THE VALUE OF ELECTRIC POWER AND POSSIBLE EFFECTS OF WEATHER MODIFICATION ON SMALL-SCALE HYDROELECTRIC PRODUCTION IN COLORADO

Prepared by
William Loehr - University of Denver
Barbara C. Welles
Lynn A. Sherretz
Weather Programs, Colorado Department of Natural Resources
1313 Sherman Street, Room 718
Denver, Colorado 80203

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SUMMARY

The purpose of this study is to determine the value of electric power in Colorado and to assess the effects on the production of small-scale hydroelectric power in Colorado of possible increases in streamflow resulting from cloud seeding. Small-scale production (less than 80 megawatts) is important to Colorado because many of the state's mountain and Western Slope streams provide suitable small-scale sites. Also, the U.S. Congress recently passed legislation that provides economic incentives to producers of small-scale hydroelectric power.

The Value of Electric Power in Colorado

Since the market for electric power in Colorado is regulated (mainly by the Colorado Public Utilities Commission), the value of power is not determined by the usual market forces. To place a value on power we examine wholesale markets and estimate costs of supplying power if the utilities supply it themselves. We conclude that the value of power in Colorado ranges between about 1.4 and 12.0 cents per kilowatt hour, depending on the circumstances in which the energy is produced and used.

Small-Scale Hydro in Colorado

A number of developers of small-scale hydroelectric sites have responded to the incentives of the Public Utilities Regulatory Policy Act of 1978 and have begun to develop facilities in Colorado. No sites have yet been completed, however, and technical details on most sites are scarce. Much development activity was temporarily suspended when PURPA was tied up in federal courts from early 1982 until mid-1983, but the resolution of key issues in favor of small power producers has again given a push to small-scale power production in the state.

A survey of permit applications filed with the FERC reveals that four general types of facilities have been proposed for Colorado: dams, irrigation ditches, run-of-river and water treatment. The total potential capacity reflected in the FERC applications is 343.6 mw. If this capacity were developed, it would increase the state's total generation capability by about six percent and hydro capacity by more than 68 percent. Viewed another way, the potential capacity of the proposed small-scale hydro sites in Colorado is approximately that required to serve Colorado Springs, the state's second-largest city.

Possible Effects of Cloud Seeding on Small-Scale Hydropower Production

Two proposed small-scale hydroelectric projects were selected for study:

- a "run-of-river" installation on the North Fork of the San Miguel River planned by the city of Telluride, and
- a turbine on the Frying Pan River at Reudi Reservoir that the City of Aspen plans to install.

These two sites were selected because they are more likely to be developed than many of the other proposed sites.

Possible effects of cloud seeding on streamflow were estimated by relating flow to April 30 snow water equivalents in the headwaters regions of the San Miguel and Frying Pan Rivers. This procedure is similar to procedures used by the U.S. Department of Agriculture, Snow Survey Unit to estimate runoff.

The value of the estimated additional energy produced each year at the San Miguel River site is about $7,100, an increase of about five percent. Assuming that cloud seeding could increase streamflow annually for the life of the project, $7,100 would constitute a permanent increase in the value of the installation. Treated as an annuity, $7,100 increases the present value of the project by about $58,000.

The value of the estimated additional power produced at the Reudi Reservoir site is about $77,000, an increase of about ten percent. Treated as an annuity, $77,000 adds about $630,000 to the present value of the project.

Conclusions

Increases in stream flow that could result from winter cloud seeding have two effects on the output from small-scale hydropower facilities:

- total electrical energy produced increases, and
- hydro generators operate closer to full capacity.

Because generators operate closer to full capacity, the estimated value of the energy output increases by a larger percentage than estimated energy production increases. At the Telluride site a 15 percent increase in April 30 snow water equivalent increases electric energy output by 3.5 percent and raises the value of energy output by 5.0 percent. At the Reudi site a 15 percent snow water equivalent increase raises energy output by 6.1 percent and its value by 9.9 percent. In both cases, estimated increases in the value of power attributable to modest increments in stream flow are substantial, especially when considered over the expected life of the projects.

It is difficult to draw comprehensive conclusions about all small-scale hydropower sites from the two sites that we have studied because developers use diverse technologies and face diverse situations. Water rights could play an important role. Developers who have senior rights probably would be less affected by incremental increases in streamflow than developers with junior rights. Based on the results of the two sites examined, however, we conclude that possible increases in streamflow from cloud seeding could increase significantly the amount and value of the energy output from small-scale hydropower facilities in Colorado.

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CHAPTER 1: INTRODUCTION

The purpose of this study is to determine the value of electric power in Colorado and to assess the effects on the production of small-scale (less than 80 megawatts) hydroelectric power in Colorado of possible increases in streamflow resulting from cloud seeding. Although cloud seeding could produce increases in streamflow beneficial to large-scale hydroelectric production as well, this study concentrates on small-scale production for several reasons:

- Colorado's many mountain and Western Slope streams provide suitable small-scale sites

- the U.S. Congress recently passed legislation that provides economic incentives to producers of small-scale hydroelectric power

- developers of large sites (mainly the Bureau of Reclamation) have the resources required to analyze their sites, while small developers do not.

The study begins with a discussion of the economic value of electric power in Colorado. Since the market for electric power is regulated (mainly by the Colorado Public Utilities Commission), the value of power is not determined by the usual market forces. The market also is rather complex, and the value of power is determined by the different conditions under which it is purchased. These conditions will be shown to be important to small-scale hydropower producers.

The study also examines hydroelectric power production in the state, distinguishing small power facilities from large, more conventional installations. A method for evaluating the economic value of power produced by small hydroelectric power facilities is explained in Chapter 4. In Chapter 5, the small-scale hydroelectric potential on the San Miguel River near Telluride and at Reudi Reservoir near Aspen is evaluated. Those case studies compare hydropower value with cloud seeding to hydropower value without cloud seeding.

In the appendices readers will find a glossary of terms used in the electric utility industry and technical details supporting the calculations used in the main body of the report.

CHAPTER 2: THE VALUE OF ELECTRIC POWER IN COLORADO

If there were a free market in electric power, as there is in most other commodities, we would determine value by simply observing the price of power in the market place. The market for power is regulated, however, and "price," which is not necessarily determined by market forces, does not necessarily represent what power is worth. Indeed, different consumers of power pay a number of different prices for power. Most of these differences are determined by cost differences across utilities and by regulatory policy, but some can be attributed to the nature of the market. Wholesale power markets tend to be much less regulated than retail markets, and they are therefore much closer to the free market. Small power producers, including small hydropower producers, will generally not retail their power, which is the exclusive right of Colorado's electric utility companies, but will either use it themselves or sell it wholesale to local utilities. Thus, the appropriate method for valuing their power will be to value it at wholesale.

One way to place a value on electrical power in Colorado, then, is to look at wholesale contracts among Colorado utilities for purchase and sale of electricity. Since the wholesale market is not highly regulated, wholesale prices should represent worth fairly accurately. Also, since utilities can usually buy power from a number of sources, competition in the wholesale market lets the market reflect "value" somewhat as other markets do. A second way to place a value on power is to determine the costs of supplying power if the utilities supply it themselves. Traditionally, regulation permits the utilities to pass on costs plus a reasonable profit, which makes the costs of production one of the main determinants of "value." Both these methods of determining the value of power are pursued below.

Method One: Wholesale Markets

Types And Examples of Transactions

Generally, Colorado's utilities are tied together by a transmission system that allows power to be shipped from one utility to another. This transmission system is weak between the eastern slope and the western slope, so transactions east and west are somewhat limited. But eastern slope utilities are tied to a transmission system that allows them to purchase power from New Mexico, Wyoming, Montana, and the Dakotas. Western slope utilities have ties with the Southwest although these ties are less well developed.

Transactions among utilities are generally of three types: "firm" purchases, "economy" transactions, and "emergency" transactions.

Firm Purchases. Most valuable to a utility is a firm contract to provide capacity or energy or both to other utilities. (For definitions of "capacity" and "energy," see Appendix A). Firm contracts normally cover periods of several years to twenty years. The selling utility obligates itself to deliver power in fixed amounts whenever power is required by the purchasing utility. The purchasing utility ensures reliable electric service to its customers without tying up capital in the construction of its own generation units. It can draw on the generation facilities of the selling utility as if those facilities were its own.

Consider two utilities with interconnecting transmission systems. Suppose that "Utility A" expects growth on its system over the next ten years and therefore builds a large power plant. Assume that the new plant at first produces more power than Utility A can use itself and that it incorporates the latest technology and therefore has very low operating costs. "Utility B" meanwhile might also expect load growth, but it has no new plant, or it has one under construction that could take five to seven years to complete. Since Utility B's plants are older than Utility A's, its cost of operation is higher. Utility B might therefore enter into a contract with Utility A for firm power during the time when Utility A has excess capacity. Contracting for firm power lets Utility B draw power more cheaply than it could have generated the power itself; Utility A sells power for which it has no other market.

Economy Transactions. Economy transactions are usually of short duration and are performed to save the purchasing utility some of its short-term operating costs rather than to insure its long-term power supply.

Large coal-fired or nuclear generation units cannot exactly match ("cycle") output to the demands upon them. Thus, utilities frequently find that they need only some of the power a plant is producing. Suppose that the Public Service Company of Colorado (PSCo) is operating its plants to cover its own load at an operating cost of 2 cents per kwh. If this load drops for a day or some other short interval, the company may sell the excess energy. (There are costs associated with turning units up and down). The PSCo dispatcher contacts other utilities to see if anyone would like to buy the temporary excess power. One potential purchaser might be Colorado Spring's Nixon unit, which has operating costs of about 2.1 cents per kwh. Since "splitting the difference" is customary in economy transactions, PSCo might charge the Springs 2.05 cents per kwh and both companies would gain by the transaction. Economy transactions are a very cheap source of energy but, since this energy is available only as happenstance determines, they are not a very valuable source.

Emergency Transactions. In all electricity purchases and sales, the time of the transaction is important. Power that can be delivered during peak periods is worth more than power that is available at other times. The reason for this is that utilities build systems to meet the loads placed on them and loads vary with the time of day, the season, and the climate. Loads are greater during the day than at night, greater in the summer in hot climates where air conditioning is used, greater in the winter in cool climates where electric heating is common.

Utilities install units to meet "base loads," loads that are expected during off-peak periods. Base load units (all coal-fired in Colorado) have low operating costs but high capital costs. They serve base loads economically because their high capital costs can be amortized over a large amount of energy output. Peaking units have high operating costs, because they usually burn natural gas, but low capital costs. Thus, during off-peak periods when all energy is being generated by burning coal, costs are low.

During peak periods when natural gas is being burned in addition to coal, costs are higher. Because all utilities use "economic dispatch" (they use first the source of power with lowest cost, second the source with the second-lowest cost, and so forth), operating costs reach a maximum during peak periods.

Emergency power is the most expensive. When physical damage forces utilities to shut down equipment, the utilities draw on whatever resources are available. Normally they contact other utilities for support during an emergency, buying power in transactions that may take place within a matter of minutes and at prices that can be very high.

<u>Survey of Contracts</u>. Following is a survey of transactions among utilities that illustrate the three basic types of contractual arrangements. Parties to the transaction are named, the transaction is described and the price of electricity is determined. (The results of the survey are summarized in Table 2.1.).

1. Public Service Company (PSCo) and Colorado-Ute Electric Association (CUEA). Since PSCo peaks in the summer and Colorado-Ute peaks in the winter, the contract is designed so that the off-peak utility can support the on-peak utility. That is, CUEA provides power to PSCo in the summer, when CUEA has excess capacity. The reverse occurs in the winter. The contract is "demand only," which means that the buying utility draws upon the selling utility for capacity. In this contract the utility that draws capacity is obliged to pay back energy drawn, but the repayment is in kwh at some time in the future, not in money.

A price of $11.38/kw/month is charged to the buying utility as capacity is used. The capacity charge in this contract (and in most other contracts) is based on the maximum capacity drawn during a stated interval (usually 30 minutes) during a month. For example, if Colorado-Ute draws upon PSCo for 50,000 kilowatts for any 30-minute interval in January, then the charge for the month is 50,000 x $11.34, or $567,000.

Although each firm has the right to draw on the other firm as necessary, Colorado-Ute draws more on the PSCo system during the winter than PSCo draws upon CUEA in the summer. Thus, Colorado-Ute ends up being the net purchaser.

2. Public Service Company and Tri-State. PSCo purchases short-term economy energy from the Laramie River units located north of Cheyenne that are owned by Tri-State, which is a generation and transmission cooperative like Colorado-Ute. The Laramie River stations were built in anticipation of load growth that has not materialized and are generally recognized as currently constituting excess capacity; they were also built at a site that has very cheap coal.

Tri-State is selling energy from those units at a price that covers operating costs plus a small contribution to fixed cost. PSCo cannot count on Tri-State units as a permanent source of power, nor for "firm" power: both firms peak in the summer, Tri-State much more severely than PSCo. So, the contracts are short-term, and short-term energy of this type is inexpensive. It pays PSCo to turn down its Pawnee unit, which produces energy at about 1.7 cents per kwh, and buy from Laramie River for 1.4 cents per kwh.

3. City of Colorado Springs and Public Service Company. The City of Colorado Springs buys some "economy" energy, primarily from Public Service Company. The price varies with the seller's marginal operating costs and the buyer's operating costs at the time of purchase, but economy purchases by Colorado Springs average about 1.5 cents per kwh.

4. Public Service Company and Redlands Water District. PSCo has a contract to buy power from the Redlands Water District near Grand Junction. The price of $15.50/kw/month and 1.77¢/kwh requires that Redlands be available on peak. This contract was struck outside the normal procedures established by the Federal Energy Regulatory Commission (FERC), though Redlands is a small facility covered by the special federal regulations of the Public Utilities Regulatory Policy Act of 1978 (PURPA).

PURPA requires that utilities buy power from small power producers at "avoided costs" that are similar to what economists call marginal costs. When a utility buys power from a small power producer instead of producing power itself, the utility avoids certain costs, costs that the utility is supposed to pay to the small power producer. The Colorado Public Utilities Commission is charged with determining avoided costs exactly and with establishing rates for small power producers. The rates established for PSCo are shown in Table 2.1. (Tables appear at the end of each chapter.) The rates are for small power producers who can supply power during peak hours (8:00 a.m.. to 10:00 p.m.) and who can maintain a 75% availability factor during those hours; prices would be lower for small power producers who cannot meet these criteria.

Method Two: Unit Costs

Complicating the task of calculating the costs utilities incur when they install and run their own equipment is the fact that utilities base their accounting on historical investment costs rather than on replacement costs. Thus, older plants seem cheaper than new ones because inflation has raised the cost of new facilities. For example, the figures shown in the demand column in Table 2.2 are derived from the original capital costs of the plants, spread over the life of the units. The oldest plant shown is Nixon and the newest is Rawhide. (Rawhide is to go on line in 1984, so costs are estimated). Nixon appears cheaper than the others, Rawhide more expensive.

The difference is largely inflation. Unlike capital costs, energy costs are current expenses and therefore do not get distorted by inflation. A further discussion of the effect of inflation on the calculation of rates from costs is provided in Appendix B.

Table 2.2 lists recently completed generation units and units that are about to be completed by some of Colorado's major utilities. Calculated for each plant are average costs for each kwh. The average total costs show the effect of combining capacity costs with operating costs. For purposes of comparison, we have assumed that all units shown have the same capacity factor (70%), an assumption needed to spread fixed costs over the same number of hours of operation. (How these costs are translated into utility rates is the subject of Appendix B.)

The very low figure shown for Craig 1 and 2 is due to a very favorable coal contract obtained by Colorado-Ute. The figure for the almost-complete Craig 3 unit, which is almost identical to units 1 and 2, reflect the fact that the coal it will burn is more expensive. Coal for the Nixon unit has to be transported a bit farther than coal for the other units, so the price is a bit higher.

The average cost of energy across the first five plants is 1.6¢/kwh. A figure of 1.7¢/kwh seems more representative since the coal supply to Craig 1 and 2 is extraordinary. The average total cost per kwh for a power plant is calculated by combining energy cost (cost of coal) with the cost of capital (interest, amortization and depreciation) spread over the numbers of kwh produced. This is done in the right-hand column of Table 2.1. The average total cost per kwh for the existing coal-fired plants is 3.73 cents. The difference between the average total column and the energy column is the part of the total costs of energy that goes toward the cost of capital tied up in the generation and transmission system. Thus, over 57 percent (2.13¢/kwh) of the cost of electric energy is attributable to the cost of capital tied up in the generation equipment.

The five coal-fired plants listed are fairly new. Older plants would have lower capital costs and higher operating costs. Since capital costs are a larger part of total costs than energy costs, the inclusion of older plants would make total costs appear lower than they are in today's terms. (Note that the cost attributable to capital in the total averages about 2.13 cents for the existing plants.)

To represent an extreme, a special-purpose peaking facility is included. Valmont is a gas-fired turbine owned by PSCo that could be used for peaking power under some circumstances, but its energy costs alone are 12 cents per kwh. Capital costs are not included because the unit was constructed in the 1960s. Inflation has distorted what it would now cost to build a similar unit, and no Colorado utilities plan to build units of this type in the future.

Also included are the costs of pumped storage. The energy costs to produce pumped storage are the kwh that do the pumping, generally two kwh for every kwh produced. The figure shown, 8 cents per kwh, is an estimate provided by the PUC staff. We have shown no capital costs for pumped storage because these facilities usually accompany other projects and their costs cannot be easily isolated. If one set out to build a pumped storage facility all by itself, the capital costs would be much higher than for any of the other facilities. Obviously, a utility would prefer to get peak-period energy from pumped storage than from a unit like Valmont.

Summary

What is power worth in Colorado? Our investigation supports the following generalizations:

Type of Power	Cost (cents per kwh)
Non-firm, energy only	1.4 to 1.7
Firm baseload	3.5 to 4.5
Firm on peak	4.6 to 5.0
Emergency or special purpose	5.0 to 12.0

Most important about these figures are their range, and their variety: the price of energy in Colorado varies with the circumstances in which the energy is produced and used.

TABLE 2.1

Contracts

Contract or Type of Power	Demand ($/kw/mo)	Energy (¢/kwh)	Average (¢/kwh)
PSCo-Colorado Ute (Demand Only)	11.38	n.a.	n.a.
PSC-Laramie River (Short Term Energy)	none	1.40	1.4
Colorado Springs (Economy)	none	1.50	1.5
PSCo-Redlands Water District	15.50	1.77	4.64*
PSCo ("Avoided Cost" Rate)	18.00	1.70	4.99*

* Assumes 75% capacity factor on peak. Adjustments proportional.
n.a.: not applicable.

TABLE 2.2

Unit Costs

Facility	Demand ($/kw/mo)	Energy (¢/kwh)	Average (¢/kwh)
Pawnee	14.11	1.7	4.50
Nixon	7.23	2.1	3.53
Craig 1 & 2	11.09	.8	3.00
Craig 3 (1984)	11.09	1.7	3.90
Rawhide (1984)	19.00	1.7	5.47
Valmont (Natural Gas) Peaking	n.a.	12.0	12.0
Pumped Storage	n.a.	8.0	8.0

Note: Costs are estimated for Craig 3 and Rawhide, which will not come on-line until early 1984.

CHAPTER 3: POWER GENERATED IN COLORADO

All Sources

Understanding the mix of power-generation facilities in Colorado, which is presented in Table 3.1, is important to understanding the production of small-scale hydroelectric power in the state.

Coal-fired generation units constitute 70 percent of power-generating capabilities in Colorado but they provide more than 70 percent of the electrical energy used. Because they are designed to provide base-load power, they are operated a larger portion of the time than peaking facilities. Combustion turbines and internal combustion units, on the other hand, are for peaking services: they constitute eight percent and one percent of the capacity of the state, but they are sources of only a small part of the state's electrical energy.

The capacity of pumped-storage hydroelectric facilities (which pump water to high elevations during off-peak periods and produce power during peak periods) is about four percent of the state total. Conventional hydro comprises slightly more than eight percent (501 mw) of Colorado's generation capacity. The Bureau of Reclamation owns 445 mw, PSCo owns 25 mw and Colorado-Ute owns 26 mw of hydro capacity; only 5 mw is owned by other parties. Although the variety of circumstances discussed below are strengthening and broadening interest in small-scale hydropower, its current contribution to the generation of power in Colorado is negligible.

Small-Scale Hydro

A number of developers of small-scale hydroelectric sites have responded to the incentives of PURPA and have begun to develop facilities in Colorado. No sites have been completed, however, and technical details on most sites are scarce. Much development activity was temporarily suspended when PURPA was tied up in federal courts from early 1982 until mid-1983, but the resolution of key issues in favor of small power producers has given a push to small-scale power production in the state.

The first step to getting a license to build and operate a small-scale hydroelectric facility is to apply to the FERC for a permit to develop a site. The permit application estimates, sometimes rather crudely, the power capabilities of the site, supplies information on the developer and so forth. Good information on sites is not available until after a license is issued; only then is the developer assured he will eventually be able to operate the facility, so only then is detailed engineering work done. No potential developer in Colorado has received a license and most developers have not been issued a permit. For this reason the information on the potential sites is not good, and figures supplied for the FERC applications are not precise.

A case-by-case survey of FERC permit applications reveals the information contained in Table 3.2. We have categorized facilities into four groups, separated by basic differences in hydro technologies. Facilities to be constructed at sites where dams exist predominate. In most of these cases the task of the hydro developer is to add the facilities needed to generate power. There are forty such projects under way in the state. Since five of these are rather large (20 mw or larger), they are shown separately. There are 13 proposals to install turbines on irrigation ditches and conduits; average capacities are 1.45 mw. Run-of-river situations (which will be described in greater detail below) are fewer; six sites have average capacity of 1.06 mw. Capacities at four sites attached to the outflow from municipal water treatment plants average 7.07 mw. (Four FERC applications were also examined where the data did not permit categorization.)

The total potential capacity reflected in the FERC applications is 343.6 mw. If this capacity were developed, it would increase the state's total generation capability by about six percent and hydro capacity by more than 68 percent.

Viewed another way, the potential capacity of small-scale hydro sites in Colorado is approximately that required to serve Colorado Springs, the state's second-largest city.*

Small-scale hydro sites are spread throughout most of the mountainous areas of Colorado. Figure 1 is a map showing approximate locations of the sites for which FERC applications have been filed.

* Capacity in mw must always exceed peak demands to protect against unforeseen forced outages.

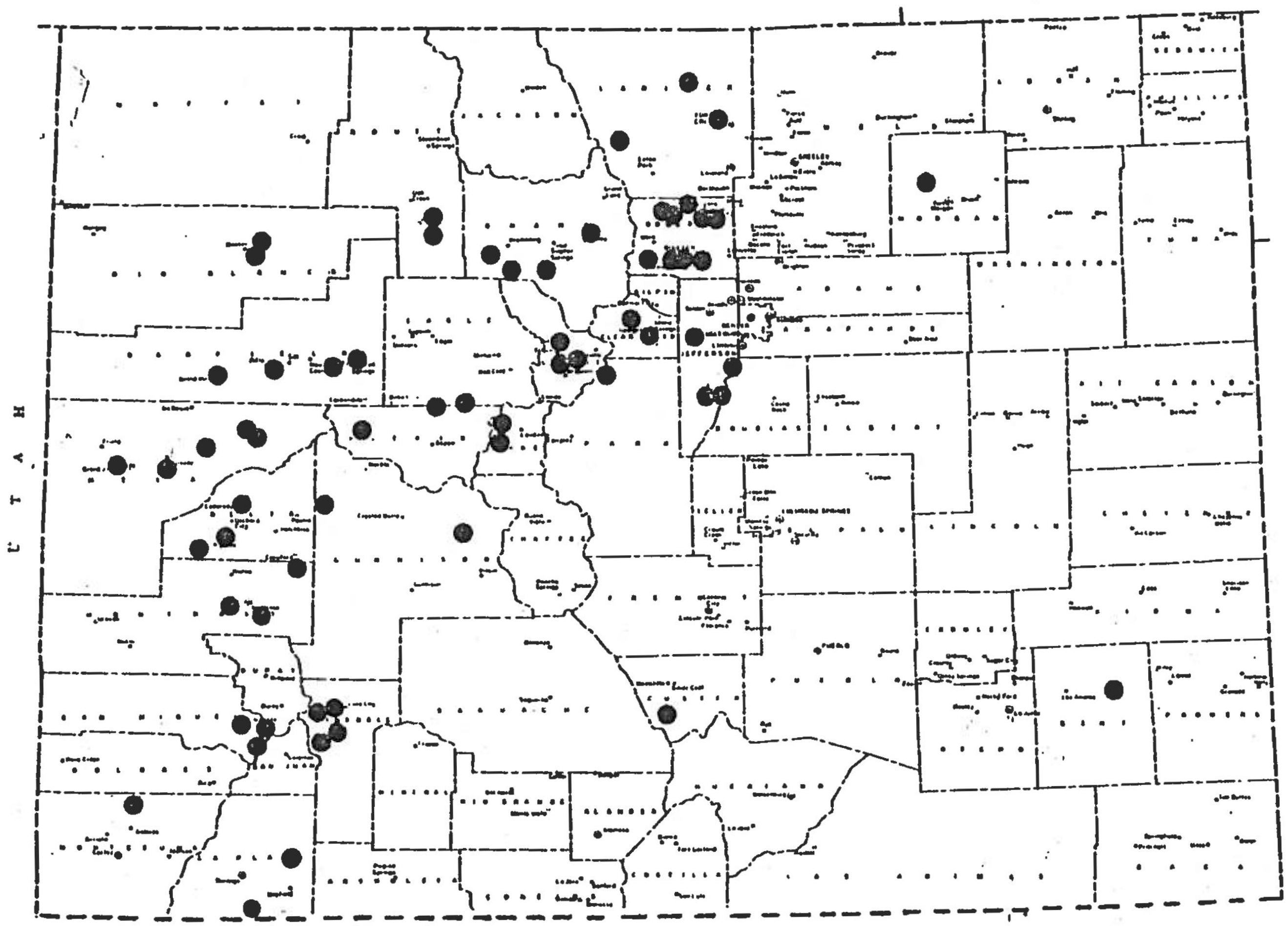

Figure 1. Locations of proposed small-scale hydropower sites in Colorado.

TABLE 3.1

Current electric generation in Colorado

	Power (mw)	Percent of State Total
Steam-Coal	4185	70
Steam-Gas & Oil	358	6
Nuclear	200	3
Internal Combustion Diesel	48	1
Combustion Turbines	466	8
Conventional Hydro	501	8
Pumped Storage	262	4
Total	6020	100

Data from Colorado PUC, Colorado Electric 1982-91 Supply Survey, October 17, 1983, Table V.

TABLE 3.2

Capacities of small-scale hydro sites in Colorado

Type Of Site	Number	Total (mw)	Average Size (mw)
Dams			
Large (over 20mw)	5	165.0	33.0
Small	35	125.0	3.6
Irrigation Ditches	13	18.9	1.5
Run-of-River	6	6.4	1.1
Water Treatment	4	28.3	7.1
Total	63	343.6	

Data from Applications filed with the FERC.
NOTE: FERC applications reveal four projects which do not adequately identify the type of facility.

CHAPTER 4: VALUATION OF SMALL-SCALE HYDROPOWER

The objective of this chapter is to provide a method for estimating the output from small-scale hydroelectric facilities and to place a value on the output. The method is presented as simply as possible. We have relied heavily on the least complex method recommended in a document prepared by the Electric Power Research Institute (EPRI) to aid the evaluation of small-scale hydropower. (EPRI, Simplified Methodology for Economic Screening of Potential Low-head Small-Capacity Hydroelectric Sites, prepared by Tudor Engineering Company, EPRI EM-1679, Project 1199-5, January, 1981). To facilitate explanations, we will develop a simple example using a "run-of-river" hydroelectric facility.

Estimation of Power Output

In what follows we state the relationship between the variables that determine power output, using standard engineering formulas from publications like the EPRI study cited above. We then go through each element in the formulas, explaining terms and identifying variables sensitive to possible increased flow from cloud seeding.

Head and Flow

Estimation of the power output from hydroelectric facilities relies on considerations of head, flow and variation in head and flow.

Head is the distance that water falls on its way from water source to turbines. Run-of-river hydro facilities do not have impoundments capable of storing more water than is needed to feed the conduits delivering water to the turbines. Thus, head generally does not vary at these facilities. But where dams store water, head varies as water levels vary behind the dam. On its way to the power plant, water encounters friction in the conduit. Friction is also caused by disturbances to the water flow within the delivery system, (e.g., disturbances where the conduit bends). Therefore, adjustments must be made to account for power lost before the water arrives at the plant. In equation (1), head (H) refers to effective head, which is static head (total head) times the efficiency of the water delivery system. For most purposes it is adequate to assume that a delivery system is 95 percent efficient. For example, if static head is 100 feet and efficiency is 95 percent, effective head is 95 feet.

The flow of a river, which is the rate at which water moves downstream, is usually measured in cubic feet per second (cfs). Flows at most sites vary daily, seasonally and yearly. Accounting for variation in flow is important because the power output of a hydro generator varies directly with the flow.

Equation (1)

Hydroelectric energy is created by the force of falling water. Power, which is measured in kilowatts, is the rate of energy production. Hydroelectric power output (P) is determined by the flow of water (Q) through a turbine, by head (H), and by efficiency (e) of the power plant according to the following formula:

$$P = \frac{Q \times H \times e}{11.8} \qquad (1)$$

Where:

P = power in kilowatts (kw)
Q = flow through the turbine (cfs)
H = effective head (in feet)
e = power plant efficiency
11.8 = conversion factor

Power Plant Efficiency

Efficiency varies with the type of hydroelectric generation technology employed. Power is lost to friction in the turbine, generator, switching equipment and other parts of a generation system. Most power loss is associated with the turbine, where efficiencies range between about 70 and 90 percent, though average efficiency falls closer to 90 percent. The other parts of the system can be assumed to have an efficiency of about 97 percent. If we assume that turbine efficiency is 87 percent and that other parts of the system are 97 percent efficient, overall efficiency is about 85 percent (.97 x .87). (EPRI recommends using 85 percent where the efficiencies of the system are unknown or where preliminary evaluations are sought.) Thus, in equation (1), a power plant efficiency of .85 will be adequate for most purposes. If turbine efficiencies are known to be substantially less than 87 percent, appropriate adjustments should be made.

Equation (2)

As an intermediate example, let us use equation (1) to assess the output of a hydroelectric facility with flow of 50 cfs:

$Q = 50$ cfs
$e = .85$
$H = 100$ feet
conduit efficiency = .95

Given the static head and the efficiency of the conduit, effective head (H) is 95 feet. The power capacity of the system (P) in kilowatts is:

$$(2) \qquad P = \frac{Q \times H \times e}{11.8} = \frac{50 \times 95 \times .85}{11.8} = 342.2 \text{ kw}$$

Streamflow

Streamflow is important to assessing the power output from run-of-river hydropower facilities. The above example assumes constant streamflow, but in mountainous Colorado streamflows vary daily, seasonally and yearly. This variation makes considerations of maximum flow, minimum flow and flow profile important.

Hydroelectric installations are designed to operate with specific maximum and minimum flows. Generally the higher the maximum flow that can be handled, the higher the minimum flow needed for operation. Streamflows that exceed the maximum usable flow cannot add to power production, and no power can be produced when flows are below the required minimum. The proper sizing of hydro facilities, which falls outside the scope of the present study, generally takes the stream profile into account. The stream profile of the San Miguel River at Placerville, for example, is shown in Figure 2. The horizontal axis shows the full range of observed flows and the vertical axis shows the proportion of the time that a given flow was exceeded. Since very high flows are expected infrequently, building a plant to use extremely high flows does not pay, because higher construction costs are unlikely to be recovered. Furthermore, since the minimum flow needed by a turbine relates to maximum flow, oversizing a turbine increases the required minimum flow.

In practice the maximum flow for which a turbine is designed is about one and-a-half to two times the mean flow; the minimum flow required is about 30 percent of the designed maximum. The mean flow of the San Miguel at Placerville (Figure 2) is 228 cfs. If the maximum flow for which the turbine is designed is one-and-a-half times this amount, the turbine will have a maximum design flow of 342 cfs, which is exceeded about 18 percent of the time. (When flow exceeds 342 cfs, the extra water is diverted around the installation.) If the minimum flow required is 30 percent of the designed maximum, then the minimum flow required is 103 cfs, which is exceeded about 49 percent of the time. The rest of the time, 51 percent, there is insufficient water to operate the facility.

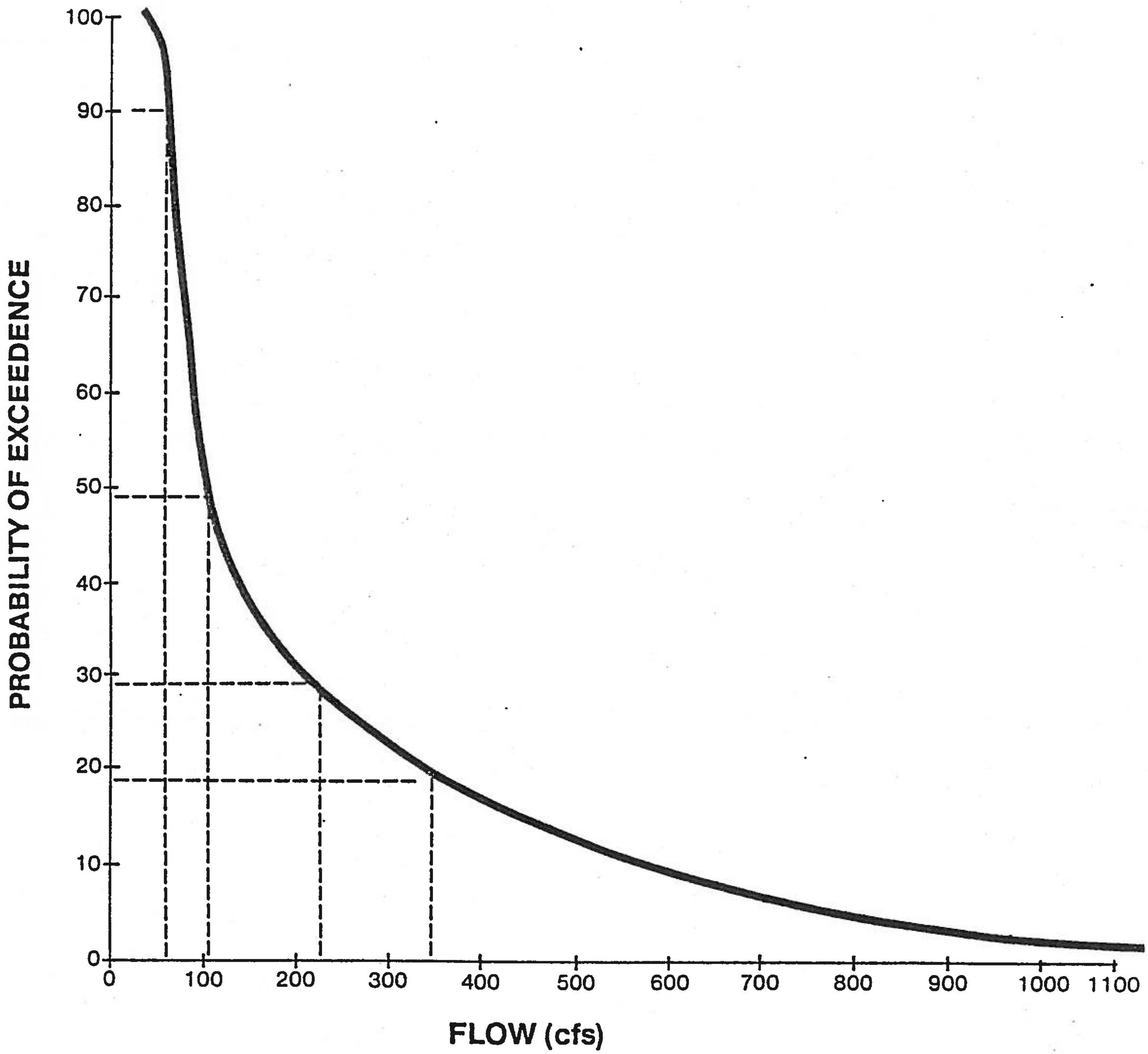

Figure 2 Flow profile, San Miguel River at Placerville

An Example

Using equation (1), an effective head of 95 feet, overall efficiency of .85, and a maximum design flow of 342 cfs, output capacity of the turbine described in this example is 2395 kw. At the minimum design flow of 103 cfs, output is 721 kw, and at mean flow (228 cfs) output is 1597 kw. Fifty-one percent of the time the facility will operate at zero capacity, since flows are below the minimum required for turbine operation. Eighteen percent of the time the facility will be at maximum capacity; 31 percent of the time the facility will operate at some intermediate capacity. Output will be different in a wet year when flows are near the maximum design capacity than in a dry year when flows fall below minimum requirements. The unique profile of each stream determines expected capacities and the number of hours a year that a facility will operate at those capacities.

Using Stream Flow Information

One way to use stream profiles to estimate power and energy output is to capture the curvature of the entire profile and the probabilities of various flows. But this method requires data that are difficult to obtain.

A second method is to use the mean streamflow. To continue with the example of Figure 2, output at the mean flow of 228 cfs is expected to be 1597 kw. If this flow were for the entire year (8760 hours), expected energy output would be about 14 million kwh (8760 hrs x 1597 kw).

In practice the stream profile should be constructed for periods of time as short as the data allow. A profile for each day of the year would be ideal, though weekly or monthly data are useful. Using data from short periods is particularly important in Colorado where streamflows vary considerably by season. In the case studies in Chapter 5 we use monthly data.

Potential Effect of Cloud Seeding

To estimate how winter cloud seeding might affect power production at small-scale hydroelectric facilities in Colorado, assume that cloud seeding increases mean flow about six percent to 242 cfs.* Expected power output using equation (1) is 1701 kw. If the profile refers to an entire year, energy production is expected to be about 14.9 million kwh, about .9 million kwh (or approximately seven percent) higher than power output without cloud seeding. Additional snow from cloud seeding would not only increase the mean stream flow for any given time period but would also probably prolong runoff. If runoff were prolonged, a facility would operate at higher power for more hours.

This study does not address effects that cloud seeding could have on designing the optimum size for hydro facilities. If developers were convinced that cloud seeding would raise stream flows above historic levels, they probably would install units with higher design capacities. In Chapter 5 we examine facilities for which the capacities have already been determined.

Economic Value

The Colorado Public Utilities Commission has established a rate for the sale of power by small-scale power producers to Public Service Company of Colorado. (The rate to be paid by the Colorado-Ute Electric Association has not yet been determined, but it probably will not differ much from that set for PSCo.) The rate to be paid by PSCo is $18/kw/month (capacity credit) plus $.017/kwh (energy credit) for producers who operate at 75 percent of capacity. The process of determining these rates was mandated by PURPA and the guiding principle was that rates should reflect a utility's "avoided costs." To recapitulate (see Chapter 2), avoided costs are costs the utility would incur if it did not buy power from the small power producer, so the rate reflects what power is worth to the utility.

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* A simple method of estimating increases in flow resulting from cloud seeding is described in Chapter 5.

Capacity Credit

Capacity credit is complex and controversial enough to merit explanation and an example. Power is worth more if it can be provided on demand. Capacity factor is the ratio of actual energy output to potential energy output. If a unit operated continuously, actual energy output would equal capacity output and the capacity factor would be 1.0. But no unit operates continuously. The value of a unit that operates a small portion of the time is less than the value of a unit that operates a large portion of the time: units are worth less and less as their capacity factors drop. A 75 percent capacity factor is specified in the rate because the standard of performance against which small power producers are compared is the performance of coal-fired plants, and most new coal-fired plants are designed to have 75 percent capacity factors. If small power producers operate with capacity factors less than 75 percent, the capacity credit is prorated.

At $18/kw/month the annual capacity credit per kw is $216. If each kw has a 75 percent capacity factor, it produces 6570 kwh (.75 x 8760) per year. On a kwh basis then, the capacity credit per kwh is $.0329 ($216/6570). We will call this the "full capacity credit." If a small power producer's capacity factor falls below 75 percent, say to 50 percent, its capacity is only .66 times (.50/.75) as valuable as the standard to which it is being compared. Thus, the capacity credit paid to this small power producer is .66 times the full capacity credit.

Energy Credit

When utilities buy power from small power producers in Colorado, they avoid burning coal. The PUC has determined that coal is worth $.017/kwh and that this amount should be paid as an energy credit. The total payment to the small power producer in this example ($.0499/kwh) is the sum of the capacity and energy credits.

Concluding Example

Earlier in this chapter we considered a hydro facility with output capacity of 2,395 kw capable of producing about 14 million kwh without cloud seeding and about 14.9 million kwh with additional flow from cloud seeding. Making allowances for forced outages and maintenance (which would take the unit out of service about 15 percent of the time), the net output is about 11.9 million kwh without cloud seeding and about 12.7 million kwh with cloud seeding.

If the plant could produce at design capacity (2395 kw) for the entire year, it would produce about 21 million kwh. Thus the capacity factors are about 57 percent (11.9/21.0) without cloud seeding and 60 percent (12.7/21.0) with cloud seeding. Table 4.1 shows the calculation of the capacity credit and the total value of the energy produced. In this example the total value is increased by about eleven percent (to $551,232) with cloud seeding, even though energy output only increases by about seven percent. The reason is that cloud seeding increases the capacity factor of the operation as a whole, thereby increasing capacity credit. Furthermore, capacity credit is raised for all kwh produced, not merely for the kwh from additional stream flow.

Summary

The possible effects of cloud seeding on the value of small-scale hydro power production can be estimated by taking the following steps.

1. Determine stream profiles for periods of time as short as the data permit.

2. Estimate power output for each period using mean flow in equation (1).

3. Estimate energy output for each period by multiplying power times the number of hours in the period.

4. Calculate capacity factor and capacity credit.

5. Add capacity credit and energy credit and multiply sum by total kwh produced to get total value of power.

6. Estimate increases in stream flow from cloud seeding.

7. Repeat steps 1 through 5 using augmented streamflow.

8. Calculate the difference between the value of power with cloud seeding and the value of power without cloud seeding.

TABLE 4.1

Estimated power output from the example hydro facility

Condition	Power* (kwh)	Capacity Factor	Capacity Credit	Energy Credit	Value per kwh	Value of Output
Without seeding	11,891,262	56.7%	$.0248	$.017	.0418	$497,055
With seeding	12,673,313	60.4%	.0265	.017	.0435	551,289
Difference	782,051					54,234
Percent difference	6.6%					10.9%

*Allowing 15 percent for forced outages and maintenance.

CHAPTER 5: CASE STUDIES

Two proposed small-scale hydroelectric projects were selected for study: a "run-of-river" installation on the North Fork of the San Miguel River planned by the city of Telluride, and a turbine on the Frying Pan River at Reudi Reservoir that the City of Aspen plans to install. Because the applications for permits that these two cities have filed with the FERC contain only preliminary information, assumptions are made about the conditions under which each facility will operate. These two sites were selected partly because they are more likely to be developed than many of the other proposed sites.

North Fork of the San Miguel River

The city of Telluride is planning a 1.2 mw "run-of-river" hydropower installation on the North Fork of the San Miguel River a few miles west of the city. Because there is no substantial dam or impoundment of water, a structure will be built in the river to divert water to the power plant. When flow exceeds the maximum for which the turbine is designed, it bypasses the intake mechanism.

CH2M Hill, an engineering consulting firm began the technical work required for site development only in October, 1983. Although we obtained as much specific information as possible from CH2M Hill, we have also had to rely on engineering rules of thumb recommended by EPRI. The flow profile must be estimated because the closest gauging station is located ten miles downstream. Using an estimate by CH2M Hill that the North Fork contributes about one-third of the flow at Placerville, we applied this proportion to the flows at the gauging station to estimate flows at the site.

Possible effects of cloud seeding on streamflows were estimated by relating stream flow at Placerville to snow water equivalent at Trout Lake and Molas Divide, locations in the headwaters region of the San Miguel where the

U.S. Department of Agriculture, Snow Survey Unit, makes monthly snowpack readings. Using a procedure similar to that used by the USDA, we developed multiple regression equations to estimate the relationship of monthly stream flow to snowpack. R^2 values, shown in Table 5.1 and based on 1958-82 data, indicate that streamflows in June and July relate moderately to April 30 snow water equivalent at Trout Lake and Molas Divide, but that streamflows in other months relate weakly or negligibly to snow water equivalents. We use these equations to estimate increases in flow of the San Miguel that could be attributed to 15 percent increases in April 30 snow water equivalent, the amount of increase that some scientists conclude winter cloud seeding could produce. Estimated increases in streamflows, which are shown in Table 5.2, are highest in June (12.2 percent) and July (18.2 percent).

Column 1 of Table 5.3 shows estimated mean flows for the North Fork of the San Miguel, assuming that flow on the North Fork is one-third of the flow at Placerville. Because some water will be left in the river to maintain fish life and scenic character, and because power generation at the site is likely to occur only during the high runoff season, we had to estimate how much water would be allowed to remain in the river. We assume that the flow remaining equals the flow occurring in the months of lowest flow (January and February). This assumption reduces by 21 cfs the flow (shown in column 2 of Table 5.3) available to the turbines.

The capacity of the installation planned is 1.2 mw with about 300 feet of head. Using equation 1 in Chapter 4 and assuming turbine efficiencies of 87 percent and effective head of 95 percent, maximum design flow is 57.1 cfs and minimum flow required is about 17 cfs.

Given the available mean flows shown in Table 5.3, flow is adequate for turbine operation only from April through September. Because mean flows exceed the capacity of the turbine in May, June and July, the turbine can operate at full capacity in these three months. During April, August and September, months when mean flows are between the maximum and minimum amounts required for operation, the turbines operate at less than full capacity.

Average electric output for each month is shown in column 3 of Table 5.3. Energy production, the product of average output and number of hours in each month, is shown in column 4. A five percent allowance for forced outages reduces the sum of production shown in column 5 to 4147 kwh. We assume that normal maintenance is performed during months when the facility is not operating. The net result is that the installation could produce 4147 thousand kwh for natural flows and an estimated 4292 thousand kwh when April 30 snow water equivalent is increased by 15 percent.

Table 5.4 shows net power output (with and without cloud seeding), capacity factors, calculated capacity credit, energy credit and the total value of the energy produced. Note that while estimated energy production increases by only 3.5 percent when April 30 snow pack is increased by 15 percent, the value of the energy increases by 5.0 percent. This is because the capacity factor and capacity credit are higher when stream flows are greater.

The value of the estimated additional energy produced each year is $7,154, an increase of about five percent. Assuming that cloud seeding could increase streamflow each year for the life of the project, $7,154 would constitute a permanent increase in the value of the installation. Treated as an annuity (assuming project life of 35 years and the cost of money as 12 percent), $7,154 increases the present value of the project by about $58,000.

Frying Pan River at Reudi Reservoir

The City of Aspen has received a permit from the FERC to develop a small-scale hydroelectric installation at Reudi Reservoir on the Frying Pan River, a Bureau of Reclamation project completed in 1968 that stores water for flood control, use downstream and power production. Information on the proposed installation is limited (the city of Aspen only recently issued a Request for Proposal for design of the facility), but good information on flow and head is available. Bureau of Reclamation management policy could affect the amount of water available to the proposed installation, but we assume that historic reservoir levels will be maintained. The planned installation has a capacity of 5 MW with a maximum head of 273 feet. Following procedures discussed in Chapter 4, we calculate maximum design flow of 261 cfs and minimum flow of 30 cfs.

To estimate possible effects of cloud seeding on flows at Reudi, we use a technique similar to that used for the San Miguel. (Data on mean flows and mean height of the reservoir are included in Aspen's RFP.) For each month, April 30 snow water equivalents were obtained for snowcourses at Nast and Kiln. Average flows at Reudi each month from 1972 to 1982 were regressed on April 30 snow water equivalents at these snowcourses and on April 30 reservoir height. Reservoir height was included to control for adjustments in reservoir levels made in response to various flow rates. Regression results are summarized in Table 5.5. Snow water equivalents or reservoir height were not included in the final equation if they did not add at least .01 to the R^2 value.

Estimated increases in streamflow when April 30 snow water equivalents at Nast and Kiln are increased 15 percent are shown in Table 5.6. These increases are based on the condition that height of the reservoir remains at historic mean levels. The main effect on flow of 15 percent increases in April 30 snow water equivalents comes not in the summer, as it does at the San Miguel site, but in the fall. Although mean flows are highest in May, June and July, percent increases in mean flows are largest in August, September and October. Management policy, the short period of record or both may cause the variation in percent increases noted in Table 5.6.

Table 5.7 (column 1) shows mean flows by month from Reudi for the period of record (1972-82). Mean head, shown in column 2, is assumed to remain constant.* Column 5 shows mean augmented flow, assuming that April 30 snow

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* Note that in July the mean head exceeds the maximum head implied in the assumptions above. We assume that the installation will be equipped to operate at maximum head pressure when design head is exceeded. Calculations use the maximum design head of 273 ft.

water equivalent is augmented 15 percent. Average output of the generator without cloud seeding and with cloud seeding is shown in columns 3 and 6. Energy production is shown in columns 4 and 7.

Allowing for maintenance* and a five-percent loss for forced outages, energy production rises from 20,724 thousand kwh without cloud seeding to 21,979 thousand kwh with cloud seeding, an increase of 6.1 percent. Table 5.8 shows net power, capacity factors, capacity credit, energy credit, and total value of the energy produced. The value of the power increases from about $782,000 per year without cloud seeding to about $859,000 with cloud seeding, an increase of about ten percent. Treated as an annuity (assuming project life of 35 years and the cost of money as 12 percent), $77,000 adds about $630,000 to the present value of the project.

* It is customary to schedule maintenance when a unit is least in demand. Since energy production is lowest in September, we assume that the facility will be shut down that month for regular maintenance.

TABLE 5.1

Intercepts, regression coefficients and R^2 values of streamflow at Placerville and April 30 snow water equivalents at Trout Lake and Molas Divide

	Intercept	Coefficients: Molas Divide	Coefficients: Trout Lake	R^2
April	6.50	.46 (.19)*		.20
May	11.54	1.56 (.52)		.29
June	7.68	.97 (1.23)	1.56 (1.28)	.61
July	-5.37	.56 (1.17)	1.47 (1.21)	.53
August	6.00	.41 (.15)		.24

*Figures in parenthesis are standard errors.
Coefficients not shown do not add at least .01 to the R^2 value.

TABLE 5.2

Estimated increases in the flow of the San Miguel River at Placerville attributable to cloud seeding

Month	Mean Flow (cfs)	Estimated Mean Flow with Cloud Seeding	Percent Increase
April	212	222	7.4
May	525	559	9.7
June	737	797	12.2
July	390	438	18.2
August	186	195	7.5
September	133	133	0
October-March	73	73	0

TABLE 5.3

Estimated flows and power output from the proposed Telluride installation on the North Fork of the San Miguel River under natural and augmented-flow conditions

Month	Mean Flow (cfs)	Available Mean Flow (cfs)	Average Output (kw)	Production kwh (000)	Assuming Augmented Streamflow: Mean Flow (cfs)	Available Mean Flow	Average Output (kw)	Production kwh(000)
Jan	21	0	0	0	21	0	0	0
Feb	21	0	0	0	21	0	0	0
Mar	24	3	0	0	24	0	0	0
Apr	70	49	1030	742	75	54	1135	817
May	173	152	1200	893	190	169	1200	893
June	243	222	1200	864	272	251	1200	864
July	129	108	1200	893	152	131	1200	893
Aug	61	40	840	625	66	45	946	703
Sept	44	23	483	348	44	23	483	348
Oct	37	16	0	0	37	16	0	0
Nov	27	6	0	0	27	6	0	0
Dec	23	2	0	0	23	2	0	0
Total	873	721	5953	4365	952	697	6164	4518
Allowance for forced outages				-218				-226
Net total production				4147				4292

TABLE 5.4

Estimated power output from the proposed San Miguel installation

Condition	Power (kwh)	Capacity Factor	Capacity Credit	Energy Credit	Value Per kwh	Value of Output
Without Cloud Seeding	4147	40.0	$.0175	$.017	$.0345	$143,451
With Cloud Seeding	4292	40.9	.0180	.017	.0350	150,605
Difference	145					7,154
Percent Difference	3.5%					5.0%

TABLE 5.5

Intercepts, regression coefficients and R^2 values of streamflow at Reudi Reservoir, April 30 snow water equivalents at Nast and Kiln snowcourses and height of Reudi Reservoir

		Coefficients			
Month	Intercept	Kiln	Nast	Height*	R^2
April	20.65	7,730 (1.90)			.28
May					
June	-32,578	16.50 (1.80)		4.20 (.86)	.37
July					
August	38.81	6.4 (1.94)	2.14 (.52)		.66
September	-7869	1.742 (.55)	3.12 (.71)	1.02 (.51)	.49
October	-10,753		5.47 (2.25)	1.40 (1.12)	.46
November	-12,442	4.14 (1.72)		1.61 (.66)	.29
December	22,491	3.60 (.85)		-2.89 (.83)	.28

* In feet.
Values not shown do not add at least .01 to the R^2 value.

TABLE 5.6

Estimated increases in the mean monthly flow available to the proposed Reudi Reservoir hydro-electric installation attributable to cloud seeding

Month	Mean Flow (cfs)	Mean Flow with Cloud Seeding	Percent Increase
Jan	138	138	0
Feb	142	142	0
Mar	136	136	0
Apr	120	135	12.5
May	174	174	0
June	245	259	5.7
July	210	210	0
Aug	130	145	11.5
Sept	95	103	8.4
Oct	106	151	42.5
Nov	124	134	8.1
Dec	141	146	4.1

TABLE 5.7

Estimated flows and power output from the proposed installation at Reudi Reservoir under natural and augmented-flow conditions

					Assuming Augmented Streamflow		
Month	Mean Flow (cfs)	Mean Head (ft)	Average Output (kw)	Production kwh (000)	Mean Flow (cfs)	Average Output (kw)	Production kwh (000)
Jan	138	248	2387	1,776	138	2387	1,776
Feb	142	239	2377	1,597	142	2377	1,597
Mar	136	231	2200	1,637	136	2200	1,637
Apr	120	228	1916	1,380	135	2156	1,552
May	174	245	2986	2,222	174	2986	2,222
June	245	273	4685	3,373	259	4952	3,566
July	210	275	4016	2,989	210	4016	2,989
Aug	130	272	2477	1,843	145	2762	2,055
Sept	95	271	1803	1,298	103	1877	1,351
Oct	106	268	1900	1,481	151	2708	2,015
Nov	124	263	2284	1,644	134	2468	1,777
Dec	141	255	2518	1,873	146	2621	1,950
Total				23,113			24,487
Maintenance allowance (September)				-1,298			-1,351
				21,815			23,136
Forced outage allowance				-1,091			-1,157
Net total production				20,724			21,979

TABLE 5.8

Estimated power output from the proposed installation at Reudi Reservoir.

Condition	Power Kwh(000)	Capacity Factor	Capacity Credit	Energy Credit	Value Per kwh	Value of Total Output
Without cloud seeding	20,724	47.3	$.0207	$.017	.0377	$782,309
With cloud seeding	21,979	50.3	.0221	.017	.0391	859,378
Difference	1,255					77,069
% Difference	6.1					9.9

CHAPTER 6: CONCLUSIONS

We have placed a value on electric power in Colorado and developed a method for evaluating the impact of weather modification on power production from small-scale hydroelectric facilities. We have applied the method to two small proposed sites using two kinds of technologies: run-of-river and conventional installation at a dam. The run-of-river site is being developed by the City of Telluride on the North Fork of the San Miguel River; the installation at the Reudi Reservoir dam is being developed by the City of Aspen.

Increases in stream flow that could result from winter cloud seeding have two effects on the output from small-scale hydro facilities. First, the total amount of electrical energy produced increases and second, hydro generators operate closer to full capacity, which raises their value. The estimated value of the energy output therefore increases more than energy production. At the Telluride site a 15 percent increase in April 30 snow water equivalent increases electric energy output by 3.5 percent and raises the value of energy output by 5.0 percent. At the Reudi site a 15 percent snow water equivalent increase raises energy output by 6.1 percent and its value by 9.9 percent. In both cases, estimated increases in the value of power attributable to modest increments in stream flow are substantial, especially when considered over the expected life of the projects.

Much remains to be done. Data on small hydro sites are incomplete. Many sites and proposed installations are not described adequately, although more information should become available as more developers receive FERC licenses to build and operate facilities. We cannot draw comprehensive conclusions about all small-scale hydro sites from the two sites that we have studied because developers use diverse technologies and face diverse situations. Also, water rights play an important role: developers who have senior rights probably would be less affected by incremental increases in streamflow than developers with junior rights. Based on the results of the two sites examined, however, we conclude that possible increases in stream flow from cloud seeding could increase significantly the amount and value of the energy output from small-scale hydropower facilities in Colorado.

APPENDIX A
GLOSSARY

Availability Factor: The proportion of time a generation unit is actually available for service.

Average Costs: Total costs divided by total output.

Avoided Costs: Costs that a utility does not incur when it purchases power from some alternative source rather than generating the power itself. The term "avoided cost" is almost entirely attributable to PURPA, which used the term instead of "marginal cost."

Capacity: A measure of the maximum rate at which an electric system can deliver energy.

Capacity Factor: The amount of energy that a generation unit actually produces as a proportion of what it is capable of producing.

Colorado PUC: Colorado Public Utilities Commission.

Demand: The requirements placed on an electrical system for power, normally measured in kilowatts.

Dispatch: The way in which the facilities of a utility are brought into and out of service to meet the demands placed on the system.

Economy Power: Energy that is available but that a utility does not guarantee to deliver when the customer demands.

Energy: An amount of power delivered over time measured in kilowatt hours.

Firm Power: Power that a utility guarantees to deliver when the customer demands.

FERC: Federal Energy Regulatory Commission.

Kilowatt (kw): A measure of the rate at which an electric system can deliver electrical energy.

Kilowatt hour (kwh): A measure of a quantity of electrical energy expressed in kilowatts times hours.

Marginal Costs: Incremental costs, or the increased costs incurred in producing a small increment in output.

Megawatt: One thousand kilowatts.

Peak Demand: The maximum demand (in kw) placed on an electrical system during a given period of time, usually one year.

Penstock: The device, usually a pipe, that brings water from an upstream location to a hydroelectric turbine.

PURPA: Public Utilities Regulatory Policy Act, passed by Congress in 1978.

Small Power Producers: For regulatory purposes, PURPA defines as small any power production facility, not owned by a utility, that has capacity under 80 mw; special rules apply to facilities that have capacities under 100 kw.

APPENDIX B

CONVERSION OF ELECTRIC UTILITY COSTS TO RATES

In Chapter 2 of this report we have shown the value of power from a number of relatively new power plants in Colorado. This appendix shows how rates are calculated from the costs borne by electric utilities.

Regulation in the electric utility industry is designed to ensure that electric rates track costs. The guiding philosophy is that electricity is worth what it costs to produce it. Costs are of three basic types:

- o fixed capital costs
- o fuel costs
- o operations and management expense

Of these costs, the fixed cost of capital is by far the largest and most difficult to deal with. Among the Colorado units surveyed in Chapter 2, the cost of capital amounts to about 58 percent of the overall cost of electric energy. Fuel costs comprise about 40 percent of the total cost. Operations and management expense is rather small, about two to three percent of total costs. We discuss each of these expenses below.

Fixed Capital Costs

The difficulty in apportioning the fixed costs of capital to each kwh sold is that power plants require large investments before any energy is produced. Furthermore, even if little energy is produced by a unit (as is the case with a peaking unit), the cost of the plant must somehow be attributed to whatever energy is produced. The steps involved in spreading the costs of capital over the kwh produced are roughly the following:

- o Calculate the annual cost of servicing the investment in the plant over the life of the investment
- o Determine the energy produced (kwh) by the plant each year
- o Divide annual costs by annual energy output

To illustrate how these steps are followed, we present a simple example. This example is designed to show the general nature of the calculations, not to represent the enormously complicated set of factors that go into actual rate determination. Also, the example considers only one power plant when in actuality a utility owns or controls a number of different plants and other facilities.

Consider the case of a utility that has built a new 500 mw power plant at a total cost of $500 million. To determine what rates are implied by this investment we must first find the annual cost of servicing the fixed capital costs of the $500 million. Service on the capital includes depreciation plus interest charges on borrowed capital plus a "reasonable" rate of return on the equity of the utility. The simplest way of calculating the annual cost is to "levelize" the costs. This procedure calculates a cost-per-year figure that remains the same for the life of the investment, much like the mortgage payment on a house does. There are other ways of annualizing the cost of an investment, but for simplicity we use a levelized approach. The formula for calculating levelized annual carrying charges is:

$$cc = \frac{kr[(1+r)n]}{(1+r)n-1}$$

Where:

cc= annual carrying charge
k = initial capital investment
r = interest rate required to service capital
n = life of the investment

If we assume the rate of interest allowed on the investment is 12 percent, the power plant has a useful life of 30 years, and the initial investment is $500 million, then the annual carrying charge(cc) equals about $62 million.

Over the life of the investment the utility must recover about $62 million annually, through the rates charged to its customers. To determine how this is reflected in rates, we determine the amount of energy to be produced by the plant.

If the plant were run at full capacity (500,000 kw) for the entire year (8760 hours) it would produce 4380 million kwh. However, no power plant operates continuously for a year because units must be taken out of service for regular maintenance, unscheduled repairs are required and sometimes there is no demand for the output from the unit.

The unit's "capacity factor" (see glossary) states the ratio of the actual output to the maximum output the unit is capable of producing if operated continuously. Assuming that the unit's capacity factor is 70 percent, instead of producing 4380 million kwh, it produces 3066 million kwh. The fixed annual carrying charge on the capital ($62 million) is:

$62 million/3066 million kwh = $.020/kwh

In practice, a new power plant has no record of operation and thus designed capacity factors are used. Once operations begin the observed capacity factor is used.

An alternative way of stating the value of the capacity component in electric rates is in terms of dollars per kw per month. This is the way utilities charge each other and charge their largest retail customers. To arrive at this rate one uses the same carrying charge ($62 million).

If the plant operates at a 70 percent capacity factor, the utility sells (on average) 350 mw. Thus, if the utility must recover $62 million per year on the sale of 350 mw it must charge:

$62 million/350,000 KW/12 months = $14.76/kw/mo.

Fuel costs

Fuel costs must be added to the cost of capital. Before a new plant begins operation fuel costs are estimated from engineering specifications. After a plant is in operation, one observes the rate at which the unit converts the heat content of coal (or applicable fuel) into electricity. Fuel costs are divided by kwh. In Colorado we have seen (in Chapter 2) that fuel costs about $.020/kwh.

Operations and Maintenance Costs

Operations and maintenance (O&M) expenses are small. Some of these costs are fixed and are treated like fixed capital costs. Property taxes are of this type since they are charged whether or not the plant is in operation. Variable O&M costs are computed similarly to fuel costs. Most common among variable O&M expenses are those associated with maintenance. By way of example, assume that total O&M expenses amount to $.002/kwh.

In the example, the cost of producing electrical energy, and therefore the value of electrical energy as determined by normal regulatory procedures, is:

cost of fixed capital	$.020/kwh
fuel cost	.020/kwh
O&M	.002/kwh
	$.042/kwh

Over the past decade inflation has had a major impact on the costs of producing power. A 500 mw plant similar to the one described above could have been built ten years ago for about one-half the amount that is now required. Also, interest rates (at times subsidized) were lower ten years ago. If a plant could have been built ten years ago for $250 million, and the cost of money was five percent, the annual carrying charge would be $15.268 million. If this plant were similar to the one in this example, the cost of fixed capital per kwh would be only $.0050/kwh, about 25 percent of what it is in the example. For this reason older power plants were not included in the survey of plants conducted in Chapter 2. The inclusion of older plants at lower fixed cost and lower interest rates would have given a low estimate of what it now costs to produce power.