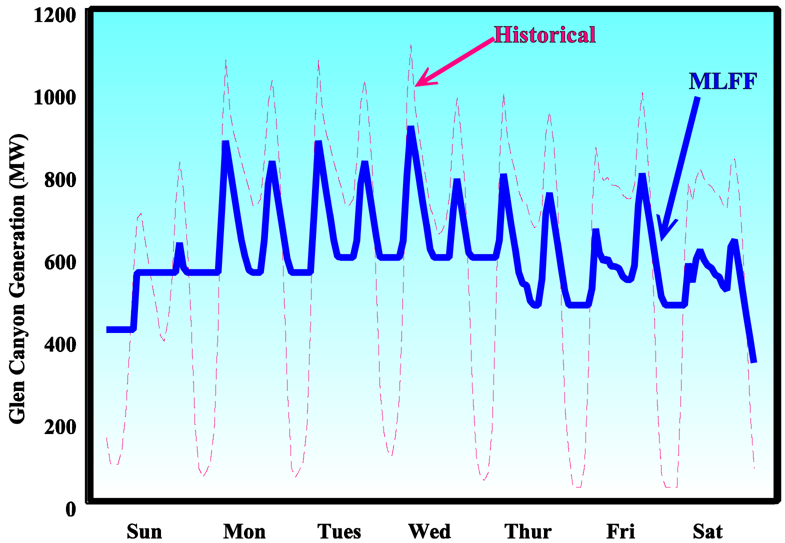

Figure 9. Hourly Generation Under the Historical and MLFF Operation Criteria Simulated Using the GCPSE95 Model.

Adaptive management is a key component of MLFF. Adaptive management is a process, "...whereby the effects of dam operations on downstream resources would be assessed and the results of those resource assessments would form the basis for future modifications of dam operations (Bureau of Reclamation 1995, p. 34).

A Federal Advisory Committee called the Adaptive Management Workgroup (AMWG) was formed to advise the Department of the Interior on adaptive management in the Grand Canyon. The bulk of this work is carried out under the auspices of the Grand Canyon Monitoring and Research Center (GCMRC). A recent paper by Walters, Korman, Stevens and Gold (2000) describes a large-scale modeling effort undertaken as part of the adaptive management program.

One of the early applications of adaptive management was the 1996 Beach-Building Habitat-Maintenance Flow. This 7-day controlled flood was conducted in late March and early April of 1996 for research purposes. This short-duration high release was designed to rebuild high-elevation sand-bars, deposit nutrients, restore backwater channels and partially restore the dynamic nature of the riverine environment.

Much of the data from this controlled flood have now been analyzed and the research results have been published. The two best sources are; *The Controlled Flood in Grand Canyon* (see Harpman 1999b) and an invited issue of *Ecological Applications* (see Patten, Harpman, Voita and Randle 2001). Since 1996 there have been several additional experimental flows. The most recent of these was the Low Steady Summer Flow experiment, which took place during the summer of 2000. There are likely to be additional experimental flows, both low and high, in future years.

In addition to the modification of flows below the dam, an analysis of temperature regime modification is now underway. Much of this work is focused on the feasibility (and desirability) of installing and operating a temperature control device (TCD) at the dam (see Bureau of Reclamation 1999). Thermal and chemical stratification develops in Lake Powell during the summer months. When the reservoir is full, the water surface elevation is 3,700 feet. The generator penstocks are located at a depth of 3,476 feet which is within the cold hypolimnetic strata. As a result, releases from Glen Canyon Dam remain about 50 degrees Fahrenheit all year long. Long-lived native fish populations persist at these relatively low temperatures, but it is believed their spawning and/or spawning success is greatly reduced.

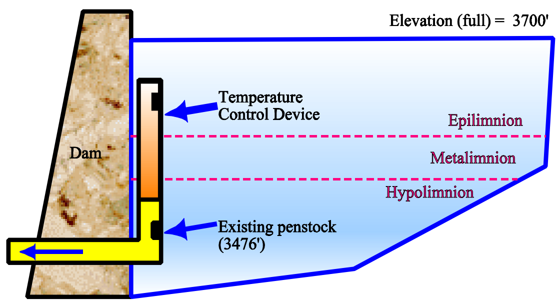

Figure 10. TCD Conceptual Design

A TCD will selectively withdraw water from the shallower layers of water. As shown in Figure 10, the concept is to extend the penstock upward and withdraw warmer water from one or more ports. Detailed temperature modeling of several designs is now being conducted. The goal of these modeling efforts is to evaluate their ability to alter the thermal regime downstream and ascertain the probabilities of successful outcomes.

The biological response to a change in temperature regime remains a critically important but largely unanswered question. It is hypothesized that the spawning and survival of native fish species will be enhanced by warmer temperatures. However, the conditions for exotic species such as trout, catfish, carp and red shiners may also be improved. Some of these exotics prey upon the native species, and others may compete for the same food sources or inhabit similar habitat areas. As a consequence, it is difficult to forecast the net result of increases in temperature on native fish populations.

Appendix 2. Electric Power Concepts

Electricity cannot be efficiently stored on a large scale using currently available technology. It must be produced as needed. Consequently, when a change in demand occurs, such as when an irrigation pump is turned on, somewhere in the interconnected power system the production of electricity must be increased to satisfy this demand. In the language of the utility industry, the demand for electricity is known as "load." Load varies on a monthly, weekly, daily, and hourly basis. During the year, the aggregate demand for electricity is highest when heating and cooling needs, respectively, are greatest. During a given week, the demand for electricity is typically higher on weekdays, with less demand on weekends, particularly holiday weekends. During a given day, the aggregate demand for electricity is relatively low from midnight through the early morning hours, rises sharply during working hours, and falls off during the late evening.

The large variation in hourly, daily, and seasonal loads has important implications for the electrical generation system. In particular, it greatly influences the amount of generation capacity required and therefore the capital cost of the system. This can be readily illustrated by two extreme cases. For the first example, assume the demand for electricity is constant and is 1.0 MW at all times. This would imply (ignoring security and reliability concerns) that a utility could supply this demand by building a 1.0 MW power plant and operating it continuously. For a month (30 days), this would imply generation of 1.0 MW for 720 hrs, which would generate 720 MWhrs of electricity. In example number two we will assume the demand for electricity is quite variable. We will assume it is 1 MW for (1) hour of the month and 0.1 MW for the rest of the hours in the month. In the latter example, the costs of constructing a 1 MW power plant must also be incurred but the plant generates only 72.9 MWhrs of energy (1MW×1 hr + 0.1MW×719 hrs) or approximately 10% of its potential. This example is somewhat extreme but is nonetheless illustrative[1]. The highly variable nature of the demand for electricity (See Figure 11) results in the following observable characteristics of the electrical power system; (1) many power plants are idle for some or all of the day or season, and, (2) the capital costs of electricity production are quite high relative to operational costs.

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[1]Nationwide, the total annual energy generated is approximately 50% of the total generation capability. This reflects an average load factor of about 60%, a variety of reserves and margins, as well as scheduled and forced outages.

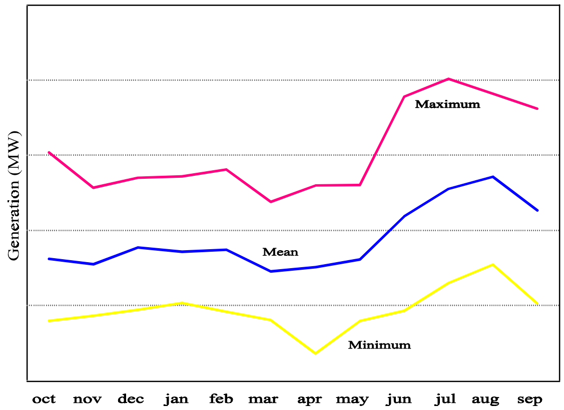

Figure 11. Seasonal Demand for Electricity

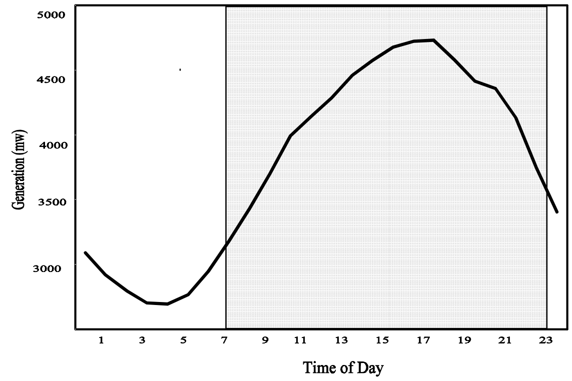

Figure 12. Demand for Electricity on a Typical August Day.

Electric energy is most valuable when it's most in demand— during the day when people are awake and when industry and businesses are operating. This period, illustrated in Figure 12, when the demand is highest, is called the "on-peak period." In the West, the on-peak period is defined as the hours from 7:00 a.m. to 11:00 p.m., Monday through Saturday. All other hours are considered to be off-peak.

The maximum amount of electricity that can be produced by a powerplant is called its capacity. Capacity is often measured in megawatts (MW). The capacity of thermal powerplants is determined by their design and location and is essentially fixed. In the case of hydroelectric powerplants, capacity varies over time because it is a function of reservoir elevation, the amount of water available for release, and the design of the facility. Because the capacity at hydropower plants is highly variable, the amount of dependable or marketable capacity is of particular significance. This amount of dependable or marketable capacity is determined using various probabilistic methods (e.g. Ouarda, Labadie and Fontane 1997).

Appendix 3. Economic Value of Hydropower

The economic value of operating an existing hydropower plant is measured by the avoided cost of doing so. In this context, avoided cost is the difference between the cost of satisfying the demand for electricity with and without operating the hydropower plant. Conceptually, avoided cost is the savings realized by supplying electricity from a low-cost hydropower source rather than a higher cost thermal source. These savings arise because the variable cost of operating a hydropower plant is relatively low in comparison to thermal units. For example, the variable cost of operating an average hydropower plant in 1995 was $5.89 per megawatt hour (MWhr). In contrast, the variable cost of operating the average fossil-fuel steam plant was $21.11 per MWhr and the variable cost of operating the average gas turbine peaking unit was approximately $28.67 per MWhr (Energy Information Administration 1996).

The economic value of operating an existing hydropower plant varies considerably with time of day. The variable cost of meeting demand varies on an hourly basis depending on the demand for electricity, the mix of plants being operated to meet demand, and their output levels. During off-peak periods, demand is typically satisfied with lower cost coal, run-of-river hydropower, and nuclear units. During on-peak periods, the additional load is met with more expensive sources such as gas turbine units. Consequently, the economic value of hydropower is greatest during the hours when the demand for electricity, and the variable cost of meeting demand, is the highest.

If the variable cost of purchasing an additional megawatt of electricity from a least-cost source were observable in the market, the economic value of producing hydroelectricity could be readily determined. For example, assume that the cost of purchasing a megawatt of electricity from the least-cost source was $30.00 in a particular hour, and the cost of producing a megawatt of hydroelectricity was $6.00. Then, the avoided cost or economic value of producing an additional megawatt of hydropower at that time would be $24.00 (30.00-6.00).

Appendix 4. The Peakshaving Algorithm

As detailed in Wood and Wollenberg (1996), given knowledge about existing generation resources, expected load, the amount of water available for release, regulatory constraints, and engineering limitations, the hydropower producer attempts to generate as much power as possible when it is most valuable. Hourly releases from the dam, q_h , are the variable under management control.

The constraints considered at Glen Canyon Dam are unique and outside the capability of most existing models. The peakshaving algorithm (Staschus, Bell, and Cashman 1990), which is also used in several commercial power system models, e.g. PROSYM (Simulation Group 1995) and ELFIN (Environmental Defense Fund 1996), allows for the efficient formulation and solution of this specialized problem. The model employed in this application uses the peakshaving algorithm to reduce peaks in the aggregate load curve, subject to operational and environmental constraints, by optimally releasing water for hydropower generation. This model allows for varying reservoir elevations and represents, in detail, the physical and engineering features of the Glen Canyon Dam and powerplant.

Three functions are used to formulate the model. The first function, fe[q_h, ele_h] calculates the electric energy produced in hour h by an hourly release q at a given reservoir elevation, ele. Both release and energy output are assumed to be constant over any given hourly time step. This function is specified in Appendix 5. The second function, ef[·], is used to calculate the release, q_h, required to produce a given amount of electrical energy at a given reservoir elevation. This relationship is obtained by solving the equation shown in Appendix 5 for release, q_h. The third function, fv[·], converts a release q, measured in cfs and maintained for a one hour period, to an equivalent water volume measured in acre-feet (af). It is given by fv[q]=q×0.0826.

The function describing the optimal series of hourly releases, $q_h(x)$, where h ranges from 1 to H, is shown in (1). Note that q_h (x) is discontinuous and monotonically decreasing in x. In equation (1), the expected aggregate load in hour h is L_h, the maximum generation release (capacity) is c, and x is an arbitrary level of release.

$$q_h(x) = \begin{Bmatrix} minf_h, & if\ ef[L_h] \le x \\ ef[L_h] - x, & if\ x \le ef[L_h] \le x + c \\ c, & if\ ef[L_h] \ge x + c \end{Bmatrix} \tag{1}$$

The peakshaving algorithm uses an iterative binary search routine to find an x that uniquely satisfies equation (2) subject to the set of constraint equations (3) through (8).

$$\sum_{h=1}^{H} fv[q_h(x)] = mvol \tag{2}$$

ST:

$$q_h(x) - q_{h-1}(x) \leq uprate \quad \textbf{(3)}$$

$$q_{h+1}(x) - q_h(x) \leq downrate \quad \textbf{(4)}$$

$$q_h(x) \geq minf_h \quad \textbf{(5)}$$

$$q_h(x) \leq c \quad \textbf{(6)}$$

$$c = \min(maxfc, pflow) \quad \textbf{(7)}$$

$$\max[q_h(x) \ldots q_{h+k}(x)] - \min[q_h(x) \ldots q_{h+k}(x)] \leq mdc \quad \textbf{(8)}$$

Where:

H	=	the number of hours in the month
h	=	the hour during the month
q_h	=	generation release (cfs) in hour h
L_h	=	expected aggregate load (MW) in hour h
maxfc	=	maximum flow constraint for the alternative
$minf_h$	=	minimum flow constraint in hour h (cfs)
uprate	=	upramp rate (cfs/hr)
downrate	=	downramp rate (cfs/hr)
mdc	=	maximum daily change in flow constraint (cfs/24 hrs)
mvol	=	release volume during the month (af)
pflow	=	the maximum flow which can be passed through the generators at a given lake elevation (cfs)
k	=	min(24, H-h)

Equation (2) is the water balance equation. This equation ensures that aggregate hourly releases equal the total amount of water available for release during the month. Equations (3) and (4) are the upramp and downramp constraints respectively. Under MLFF, the minimum flow constraint varies by time of day and is described by equation (5). Equations (6) and (7) jointly define the maximum flow constraint, which for MLFF is the lesser of 25,000 cfs or the greatest amount of water that can physically be released given the elevation of the lake. Equation (8) is the maximum daily change constraint. For MLFF, this constraint varies with the amount of water released during the month. In addition to constraint equations (3) through (8), there are a number of other physical and engineering constraints which are not shown. These additional constraints are not explicitly described since they are common to both historical and MLFF operations and are not binding except under unusual circumstances.

Appendix 5. Flow, Head and Generation

The electric energy generated at Glen Canyon Dam is a function of discharge through the turbines and reservoir elevation as shown in the equation below (units of measure shown in parentheses). Both discharge and electrical energy production are assumed to be constant over any particular hourly time step.

$$fe[q_h, ele_h] = \frac{\gamma \times q_h \times eff \times head(ele_h)}{hptokw \times 1000} \qquad \textbf{(9)}$$

Where:

h	=	hour
γ	=	62.40, specific weight of water at 50 degrees Fahrenheit (lbs/ft^3).
eff	=	0.889, efficiency factor (dimensionless).
$head(\cdot)$	=	effective head (feet).
q_h	=	turbine discharge (cfs).
ele_h	=	reservoir elevation (feet above mean sea level)
$hptokw$	=	737.5, horsepower to kilowatt conversion factor (KW/(ft-lbs/sec)).

Note: There are 1000 kilowatts in a megawatt.

The methods described in Bureau of Reclamation (1988, sections 3.38.2-3.38.5 and 1987, sections 9.1-9.2) are used to calculate effective head.

Appendix 6. Representative Monthly Release Volumes

Monthly release volumes and end-of-month reservoir elevations at Glen Canyon Dam are highly variable and dependent on a number of factors including inflow and operational considerations. The monthly release volumes in Table A6.1 below are approximately representative and may be useful for analyses undertaken in the absence of more detailed or specific hydrologic information.

Table A6.1
Representative Monthly Release Volumes and Reservoir Elevations for Glen Canyon Dam

	Monthly Volume (af)	End-of-Month Reservoir Elevation (ft)
October	850,000	3685.4
November	900,000	3683.7
December	950000	3681.6
January	1,100,000	3677.7
February	950,000	3674.8
March	850,000	3673.2
April	825,000	3673.8
May	875,000	3681.2
June	1,000,000	3690.5
July	1,050,000	3691.6
August	1,100,000	3688.4
September	850,000	3686.3
TOTAL	11,300,000	

Appendix 7. Input Data.

Avoided cost (price) data

For modeling purposes, the hydroelectric energy generated in any alternative is evaluated using a set of hourly avoided costs (prices). These avoided cost data were estimated using the AURORA model (Electric Power Information Solutions 2001). The AURORA model is a proprietary production-cost and market simulation model employed by the Northwest Power Planning Council and various private firms for comprehensive economic and financial analyses. The AURORA model estimates the hourly market clearing electricity price and calculates the total cost of operating all the powerplants in the Western System Coordinating Council area.

Load data.

An aggregate hourly load curve was assumed to represent the demand for electricity during the water year. This aggregate load curve was constructed from actual 1999 hourly load data reported by utilities in the Northwest, Rocky Mountain, and Southwest Power Pools. These publicly available data were obtained from information provided to the Federal Energy Regulatory Commission on form 714. These data represent utilities that receive approximately 95 percent of the electricity generated at Glen Canyon Dam.

Load data for the years following 1999 were estimated using the techniques described in Veselka et al, (1994 Appendix G) and forecasts of monthly energy and capacity requirements published by the Western System Coordinating Council.

Hydropower production cost.

The variable cost of hydropower production at Glen Canyon Dam was obtained from a recent study which compared a variety of performance benchmarks at private and federal hydropower plants (National Performance Review Power Management Laboratory 1997). Although there is no fuel consumed to produce hydroelectricity, hydropower production does result in mechanical wear on generating equipment and requires labor and other inputs. These costs of production vary with output level, plant design, size and number of units, and other factors. In a recently released study, the average production or variable cost of producing hydropower at Glen Canyon in fiscal year 1995 was estimated to be $1.80 /MWhr. This is slightly less than the average production cost for conventional investor-owned hydropower plants of comparable size (National Performance Review Power Management Laboratory 1997).

Appendix 8: Example—Comparing Historical and MLFF Operations

The constraints and parameters which describe the operation of Glen Canyon Dam prior to 1991 and those that guide operations today are described as "Historical" and Modified Low Fluctuating Flows (MLFF) respectively. These are listed in Table A8.1. Representative monthly release volumes and reservoir elevations can be found in Appendix 6 Table A6.1.

Table A8.1. Historical and MLFF Operating Criterion

	Historical Operation Criteria	Modified Low Fluctuating Flow[a]
Minimum releases (cfs)	1,000 Labor Day-Easter 3,000 Easter-Labor Day	8,000 between 7 a.m. and 7 p.m. 5,000 at night
[b] Maximum releases (cfs)	31,500	[c] 25,000
Allowable daily flow fluctuations (cfs/24 hours)	Unrestricted	[d] 5,000 6,000 or 8,000
Upramp Rates (cfs/hour)	Unrestricted	4,000
Downramp Rates (cfs/hour)	Unrestricted	1,500

[a] Non-operational elements and periodic special releases such as beach-building and habitat-maintenance flows, are not included in this table. See Bureau of Reclamation (1995) for details.
[b] Maximums may necessarily be exceeded during high water release years.
[c] Will be exceeded during beach-building and habitat-maintenance flows.
[d] Daily fluctuations are limited to 5,000 cfs for monthly release volumes less than 600,000 acre-feet; 6,000 cfs for monthly release volumes of 600,000 to 800,000 acre-feet; and 8,000 cfs for monthly volumes over 800,000 acre-feet.

Assume we were interested in estimating the difference in generation, capacity, minimum and maximum flow, if any, between historical operations and MLFF operations during the month of March in Water Year 2002. To estimate these differences using the GCPSE95 model, we would simulate the historical operations and the operations under MLFF and take the difference between these results.

First, simulate historical operations using the following approach.

1. Close the GCPS05 program and then re-start the program by double-clicking on the icon. This will return all of the parameter values to their default levels.
2. Select the month of March and select water year 2002.
3. Using the arrow buttons or by typing it in, ensure a monthly release volume of 850,000 af is indicated.
4. Then, enter the reservoir elevation for March from Table A6.1 (3673.2 ft).
5. Click on the “Maximum Flow” tabbed page and using the arrow buttons, set the maximum flow constraint to 31,500 cfs.
6. Click on the “Minimum Flow” tabbed page. Using the mouse, press the “Constant” flow radio button and then use the arrow buttons to set the minimum flow to 1,000 cfs as shown in Table A8.1.
7. Click on the “Constraints” tabbed page. Set the upramp rate, downramp rate and maximum daily change constraints to 40,000 cfs using the slider bars.
8. Now, click on the “Run” button to start the simulation.
9. You should obtain the results shown in the second column of Table A8.2.

Next, to simulate the operations under MLFF use the following approach:

1. Close the GCPS95 program and re-start it by double-clicking on the icon. This will return all of the parameter values to their default levels.
2. Using the drop down lists, select the month of March and select water year 2002.
3. Using the arrow buttons or by typing it in, ensure a monthly release volume of 850,000 af is indicated.
4. Then, enter the reservoir elevation for March from Table A6.1 (3673.2 ft).
5. Click on the “Maximum Flow” tabbed page. Ensure the maximum flow is set to 25,000 cfs. If not, use the arrow buttons, to set the maximum flow constraint to 25,000 cfs.
6. Click on the “Minimum Flow” tabbed page. Ensure the “Hourly varying” flow radio button is “on” and the indicated minimum flow file is “minflow.par.” The minimum flows in the minflow.par file correspond to the MLFF pattern.
7. Click on the “Constraints” tabbed page. Ensure the upramp rate is set to 4,000 cfs, the downramp rate is set to 1,500 cfs and the maximum daily change is set to 8,000 cfs.
8. Now, click on the “Run” button to start the simulation.
9. You should obtain the results shown in the First column of Table A8.2.

In general, the imposition of the MLFF criterion reduces the amount of generation capacity but does not affect the amount of energy generated at the powerplant. This results in a significant but perhaps not catastrophic economic cost which is borne both by users of Federal hydropower and potentially by all U.S. taxpayers. Due to the importance of capacity in the electric power system, there remains some debate about whether the purchase of long-run replacement capacity is necessary in addition to the economic value foregone as calculated by the GCPSE95 model. To date, no additional capacity costs have been incurred, although this will not necessarily continue in the future. MLFF has either no or very little effect on the ability of the Glen Canyon powerplant to furnish other ancillary services such as voltage and VAR control, spinning and other reserves, and blackstart capability.

Table A8.2. Comparison of Historical and MLFF Simulated Results.

	MLFF	Historical	Difference
Maximum Flow (cfs)	25,000.00	31,500.00	-6,500.00
Minimum Flow (cfs)	5,000.00	1,000.00	4,000.00
Maximum Generation (MW)	997.65	1,257.04	-259.39
Minimum Generation (MW)	199.53	39.91	159.62
turbine release (af)	850,004.90	850,000.50	Nil
generation (MWhrs)	410,435.32	410,433.19	Nil
economic value ($)	10,034,733.50	12,800,984.68	-2,766,251.18

Appendix 9: Example—Comparing Historical and SASF Operations

The constraints and parameters which describe the operation of Glen Canyon Dam prior to 1991 are described as "Historical," and an alternate operational scheme considered in the Operation of Glen Canyon Dam Environmental Impact Study (Bureau of Reclamation 1995) was termed the Seasonally Adjusted Steady Flow Alternative (SASF). The relevant parameter values for each of these are listed in Table A9.1.

Table A9.1. Historical and SASF Operating Criterion

	Historical Operation Criteria	Seasonally Adjusted Steady Flow[a]
Minimum releases (cfs)	1,000 Labor Day-Easter 3,000 Easter-Labor Day	8,000 Oct-Nov 8,500 Dec 11,000 Jan-Mar 18,000 May-Jun 12,500 Jul 9,000 Aug-Sep
[b] Maximum releases (cfs)	31,500	[c]18,000
Allowable daily flow fluctuations (cfs/24 hours)	Unrestricted	±1,000 daily 2,000 between months
Upramp Rates (cfs/hour)	Unrestricted	0
Downramp Rates (cfs/hour)	Unrestricted	0

[a] Non-operational elements and periodic special releases such as beach-building and habitat-maintenance flows, are not included in this table. See Bureau of Reclamation (1995) for details.
[b] Maximums may necessarily be exceeded during high water release years.
[c] Will be exceeded during beach-building and habitat-maintenance flows.

Presume we were interested in estimating the difference in generation, capacity, and minimum and maximum flow, if any, between historical operations and SASF operations during the month of March in Water Year 2002. To estimate these differences using the GCPSE95 model, we would simulate the historical operations and the operations under SASF and take the difference between these results.

First, simulate historical operations using the following approach.

1. Close the GCPS05 program and then re-start the program by double-clicking on the icon. This will return all of the parameter values to their default levels.
2. Select the month of March and select water year 2002.
3. Using the arrow buttons or by typing it in, ensure the typical monthly release volume for March of 850,000 af is indicated.
4. Then, enter the reservoir elevation for March from Table A6.1 (3673.2 ft).
5. Click on the "Maximum Flow" tabbed page and using the arrow buttons, set the maximum flow constraint to 31,500 cfs.
6. Click on the "Minimum Flow" tabbed page. Using the mouse, press the "Constant" flow radio button and then use the arrow buttons to set the minimum flow to 1,000 cfs as shown in Table A9.1.
7. Click on the "Constraints" tabbed page. Set the upramp rate, downramp rate and maximum daily change constraints to 40,000 cfs using the slider bars.
8. Now, click on the "Run" button to start the simulation.
9. You should obtain the results shown in the second column of Table A9.2.

To simulate operations under SASF, use the following approach:

1. Close the GCPS95 program and re-start it by double-clicking on the icon. This will return all of the parameter values to their default levels.
2. Using the drop down lists, select the month of March and select water year 2002.
3. Using the arrow buttons or by typing it in, ensure a monthly release volume of 850,000 af is indicated.
4. Then, enter the reservoir elevation for March from Table A6.1 (3673.2 ft).
5. Click on the "Maximum Flow" tabbed page. Using the arrow buttons, set the maximum flow to 18,000 cfs.
6. Click on the "Minimum Flow" tabbed page. Turn "on" the radio button for "Constant" minimum flows. Using the arrow buttons, set the constant minimum flow to 11,000 as shown in Table A9.1.
7. Click on the "Constraints" tabbed page. Set the maximum daily change set to 0.0 cfs.
8. Now, click on the "Run" button to start the simulation.
9. You should obtain the results shown in the first column of Table A9.2.

In general, the imposition of the SASF alternative reduces the amount of generation capacity but does not effect the amount of energy generated at the powerplant. This results in a significant economic cost. Moreover, the maximum generation or capacity is drastically reduced. Due to the importance of capacity in the electric power system, it is likely the purchase of long-run replacement capacity would be necessary in addition to the short-run economic value foregone as calculated by the GCPSE95 model. The SASF alternative would probably affect, to some extent, ability of the Glen Canyon powerplant to furnish other ancillary services such as voltage and VAR control, spinning and other reserves, and blackstart capability.

Table A9.2. Comparison of Historical and SASF Simulated Results.

	SASF	Historical	Difference
Maximum Flow (cfs)	13,824.00	31,500.00	-17,676.00
Minimum Flow (cfs)	13,824.00	1,000.00	12824.00
Maximum Generation (MW)	551.66	1,257.04	-705.38
Minimum Generation (MW)	551.66	39.91	551.75
turbine release (af)	850,000.00	850,000.50	Nil
generation (MWhrs)	410,432.95	410,433.19	Nil
economic value ($)	9,612,130.14	12,800,984.69	-3,188,854.54

Appendix 10. Glossary of Terms.

acre-foot (af). Volume of water (43,560 cubic feet) that would cover 1 acre, 1 foot deep.

baseloaded. A condition in which the output level of the powerplant is fixed or constant.

cubic feet per second (cfs). A measure of a moving water volume. The number of cubic feet of water passing a reference point in 1 second.

capacity. The maximum electrical output of a powerplant or system.. Usually measured in megawatts.

energy. The amount of electricity delivered over time. Usually measured in megawatt-hours (MWhrs).

megawatt (MW). One million watts of electrical power or capacity.

megawatt-hour (MWhr). One million watt-hours of electrical power or capacity.

Upramp rate. Rate of increase in the water release from the dam during a one hour period.

Downramp rate. Rate of decrease in the water release from the dam during a one hour period.

spill. Water releases from a dam that do not pass through the turbines and generate electricity.

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