AN INCREMENTAL ECONOMIC DISPATCH METHOD FOR
CASCADED HYDROELECTRIC POWERPLANTS

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Abstract - The Bureau of Reclamation (Reclamation) has undertaken a program to improve water resource management at its hydroelectric powerplants. One feature of the resource optimization program involves the development of economic dispatch methods which will enable plant operators to meet power and water demands while increasing overall operating efficiency. The economic dispatch method described herein has been designed and simulated using a computer model of the Lower Colorado River Basin's hydraulic and electric power systems. Simulation results demonstrate that the economic dispatch method yields significant efficiency improvements with sufficient speed for practical application.

INTRODUCTION

Optimizing powerplant efficiency is one of Reclamation's highest priorities. Improved generation and water resource management are achieved by increasing the amount of energy produced from the water available for release. Higher powerplant efficiencies provide added generation and spinning reserve, without additional production costs or new equipment installations. This translates into a greater supply of clean, economical energy for the nation's consumers.

To contribute to Reclamation's goal of improving powerplant operation, the Electric Power Branch of the Division of Research and Laboratory Services was commissioned to investigate methods of performing generation coordination and control functions at the hydroelectric powerplants on the Lower Colorado River. Hoover, Davis, and Parker Powerplants were modeled for this study. The Lower Colorado River Basin is illustrated in figure 1 and the powerplant facilities are described in table 1.

The intent of the research effort was to create a river basin computer model for use in designing and evaluating various optimum plant and unit control methods. The river model describes the generation characteristics and water flow dynamics of the cascaded

Figure 1. A portion of the Lower Colorado River Basin, illustrating the hydroelectric installations included in the generation control model.

Table 1. HYDROELECTRIC POWERPLANT FACILITIES

<u>Powerplant</u>	<u>Number of Units</u>	<u>Installed Capacity (MW)</u>	<u>Average Head (ft)</u>
Hoover	19	1,900	550
Davis	5	240	140
Parker	4	120	85

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powerplants. The findings of the research will be used to specify the automatic generation control (AGC) strategy for a proposed supervisory control and data acquisition (SCADA) system for the Lower Colorado River [1,2].

The generation dispatch function is one important feature of the basin control system. Ideally, basin generation requests will be

allocated to powerplant units such that the request is met most economically and within the operational constraints of the river. The economic dispatch method described herein has been developed to perform this function. The basin generation request is allocated among Hoover, Parker, and Davis Powerplants within a normal 2-second AGC cycle. Only those generators which are operating on AGC are available for loading and/or unloading using the economic dispatch routine.

ECONOMIC DISPATCH PROBLEM FORMULATION

The objective of the economic dispatch function is to minimize the total cost of producing the basin energy demand. Unit energy cost is the amount of potential energy required for a single turbine-generator to produce a portion of the total basin output energy. This energy is proportional to flow times head ($\text{ft}^3/\text{s} \times \text{ft}$). The summation of all unit costs is the total cost of satisfying the basin energy demand.

Stated mathematically, the objective is to

$$\text{minimize } Ct = \sum_{i=1}^n C[i] (P[i])$$

where i = generation unit index

n = number of units available for AGC

C = individual unit energy production cost for a given output P ($\text{ft}^3/\text{s} \times \text{ft}$)

P = individual unit generation output (MW)

Ct = total energy production cost ($\text{ft}^3/\text{s} \times \text{ft}$)

Subject to:

$$(1) \sum_{i=1}^n P[i] = Pt$$

$$(2) Pmin[i] \leq P[i] \leq Rzlow[i] \text{ or}$$

$$(3) Rzhigh[i] \leq P[i] \leq Pmax[i]$$

where Pt = total basin generation demand (MW)

$Pmin$ = lower generation limit of unit (MW)

$Pmax$ = maximum generation capacity of unit (MW)

$Rzlow$ = lower bound of turbine rough zone (MW)

$Rzhigh$ = upper bound of turbine rough zone (MW)

(4) Each powerplant meets its daily water release schedule by the end of the 24-hour day.

In addition to the constraints stated above, the economic dispatch routine must determine unit allocations within 2 seconds after the request for basin generation is received from the AGC control center.

LOWER COLORADO RIVER MODEL

A computer model of the Lower Colorado River Basin was developed using a 25 MHz personal computer. The river model represents the system's hydraulic and electrical characteristics and is used to simulate its dynamic response to various control inputs and operating conditions. The Lower Colorado River Basin consists of 3 cascaded hydroelectric powerplants with a total of 28 generating units. No simple set of equations exists which characterizes the time-dependent behavior of the powerplant network. Therefore, the river basin has been described using a combination of parameters, equations, and empirical data.

The model is divided into two sections. The first is a collection of databases which contains river, reservoir, powerplant, and generator parameters. Equations and empirical data define river delays and time constants; reservoir volumes and surface areas; powerplant forebay and tailbay elevations; and unit capacities, rough zones, and turbine-generator flow curves. The second section of the river model is the controller section which contains the AGC algorithms. The AGC functions include: unit commitment, economic dispatch, and synchronous condensing (motoring).

A retrospective simulation of the river basin was performed to verify the accuracy of the computer model. A 1-week period of operational data was obtained from historical basin measurements. The recorded data included hourly unit generation settings for each generator in the basin, as well as reservoir elevations and total basin energy production.

The historical simulation was conducted with all basin units operating at their recorded (historical) generation values. The simulated water releases, reservoir contents, forebay and tailbay elevations, and total energy output were compared against the historical data. In every comparison, the trend of the historical simulation was similar to the recorded historical data, typically with an error of less than 0.5 percent. These results were used to validate the computer model and to provide a benchmark of historical basin efficiency for future comparisons.

Hourly basin generation and capacity schedules were determined for the subsequent simulations by summing the historical unit generation settings and plant capacities, respectively. Plant capacity schedules were then used to establish unit commitment requirements, that is, the minimum online capacity capable of satisfying the scheduled generation and spinning reserve demands. The simulated online capacity was always equal to or greater than the scheduled (i.e., historical) capacity. Hence a small amount of excess capacity tended to be provided in the simulated runs. The excess slightly decreases simulated basin efficiency results.

Certain approximations and simplifying assumptions were necessary to make the river model and control functions tractable. One important simplification relates to the active

power transmission line and transformer losses. In the present model, the transmission losses are neglected when comparing the economics of assigning generation to one powerplant versus another. Differing powerplant transmission losses (for a given plant loading) may impact the overall efficiency of the basin.

ECONOMIC DISPATCH ALGORITHM DEVELOPMENT

Equal Incremental Production Costs

The economic dispatch algorithm developed for the Lower Colorado River Basin is a modification of the classic equal incremental cost method [3,4,5]. An incremental approach was preferred over other dispatch techniques since it executes quickly and can easily be formulated to eliminate excessive control of the generating units. Nonlinear searches and dynamic programming techniques, for example, tend to determine entirely new dispatch solutions for each demand request, with no regard to present loads on the units. This can force large variations in unit loads for a small change in demand. Excessive adjustment is highly undesirable and has been restricted unless turbine rough zone avoidance or other constraints dictate such operation.

The input to a hydroelectric generating unit is water released per unit time or flow, Q (ft^3/s); the output is electrical energy, P (MW). The derivative of a unit's input-output curve (dQ/dP), also known as its flow slope, represents the incremental cost of varying the unit's generation level. The traditional incremental dispatch technique compares the flow slope values of available generators to determine which unit should be incrementally loaded or unloaded. If the flow slope value of any unit is higher than that of another, it is possible to produce the same incremental amount of energy from the second unit at a lower cost. The optimal dispatch occurs when the load is distributed among the available generators in such a way that the incremental production costs of all units are equal.

The equal incremental flow slope method can be illustrated by considering two hydro units with similar flow slope characteristics, initially operating at point A, as shown in figure 2. One unit is unloaded by a small amount, ΔP , and now operates at B_1 . The required flow has been decreased by $\Delta Q_1 = dQ_1/dP \times \Delta P$. The output of the second unit is increased by ΔP and now operates at B_2 with an increased flow of $\Delta Q_2 = dQ_2/dP \times \Delta P$. There is no change in total MW generation, yet the total flow (i.e., input energy) has increased since $\Delta Q_2 > \Delta Q_1$. The total production cost was minimized when both hydro units operated at the same point on the flow slope curve.

Modified Incremental Dispatch Method

Guaranteed arrival at the optimal dispatch solution via the equal incremental cost method requires that the incremental cost curves be increasing, strictly convex functions (refer to curve in figure 2).

Figure 2. Example of a hydrogenerator flow slope curve with a convex, strictly increasing characteristic.

Thermal cost curves for steam turbine units normally exhibit this property and hydro systems are generally presumed to have this characteristic [6,7]. However, penstock flowmeter data suggest that many of Reclamation's turbine-generators actually have flow slope curves which are neither constantly increasing nor strictly convex. This is particularly true for larger units operating at medium or high heads. A representative incremental cost curve of a Reclamation hydroelectric unit is illustrated in figure 3.

The classic equal incremental cost technique loads units with low incremental costs and unloads units with high costs. When a change in the generation schedule occurs, because of a demand increase for example, the ideal response for the convex system is to distribute the increase among the units such that all incremental production costs remain equal. However, when units have nonconvex flow slope curves, the optimal response to a change in load may be different. Multiple dispatch configurations can exist where all incremental costs are equal, yet it may be possible that none of these configurations optimizes basin efficiency. In fact, at times the efficiency is actually maximized when units are not operated at equal flow slopes, but rather when there is a "separation" of unit flow slope values.

The advantage of operating units at unequal flow slopes is illustrated in figure 3 where two hydro units with identical nonconvex flow slope characteristics are shown operating at point A. As in the previous example, the output of the first unit is decreased by ΔP and the output of the second unit is increased by ΔP . Again, there is no overall change in generation. However, the total flow required to meet the demand has been reduced since in this case $\Delta Q_2 < \Delta Q_1$. In general, when two units with nonconvex behavior are operating along the decreasing portion of their curves, it is more economical to operate the units at different flow slope values.

Finding a practical dispatch solution for a large, constrained, multipplant system, such as the Lower Colorado River Basin, is a complex problem. As previously mentioned, the

Figure 3. Typical hydrogenerator flow slope curve with a nonconvex characteristic.

optimum response to a generation request depends on the present loads of the generating units. It is also recognized that the objective of the dispatch function is to maximize efficiency, rather than minimize flow; hence, the relative powerplant heads must also be considered. Efficiency is determined as follows:

$$\text{eff} = \frac{\text{energy output}}{\text{energy input}} = \frac{P}{Q \times \text{head} \times K}$$

where P = electric power generated (MW)
 Q = water released (ft³/s)
 head = net powerplant head (feet)
 K = constant equal to quantity of megawatts produced per 1 cubic foot of water for 1 foot of head

Each powerplant has a distinct (albeit varying) net head so that the same flow through different plants represents different amounts of potential energy. The higher the head the greater the amount of energy a given release represents. In order to make valid incremental cost comparisons between units at different powerplants, it was necessary to use the so-called "relative flow slope," rather than the actual flow slope characteristic of each turbine generator. The relative flow slope is simply the actual flow slope multiplied by the plant head, that is

$$\text{relative flow slope} = dQ/dP \times \text{head}$$

When the classic incremental dispatch method is used to allocate basin generation demands among available units, relative flow slope values corresponding to each generator's operating point (i.e., output) are used to select units to be loaded and unloaded. Basin generation is decreased by reducing the output of the unit with the highest incremental cost by one percent of the unit's capacity. The unit's new incremental cost is then compared with the costs of the other generators to choose the next unit to be incrementally unloaded. This process continues until the difference between the actual basin generation and the demand is within ± 1 percent of the capacity of the largest unit available for AGC. Basin generation is increased in a similar fashion by incrementally raising the output of units with the lowest incremental costs.

Figure 4 depicts a typical nonconvex flow slope curve divided into three different regions of operation. In regions 1 and 3, the incremental costs increase as unit output is raised. In region 2, the incremental cost decreases as unit output is raised. Given an increase in demand for basin generation, the unit with the lowest flow slope value is selected to provide an incremental portion of the increase, regardless of which region the unit is operating within. If a unit with nonconvex flow slope behavior is operating near the boundary between regions 1 and 2 (i.e., approaching the peak), the flow slope value may not actually be the lowest, yet by increasing the unit output, the unit incremental cost may be reduced below that of any other available unit. It is possible that this is the most economical means of supplying the generation increase. An analogous situation occurs when a unit is operating around the minimum between regions 2 and 3. This unit may be the most economical to be unloaded, but it too can be overlooked if the selection is based only on the present flow slope value.

Figure 4. Nonconvex hydrogenerator flow slope curve divided into regions of strictly increasing and decreasing incremental costs.

Since the classic economic dispatch algorithm cannot "look ahead" to see the shape of a unit incremental cost curve, it cannot anticipate the benefit of moving a unit by more than a single increment. The classic approach assumes that the incremental cost will always increase with an increase in output, and vice versa. At times, this assumption results in some units being operated at suboptimal efficiencies. Hence, the overall basin efficiency achievable from the classic incremental dispatch method is limited when unit characteristics are described by nonconvex flow slope curves.

To overcome the shortcoming of the classic incremental dispatch technique, cost criteria based on averages of the relative flow slope values above and below a unit's operating point were developed. These flow slope averages are illustrated in figure 5. For a load increase, the unit with the smallest upper relative flow slope average is incrementally raised. For a requested decrease in demand, the unit with the largest lower relative flow slope average is selected.

Figure 5. Example of a hydrogenerator flow slope curve with upper and lower flow slope averages illustrated.

Flow slope averages are useful because they represent the trend of the flow slope curve, not just the behavior at the present operating point. This approach accounts for the effect of nonconvex curves by enabling the dispatch algorithm to predict the overall direction of incremental costs, i.e., to anticipate where the unit cost is going, not just where it is. Although the use of flow slope averages does not yield optimal results, the modified dispatch technique does preserve the computational speed advantage of the incremental allocation and produces good results with both convex and nonconvex input-output curves.

Optimal Dispatch Using Dynamic Programming

A dynamic program (DP) was implemented to determine the optimum generation dispatch configuration for any given basin demand [8]. The DP was able to calculate the generator allocations which optimize the available water releases regardless of the convexity of the turbine-generator flow curves.

When contrasted with the complete enumeration of all possible dispatch configurations, the DP results in a significant reduction in computational effort. Even so, it takes an unacceptably long time to execute. Simulations of the Lower Colorado River indicate that a 24-hour schedule requires approximately 6 hours to optimize. Such an execution time is intolerable in a system where instantaneous load data are sent to the control program on a 2-second cycle and whose dispatch policy must be determined within that time frame. Furthermore, the DP does not easily accommodate additional operating constraints, such as water schedules and rough zone avoidance. The significant contributions of the DP are the optimum unit allocations and resulting basin efficiency enhancements. This information was invaluable for quantifying the performance of the modified incremental dispatch method.

OPERATIONAL CONSTRAINTS

The function of the economic dispatch algorithm is to allocate the load among available generating units in the most

efficient manner. At times, however, economic considerations must give way to other constraints imposed on the hydro system. The first priority of the Lower Colorado River control scheme is to ensure that sufficient water is released, particularly past Davis and Parker Powerplants. Another influencing factor is the need to avoid turbine-generator rough zones where the units are especially susceptible to cavitation and damaging mechanical vibrations.

Water Constraints

Plant water releases may be scheduled on a monthly, weekly, daily, or hourly basis. The Parker and Davis water schedules are allocated daily. Presently, the Hoover scheduled release is determined monthly and converted into a daily schedule for the simulation. During normal conditions Davis and Parker are operated close to their water schedules while Hoover is allowed the flexibility to respond to the actual power system loads.

At the beginning of each hour the remaining daily release required for each plant is determined by subtracting the actual release from the scheduled daily release. The difference is converted into an approximate equivalent plant generation requirement in MWH. The generation requirement is then divided by the number of hours remaining in the day. This provides a target plant generation for the present hour.

An envelope of permissible plant output is defined by allowing 20 to 180 percent of the targeted hourly flow to be released during the first hour. This envelope is illustrated in figure 6. By recalculating the limits each hour, the envelope is linearly reduced so that the water schedule is met to within ± 5 percent by the last hour of the day. Each hour the allocated plant generation must operate within the estimated release boundaries. This will, at times, force the plant output to increase or decrease to meet the constraint. This approach is designed to provide operations as much latitude as possible while still satisfying the water requirements.

Figure 6. Example of a water-constrained plant generation target (T) and envelope of permissible operation.

Rough Zone Avoidance

Turbine rough zones are regions of operation where nonuniform pressures in the turbine flow passages produce excessive mechanical vibration. In order to prevent or minimize damage to the hydro turbine and the surrounding structures, turbine rough zones are best avoided. A typical rough zone is illustrated in figure 7.

Figure 7. Example of a hydrogenerator flow slope curve with rough zone illustrated.

In general, the rough zone avoidance scheme treats the rough zones as invalid generator output settings. However, if the energy demand of a plant or the basin cannot be met while rough zones are avoided, the generation schedule takes precedence and, as required, units will be allowed to operate within their rough zones. The highest priority is placed on removing units from their rough zones during the next available AGC cycle.

ECONOMIC DISPATCH ALGORITHM FLOW CHART

A flow chart of the economic dispatch algorithm developed for the Lower Colorado River Basin is represented in figure 8. The plant water requirements and unit rough zone avoidance are not detailed since these constraints are embedded in the unit selection process. This diagram illustrates the use of relative flow slope averages as unit selection criteria. The process of unit selection and incremental change in unit output repeats until the online basin generation is within specified tolerance of the scheduled basin generation.

SIMULATION RESULTS AND COMPARISONS

Seven-day average basin efficiencies from the historical simulation, the dynamic program, and various incremental dispatch configurations are illustrated and compared in figure 9. The dynamic program provides the "optimal" dispatch policy and gives the highest basin efficiency. Since neither motoring nor water and rough zone constraints were incorporated into the DP, the results are primarily useful for quantifying the

Figure 8. Flow chart illustrating incremental economic dispatch algorithm, based on flow slope averages.

efficiency sacrificed to implement the (unconstrained) incremental dispatch approach. This is a loss of about 1.44 percent. The DP demands approximately 6 hours to determine a 24-hour dispatch schedule, whereas the incremental method requires less than 1 minute. A decrease in basin efficiency of 1.44 percent is acceptable, a 6-hour computation time is not.

Satisfying powerplant water release demands is the highest priority of the dispatch control algorithm. The addition of water constraints to the incremental dispatch algorithm results in an efficiency loss of about 1.74 percent. Avoiding rough zones reduces basin efficiency by an additional 0.25 percent.

Units scheduled to be online to meet basin capacity requirements cannot be shut down to improve efficiency. However, unit motoring can forbear the operation of units at low-efficiency output settings without reducing the basin online capacity. The few

Figure 9. Comparisons of economic dispatch methods and configurations. Basin efficiency increases over simulated historical value are given in parentheses.

megawatts of energy required to motor a unit are supplied from higher-efficiency generating units. Enabling the unit-motoring feature of the incremental dispatch method increases basin efficiency about 0.81 percent. The final and most practical economic dispatch configuration includes the motoring function as well as water constraints and rough zone avoidance. For the week under consideration, the incremental dispatch algorithm improves the overall basin efficiency by about 1.69 (or 1.7) percent over the comparable historical efficiency value.

CONCLUSIONS

The incremental dispatch routine developed for this application operates well within the specified 2-second cycle. In fact, a single generation allocation is typically performed in less than one tenth of a second. Rapid computations make the algorithm practical to implement and useful as a tool for off-line dispatch configuration studies. The algorithm also successfully manages nonconvex flow curves. This is particularly beneficial since hydro unit flow (and flow slope) data may have nonconvex characteristics which obstruct the use or performance of methods like the classic incremental dispatch technique, or linear and nonlinear (e.g., quadratic) programming. This study indicates that by consolidating the Lower Colorado River's powerplants and utilizing the improved incremental dispatch technique, a significant gain in overall basin efficiency can be achieved. A 1.7-percent increase in basin efficiency provides:

- 1) 100,000 MWH generated annually, on the average.
- 2) An annual savings of about 170,000 barrels of crude oil [9].
- 3) Approximately 34 MW of additional basin spinning reserve.
- 4) \$2.2 million, based on 25 mils/kWh.

ACKNOWLEDGMENTS

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Discussion

M. E. El-Hawary (Technical University of Nova Scotia, Halifax, N.S., Canada): This is a welcome contribution to the area of optimum operation of hydroelectric power systems. The paper offers some valuable insights into the practical aspects of actually trying to optimize a real system. The proposed technique will prove useful in this very important area.

It might be worthwhile to provide the reader with some additional insight into the characteristics of the hydro plants treated. The author's additional remarks on the following would be appreciated:

- Sample data relevant to points on Figure 5 such as maximum incremental cost, minimum incremental cost as well as maximum and minimum generation.
- Sample values for rough zones.
- Further details on the procedure followed to obtain the daily releases may be of interest.

Once more, the author is congratulated for an informative paper.

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L. M. RUX: The author wishes to thank Mr. El-Hawary for his most welcome comments.

1. Figure 5 is an example of a hydrogenerator flow slope curve. Typical values associated with this curve are as follows: $P_{min} = 5$ MW; $P_{max} = 130$ MW; Minimum $dQ/dP = 10$ cfs/MW; and Maximum $dQ/dP = 35$ cfs/MW.

2. A flow slope curve illustrating turbine rough zones is shown in Figure 7. Typical values for this figure are $R_{zlow} = 60$ MW and $R_{zhigh} = 75$ MW.

3. The source of daily release schedules was not discussed in the paper since plant release constraints were presumed to be parameters input to the economic dispatch routine. However, in these times of limited resources and heightened environmental awareness, there is a legitimate interest in decisions involving water release schedules.

The Lower Colorado River Basin, like other Reclamation projects, serves multiple purposes. The benefits include protection from floods; water for irrigation, domestic and other uses; power generation; recreation; and the preservation of fish and wildlife.

Satisfying the demands of this broad range of clients can be a difficult (sometimes impossible) task. To best balance regional and national water needs, Reclamation performs the water scheduling function according to the following criteria, listed in order of priority: flood control, environmental considerations (e.g. the Wildlife Protection Act), irrigation needs, peaking power demands, and finally, recreational activities.

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