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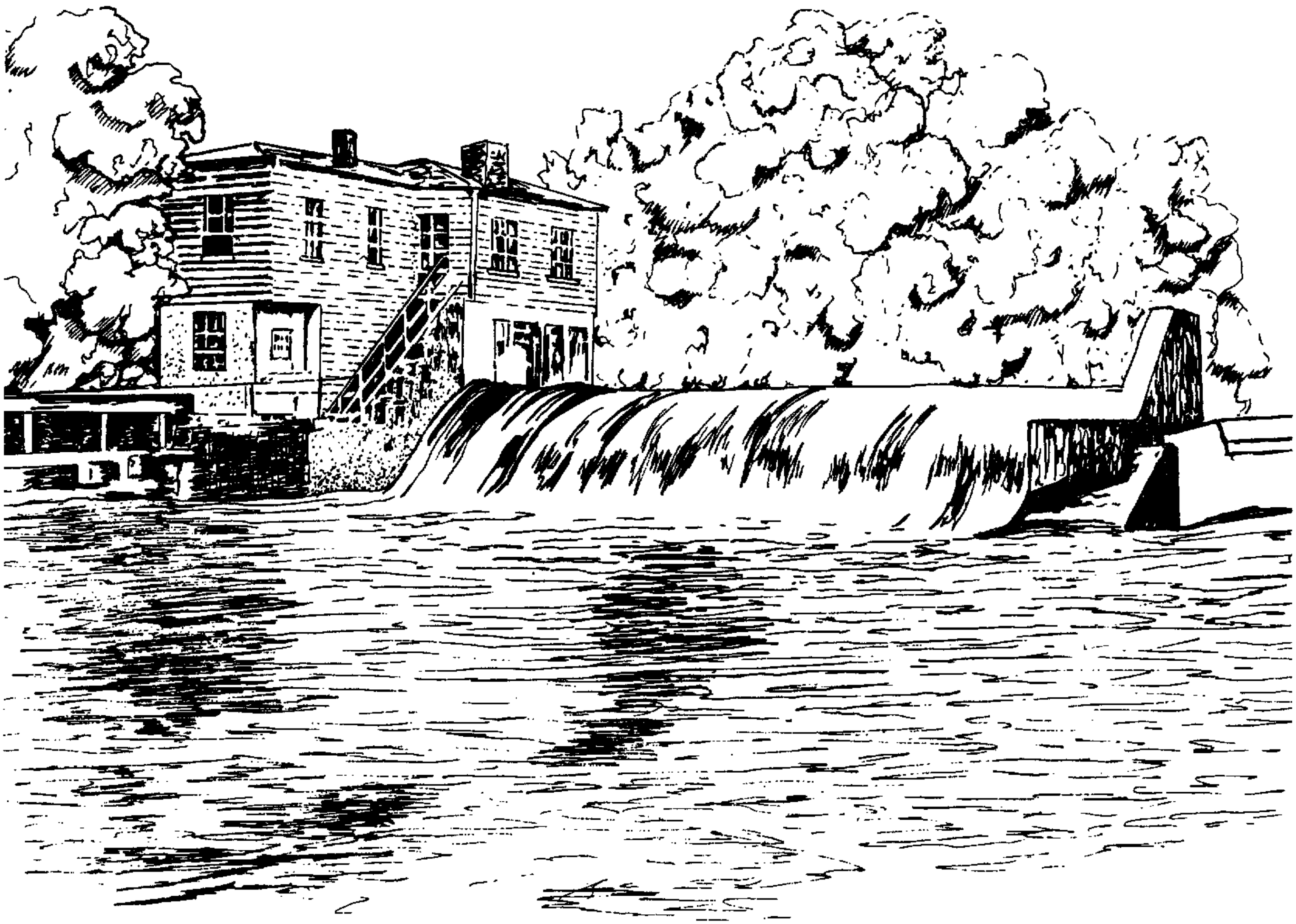
Water Over The Dam
A Small Scale Hydro Workbook for Colorado

Colorado Office of Energy Conservation

Colorado Water Conservation Board



Water Over the Dam
A Small Scale Hydro Workbook for Colorado

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Department of Regulatory Agencies
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PREFACE

The update for this document was completed on January 15, 1982. Since then, several changes have taken place affecting regulatory procedures at both the federal and state levels.

Federal Proceedings

On January 22, a decision was handed down by the United States Court of Appeals for the District of Columbia Circuit in American Electric Power Service vs. Federal Energy Regulatory Commission (Case No. 80-1789).

This decision vacates two sections of the Public Utilities Regulatory Policy Act (PURPA): Section 292.303(c)(1) requiring the utilities to interconnect with small power producers and cogenerators, and Section 292.304(b)(2)-(4) requiring the rates to be paid to small power producers and cogenerators to be based on the utilities' full avoided cost. Although the decision was handed down in the District of Columbia, it presents a cloud over these two rules as they apply throughout the United States.

FERC has filed a petition for rehearing and has indicated that they will appeal this decision. The critical question is: "what effect will the decision have on the marketing of small power production to the utilities?"

(1) The appeal process could take from 3-12 months. During this time, the federal court decisions will likely be stayed; if so, the present FERC rules requiring interconnection and payment of avoided cost will continue. It should be recognized, however, that financial institutions

may have serious reservations about investing in projects relying solely on rates dependent on these two FERC rules, knowing the uncertainty of their future.

(2) If the interconnect rule remains vacated, the mechanism remaining to accomplish interconnection is found in the Federal Power Act, Section 210 and 121. This calls for an appeal procedure to FERC and an evidentiary hearing. This process could be lengthy and, to the extent time equals money, may be costly.

(3) If the avoided cost rule remains vacated, negotiations between small power producers/cogenerators and utilities must rely on other factors to determine rates.

(4) If the rules remain vacated, FERC will likely set about rewriting both the interconnect and the avoided cost rules, and proceed with the official rulemaking process. This could take approximately one to two years.

State Proceedings

On January 12, 1982 the Colorado Public Utilities Commission issued Decision No. C82-73 regarding the PURPA requirements as they apply to Colorado. It required, among other things, that utilities interconnect and pay avoided cost rates. The utilities were required to submit tariffs reflecting standard avoided cost rates for units under 100 kW.

Due to the District of Columbia Decision, the PUC issued Decision No. C82-138 on January 26, staying Decision No. C82-73 pending further order of the Commission, and extending the deadline for requests for rehearing and reconsideration of that decision to March 1, 1982.

On March 23, 1982, the Commission entered Decision No. C82-436, which indefinitely continued the stay entered in Decision No. C82-138—thus Decision No. C82-73 will not become effective until the PUC order to stay is lifted.

Under Decision No. C82-436, the PUC will initiate new rule-making proceedings for Colorado, not based on PURPA or the FERC Rules. This procedure could take several years to complete.

A brief polling of developers presently holding multiple small scale hydro permits in Colorado indicates that the federal court decision will not have a major effect on marketing power from the bulk of their sites. It is not known what the effect will be on other small scale hydropower technologies. It is our belief that many hydro sites in Colorado have power that will be attractive to the utilities in any case.

It is the decision of the editor of this document to proceed with publication, even though portions of the document are written as if the federal court decision had not been rendered. The bulk of the guidance in the document is sound in any case. The reader will have to make adjustments in using the enclosed information, depending on the outcome of the proceedings discussed here.

Barbe Chambliss
Colorado Small Scale Hydro Coordinator
March 30, 1982

CREDITS

The contents of this manual have been researched, begged, borrowed and paid for. Major contributions were made by: Kenneth Wonstolen, George W. Sherk, William Ferguson, of the National Conference of State Legislatures, Denver, Colorado; Barbe Chambliss, of the Colorado Office of Energy Conservation and the Colorado Water Conservation Board, Denver, Colorado; Raymond E. Cunningham, of International Engineering Company, Darien, Connecticut; Peter A. McGrath of American Hydro Power Company, Villanova, Pennsylvania; William N. Hedeman of the Environmental Protection Agency, Washington, D.C.; Jeff Kahn of the Colorado Office of the Attorney General, Denver, Colorado; and Gil McCoy of the Washington State Energy Office, Olympia Washington.

Additional thanks are due to technical reviewers: Hal Simpson, Larry Smuckler, Martin Ringo, Ron Corso, W. H. Edelman, Phil Stern, Chuck Spinks, Nelson Jacobs and Mike Homyak.

No less credit should be given to those responsible for the production of this document: Barbe Chambliss, Project Director, and to Opal Anderson and Ann Nye.

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INTRODUCTION

This manual is for individuals interested in developing small scale hydropower sites in Colorado. Although small scale hydro is sometimes defined as power production up to 80 megawatts, most developers using this handbook will have projects ranging from 10 kilowatts to 20 megawatts.

No information is provided in this handbook about constructing new storage or diversion structures on the assumption that the sites to be developed involve existing dams or minor diversion projects.

This handbook is to be used only as an introductory guide. It in no way purports to provide definitive legal, engineering, or financial information. Once you decide to proceed with small scale hydro, we urge you to seek professional expertise in these areas, regarding a specific site.

The format for this handbook has been carefully selected. We chose to be functional rather than fancy. It seemed appropriate to small scale hydro development. We have adopted the three-ring binder approach because much of the information is changing periodically, especially in the financing and permitting areas. Updated information will be provided as it becomes available.

INSTRUCTIONS

This packet contains updated information for the document entitled Water Over The Dam - A Small Scale Hydro Workbook for Colorado.

This update was anticipated at the time of original publication due to the expected substantial changes in federal and state laws. Changes occuring up to January 15, 1982, have been incorporated in this update. The reader should be aware that additional changes will continue.

Replace each old page with the new page bearing the same number, (for example, old page four should be discarded; new page four takes its place.) Pages having numbers such as 65a should be put in the notebook immediately following the page by the same number (64, 65, 65a, 65b, 66.)

January 15, 1982

CHAPTER I: WHY AND HOW

Hydroelectric operation has, in essence, been rediscovered since oil supplies were interrupted in 1973. Though hydroelectric generation is one of America's oldest sources of electricity, its use decreased as larger fossil fuel and nuclear generating facilities produced more reliable and less expensive electricity.

There has been a substantial resurgence of interest in hydroelectric generation in recent years. Because hydropower is a renewable source of energy and does not add to our oil imports or balance of payments problems, the Federal government has chosen to carefully examine the barriers and incentives that have kept hydropower from developing in recent years. Regulatory and tax laws have been changed to pave the path for small scale hydro sites once again becoming a viable part of our "mix" of electrical energy.

Hydropower has many inherent advantages:

- It is a solar powered, renewable source of fuel.

- Although the "fuel" supply is subject to natural weather variations, the fuel costs are immune to inflation.

- There are no air, thermal, or other pollution byproducts.

- It is a proven energy source, using a well-tested technology.

- The life of a dam and powerhouse is estimated to be two to three times that of a fossil fuel plant.

- Because of the relative simplicity of the equipment involved, the operation and maintenance costs are low compared to other electrical generation sources. Many new small scale sites will be unattended.

- Hydro can be used for both base and peaking power in certain circumstances, and can minimize the need for reliance on planned, large scale fossil fuel plants.

- Small hydro sites dispersed throughout the state would provide back-up stability to our power generation system now concentrated at a few large sites.

In Colorado we have many sites where many of the preliminary requirements for hydropower generation already exist. There are 2,300 dams in the state; only a handful are equipped to make power. We have many diversion structures that channel water into useable conduits. Many municipalities have water or sewage treatment systems that involve gravitational flow. Many of the irrigation systems in the state have useable "drops" in the conduits. Additional advantages accrue from making power at these sites:

- Costs can be shared with other water uses.

- Energy requirements of the present water useage (irrigation pumping, water treatment, etc.) can be supplied.

- Most environmental impacts have already occurred.

- Retrofitting or expanding an existing structure can be completed in one to two years compared with 10-15 years required to design and construct a fossil fuel plant.

Small scale hydro sites also present certain challenges that should be known from the onset of a project:

- Development costs will be between \$800-2,400/kilowatt of installed capacity depending on factors such as length of penstock, length of transmission line, and whether the work is contracted or done "in-house". These costs do not take into consideration construction of a dam.

- Development requires substantial front-end capital with payback ranging from approximately one to five years after initiation.

- Developing a hydrosite requires expertise in hydrology, civil engineering, electrical engineering, construction, finance, taxation, regulatory and permitting procedures, contract negotiations, environmental analysis, public utility law, and real estate law.

- There may be some environmental alterations of a site involved, including a change in the aesthetics of the setting.

- In Colorado, many potential hydro sites are connected to irrigational projects which flow only from spring to fall, or are on waterways with substantial seasonal flow variations.

In developing a small scale hydro site, many activities must occur simultaneously. The steps include:

- Deciding Who Will Develop The Site

- Prefeasibility Study

- Feasibility Study

- Permits, Licensing, and Agency Contacts
- Financing Plan
- Power Purchase Plan
- Design and Equipment Selection
- Construction
- Operation and Maintenance

Figure 1 gives a graphic view of the process that is required. The following chapters provide details of each of these steps.

Figure 1
GENERALIZED OVERVIEW OF THE PROCESS
PRIOR TO CONSTRUCTION OF A HYDROPOWER PROJECT

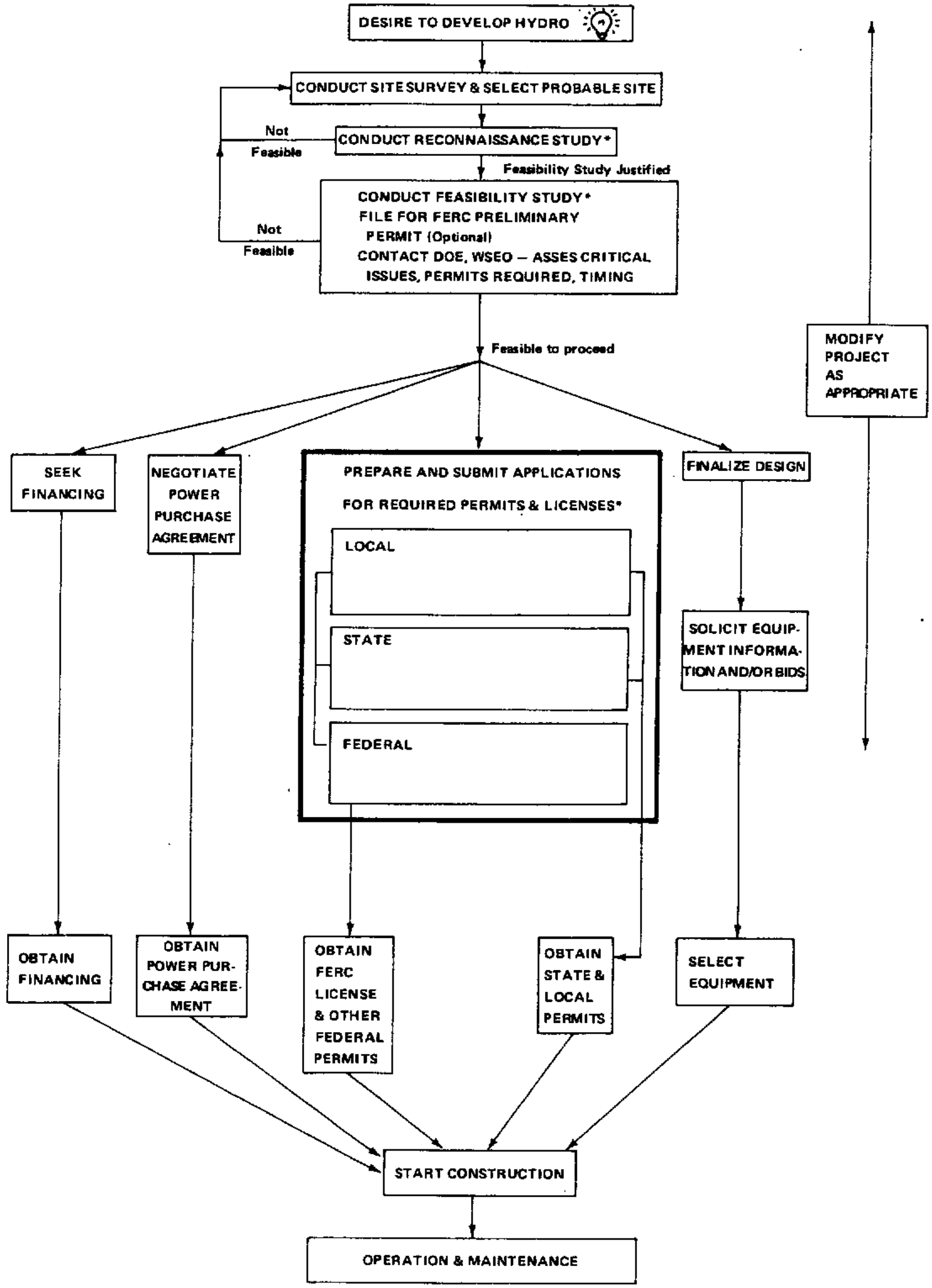


Chart derived from Developing Hydropower in Washington State as modified by the Colorado Small Scale Hydro Office, June, 1981.

Who Should Develop the Site?

CHAPTER II: WHO SHOULD DEVELOP THE SITE

Do-It-Yourself or Professional Developer?

The owners of potential hydroelectric sites are confronted with a basic decision: whether to develop the site themselves, or to arrange for the site to be developed by a private developer. The advantage to developing the site yourself, of course, is that all of the rewards from development flow directly to the site owner. Prior to making such a decision site owners should carefully assess a variety of factors which will have impact on the extent to which they can be successful with their own development plans.

A key task is gathering the information necessary for development. There is some cost involved in learning about hydroelectric technology, utility rates, government licensing procedures, dam repair and related financial aspects. Part of this learning process will involve direct expenditure of both time and money on the part of the owner, which may never be recovered if at any point the decision to develop the site is terminated. From the start, the process of developing a site is both a management problem and a financial risk.

Another factor to be considered is the availability of capital. Site owners must determine whether the amount of capital necessary to develop the site when compared to the return on investment may or may not be sufficient to warrant development. Industrial firms may have competing uses for their capital. Municipalities must examine if there are more critical competing uses for their limited borrowing capacity for long term capital projects.

For those site owners who, after consideration of their resources and the tasks involved, choose to develop their own sites, the publication, Micro-Hydro Power: Reviewing an Old Concept, will be of use. This may be obtained by writing to The National Center for Appropriate Technology, P.O. Box 3838, Butte, Montana, 59701.

The alternative to developing a site yourself is to use a private developer. Generally, development costs fall when more than one site is developed. Overhead can be spread over several projects, and after the first project learning costs fall rapidly. A private developer generally has broader information on financing alternatives, negotiations with utilities, the selection and installation of equipment, and compliance with the numerous governmental agencies involved in the licensing process. The time necessary to complete a project should be shorter which would also lower the overall cost of development. Capital would begin earning revenues in a shorter period of time, and thus would yield a higher rate of return.

Ultimately the owner of the site must ask the question: "What business am I in?" There is a trade off between risk and reward. Prior to any decision to develop the site internally, the owner should weigh carefully the total risk involved against the reward to be gained. The next section covers the key factors which vary from site to site and which determine the value of a site should the owners wish to sell the site or turn it over to a private developer.

Specific Site Values

In the event a site owner chooses to contract with a private developer, some formula needs to be devised to determine the value of the site. There are two major factors which a developer will consider in arriving at the value of a specific site. One is the potential revenues which can be generated at the site, the second is the total development and operational cost which will be incurred.

On the revenue side, there is a wide range of possibilities. Under the Public Utility Regulatory Policy Act (PURPA) of 1978, utilities must agree to purchase power from small scale hydro producers at what is determined to be their avoided cost. Not all utilities will have the same avoided cost and thus not all sites will have the same revenue potential. If a utility has mine mouth coal generating plants, its avoided cost calculations will show a much lower buy-back rate under the PURPA regulations than a utility using oil.

Another factor which determines the amount to be paid by the utility is the extent to which they are over or under their capacity to generate power in response to the demand placed on their system. Because of Colorado's population growth in recent years, our utilities predict future demands which exceed their current capacity, and are building new plants. Some utilities are presently purchasing power from outside the state.

Peaking power can command a higher avoided cost rate. Therefore sites which have the capability of producing peaking power will be of more value than those sites which do not.

Thus, sites comparable in all other respects will have different valued depending on the buy-back rates of the utilities involved. Some additional revenue, however, may be possible by selling power to a utility with a higher buy-back rate, or by selling power to an on-site industrial user to whom the power may have a higher value.

The second major factor in determining the value of a site is the cost incurred to develop and operate it. Thus, some sites will be more attractive than others based solely on these cost consideration.

Sites with lower initial construction costs will have a higher value to a developer. A site with an existing powerhouse and penstock will be worth more than a site requiring installation of new facilities. On the other hand costs for repairs to the dam, dredging and repairing the tailrace or headrace and the cost of installation of new transmission facilities to tie in to the power grid or other end users, might devalue the site.

Ultimately, the developer will compare the cost of construction and repairs to the overall cost per dollar of installed kilowatts. The two factors which determine the kilowatt capacity of a site are the stream flow and the head. The head is probably the most critical variable in determining the value of a site. The cost per kilowatt falls significantly as the head increases, because the amount of steel and other civil work needed to generate a given number of kilowatts drops.

A second major component is the stream flow as measured in cubic feet per second. A site with inadequate stream flow to produce sufficient kilowatts is less attractive to a developer. When combined with the head, the stream flow must be sufficient to yield an installed capacity large enough to produce sufficient revenues to cover the fixed cost of development.

Each hydro site has certain fixed costs regardless of size. These include the Federal Energy Regulatory Commission and other government licensing processes, the cost for preparing feasibility studies, design and engineering drawings, legal and financial placement costs, and costs of negotiating utility sale and purchase rates. The smaller the project, the larger the proportion of fixed costs.

In addition, there are certain minimum equipment costs regardless of the size of the project. For example, even though a smaller site will require a smaller turbine and generator, the cost for certain electrical switch, gear and control devices will be the same regardless of size.

Frequently, unusual costs arise in connection with development, especially if it poses any special environmental or other related problems as part of the government approval process. For example the installation of fish ladders or in-depth environmental impact studies might be required prior to development; or special methods of construction might be imposed to preserve near-by structures of historical or archeological significance. Such costs would lower the value of the site.

On-going operating costs of a special nature would also lower its value, as would high local property or income taxes which might be levied on hydroelectric development, or special insurance above that normally required for hydroelectric projects. The smaller the plant, the higher the costs for operations and maintenance in proportion to gross revenues. Every site requires some monitoring whether it is 400 kW or 2,400 kW. Yet the cost for monitoring is the same for both projects, and each site will have the same cost for billing, record keeping and other overhead expenses.

Alternative Payment Plans to the Site Owner

There are two basic approaches to compensating the owner of a hydroelectric site. One approach is to purchase the site and/or the rights to the site outright. A second approach is to lease the site from the owner or pay the owner royalty fees.

Under the first approach, the site owner may choose to sell the entire property or just the property needed to produce power. Developers tend to avoid purchasing the full site because the total package often involves excess real estate in the form of land or buildings. Most developers don't want to be in the real estate business, so they prefer to limit their purchase to that property or easements required to generate power.

Under a lease or royalty arrangement, the owner is paid a percent of the gross and/or net revenues. One variation on this is to guarantee a fixed minimum payment and a percentage of gross revenues, whichever is larger. The risk to the developer is that in any given year the site may not generate enough revenues to cover all costs plus the minimum royalty. Such a situation would require the developer to fund such expenses from sources other than the project. One way to protect against such a situation would be to have the cumulative gross revenues in past or future years credited toward these guaranteed minimums.

A more important consideration for site owners is to see actual development plans proposed for their site. Owners should verify that the installed capacity and the total kilowatt hours proposed by a developer are the optimum that could be installed at the site. Unless the developer is required to install equipment that best utilizes the sites power potential, total gross revenues may not be as large as revenues using some other configuration of equipment or civil work.

A third approach would be a joint venture between the developer and the site owner. Normally, the owner would contribute the value of the site as the basis for an equity position in the overall project. This is attractive to developers since it provides the project with an equity base equal to the value of the site itself. It also is attractive when arranging financing for the project, especially where the site is marginal and cash flows in the early years must be used to cover debt service and other direct operating expenses.

In the event a site owner needs the power, a fourth compensation approach might be tried. In this situation, the developer could sell power to the site owner at a lower price than the owner would have paid the local utility. Firms with dams on their property thus convert a liability to an asset without committing capital or bearing a risk.

Negotiation of a Fair Price

Because of the large initial capital investment required to develop a hydro project, it is essential that any price paid to an owner, either in the form of a royalty or as an absolute purchase, be compatible with the debt service needs of the project. For example, consider the two projects shown in Table 1 on page 15. Project A is clearly a more attractive site. It has a 40 foot head and costs $1,750 per kW to build, while Project B has only a 20 foot head and costs $2,000 per kW. Although Project A costs $3.5 million it produces 8.76 GWh while Project B costs $2.0 million but generates only 4.38 GWh.

TABLE 1

Comparison of Costs and Returns of Two Similar Hydro Sites

	Head	CFS	GWh per Year	Rated Capacity in kW	Cost	Cost per kW	Buy-back rate	Gross Revenues per year	Debt Service*	10% Royalty	O & M @ 1% of proj.cost	Profit/ Loss
PROJECT A	40	700	8.76	2,000	$3.5 mil.	$1,750	50 mills	$438,000	$373,500	$43,800	$35,000	(-$14,300)
PROJECT B	20	700	4.38	1,000	$2.0 mil.	$2,000	50 mills	$219,000	$213,450	$21,900	$20,000	(-$36,350)

*30 years @ 13% with 80% financing.

Source: McGrath, Peter, "Developing a Site," The Energy Bureau Conference, Washington, D.C., April 27-28, 1981, page 9.

For comparison, it is assumed that both sites are financed with 80 percent debt at 13 percent interest (tax free industrial development bonds) for 30 years. Project A has gross revenues of $438,000. If a royalty of ten percent of gross revenues ($43,800) is paid to the owner, $394,200 remains to service the debt and pay operating and maintenance costs. Debt service is $373,500, leaving $20,700 to pay taxes, insurance, and maintenance which normally total about one percent of project costs, or $35,000. Revenues may not be sufficient to cover all these costs and some renegotiation of the royalty may be needed. In Project B, there clearly is not sufficient cash flow even to pay both debt service and operating and maintenance costs. For this project to be profitable, royalty payments and costs must be delayed until utility buy-back rates rise high enough to provide the needed revenues.

Generally, only the most attractive projects can support a royalty payment of ten percent or above. These sites will have low costs per installed kW and provide enough initial cash flow to pay all costs in addition to the royalty. Every site factor must be favorable. The site must have a high head, substantial flow, an existing powerhouse with a dam in good condition, minimum environmental problems, clear access for electrical transmission, and be located in a utility service area heavily dependent on oil with high buy-back rates. Most sites however, don't meet all of these criteria and thus can't support payment of a royalty above ten percent.

In fact, most developments may require some form of deferred or reduced royalty payments during the initial years until buy-back rates rise sufficiently to cover costs. The only other alternative is to increase the equity contribution and reduce the debt level to bring yearly debt service requirements in line with yearly revenues. Any increase in the equity in a project, of course, lowers the return on investment and may not provide sufficient incentive to the developer to proceed.

There are several ways, however, to structure a marginal project to bring about its development. As already mentioned, the owner may defer royalty payments during the early years. In addition, developers and equipment suppliers may take back notes with deferred interest and principal payments on all or a portion of their share of the project costs. The expectation, of course, is that buy-back rates will rise in future years.

The same approach can be taken in situations where the site owner requires an up-front lump payment. It is relatively easy to calculate the value of a royalty payment in terms of an up-front payment. The first step is to project how much revenues will increase each year over life of the project, perhaps 25 or 30 years. Each future year's after-tax royalty payment would then be discounted so as to convert these payments into present dollars. By totaling these 25 years of discounted royalties, a present value for the site can be determined. The present value assigned to the site will depend on the inflation rate projected for the increase in the buy-back rate, and the rate at which future dollars are discounted back into current dollars.

Ultimately, the agreement between the owner and developer on the value of a site and the method of compensation will be the result of the competitive market forces at work. If a developer offers too little to the site owner, the owner will either find another developer or do the job himself. If the owner asks too much, a developer will pursue other sites, rather than earn only a marginal rate of return for the effort and risks.

Establishing the price for a site before a detailed feasibility study may be difficult because neither the owner nor the developer has sufficient information on costs and thus what a site is actually worth. A preliminary agreement, however, is necessary to protect the developer from an owner who, knowing that the developer has already spent a significant amount on the feasibility study, holds out for an unreasonably high royalty. Conversely, a preliminary agreement protects the owner from the developer who offers an unreasonably low royalty after the site is tied up with a Federal Energy Regulatory Commission permit and the owner can deal with no other developers until the permit period runs out.

A preliminary agreement may be reached prior to the feasibility study and prior to the end of the FERC notice period, which sets a minimum royalty payment of five percent and a maximum royalty payment of ten percent. When the site data is available from the feasibility study, both parties would then be free to negotiate a final agreement on a payment between these two limits once the data on the site were available from the feasibility study. If the royalty offered were under five percent, the owner would be freed from his obligation to the developer. Likewise, the developer would be able to proceed with the project with a royalty payment of no more than the maximum ten percent specified in the agreement. Such an agreement thus protects both the owner and the developer and sets reasonable limits on what either can demand in the negotiation process. Potential hydro sites located in or near municipalities present unique opportunities for joint public/private development, with advantages to both parties. A discussion of these opportunities is found in Appendix A, on page 106.

Feasibility

CHAPTER III: FEASIBILITY

All successful engineering projects are based on a suitable blend of technical, economic, and environmental factors. These factors must be assessed at several times and at varying levels of detail during the development of a hydroelectric power site. The prefeasibility assessment, feasibility evaluation, licensing and permitting, design, and construction stages of a hydropower project are all shaped by the technical, economic, and environmental factors relevant to that site.

Prefeasibility Study

Typically, the technical and economic factors are initially addressed by performing a relatively complete, but small scale, investigation of the site. Studies of this type are usually called prefeasibility, reconnaissance, or appraisal studies. They answer such questions as: Should I perform a detailed feasibility study? What is the hydropower potential of this site? About how much money is involved? They are designed to significantly reduce the risk of investing substantial sums to develop a project only to learn that it is not feasible.

Prefeasibility studies are based on estimates of head, average annual flow, cost data from similar projects, and proper application of cost curves, simplified formulas, and rules of thumb. A prefeasibility study normally costs a magnitude less than a comprehensive feasibility study, or from $2,000 to $15,000 per site, depending on site, existing work and environmental factors. The validity of the results depends heavily on the experience and judgment of the person analyzing the site. Quotes should be obtained from at least three sources.

A typical prefeasibility study assesses the technical and economic factors listed in Table 2 on page 21. A logical place to start a prefeasibility study is by assessing the market for your power by determining the value of your power and identifying potential buyers. If you can identify a favorable market for the output of your project, the next step is to estimate the hydroelectric power potential of the site based on the available head and average annual flow.

The available head, that is, the difference between headwater and tailwater elevation, can be directly measured in various ways. However, it may be available from the Inventory of Dams compiled by the Army Corps of Engineers or other published source. Additional data may be available if a Phase I Dam Safety Inspection and Evaluation of the dam has been performed by the U.S. Army corps of Engineers, or if an evaluation has been made by the Colorado Division of Water Resources.

The optimum installed capacity of the turbine-generator unit(s) will vary from site to site but will typically correspond to a rated unit discharge ranging from the average annual flow of the stream to twice the average annual flow.

Determining average annual flow can be more challenging. The factor appropriate for your area can be estimated from water resource data published by the U.S. Geological Survey (USGS) for gaging stations located in the vicinity of your site. The drainage area for your dam can be obtained from the Dam Safety Report, if available; from other information compiled by the Corps of Engineers or the Colorado Division of

TABLE 2

PRINCIPAL TECHNICAL AND ECONOMIC FACTORS FOR PREFEASIBILITY STUDIES

- Determine the value of power and identify potential buyers.
- Estimate the hydroelectric power potential.
- Assess the integrity of the dam and other existing features.
- Estimate the project costs.
- Calculate power and energy benefits and determine economic feasibility.

Information derived from "Developing A Site," Raymond Cunningham of International Engineering Company, Inc., The Energy Bureau Conference, Washington D.C., April 27- 28, 1981. p.2.

Water Resources; or by measuring it using a USGS topographic map (readily obtainable from many commercial cources). Of course, ideally, there is a USGS gaging station located on your stream from which you can get this flow data directly.

Once you have the head and average annual flow for your site, it's hydropower potential can then be calculated using the following formula:

$$kW = \frac{QHE}{11.8}$$

where:

Q = 1.0 to 1.5 times average annual flow
H = available head in feet
E = overall efficiency = 0.8 (A reasonable first approximation
kW = installed capacity in kilowatts

The average annual energy produced can be estimated as follows:

$$kWh = \frac{8760\ QHE\ pf}{11.8}$$

where:

kWh = average annual generation in kilowatt-hours, with Q, H, and E defined as before
pf = annual plant factor

Estimating annual plant factor is a complex process, as it depends on the size of turbine-generator unit(s) installed, on the statistical variation of streamflow at the site throughout the year, and on the regulatory effects of upstream reservoirs, if any. If an existing dam or reservoir is involved, the decreed use of the stored water must be determined. The historic release pattern of the reservoir must also be known to determine whether this pattern is compatible with projected power generation needs of the project.

Once the hydropower potential has been estimated, the integrity of the dam and other existing features should be assessed. The extent of repairs or reconstruction will clearly affect the economic factors. The existence of a state or federal dam safety report would be helpful here also if available.

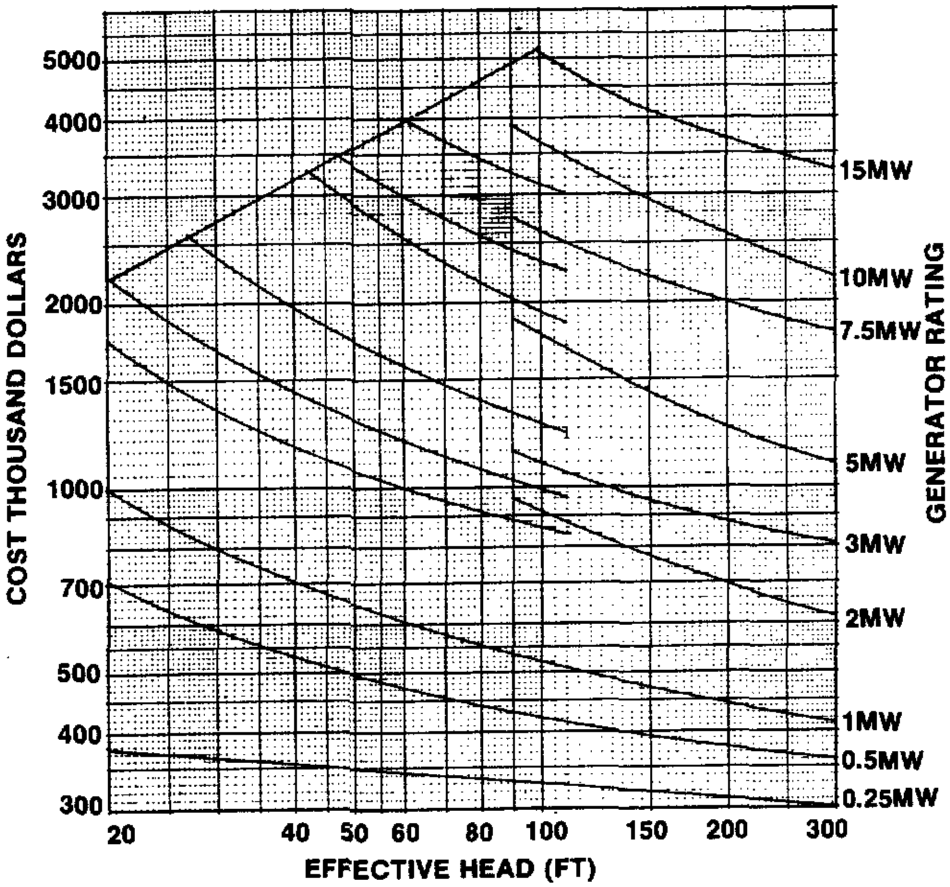
The next step is to estimate project costs. The cost curves and data presented in Exhibits 1 and 2 on the following two pages may be helpful in estimating the cost of your project. They are taken from a recent publication by the Corps of Engineers titled "Feasibility Studies for Small Hydropower Additions -A Guide Manual," dated July 1979. Read the "fine print" carefully. Such curves and cost data can be misused easily.

The final step is to calculate power and energy benefits and determine economic feasibility using any of the accepted methods of analyzing time streams of benefits and costs: net present worth, benefit-cost ration, internal rate of return, etc.

Feasibility Study

If the results of the prefeasibility assessment are favorable, the technical, economic, and environmental factors are then addressed at the feasibility study stage. The purpose of a feasibility study is to identify and formulate the most attractive hydropower development for the site and to determine whether it merits an investment commitment.

EXHIBIT 1



NOTES:

1. Estimated costs are based upon a typical or standardized turbine coupled to a generator either directly or through a speed increaser, depending on the type of turbine used.
2. Costs include turbine/generator and appurtenant equipment, station electric equipment, miscellaneous powerplant equipment, powerhouse, powerhouse excavation, switchyard civil works, an upstream slide gate, and construction and installation.
3. Costs not included are transmission line, penstock, tailrace construction and switchyard equipment.
4. Cost base July 1978.
5. The transition zone occurs as unit types change due to increased head.
6. For a Multiple Unit powerhouse, additional station equipment costs are \$20,000 + \$58,000x(n-1) where n is the total number of units.
7. Data for this figure was obtained from figures and tables in Volumes V and VI.

Source: "Developing A Site," Raymond Cunningham of International Engineering Company, Inc., The Energy Bureau Conference, Washington D.C., April 27-28, 1981, page 4.

EXHIBIT 2

MISCELLANEOUS RECONNAISSANCE ESTIMATE COSTS*
(Cost Base July 1978)

PENSTOCK COST

Effective Head (Ft)	10	20	50	100	200	300
Cost Index (CI)	960	480	200	110	55	35

Installed cost = CI x Penstock Length (ft) x Installed Capacity (MW)
Minimum Penstock Cost is $50 per linear foot.

TAILRACE COST

Construction Cost = $15,000 fixed plus $200 per linear foot.

SWITCHYARD EQUIPMENT COST
(Thousand Dollars)

Plant Capacity	Transmission Voltage			
	13.8	34.5	69	115
1 MW	50	60	110	160
3 MW	85	100	120	175
5 MW	110	125	150	210
10 MW	150	170	210	280
15 MW	185	220	250	320

TRANSMISSION LINE COST
(Thousand Dollars)

Plant Capacity	Miles of Transmission Line				
	1	2	5	10	15
0.5 MW	30	60	150	--	--
5 MW	45	80	160	320	500
10 MW	60	100	180	380	600
15 MW	80	140	230	460	700

*Data derived from Feasibility Studies for Small Hydropower Additions - A Guide Manual, Volume V (Figures 6-4 and 6-5) and Volume VI (Figure 3-1 and Table 4-2), U. S. Army Corps of Engineers, July 1979.

The methodology of a feasibility study is similar to that of a prefeasibility study; however, the simplistic assumptions, estimating techniques, and rules of thumb characteristic of the prefeasibility level are discarded, and more rigorous and comprehensive procedures are used. Hydrologic data for the entire period of record is utilized to assess the hydropower potential of the site. Actual cost data based on material quantities and equipment quotations are used in lieu of cost curves. The environmental, historic, scenic, recreational, and related aspects of the project are assessed on a preliminary basis.

Occasionally, subsequent events will alter a decision to make an investment commitment; for example, undiscovered site problems, foundation problems, financing difficulties, unfavorable bids, etc. Nonetheless, a proper feasibility study should significantly minimize the likelihood of unforeseen problems occurring in the later stages of a project.

Feasibility study costs should range from about \$25,000 for a 1,000 k/w plant up to about \$100,000 for a 25,000 kW plant. If substantial dam repairs are required or if a new dam is contemplated, these figures should be increased accordingly.

Typically, the technical, economic, and environmental factors shown in Table 3 on the following page are addressed during feasibility level studies. The study begins with the collection and review of existing data about the site. All available material, such as Phase 1 Dam Safety Reports, USGS topographic maps, flood insurance studies, design drawings of existing facilities, and geotechnical data, is collected and assembled for later use.

TABLE 3

PRINCIPAL TECHNICAL AND ECONOMIC FACTORS FOR FEASIBILITY STUDIES

- Collect and review existing data.
- Survey site to obtain river profile, cross sections, and topography, as necessary.
- Investigate foundation conditions and site geology.
- Perform hydrologic and hydraulic studies.
- Define range of development alternatives.
- Identify types of turbines suited to site and obtain vendor data.
- Prepare conceptual layouts and preliminary cost estimates for alternatives.
- Evaluate capacity and energy potential of site.
- Select alternative(s) for more detailed study.
- Research and confirm ownership of land and water rights.
- Prepare project financing plan.
- Research tax implications.
- Perform preliminary environmental assessment.
- Prepare drawings of the selected development alternative(s).
- Estimate project licensing, engineering, construction and operational costs.
- Prepare project schedule covering licensing, engineering construction, and startup.
- Prepare a power marketing plan and determine power and energy values.
- Perform an economic/financial analysis of the project.
- Prepare feasibility report.

Derived from "Design & Economic Considerations," Raymond E. Cunningham, The Energy Bureau Conference, Washington, D.C., April 27-28, 1981, page 4.

Typically, a wealth of information is available either free or for very little cost from state or federal agencies or other sources. Examples might include detailed topographic maps from the city engineer's office, river profile and cross section data from the Federal Emergency Management Administration, or the many water resource studies performed by the Corps of Engineers. This information could cost thousands of dollars to develop independently.

If the required topographic and river bottom surveys are unavailable, the site must be surveyed to obtain the necessary river profile, cross section, and topographic data. These data are required to calculate tailwater rating curves, accurately determine head, estimate excavation quantities, and perform other tasks essential to a hydropower feasibility study.

Two of the major steps during the feasibility study are the determination of installed capacity and the identification of suitable turbine-generator equipment. These deserve special attention.

Installed Capacity

The second major aspect of the feasibility study is to determine installed capacity. Selecting the near-optimum capacity of a hydroelectric plant can be time consuming and expensive. However, it is a necessary part of any engineering feasibility study; and with the aid of a computer, the necessary input data can be rapidly manipulated to aid the engineer in making the proper selection.

Because the majority of small hydro sites currently being considered for redevelopment are marginally feasible, care must be exercised in properly planning and estimating the costs associated with redevelopment. Once a conceptual layout for a project has been prepared by an experienced hydro planner to take advantage of the topography, geology, accessibility (and,if a redevelopment, the existing structural components of the dam, spillway, and power plant, as well as adjacent, nonproject structures), the process of selecting installed capacity begins.

Normally, a flow duration curve is prepared to aid in making the selection of trial plant capacities. Installed plant capacities in the range of 15 percent to 40 percent flow exceedance are usually selected to cover the normal range over which small hydroelectric plants are optimized. However, multiple units will present a range of exceedances. This spans the range of flows from somewhat less than average annual flow to about twice average annual flow.

For each of the trial installed capacities, costs are computed for all electrical, mechanical, and civil works. Allowances for contingencies and the costs associated with engineering, legal, administrative services are added to arrive at the total construction cost. Interest accrued to the project during construction is also considered and is accounted for in the analysis. Several manufacturers of small hydro equipment are contacted to solicit cost information and performance data. Past quotes provided by manufacturers for other similar projects are also consulted to provide additional cost information.

The annual cost for each trial plant capacity is computed based on the cost of money, overhead and maintenance charges, interim replacements, insurance and taxes. Associated benefits to the project are computed using flow data taken from USGS gage records and pro-rated to the site. Usually an average year is selected and average daily discharges used to calculate energy production. A computer is the most efficient way to make these calculations. Input data must include turbine-generator performance characteristics, headwater data, tailwater data, low flow release criteria, and the flow range of the turbine.

For those who desire to do as much as possible on their own, the Corps of Engineers' publication entitled "Feasibility Studies for Small Hydropower Additions-A Guide Manual" is highly recommended. It can be ordered from: The Hydrologic Engineering Center, 609 2nd Street, Davis, California 95616. A check payable to the Treasurer of the United States in the amount of $14.00 must be included with your order.

Appendix B on page 110 lists over seventy Colorado, national and international engineering and manufacturing firms in small-scale hydro. More detailed information on each firm may be obtained by requesting the "Colorado Manual of Small Scale Hydro Engineering and Manufacturing Firms," from the Colo. Small Scale Hydro Office, Room 823, 1313 Sherman Street, Denver, Colorado 80203, (303) 866-3441.

Turbine-Generator Equipment

Traditionally, consulting engineers have specified hydropower generating units on the basis of an optimized solution uniquely applicable to a given site. The performance characteristics of the equipment have been defined within narrow limits and have been realized by custom engineering of the turbine-generator unit(s). The range of suitable equipment types has been generally small, usually a Francis or conventional vertical Kaplan unit, or possibly a Pelton unit if the head is very high. Since the equipment contribution to total project cost has typically amounted to 10 to 20 percent, particularly on larger projects, the additional costs associated with this method have been insignificant compared with its benefits. In any case, the cost of the civil work has been the controlling factor in selecting the optimum project configuration.

This traditional equipment selection method is not well suited to small and low-head hydropower plants. The equipment contribution to the total cost of a small hydro project will typically range from 40 to 65 percent, and could be much higher in situations where new units can be fitted into an existing powerhouse. Therefore, the cost of the civil work no longer controls the configuration of the project. Instead, equipment and civil cost consideration have relatively equal influence. Thus, equipment cost is an area in which substantial savings may be realized, a principal factor in the evolution of standardized, pre-engineered turbine generator units.

The consulting engineer involved with equipment selection for a small or low-head hydro project has a relatively large number of standardized, pre-engineered types of units to consider. At the present time, these options include:

- Horizontal or inclined tube-type units, with either variable-pitch or fixed-blade runners.

- Tube-type units with right-angle drive gear boxes.

- Horizontal bulb-type units.

- Vertical and horizontal Francis units.

- Cross-flow (Ossberger) units.

- Rim-type (Straflow) units.

- Various impulse-type units.

- Open Flume

Within this range of options, it is difficult for the engineer to identify the best unit(s) for a site in advance of the bidding process. He can utilize preliminary quotation and performance data obtained from the various manufacturers to narrow the range; however, he runs the risk of eliminating the most attractive type and combination of unit(s) due either to market factors or to out-of-date, inaccurate, or overly conservative/liberal quotations and performance data.

If the project schedule permits, a good procedure for selection involves the preparation of a performance-oriented turbine generator bid package based on flow and head conditions at the site. This package should include sufficient prescriptive clauses to ensure conformance to local code requirements and desired quality standards, as well as specific site constraints. The manufacturers then have the opportunity to propose various combinations and types of units to take advantage of the unique cost and performance characteristics of their product lines. However, it should not be assumed that they will necessarily take advantage of this opportunity, particularly if their sales/applications engineers are flooded with requests for quotations.

At the present time, the best procedure for equipment selection probably lies somewhere between the traditional method and site-specific bid quotations from manufacturers. This is partly because the market for standardized, pre-engineered, turbine generator units is not well established. The number of such units actually sold and delivered is reasonably small. Many manufacturers have not invested the development time and expense to completely pre-engineer their product lines. Furthermore, by overlapping the equipment selection and civil-works design tasks, the design and construction schedule can be shortened to the benefit of the project. The key to the equipment selection process is the acquisition of accurate cost and performance data by the engineer for use in formulating reasonable powerhouse arrangement(s), and equipment specifications that do not improperly exclude a turbine manufacturer's product.

CHAPTER IV: WATER LAW

Doctrine of Prior Appropriation

In Colorado the doctrine of "prior appropriation" governs the allocation and distribution of water. This doctrine was law in Colorado before statehood and is embodied in the state constitution. The constitution provides that waters of natural streams are property of the public and dedicated to the use of the people, subject to appropriation. The doctrine of prior appropriation is a "first in time is first in right" system for allocation of water. Simply stated, the first person to appropriate water and apply it to a beneficial use has the first right to use water from that source. Each successive appropriator may take his share of the water only after all those water rights senior to his are satisfied.

The doctrine of "prior appropriation" is unlike the "riparian rights" doctrine which is followed by most of the eastern states. That system limits water rights to those who own land adjacent to a river or stream. In Colorado it is not necessary to own land on a river or stream to acquire a water right, and the ownership of such land does not carry with it the right to use any water.

Adjudication of a Water Right and Establishing a Priority

A court decree is not necessary to obtain a water right; a water right is created by diversion of water and applicaton to beneficial use. However, failure to adjudicate water rights renders the right junior in priority to those who obtain decrees. Whenever an owner or claimant of a water right wants a determination establishing the amount and priority of his water right, he must file an application with the proper water court.

The Water Right Determination and Administration Act of 1969, Colorado Revised Statutes 1973, 37-92-101 et. seq., provides special statutory procedures for adjudicating water rights.

Elements of an Appropriation

There are two basic elements in the acquisition of a water right. First, the water must be diverted from its source. Second, the water diverted must be applied to a beneficial use.

1. Diversion requirement

   The diversion requirement generally means removing water from its natural course or location, or controlling water in its natural course or location by a ditch, canal, reservoir, or other structure or device.

2. Beneficial use

   What constitutes a beneficial use is a question of fact which depends upon the circumstances in each case. Generally, it means the use of that amount of water that is reasonable and appropriate under reasonably efficient practices to accomplish without waste the purpose for which the diversion is lawfully made. This includes the impoundment of water for generating power.

Conditional Water Rights

Because some appropriations take substantial time to complete, Colorado now has recognized conditional water rights which allow a claimant to obtain a place in the priority system. A claimant who established a firm intent to appropriate water and has taken the first physical step in furtherance of the plan to appropriate is entitled to relate his priority date to the time the project was begun if the appropriation is completed with due diligence.

Under the 1969 Act, the holder of a conditional water right must show to the court each four years that he is proceeding with reasonable diligence to perfect his water right. Failure to proceed with reasonable diligence may result in cancellation of the conditional water right by the water court.

Nature of Right Acquired

A water right is a property right under Colorado law. As an inherent part of this property right, Colorado law recognizes the right of an owner to change the place of use, point of diversion, time or type of use of a water right, provided that such changes do not injure the vested water rights of others.

Both junior and senior appropriators have a right to resist all proposed changes in water rights which would materially injure their rights.

If a proposed change would cause injury, and conditions may be imposed on the change which would prevent such injury, the change will be permitted subject to such conditions.

Loss of the Right

A water right may be lost by abandonment or adverse possession. A conditional water right may be lost by abandonment or failure to exercise due diligence in putting the water to a beneficial use.

1. Abandonment

If it can be shown that a water right has not been used for a period of time and that the owner had an intent to relinquish the right, it may be declared abandoned.

2. Adverse possession

If the claimant can prove that he had actual, open, notorious, continuous, hostile, and exclusive possession of a right for a minimum of eighteen years, he may be declared the owner by adverse possession.

3. Cancellation

Conditional water rights may be "cancelled" if they are not developed with due diligence or the owner fails to apply for a quadrennial finding of due diligence.

Acquisition of a Water Right

1. By Appropriation

As previously noted, a water right is acquired by appropriation. Since many, if not all Colorado streams are fully appropriated for at least a portion of the year, any new appropriation may not be sufficiently senior to provide a reliable water supply. Thus, a potential appropriator must thoroughly evaluate the reliability and yield of a new appropriation before investing in the development of such a water right.

2. By Purchase

Another means to acquire a water right is to purchase an existing water right. Since water rights in Colorado are considered to be property rights, transfer of water rights is accomplished by deed.

Prior to purchase of a water right, the purchaser should examine the decree adjudicating the water right to determine, among other things:

1. Whether the right is absolute or conditional.
2. The amount of water decreed.
3. The point of diversion.
4. The place of use.
5. The decreed use.
6. The appropriation date.

Also, it is advisable to consult an attorney familiar with water rights in Colorado whether any conditions or limitations to the right exist. This is particularly true if the purchaser intends to make any change of a water right.

The water courts in Colorado are as follows:

Division	Stream	Location
1	South Platte drainage	Greeley
2	Arkansas drainage	Pueblo
3	Rio Grande drainage	Alamosa
4	Gunnison, and portions of Dolores drainage	Gunnison
5	Colorado drainage	Glenwood Springs
6	White, Yampa and North Platte drainage	Steamboat Springs
7	Los Pinos, Animas, San Juan, La Plata and portions of Dolores drainage	Durango

Conclusion

This chapter is intended only as a general introduction to Colorado water law. We urge prospective hydroelectric producers to consult an attorney competent in Colorado water law prior to undertaking any acquisition of water rights for hydropower development.

CHAPTER V: PERMITS & LICENSES

This chapter discusses the local, state, and federal requirements involved in developing a hydropower site. Most of these laws are based on allowing development of the project in a framework that protects our environment, provides for general safety, protects public and private property rights, and places the project in a perspective larger than a single site development.

MOST PROJECTS WILL NOT REQUIRE ALL OF THE ACTIONS LISTED.

Small projects in particular are likely to require very few permits. The federal government, especially in recent months, has streamlined and simplified what was once a highly cumbersome process.

It is important for the prospective developer to regard these various regulatory requirements not as barriers to be surmounted with minimum effort (or circumvented) but as a useful means to identify potential problems associated with a particular site or project design. Agencies should be consulted early in the process so that appropriate modifications can be made in a timely manner. This will avoid last minute misunderstandings and unnecessary delays.

The Local Process

The actions required at the city and county level will vary, not only with each city and county, but with each project. The following information in Table 4 should be used only as a guideline to begin individual investigation.

TABLE 4

Possible Local Permits

ACTION REQUIRED	AGENCY	REASON
Zoning/Conditional Use Permit/Special Use Permit	Planning Department/Zoning Department	Required if hydropower is not a use permitted under present zoning
Drainage of Surface Water Permit	Department of Public Works	If surface water is to be drained. May be required for other permits
Building Permit	Building Department	For construction of powerhouse and other structures
Temporary Road Closure Permit	Department of Roads or Department of Public Works	Needed for any construction that would close a road to traffic
Other Road Permits of Temporary Nature	Department of Roads or Department of Public Works	To operate overweight vehicles, etc.
Utility Permits	Department of Public Works	Needed for transmission lines; interconnection
Plumbing Permit	Building Department or Plumbing Department	Approval of any plumbing plans
Temporary Sewage Holding Tank Permit	Sanitation Department or Department of Health	For sewage facilities installed as part of project on permanent basis
Grading Permit	Department of Roads or Department of Public Works	For all excavation or filling activities except as noted in Uniform Building Code
Floodplain Permit	City/County Planning Department/ Zoning Department and/or Building Department	For any development in a regulated floodplain that would potentially affect flood flows or flood elevations

Data derived by Colorado Small Scale Hydro Office in consultation with state agency officials.

The State Process

In Colorado, the state licenses required for a hydropower project will vary with each specific site. Table 5 indicates eighteen possible permits, approvals, or consultations in eleven different state agencies. **MOST PROJECTS WILL REQUIRE ONLY A FEW OF THE PROCEDURES.**

It is the applicant's responsibility to contact all the appropriate agencies. Failure to do so may cause unnecessary delays and expense in the site development process. Appendices C and F on pages 112 and 145 respectively, provide further details about information required and contacts for each permit. Although most of the agencies are located in Denver, nearly all interaction may be accomplished by mail.

TABLE 5

Possible State Action Required for Development of a Small Scale Hydroelectric Project

REQUIRED ACTION	AGENCY	COMMENTS	TIME
Water Right	District Water Courts	Non-consumptive, industrial water and/or storage rights are needed to protect the right to use water for hydropower.	6-12 months
Small Power Producers Qualifying Status	Public Utilities Commission	If the power will be sold into the grid or if project is located on navigable waters, is 80 MW or less, less than 50% utility-owned.	1 day
Recommendation of Study of Project Effects on Fish and Wildlife or Recommendation of No Study Needed	Division of Wildlife	To assess impact of the project on fish and wildlife. Required of FERC Preliminary Permittees. The Study (or letter stating no study required) must accompany license applications to FERC.	90 days
Review and Recommendations of Guarding Project's Effects on Archeological and Historical Sites	State Historic Preservation Office	Consideration of effects of project on historical and archeological resources. Required of FERC Preliminary Permittees.	60 days?
Review and Recommendation on Project's Effects on Recreation Resources	Division of Parks & Recreation	If project affects state owned or leased recreation resources directly or indirectly. Required of FERC Preliminary Permittees.	30-80 days
401 Water Quality Control Certification	Water Quality Control Division Division	Regarding impacts on water quality of the discharge to the receiving water body or adjacent wetlands. A companion permit (identical applications) to the 404 permit issued by the Corps of Engineers. Required of FERC Preliminary Permittees.	6-8 weeks
Consultation	Colorado Water Conservation Board or Division of Water Resources or Landowner	If project involves use of water from existing state or federal reservoirs, these agencies can inform developers of operating principles, compact agreements, seasonal limitations, etc., which would affect hydro development.	1 day

TABLE 5, cont.

REQUIRED ACTION	AGENCY	COMMENTS	TIME
NPDES Permit (National Pollutant Discharge Elimination System)	Water Quality Control Division	Needed for all point source discharges to surface waters. Projects with dams may require permit due to trace metals and deoxygenation of water.	6 months
Site Approval of New Sewage Treatment Facility	Water Quality Control Division	Required for construction or expansion of any sewage treatment facility.	
Approval of Location and Construction of Water Works	Water Quality Control Division	If a potable public water supply system is involved.	45 days
Dam Safety Approval	Division of Water Resources	Required of new dams, enlargements, alterations, or repairs to existing dams over 10 feet with a capacity of more than 1,000 acre-feet.	4-12 weeks
Lease and/or Right of Way on State Land	State Board of Land Commissioners	For projects involving activities on state school lands.	3-6 months
Open Burning Permit	Air Pollution Control Division	Open burning.	7-10 days
Emission Permits	Air Pollution Control Division	Incinerators, sewage treatment plants, refineries, fuel burning which involves new air pollution sources.	90-150 days
Special Transport Permit	Department of Highways	For movement of oversize or overweight vehicles or loads.	1-30 days
Access Control Permit	Department of Highways	For projects affecting access (entrances) to the highway system.	up to 45 days
Permit for Explosive Materials	Division of Labor, Public Safety Section	When sale, manufacture, use, purchase, storage, or transportation of explosive materials is involved.	1-7 days

Data derived by Colorado Small Scale Hydro Office in consultation with local officials and private hydro developers, June 1981.

FEDERAL PERMITS AND LICENSING

Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission, formerly the Federal Power Commission, is the primary federal agency responsible for issuing licenses for all non-federal hydroelectric projects under its jurisdiction.

> Detailed information and application forms for FERC Permits, Licenses and Exemptions may be obtained by ordering the "blue book," entitled "Procedures to Apply for Hydropower Licenses of Preliminary Permits," from:

Federal Energy Regulatory Commission
Federal Building, Suite 9A05
819 Taylor St.
Fort Worth, Texas 76102

The purpose of federal licensing is best stated in Section 10(a) of the Federal Power Act which requires the commission to assure that:

> "the project adopted...will be a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of waterpower development, and for other beneficial public uses, including recreational purposes..."

In more direct terms, congress wanted to assure that hydropower development in any river basin would be compatible with the best overall use of the resource. In addition to the Federal Power Act, Congress has enacted a number of other statutes to assure the original intent of the Act and to protect other public interests.

FERC procedures cover three categories: Preliminary Permits, Licenses, and Exemptions.

Preliminary Permits

What is the purpose of a preliminary permit?

> It gives the permittee, during the term of the permit, priority for a license at a site while the necessary studies and examinations are undertaken to determine the engineering and economic feasibility for the project, the market for the power, and all information necessary for inclusion in an application for license. The permit does not authorize construction.

Is a preliminary permit required?

> No, it is optional. The advantage of having such a permit is that it reserves your right to first consideration for a license.

What is the term of a permit?

> It can be up to 36 months. Twelve to 18 month terms are most often granted.

How is a preliminary permit obtained?

> By filing an application with the Commission.

What does a preliminary permit application entail?

> It calls for the location of the project, the name and address of the applicant, the desired term of

permit, the name of the owner of the site, and four exhibits. (See Appendix D).

Can anyone else file for a permit on the same site?

Yes, within 90 days after public notice of the original permit application, competing applications may be filed.

Is there any preference in permitting?

Yes, states and "municipal" entities have preference provided that their plans for the project in question are equally well adapted to conserve and utilize in the public interest the water resources of the region. In the case of only competing private developers, all things being equal, the first applicant is given preference.

Who may file?

Any citizen, association of citizens, domestic corporations, municipality, or state.

To whom are preliminary permit applications submitted?

Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, DC 20426

If the permit is granted, then what?

The permittee is given a specific period in which to:

- consult appropriate federal, state, and local agencies regarding the impact of the

- consult appropriate federal, state, and local agencies regarding the impact of the project on the surrounding natural resources.

- establish a liaison officer for contacting these agencies.

- consult with the U.S. Fish and Wildlife Service and the Colorado Division of Wildlife about the recommendations for a study (or lack of need for a study) regarding mitigating measures for any effects of the project on fish and wildlife resources.

- prepare a memorandum of agreement with the owner of the site regarding use of the land.

- file six-month progress reports.

How long does it take to obtain a permit?

- Two to four months after an acceptable application is received.

<u>Licenses</u>

What projects are subject to licensing?

Any non-federal project which either:

a) occupies in whole, or in part, federal lands;
b) is located on navigable waters of the United States;
c) utilizes surplus water or water power from a federal dam; or
d) affects interstate or foreign commerce.

Only a very small project which does not affect a navigable waterway or interstate commerce, and does not hook up with a grid system would be exempt from FERC involvement.

If there is uncertainty regarding FERC jurisdiction, there is a relatively simple legal procedure to obtain a FERC decision regarding federal juridiction over a particular project. A Declaration of Intention is filed according to Part 24 of the FERC regulations (Title 18 CFR). The requirements are short and uncomplicated and can be completed with a minimum of data. A more direct method is to request an unofficial opinion from the FERC staff.

Is a license optional or required?

It is required for projects meeting the above criteria, unless an exemption is issued.

What is the purpose of licensing?

To assure that hydropower developments will be compatible with the overall best use of available resources.

How is a license obtained?

By filing an application with the Commission.

Who may file?

Any citizen, association of citizens, domestic corporation, municipality, or state which is the owner or operator of an existing or proposed hydro development.

To whom are license applications submitted?

Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, DC 20426

Is there more than one kind of license?

Yes, there are three kinds of licenses:

a) Short Form for Minor Project and Major Projects under 5 MW. A greatly reduced "Short Form Application" is used.[1]

b) Major Project - Existing Dam for projects over 5 MW which would not significantly alter the elevation or surface area of an impoundment, and would not result in a significant environmental impact. The somewhat reduced "Application for License for Major Project - Existing Dam" is used.

c) Major Project - New Construction for projects exceeding 1.5 MW requiring construction of a new dam. The "Application for License for Proposed Unconstructed Major Project" is used. This is the most rigorous of the FERC hydro procedures.[1]

What does the license application entail?

The applications involve a rather brief legal submission identifying the project, the applicants, and state legal requirements. A number of very detailed exhibits are also required. Many of the exhibits require time and effort to prepare and some call for coordination with or permits from state and federal agencies. More details are found in Appendix D.

How long does it take to obtain a license?[2]

After an acceptable license application is received:

Minor Project - 5-9 months
Major Project - Existing Dam - 9-15 months
Major Project - Unconstructed - 12-24 months

Can construction begin during this time?

No, construction may not commence until the license is granted.

Is there any preference in granting licenses?

Yes, the same preferences as in permitting. (See page 47.)

Exemptions

Are some projects exempted from licensing?

Yes. Presently three types of projects are exempt:

a. Projects of less than 15 MW built on man-made conduits, canals, or pipeline used primarily for domestic, agriculture or industrial purposes and which discharge flows for hydropower in a conduit. The project, including especially the powerhouse, must be on non-federal land.

b. Projects of 5 MW or less that meet certain criteria regarding environmental impact and where the owner has clear right to use the property, will be generically exempted.

c. Certain projects of less than 5 MW on existing dams or natural waterways, where an owner has clear right to use the property but all the criteria of b (above) may not be clearly met. These projects are exempted on a case-by case basis.

The practical effect of exemptions is to excuse project sponsors from preparing several of the exhibits ordinarily required by FERC in a hydro project license application. They do not excuse sponsors from coordinating with the appropriate federal and state fish and wildlife agencies or from obtaining other federal, regional, state, or local approvals.

How is an exemption application obtained? To whom is it submitted?

By requesting the appropriate exemption application form from:

Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, DC 20426

For more details on FERC permits, licenses and exemptions, see Appendix D on page 122.

Other Federal Permits

Permits and/or consultation with other federal agencies may be required. These include: The Corps of Engineers, Environmental Protection Agency, Department of the Interior, U.S. Fish and Wildlife Service, National Park Service, Bureau of Land Management, Bureau of Reclamation, and U.S. Forest Service. It is highly unlikely that a project would involve all of these agencies; generally only three or four are required. For more information on the interaction with these agencies, see Appendices D and F on pages 122 and 145.

Transmission Lines

The above information does not necessarily involve thorough coverage of permits required for transmission lines. This research is presently underway at this time.

Footnotes

[1]FERC Rules (Docket Numbers RM 80-39 and RM 81-10) revise the Short Form Application to be applicable to projects of 5 megawatts or less, and simplify existing regulations involving Major Projects-New Construction.

[2]If there is significant opposition to any project and an evidentiary hearing is required, these time frames do not apply.

[3]18 CFR part 4, Subpart K, 46 Federal Register 1294, January 5, 1981.

CHAPTER VI: ENVIRONMENTAL EFFECTS

Small scale hydropower projects have many positive aspects, not the least of which is the conversion of an existing, renewable resource into power. Generally speaking, there are fewer changes in the environment as a result of small scale hydro projects than in fossil fuel power production. However, hydropower production does affect the environment. Some of these effects are controlled by federal, state, and local agencies in their permitting processes, while others involve personal value judgements.

There are some sites which, by virtue of their value for some non-hydro uses, require specific government agency approval. Table 7 on the following page discusses those sites with major site restrictions, and the agencies which must be contacted. There are other types of "managed" lands in Colorado that require consultation with the managing agency. These are listed in Appendix E on page 143.

If you do not know whether your site involves or affects "managed" lands, or are unclear about the agency involved, you may contact:

The Colorado Natural Areas Program
1313 Sherman St., Room 718
Denver, CO 80203

This program has identified most of the managed areas in the state. The site must be identified by township, range and, if known, the USGS Quadrangle. Approximate acreage involved should also be given.

TABLE 7

Major Site Restrictions for Small Scale Hydropower

Project Located In/Affects	Action Involved	Agency	Statutory Basis
Wild & Scenic River ("designated" or "study")	FERC may not license projects on or directly affecting any component of the National Wild and Scenic Rivers System. No federal agency can make a loan or provide assitance for a project on these rivers without assurance that the project will not adversely affect the river's special values. Developer is required to consult with the appropriate agency.	National Park Service or U. S. Forest Service	Wild & Scenic Rivers Act of 1968 (16 USC 1271)
Historic and Archeological Sites	If the site is listed on the National Register of Historic Places or has been officially determined eligible for the National Register, procedures for impact avoidance or mitigation must meet approval of the State Historic Preservation Officer and the Advisory Council on Historic Preservation.	State Historic Preservation Officer	National Historic Preservation Act of 1966 (16 USC 470a) and Colorado State Register Act of 1975 (CRS 24-80.1-101-108)
Wilderness Areas ("designated" and "study")	If the site occurs within boundaries of land designated in the National Wilderness Preservation System, the land must be managed by the federal agency according to the provisions of the 1964 Wilderness Act. The U. S. President can authorize development in a Wilderness Area for reasons of national interest. Feasibility studies may be permitted in "Study" Wilderness Areas if activities do not affect the area's potential for designations. Developer is required to consult with the appropriate managing agency.	U. S. Forest Service or U. S. Bureau of Land Management or National Park Service or U. S. Fish & Wildlife Service	Wilderness Act of 1964 (16 USC 1131-1136) and 1976 Federal Land Policy and Management Act (43 USC 1701-1781) and National Forest Management Act (16 USC 1609)
Threatened and Endangered Species	If listed or candidate species of threatened/endangered plant or animal is known or projected to occur on the site, FERC will officially request a formal consultation with the U. S. Fish & Wildlife Service, after completing a Biological Assessment. For both state and federally listed species of animals, the Colorado Division of Wildlife must be consulted. Consultation with the Colorado Natural Areas Program is encouraged for federally "listed," "candidate," and "sensitive" species of plants.		

Data derived by Colorado Small Scale Hydro Office in consultation with state and federal agencies. June, 1981.

Construction and Operation Effects

Although environmental impacts vary greatly with the size and the characteristics of each site, there are two phases of development in which impact occurs: construction and operation. Table 8 and Figures 1 and 2 on the following pages indicates the impacts resulting from construction and measures to mitigate them.

Environmental effects of the operation of a hydro project are more diverse and, of course, ongoing. (See Table 9). These types of impacts and their mitigation measures are shown in Figures 3-6 on pages 62-65.

National Environmental Policy Act (NEPA): Federal agencies making decisions on hydroelectric project licenses are required to comply with the National Environmental Policy Act. For minor projects and for the additions of hydroelectric facilities to existing dams, the developer is initially required only to provide enough environmental information for the Federal Energy Regulatory Commission to determine environmental significance. If the project is determined to be environmentally significant, a full Environmental Impact Statement (EIS) is required. When a full EIS is required to comply with the National Environmental Policy Act (NEPA), it is written by the FERC staff using the information provided in the license application (Exhibit W or the Environmental Report). When necessary, FERC will require additional studies and information.

It should be emphasized that most environmental impacts are the result of projects which are relatively large and/or involve new reservoir and dam construction. **MOST SMALLER HYDRO PROJECTS WILL HAVE FEWER ADVERSE EFFECTS ON THE SURROUNDING HABITAT.** Likewise, if the project is located at an existing dam or diversion site, most adverse impacts have already been mitigated by previous measures.

Some small scale hydro sites will change a free-flowing water system into a closed, controlled system, which will involve some aesthetic tradeoffs. One must weigh the values of power production and potential income against some "hard-to-financially-appraise" values of beauty and sound.

For more details on certain aspects of environmental issues, we recommend the following volumes:

> <u>Analysis of Environmental Issues Related to Small Scale Hydroelectric Development</u>, Oak Ridge National Laboratory, January 1981.
>
> > Vol. I - Dredging
> >
> > Vol. II - Design Consideration for Passing Fish Upstream Around Dams
> >
> > Vol. III - Water Level Fluctuation
> >
> > Vol. IV - Fish Mortality Resulting from Turbine Passage from Oak Ridge National Laboratory.

Other helpful sources are listed in the Bibliography on page 167.

TABLE 8

Environmental Impacts from Construction Activities

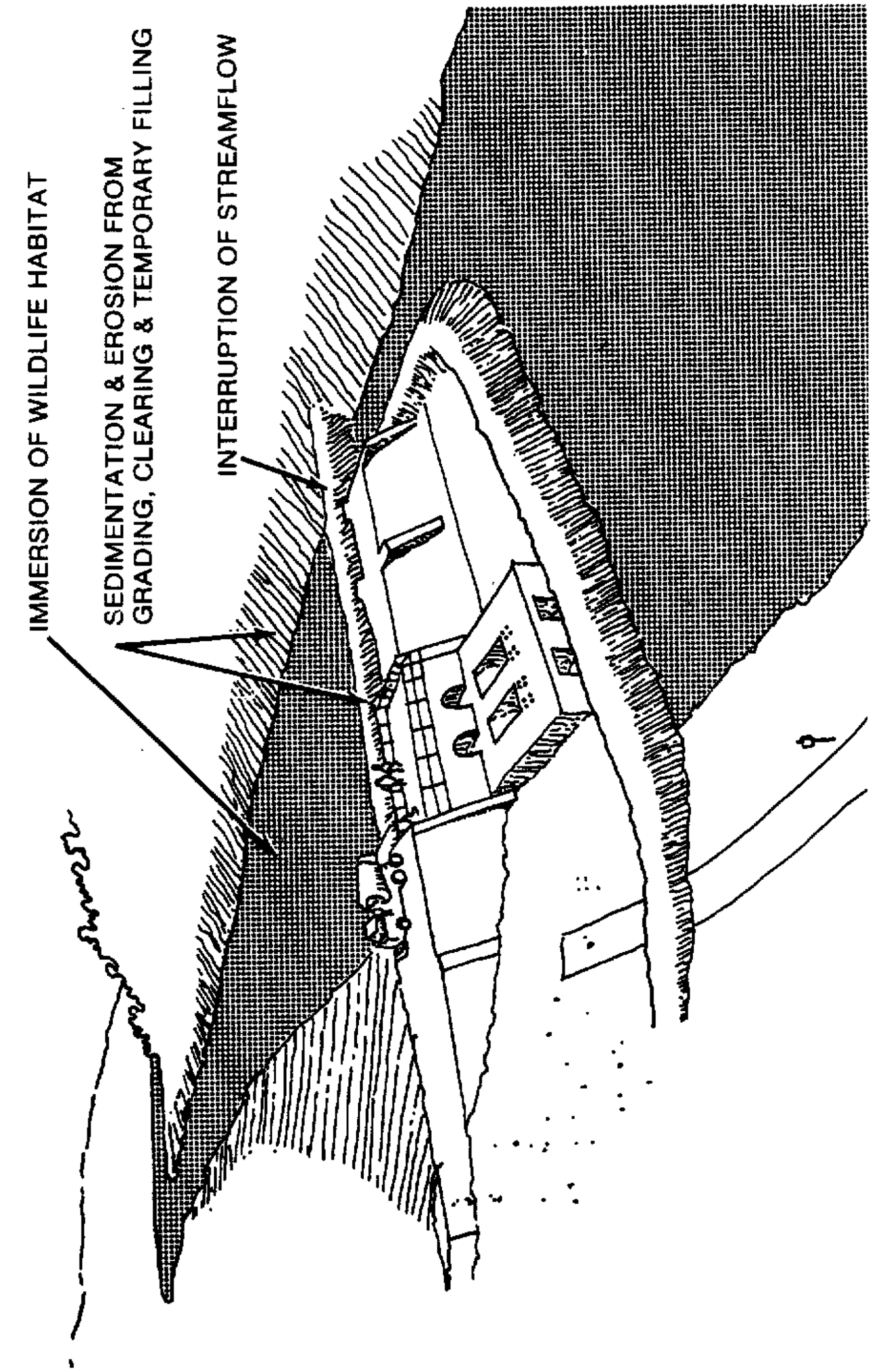
TYPES OF IMPACT DEPEND ON	Amount of land to be cleared
	Location and size of excavation, borrow and fill areas
	Extent of road relocation
	Disruption of stream flow

MITIGATION MEASURES INCLUDE	Stockpiling topsoil for later use
	Contouring to land to reduce runoff
	Building catchment basins
	Scheduling of work
	Revegetating disturbed areas

Information derived from "Environmental Concerns and EPA Involvement," William J. Hedeman, The Energy Bureau Conference, Washington, D.C., April 27-28, 1981, page 1.

FIGURE 1

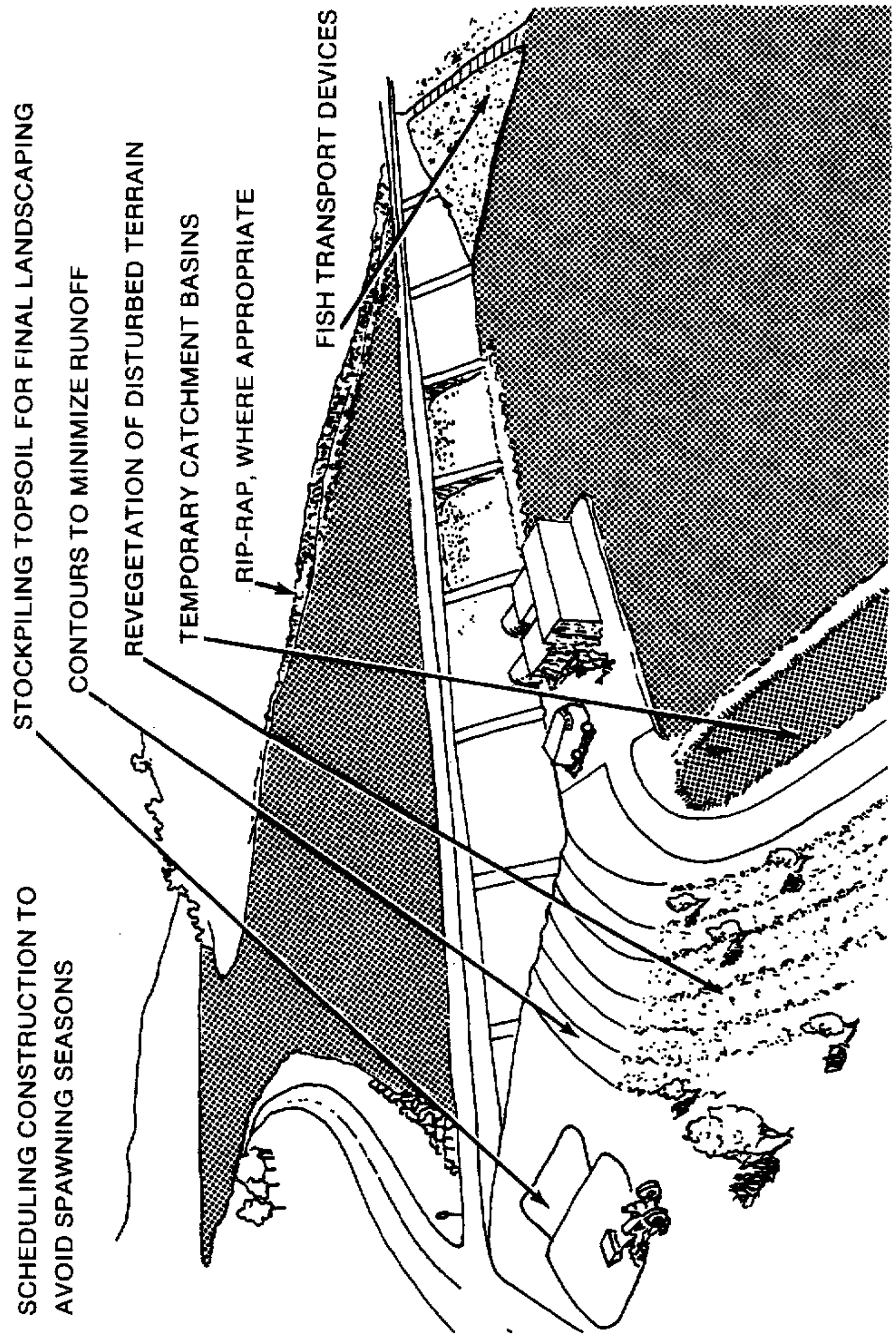
POTENTIAL CONSTRUCTION IMPACTS (SCHEMATIC)



Sketch taken from "Environmental Concerns & EPA Involvement," William N. Hedeman, The Energy Bureau Conference, April 27-28, 1981, p. 5.

FIGURE 2

IMPACT REDUCTION IN CONSTRUCTION (SCHEMATIC)



Sketch taken from "Environmental Concerns & EPA Involvement," William N. Hedeman, The Energy Bureau Conference, April 27-28, 1981, p. 6.

TABLE 9

Environmental Impacts from Operation

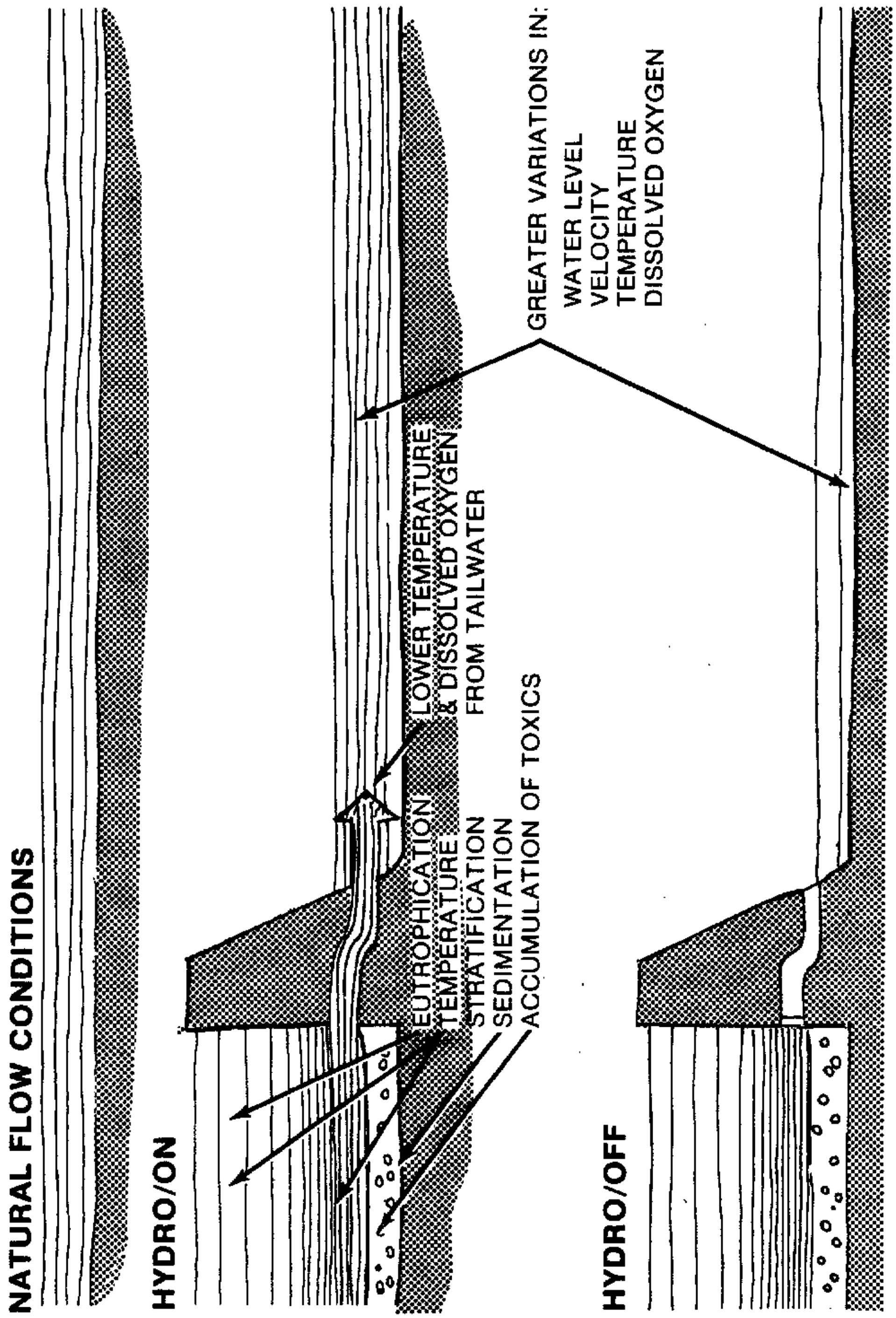
Type of impact depends on size and type of facility and mode of operation, i.e., run of the river or peak load. Impacts include:

IMPACT	RESULT
IMPACTS ON AQUATIC ORGANISMS	Loss of diversity and stability of aquatic organisms indigenous to streams on which the project is to be located
EFFECT ON WATER QUALITY	Impoundments often accelerate eutrophication and deplete the level of dissolved oxygen
IMPACT OF THE RELEASE OF IMPOUNDED WATER DOWNSTREAM	These releases are often much colder than the downstream receiving waters and have dissolved oxygen levels that are often far less than prescribed state water quality standards
IMPACT OF PERIODIC DISCHARGES	Periodic discharges can radically alter downstream flows, providing insufficient amounts of water to assimilate or dilute previously permitted wastewater discharges
SEDIMENT IMPACT	Dams can be extremely effective traps for sediments. In areas with high erosion, sediments can accumulate at a high enough rate behind the dam to make the hydro facility economically infeasible
DRAWDOWN ZONE	Large and/or frequent changes in reservoir level may occur, especially with peaking power sites. The area vacated by the draw down may be muddy, unvegetated, biologically unproductive and subject to erosion and/or dust production
IMPACT ON THE TERRESTRIAL ENVIRONMENT	Hydro projects affect the terrestrial environment when, in the case of larger facilities, many acres of wildlife habitat are inundated by impoundment water
RECREATIONAL IMPACT	Hydroelectric projects may significantly alter the existing recreational activities of the area, although substituting a different form of recreation opportunity

Information derived from "Environmental Concerns and EPA Involvement," Wiliam N. Hedeman, The Energy Bureau Conference, Washington, D.C., April 27-28, 1981, page 1.

FIGURE 3

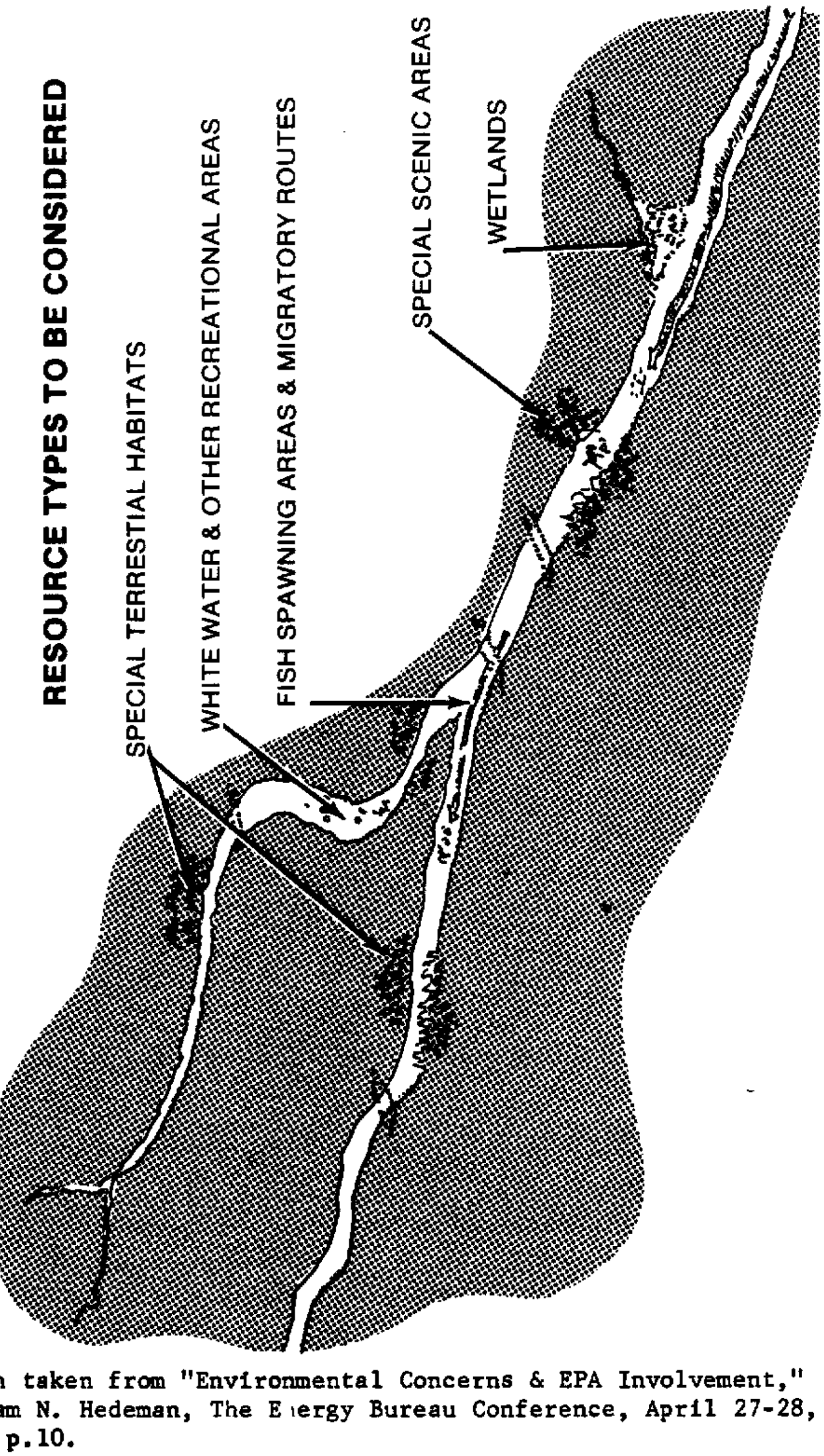
OPERATIONS IMPACTS ON WATER CONDITIONS (SCHEMATIC)



Sketch taken from "Environmental Concerns & EPA Involvement," William N. Hedeman, The Energy Bureau Conference, April 27-28, 1981, p.7.

FIGURE 4

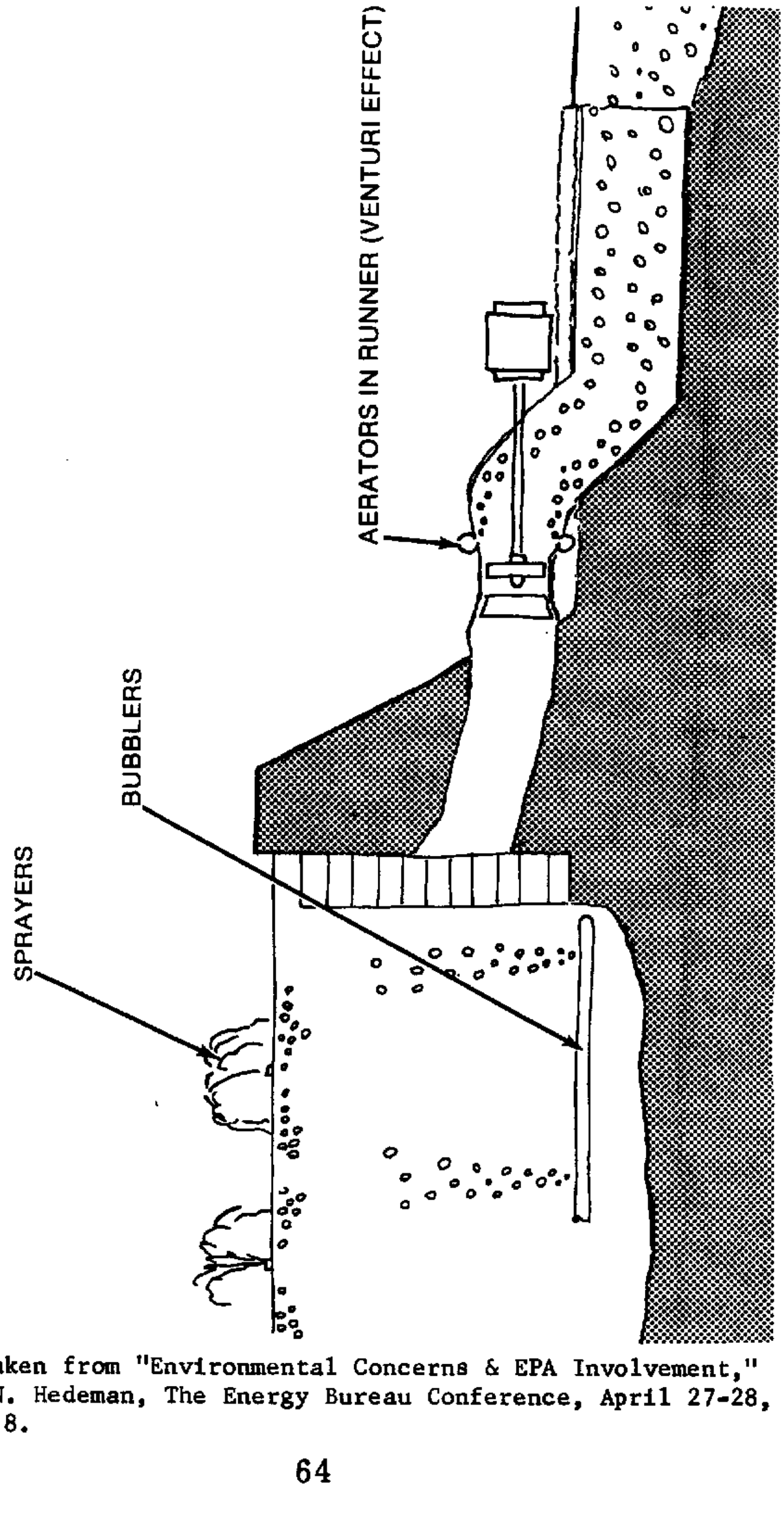
IMPACT REDUCTION IN CAREFUL SITE SELECTION



Sketch taken from "Environmental Concerns & EPA Involvement," William N. Hedeman, The E ergy Bureau Conference, April 27-28, 1981, p.10.

FIGURE 5

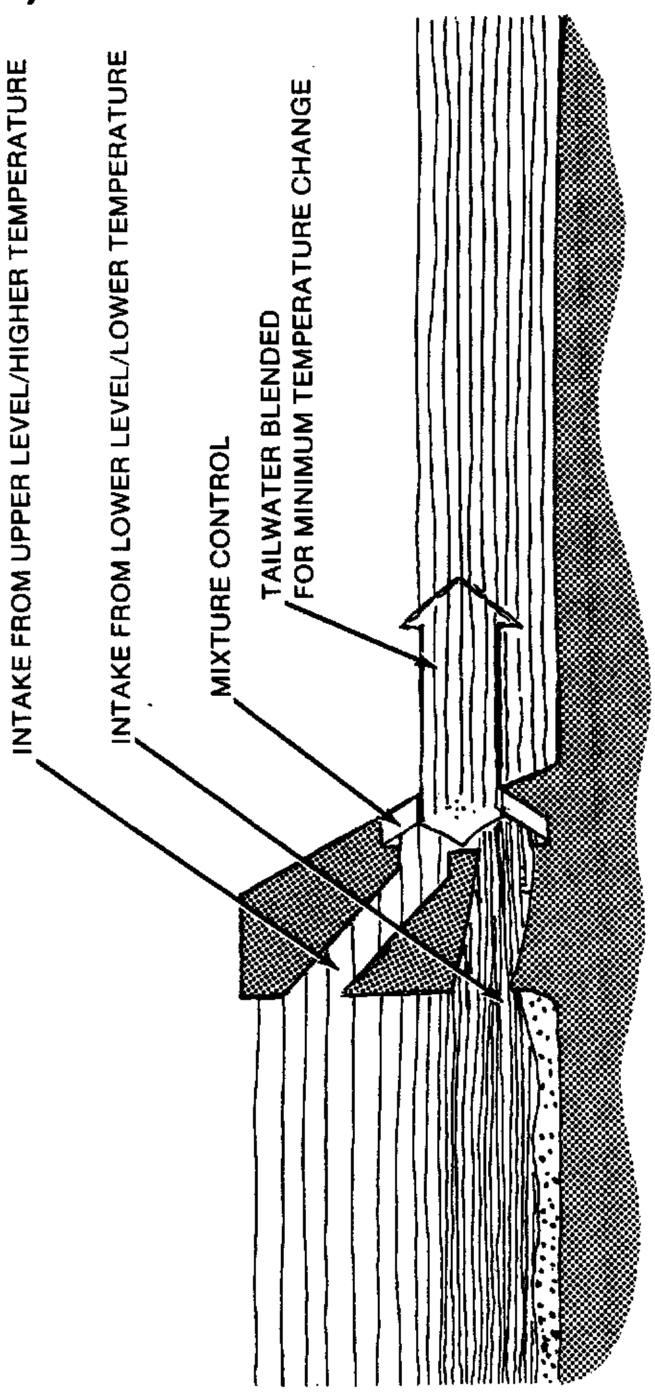
AERATION TO INCREASE DISSOLVED OXYGEN (SCHEMATIC)



Sketch taken from "Environmental Concerns & EPA Involvement," William N. Hedeman, The Energy Bureau Conference, April 27-28, 1981, p. 8.

FIGURE 6

MIXING INTAKE TO REDUCE TEMPERATURE IMPACTS (SCHEMATIC)



Sketch taken from "Environmental Concerns & EPA Involvement," William N. Hedeman, The Energy Bureau Conference, April 27-28, 1981, p. 9.

Sale and Purchase of Power

CHAPTER VII: SALE AND PURCHASE OF POWER

Three economic facts of small-scale hydroelectric facilities have significant effect on the financing and the sale of power. First, the cost of constructing hydroelectric facilities is generally high compared to the cost of construction of coal or oil powerplants. Second, the operating and maintenance costs of hydroelectric facilities are usually substantially less than coal or oil facilities, due to long equipment life and low fuel (water) costs. Third, hydroelectric facilities usually produce a fluctuating and possibly unreliable electric output, due to changing waterflows and other uses of the river system.

The economics of a small-scale hydro facility are very site specific. Many factors determine the precise economics of a given site and these factors vary greatly. The following discussion will provide a potential developer with an understanding of the basic principles involved. However, the actual business plan for any facility should be developed using marketing and financing experts, with all the site specific factors carefully analyzed. A more detailed analysis of concerns in the sale of power can be found in two reports prepared by the Energy Law Institute.[1]

The marketing of electricity and financing of a small-scale hydro facility pose unusual problems compared to many other types of small businesses. A large amount of capital is required, and the terms governing the sale of power are complex. The primary value of a facility is its revenue stream. Hydroelectric sites and civil works themselves are usually worth very little as collateral, since they cannot be readily moved or used for any other purpose. However, the hydro equipment may be moveable and have some resale value. For most projects, the terms of the sale of power, also known as power marketing, constitutes the primary value of the project on which financing will be based.

Several federal tax incentives have recently been enacted to encourage private investment in small-scale hydroelectric facilities. Interest in public development also is increasing. Whatever the type of developer, the sale of power contract and the type and cost of financing will be the primary factors in determining economic viability of a project.

Some facilities may not sell any power; rather, the developer will consume all of the power internally. In such cases a sale of power contract will not be necessary. The value of the project will be the value of the electricity replaced by internal production over the life of the project.

Colorado Utilities

The most likely purchaser of small-scale hydroelectric output is the local utility. Colorado has four different types of utilities. These are investor-owned utilities (IOUs), rural electric associations and cooperatives (REAs and RECs), municipal utilities, and federal and state wholesale suppliers.[2]

Investor-owned utilities generate most of their own power, but will purchase power under arrangements which are negotiated, or made and reviewed pursuant to federal law. Rural electric associations and cooperatives usually generate no power, but purchase all their power from generation and transmission cooperatives which supply wholesale electricity. Municipal utilities may or may not have generation capability, and serve only the municipality. Wholesale suppliers, including generation and transmission cooperatives and the federal power authority sell to other utilities, and make no retail sales.[3]

A developer will usually need to contact the utility (or utilities) in the area which engage in retail sales of power. Interconnection agreements and power purchase contracts will normally be made with the local utility. In some cases, a utility may transmit the power for sale to a second utility. A list of utility jurisdictions may be found in Appendix G on page 154.

One aspect in marketing electricity from a small power operation is that the local utility is usually the only potential purchaser, and thus has a large bargaining advantage. There are two ways a developer can approach marketing power. One way is to use the methods established by the Public Utility Regulatory Policies Act of 1978 (PURPA). The second way is to negotiate a power purchase contract with the local utility. Each of these methods is discussed below.

Public Utility Regulatory Policies Act of 1978 (PURPA)

The federal government has attempted to solve the major problems of marketing hydropower with the Public Utility Regulatory Policies Act of 1978 (PURPA).[4] PURPA authorizes the Federal Energy Regulatory Commission (FERC) to establish incentives for certain small-scale hydro sites. In Colorado these incentives are administered by the state Public Utilities Commission (PUC) regarding sales to regulated utilities, including rural electric associations and cooperatives, subject to review by the FERC. However, PURPA's effectiveness has limits.

The PURPA incentives are extended to "qualifying facilities." A qualifying facility is defined as the owner or operator of a facility which (1) uses renewable resources as a primary energy source, (2) has a power production capacity of 80 megawatts or less, and (3) is owned by a person not primarily engaged in the generation or sale of electric power (except power from the small power facility itself).[5] In Colorado, the Public Utilities Commission has determined that municipalities which generate and sell power as one of many services provided to their customers are not considered as "primarily engaged" in the sale of electric power and therefore could meet this criteria for being a qualifying facility. Many small-scale hydro sites will meet these requirements, and are eligible for the PURPA incentives.

Title II of PURPA offers three major incentives in an attempt to minimize the institutional barriers for qualifying small power producers. First, electric utilities will be required to physically connect ("interconnect") with a qualifying facility.[6] The requirements of interconnection will be determined by the utility, and the cost of interconnection will be paid by the developer. Additionally, a Colorado Public Utilities Commission order specifies several conditions regarding interconnection.[7]

Second, an electric utility will be required to purchase the output of a qualifying facility at rates that do not exceed the "avoided cost" for the utility. The avoided cost is the utility's cost for construction and operation of generation facilities or the cost of power purchases, which can be avoided by buying power from the qualifying facility.[8]

In determining the avoided cost to a utility, both the capacity value and the energy value of the output from a qualifying facility will be considered. Capacity value is calculated by determining the amount of construction costs for additional generation facilities which can be postponed as a result of the availability of power from the qualifying facility. This value will include considerations regarding how much reserve capacity the purchasing utility has, when new plant construction is anticipated, and the reliability and availability of the output of the qualifying facility. The energy value of the output is calculated by comparing the fuel costs and operating and maintenance costs of existing utility facilities. The rates paid to a qualifying facility depend on several factors. The Colorado Public Utilities Commission has chosen to require its regulated utilities to submit tariffs, based on their avoided costs, which will be the standard rate paid to all facilities providing 100 kW or less.[9] These tariffs and the methodology used to calculate them are subject to PUC review, and will have separate hearings, should the Commission question the submitted information.[10]

There will be no standard rates for facilities producing more than 100 kW; owners of such facilities are expected to negotiate individual contracts with the utility, in which they may or may not use the tariffs submitted for under 100 kW units as a basis for rate determination.[11]

It should be noted that this approach to determination of avoided costs for Colorado utilities differs substantially from the PUC Recommended Decision No. R81-801 issued May 6, 1981, and differs substantially from what was indicated in Appendix H of the first edition of this publication (Water Over the Dam, July 1981). In both cases, avoided cost rates were listed for each utility. These should be disregarded, as it is determined in their final order that is inappropriate for the PUC to determine either avoided cost methodology or utility specific rates.[12]

A qualifying facility may need to consume electricity internally. The qualifying facility has the option of either using a portion of the facility's output internally, or selling all the power produced and purchasing any power needed. If the avoided cost rate is higher than the retail rate for the facility, maximum profits can be achieved by selling all the output of the facility, and purchasing any power needed. On the other hand, if the avoided cost rate is lower than the retail rate, the facility can maximize its profits by supplying internal needs with internal production, selling only the remaining power. This aspect of PURPA is one of the most controversial.

If the facility purchases power from the local utility the utility must provide power to a qualifying facility at rates which are just, reasonable, and non-discriminatory.[13] A rate which is the same as the rate to other non-generating retail customers of the utility with similar load or other cost-related characteristics will be considered non-discriminatory.[14] A different rate can be established if the utility demonstrates sufficient reason. The rate for sale of back-up and maintenance power cannot be based on an assumption that all qualifying facilities will have simultaneous outages, or that such outages will occur during system peaks.[15]

Third, FERC is authorized to exempt qualifying facilities of less than 30 megawatts from all or parts of the provisions of the Public Utility Holding Company Act, from state laws and regulations governing the rates and the financial or organizational activities of electric utilities, and certain parts of the Federal Power Act.[16]

As mentioned, administration of PURPA incentives is delegated to the Colorado PUC. After extensive hearings, the Commission issued its preliminary order on May 6, 1981. On January 12, 1981 the Commission issued its final order, Decision No. C82-73. The primary difference between the recommended and final orders is that the final order omits the avoided cost methodology and the listing of the utility specific avoided cost rates found in the recommended order. Copies of the final order may be obtained from the Colorado Public Utilities Commission, 500 State Services Building, 1525 Sherman Street, Denver, CO 80203. A person interested in using the incentives available under PURPA should read the entire order.

The proposed order sets forth the following rules. Rule 1.000 defines the terms which will apply for Colorado. These definitions closely follow the definitions specified in PURPA. The owner/operator of a facility who wishes to be certified as a qualifying facility for purposes of the PURPA incentives should contact the Colorado PUC. The owner/operator must provide information regarding size of facility, fuel use, and ownership details to the Commission.

Rule 2.000 defines a qualifying small power production facility, which also closely follows the definition set forth in PURPA.

Rule 3.000 governs the arrangements between electric utilities and qualifying cogeneration and small power producing facilities. It details negotiation authority, data to be filed or made available by utilities, and special rules for small utilities. It outlines the utility obligations to purchase, sell, interconnect, and wheel power to qualifying facilities and the rules for parallel operation.

Rule 3.000 also discusses rates, indicating that standard rates for units under 100 kW will be established by tariffs and methodologies submitted by each utility based on its avoided costs. Rates may vary by technology and are to submiteted annually. Three factors are outlined as affecting rates for purchases, including availability of capacity or energy (with seven criteria), relationship of energy and capacity to avoided costs, and line losses. Provision of supplementary, back-up, maintenance, and interruptible power and rates are outlined.

Rules for interconnection are also enumerated in Rule 3.000. If a local utility only distributes power, a qualifying facility may sell directly to that utility or to the generating facility by wheeling through the distributor's lines. Costs for interconnection are paid by the small power producer. These costs can be paid over time with interest, unless the utility can prove the qualifying facility's lack of credit-worthiness. System emergencies are discussed.

Rule 4.000 establishes the standards for operating reliability of qualifying facilities. Minimum standards are suggested for facilities of 25 kilowatts or less of capacity. A conference between the utility owner of the qualifying facility is required at the earliest possible date. The operator of a qualifying facility must submit design information to the local utility at least 150 days before interconnection. The utility must approve the design, subject to review by the PUC. The design plan must specify compliance with electrical and construction codes, sizing criteria, physical distances, inspections, grounding practices, type of generator, harmonic content of the output voltages, disconnection equipment, and any other safety equipment and procedures. Interconnection sooner than 150 days is allowed if mutually agreed upon by the facility and utility.

Meters are provided by the utility at cost, paid by the qualifying facility and which may be included as interconnection costs and paid on an installment basis.

Maintenance of meters is provided by the utility at cost which is paid by the qualifying facility as incurred. The facility owner must file scheduled maintenance plans with the utility. Rules for indemnity are also enumerated in Rule 4.000. Scheduled maintenance plans must be filed by the qualifying facility. Rules for indemnity are enumerated in Rule 4.000.

Rule 5.000 exempts qualifying facilities from Colorado state laws and regulations regarding the rates of electric utilities and regarding the financial and organizational regulation of electric utilities. It describes situations in which a utility may apply for a waiver to the rules. The PUC has the right to review all utility contracts.

In the near future PURPA may not be as significant an incentive for facilities which must be privately or publicly financed as had originally been hoped. First, the "avoided cost" rate set by the Commission is subject to change. Until there is a record of how this rate will change, there is no guarantee of a revenue stream sufficient to cover debt service. The debt service of a facility often runs 7 to 10 years, and a financial advisor or bond counsel would discourage investment in a project which could not provide a reasonable secure revenue stream over that time at the minimum. The avoided cost rate may not offer sufficient security.

Second, portions of the act, including the incentive requiring purchases at the avoided cost rate, have been declared unconstitutional by a federal district judge in Mississippi (Mississippi v. FERC, J79-0212 (S.D. Miss. February, 1981)). FERC has appealed this decision to the U.S. Supreme Court but a ruling is not likely sooner than spring 1982, and could come later. Since the decision is from the federal district court for Mississippi, it is legally binding only to the parties involved. However, it has placed a cloud over the legality of PURPA. Another decision has been handed down by the District of Columbia Court of Appeals (American Electric Power Service Corp. vs. FERC) overturning the interconnect and avoided cost rules of the PURPA order. Even without the court decisions, financial institutions may perceive other risks with PURPA. For example, they may fear the law may be changed, may be improperly implemented, or may reflect unnecessarily low rates.

For these reasons, it appears that most small-scale hydro sites developed in the near future will use a negotiated power purchase contract with the local utility. A power purchase contract will offer the developer long-term security based on the financial viability of the utility. The cost of obtaining this security will usually be shown by a reduction in the price paid for the output of the facility.

Power Purchase Contracts

Because of legal and governmental actions, equipment downtime, natural disasters, low stream flow, marketing problems and a short history, small-scale hydro development is a relatively risky business. Generally, the developer will be forced to carry the cost of this risk in either the marketing structure or the financing structure. To the extent the utility will absorb the risk, this cost will be seen by the developer as a lower price for the facility's output. To the extent the utility does not absorb the risk, the developer can receive a higher price. However, the cost of capital will increase with increased risk to investors. Determining the correct allocation of risks is complex and requires careful analysis.

Many types of power purchase contracts are in existence. The following discussion will identify several of these as they relate to small-scale hydro development. Generally, a developer will want the contract to run at least until the conclusion of debt service payments, as this contract will provide the basis for financing.

One type of contract is a constant cash flow contract,[17] in which the utility pays a set annual fee, independent of power actually produced. The contract can provide that the cash flow escalate or remain constant. This type offers good security to investors, since payments will be made even during periods of zero output. However, it results in a low price for electricity.

A second type which also provides good security to investors is a cost of service payment.[18] Under this contract, the facility recovers all costs plus some profit from the utility. This system is similar to the one used by the state PUC to regulate investor-owned utilities in Colorado. This system transfers risk to the utility at a cost in price. However, the risk of zero-output is not transferred to the utility.

A third type provides little security to investors and is analogous to a spot market type of agreement,[19] in which the utility pays a floating price determined by the cost to the utility of purchasing power elsewhere. This probably offers the highest price, but also entails the highest risk to investors.

Several kinds of contracts are possible between the extremes of spot market (high price, high risk) and constant cash flow or cost of service (low price, low risk). One kind is to tie the price to some component(s) of the utility's rate base, such as fuel costs, billing rate, operation costs, etc.[20] Another kind is a cash flow contract with minimum and maximum payment limits.[21]

There are many variations in detail among these types of contracts. A decision as to the best power purchase contract will be determined by the type of developer and the financing structure chosen.

Summary

This chapter has examined the subject of selling and purchasing power. The value of a facility is derived almost completely from its revenue stream. Two major avenues for the sale of power exist. One is to use the mechanism provided in the Public Utility Regulatory Policies Act of 1978 (PURPA). The second is to negotiate a power purchase contract, of which there are several types. This material should be read in conjunction with the chapters on financing and taxation, and should be used in consultation with competent counsel.

For more detailed information, the publication entitled Guide to Negotiations Between Small Power Producers and Utilities may be obtained from the Colorado Small-Scale Hydro Office, 1313 Sherman Street, Room 823, Denver, Colorado 80203, (303) 866-3441.

Footnotes

[1]A Manual for the Development of Small-Scale Hydroelectric Projects by Public Entities (1981) - DOE/CE/04934-45; The Financing of Private Small-Scale Hydroelectric Projects (1981) - DOE/CE/04934-

44. These reports may be obtained from NTIS/Department of Commerce/5285 Port Royal Road/VA 22161.

[2]State of Colorado Electric Utilities, prepared by CH2M HILL, Inc. (Doc. D14062.BO, December, 1980), pp. 1-2.

[3]Id.

[4]Public Utility Regulatory Policies Act of 1978 (PURPA), Public Law 95-617 (Nov. 9, 1978).

[5]PURPA, Sec. 201.

[6]Id., Sec. 202.

[7]In the Matter of the Rules of the Public Utilities Commission of the State of Colorado Regulating Rates and Service of Cogenerators and Small Power Producers, Case No. 5970, Decision No. C82-73, January 12, 1982, Rules III and IV. Copies of the order may be obtained from the Colorado Public Utilities Commission, 500 State Services Building, 1525 Sherman Street, Denver, Colorado 80203.

[8]PURPA, Sec. 210.

[9]PUC Order No. C82-73, Attachment 1, Rule No. 3.508.

[10]Id., Rule No. 3.304.

[11]PUC Order No. C82-73, Introductory Remarks, p. 9.

[12]Id.

[13]PURPA, Sec. 210. PUC Decision No. C82-73, rule No. 3.501,502 specifies that upon the request of a qualifying facility, the local utility will provide supplementary, back-up, maintenance, and interruptible power.

[14]PUC Decision No. C82-73, Rule No. 3.801.

[15]Ibid. Rule No. 3.8051.

[16]PURPA, Sec. 210. PUC Decision C82-73, Rule No. 5.000, Supra.

[17]The Financing of Private Small-Scale Hydroelectric Projects (DOE/CE/04934-44), supra, p. 83.

[18]Id.

[19]Id.

[20]Id.

[21]Id.

CHAPTER VIII: FINANCING

Financing is the critical component in the development of a hydro project. Special problems are presented due to the capital-intensive nature of hydro development and because most project costs are incurred before revenues are generated. Developers, whether public or private, will rarely have the financial resoures to construct hydro projects on their own. Thus, they must seek additional financing from government programs,[1] lending institutions and capital markets. It is the availability and cost of this outside funding, coupled with net project revenues from the sale of power, which will determine the economic feasibility of a project.

Financing must be secured for a number of stages in the development of a hydro project. These include: reconnaissance study, feasibility study, permitting and licensing, engineering design, legal fees, financing costs, construction, equipment purchase and project maintenance and operation. Various combinations of short and long-term financing may be necessary to achieve these steps. Numerous funding sources may be tapped at different stages of development, as well.

This chapter is intended to provide an overview of the various business structures and financing mechanisms available to both private and public developers, alone and in combination. A more detailed analysis of hydro financing can be found in two reports prepared by the Energy Law Institute.[2] These sources of information may serve as a starting point for investigation of project financing options in conjunction with competent legal and financial advisors. Other sources of information include investment bankers, bond counsels, equipment manufacturers and private developers.

Private Development

Private hydro development will usually occur through two basic structures or their subtypes. These are the corporation (including the "Subchapter S" Corporation) and the partnership (including the "limited partnership.") The primary advantage of corporate status is that the personal liability of directors and stockholders is limited to their investment in the corporation. Similarly, the liability of limited partners, investors who have no control over the day-to-day operation of a partnership, is limited to their financial stake in the enterprise. General partners and, in rare situations, corporate directors may become personally liable for business activities which give rise to legal damages.

There are also tax differences between corporate and partnership structures. Corporate income and losses are accountable to the corporation, not to its stockholders (who pay income tax on stock dividends). On the other hand, partnership income and losses accrue to the individual partners and can be applied against other income. This is also true for the stockholders of a Subchapter S corporation and closely held corporations. Thus, tax benefits are more likely to be fully realized by investors in partnerships and Subchapter S corporations. The Energy Law Institute manual on private financing (see footnote 2) contains further discussion on such arrangements.

A number of tax incentives are available for hydro investors, including the investment tax credit, the energy tax credit, capital depreciation and other business deductions. Tax savings can constitute a significant portion of the "return" on a project but are subject to numerous qualifications. See the chapter on taxation (page 92) for further information.

A hydro project will generally require both equity and debt capital. Equity investors buy a stake in a project and receive a proportionate share of profits and losses. The return on equity is usually variable, depending on net income after all costs have been subtracted from revenues. The equity investor may also realize capital gains if he sells his share. The equity investor is, in effect, at risk for the amount of his investment should a project fail, although he will receive a liquidated share of project assets after creditors are paid. This risk, plus the variable nature of the return, means that projects must offer a relatively high expected rate of return to attract equity capital.

Debt capital, on the other hand, usually receives a fixed rate of return, independent of project revenues and losses. Suppliers of debt capital (creditors) do not purchase a share of a project, although the debt may be secured by project assets. The security for debt capital may be the stream of revenues from a project ("non-recourse" debt) or the credit of the borrower ("recourse" debt). Creditors are generally less willing to take risks than are equity investors. This factor, plus the fixed rate of return, means that debt capital can usually be attracted at a lower cost than equity capital.

It should be noted that making a project simultaneously attractive to both equity and debt capital may be a difficult task. For instance, many risk-reduction measures such as spending more on feasibility studies, licensing and project construction to enhance reliability, will tend to reduce potential returns on equity while providing better security to creditors. In like fashion, sale of power contracts which forego possible revenue increases over time for the sake of revenue stability will be more attractive to creditors than to equity investors.

There are a number of potential sources of capital for hydro projects, including commercial banks (especially large banks with energy loan departments), investment banking houses, syndication firms, hydro-turbine suppliers, energy development firms, federal agencies and state or local authorities (public financing will be discussed below[3]). The developer will usually retain an equity interest in a project in order to obtain tax savings and in hopes of a high rate of return.

The task, then, for the private developer is to structure a business arrangement which maximizes his return (including tax savings) and minimizes his risk (including personal liability). He must try to obtain the optimal mix of equity, debt and, perhaps, public financing. This is a complex and challenging task. Indeed, the technical and engineering aspects of hydro development are relatively straightforward in comparison.

Public Development

The development of hydro projects by public entities may offer several advantages. The Federal Power Act provides a "public preference" for hydro sites. Public entities can usually obtain tax-exempt financing.[4] Hydropower can enhance local public utility system reliability, as well as providing an inflation-proof source of electricity.

The first requirement for any public entity in considering hydro development and power sales or distribution is to examine its legal authority to engage in such activities. The Colorado Constitution and statutes, as well as home rule charters, are the possible sources for such authority. At present, the only political subdivisions in Colorado with authority to engage in hydro development are municipalities, counties, water conservancy districts, water conservation districts, the Colorado Water Conservation Board, and the newly created Colorado Water Resources and Power Development Authority.[5]

Both statutory [6] and home-rule[7] cities are empowered to acquire, construct and operate electric light and power works. Joint ventures with private developers,[8] as well as with other cities and towns[9] are also authorized. In fact, municipal utilities may combine and form regional "power authorities" to "effect the development and transmission of electric energy resources."[10] Such power authorities may include cities and towns from adjoining states (within fifteen miles of the Colorado border) and possess independent bonding authority.

The formation of a municipal utility in the first instance requires the adoption of a municipal ordinance[11] which must be approved in a local election[12] similar to that required for the incurring of local debt. This appears to be true even if the utility project is to be financed by a revenue bond issue.[13] Regional power authorities are not subject to an additional referendum, but are formed by contract between existing municipal utilities.[14]

Municipalities have two basic sources of funds for utility formation: local debt[15] and a public works fund.[16] Local debt may be incurred through "general obligation" bond issues, supported by the taxing authority ("full faith and credit") of the municipality, or may be incurred through "revenue" bond issues, supported by project revenues. "Double-barrel" bonds supported by both project and general revenues are also authorized.[17]

General obligation bonds are more cumbersome than revenue bonds due to the election requirement[18] and constitutional or statutory debt limitations. Therefore, they are generally reserved for traditional, non-revenue generating, public services. However, since they are backed by the taxing authority of the municipality, general obligation bonds usually obtain a lower interest rate than revenue bonds.

Neither type of local debt is particularly suited to finance the front-end stages of a hydro project, including reconnaissance study, feasibility study and license application. These stages are too risky for a revenue bond issue since the project may be found infeasible, or a license may be denied. Hence, no revenues would be generated to repay the bonds. If tax revenues are to be used for these early stages of project development, they would be better allocated from the municipal budget rather than being pledged to repay bonds with interest. This would also avoid election and financing (underwriting) costs.

Fortunately, Colorado municipalities have another option which is well suited to fund project reconnaissance and feasibility studies, as well as license application. They may create a "public works fund" capitalized by a tax levy.[19] Using such a public works fund would enable a municipality to bridge the gap between the risky early stages of project development and the later stages amenable to bond financing.

Another option to defray certain front-end costs, including debt service until project revenues are generated, is the use of qualified "arbitrage bonds." Under this option, a municipality would issue bonds sufficient to construct the project, pay engineering, legal and underwriting fees, and capitalize a debt service reserve fund. After paying the fees, it would invest the bond proceeds in a high-yield security (such as treasury bills) and use the interest differential (the "spread" between what it pays on the bonds and receives on the investment) to defray initial project costs and debt service requirements. To avoid losing tax-exempt status, such arbitrage bond proceeds, minus reasonable reserve requirements and debt service payments, must be expended within three to five years on the project.[20] The use of arbitrage bonds in this manner is a very tricky and highly complex maneuver, which should not be attempted without the advice of expert bond counsel.

Once a hydro project is constructed, project revenues are the prime source of bond repayment, as well as covering operation and maintenance costs. If the municipal utility sells the power to its own customers it will collect user service charges.[21] If these charges generate insufficient revenue, the municipal utility may dip into its debt service reserve fund (if available) or it may collect a special municipal utility property tax[22] (up to 3 mills annually per dollar of assessed value) to cover the deficit.

There are two additional options for public financing which are unique to Colorado. The first is the Colorado Water Conservation Board Construction Fund, established in 1972 to provide assistance to water development activities in the state. The fund can provide up to 50% of project costs to be repaid within forty years. The service charge is no less than 5%. Assistance is also available for feasibility studies. The General Assembly enacted important changes in 1981 concerning criteria for project authorization. The new criteria relevant to hydropower are:

1. Approximately two-thirds of the moneys available to the Fund shall be devoted to projects which will increase the beneficial consumptive use of Colorado's compact entitled waters;

2. The balance of the moneys available to the Fund shall be devoted to projects for the repair and rehabilitation of existing water storage and delivery systems, which could include hydro retrofit;

3. The Board shall participate in only those projects which can repay the Board's investment. Grants shall not be made.

4. All other means of financing shall be thoroughly explored before use is made of Fund moneys.

5. For all feasibility studies the Board shall ensure that the scope of the study is confined as nearly as possible to a single integrated project.[23]

The second is the new Colorado Water Resources and Power Development Authority, established by the 1981 Colorado General Assembly.[24] While not yet operational, the new authority offers another potential for financing construction of water projects. To finance any projects authorized by the General Assembly, the Authority may issue revenue bonds. Authority to include hydroelectric generating facilities in multiple purpose projects is provided. The Authority may also make loans for project planning. Information on the statusof the Authority can be obtained by contacting the Colorado Water Conservation Board.

In summary, there are numerous municipal financing mechanisms available for hydropower development, ranging from traditional local debt options, double-barrel bonds and arbitrage bonds, to mechanisms unique to Colorado. In addition, municipalities may combine with other cities and towns to form regional power authorities with independent bonding authority. Finally, they may form a joint venture with private developers, as will be discussed below.

Joint Development

Although the Colorado Constitution prohibits the lending of state or local credit to private enterprise,[25] municipalities are authorized to become a "joint owner with any person...in order to effect the development of energy resources after discovery, or production, transportation or transmission of energy in whole or in part for the benefit of the inhabitants..."[26]

This option is highly significant. For example, a joint venture might be structured whereby private risk capital was used for project analysis and start-up, with public funds committed for construction only after feasibility is established and a license obtained. This would allow equity investors to finance the risky front-end stages of project development, which are problematic for public financing. Remember, however, that combinations of private and public capital will have tax consequences for private investors. The "leveraged lease," a multi-party agreement, is a complicated structure which may maximize certain tax advantages. Legal counsel is advised.

Another attractive method for public-private joint ventures may be the use of county and municipal development bonds (usually referred to as "industrial development bonds"). Colorado counties and municipalities are authorized to finance, acquire, lease, own and dispose of properties designed to promote industry or economic activity, to further the use of natural resources, or to provide more adequate facilities for the furnishing of water and energy.[27] Eligible utility plants specifically include facilities for diverting, developing and impounding water.[28]

In order to accomplish this purpose, the local government issues revenue bonds pursuant to a financing agreement with the private participant. This agreement may be a lease, sublease, installment purchase contract, rental agreement, option to buy or other arrangement, including combinations thereof.[29] Eligible projects must be located within a county or within eight miles of a municipality wishing to issue development bonds.[30]

Bonds issued under this act may be used for virtually all project requirements,[31] including fees for legal and financial consultants, payment of debt service for the first three years of project operation, and the establishment of a reserve fund for bond retirement and project maintenance. In addition, the issuing authority may exchange the bonds for an equity share in the project.[32]

The interest paid on these development bonds is exempt from Colorado income tax.[33] The federal tax status of such bonds is affected by such regulations as the small issue exemption, the local furnishing of electricity rule and the special hydroelectric exemption provided by the Crude Oil Windfall Profits Tax Act. (See the Chapter 9 on taxation (page 92) for a discussion of these issues.) It should be noted that wheareas city and county property is normally exempt from property ad valorem property taxation, development bond projects owned by a city or county must make an equivalent "in lieu of" payment from project revenues to the local taxing authorities.[34]

Finally, the powers and authority granted to cities and counties in the development bond act are complete and exclusive. No other municipal finance or local government laws, such as those requiring a bond election, apply to the exercise of these powers.[35] A county or municipality simply proceeds by way of a resolution or ordinance.[36] It should be noted, however, that local eminent domain powers may not be utilized in conjunction with the act.[37]

In conclusion, there are numerous approaches to public-private joint development. These include joint ventures, partnerships, owner-operator agreements, lease arrangements and public funding with subsequent transfer to (purchase by) the private developer. Innovative combinations to maximize project feasibility are possible and should be carefully considered.

Summary

This chapter has examined the complex and challenging area of project financing, through private-sector, public-sector and joint arrangements. A range of mechanisms, each with different impacts on tax savings, equity returns, debt security and bond marketability has been suggested. This material should be read in conjunction with the chapters on taxation and sale and purchase of power, and should be used in consultation with competent counsel.

Footnotes

[1]The Department of Energy was authorized by the National Energy Act of 1978 to provide low-interest, forgivable loans for project feasibility studies and licensing. This program has been suspended by the new administration. In addition, the Farmers Home Administration, the Small Business Administration, the Rural Electrification Administration, the Economic Development Administration and the Department of Housing and Urban Development all have programs which could theoretically be extended to hydro development. However, with the administration recommending extensive budget cuts, if not outright abolition, for these programs, the prospects for

federal financial assistance are in a constant state of flux.

[2] A Manual for the Development of Small-Scale Hydroelectric Projects by Public Entities (1981) - DOE/CE/04934-45; The Financing of Private Small-Scale Hydroelectric Projects (1981) - DOE/CE/04934-44. These reports may be obtained from: NTIS/Department of Commerce/5285 Port Royal Road/VA 22161.

[3] For additional information regarding funding sources, an interested reader should obtain the manual, So You Want To Get into the Small-Scale Hydropower Business, from the U.S. Department of Energy, Region 8, Assessments and Integration Division, 1075 South Yukon Street, Lakewood, Colorado 80226.

[4] Internal Revenue Code Sec. 103(a).

[5] Water conservancy districts (see Colorado Revised Statutes (CRS) 37-1 through 37-5 and 37-45) and the Colorado Water Conservation Board (see CRS 37-60) have clear authority to develop hydropower. Conservancy districts have no revenue bonding capability, but do otherwise have adequate finance mechanisms. As of the time of publishing this manual (May, 1981), legislation which would grant revenue bonding authority has been introduced in the Colorado legislature, but has not been made law. The Colorado Water Conservation Board is a special body corporate and politic, primarily funded by legislative appropriations (with attendant legislative oversight). It has statutory authority to fund hydro projects in Colorado with Construction Fund monies appropriated by the Legislature (CRS-37-60-119.) Water conservation districts (see CRS 37-46, 37-47, and 37-48), which possess the full range of finance mechanisms, have inferential authority to develop hydropower. The

Colorado Water Resource and Power Development (see CRS 37-95) has the authority to issue revenue bonds for water and power projects that are recommended by the Colorado Water Conservation Board and authorized by the General Assembly. Counties and municipalities can build, purchase, improve, equip, finance and sell any utility plant (CRS-37-93 102-104; 31-15-707; 31-31-101 and 201.)

[6]CRS 31-15-707.

[7]Art. XX Sec. 6 (Note that the actual language appears in Sec. 1, relating to Denver home rule, and is incorporated into Sec. 6 by reference).

[8]Art. XI Sec. 2 (1974 amend.).

[9]CRS 29-1-204.

[10]Id.

[11]CRS 31-16-101 et seq.

[12]CRS 31-15-707.

[13]CRS 31-32-201; Colo. Central Power Co. v. Municipal Power Development Co. 1 F. Supp. 961 (D. Colo, 1932).

[14]Supra note 7.

[15]Art. XI Sec. 6; see also CRS 31-15-302 and 31-21-101 et seq.

[16]CRS 31-15-302(1)(f).

[17]Supra note 13.

[18]CRS 31-15-302(1)(d)(I).

[19]CRS 31-15-302(1)(f).

[20]Treas. Reg. Sec. 1.103-14(b)(2)(ii). See also ELI Public Finance Manual (supra note 2) at pp. 21-22.

[21]CRS 31-15-707(1)(a)(IV)(d).

[22]Id.

[23]CRS 37-60-121 through 123.

[24]CRS 37-95.

[25]Art. XI Secs. 1 and 2.

[26]Art. XI Sec. 2 (1974 amend.).

[27]CRS 29-3-102; see also Allardice v. Adams County 173 Colo. 133, 476 P. 2d 982 (1970). Forty-five states have authorized some form of revenue bonding to stimulate local economic development by providing financial assistance to private entities.

[28]CRS 29-3-102.

[29]Id.

[30]CRS 29-3-104.

[31]CRS 29-3-104 and 106.

[32]CRS 29-3-106.

[33]Id.

[34]CRS 29-3-120.

[35]CRS 29-3-123.

[36]Supra note 29.

[37]CRS 29-3-121.

CHAPTER IX: TAXATION

The developer of a small-scale hydroelectric generation facility, as with any other individual or corporate enterprise, will be subject to a wide range of federal and Colorado taxes. Because of the wide variety of taxes and special district assessments, the developer may wish to retain a tax law specialist. Questions of tax liability and business organization usually require professional assistance.

A developer's tax liability will depend partly on the form of business arrangement that the developer selects. Both the federal government and the state of Colorado require payment of both personal and corporate income taxes. The state (and the political subdivisions of the state) may require payment of ad valorem (property) taxes. These property taxes may apply to both real and personal property.

A developer may also be required to pay special district assessments. Though not technically a tax, these assessments are based on enhancement of property values due to special district activities. Special district assessments will vary, depending on the location of the development in the state.

There are various tax incentives available under federal law to encourage small-scale hydroelectric development, but there are few tax incentives available under Colorado law at the present time.

Federal Law

The Crude Oil Windfall Profits Tax Act of 1980 (COWPTA)[1] contained tax incentives to encourage small-scale hydroelectric development. Prior to the passage of COWPTA, a 10 percent investment tax credit existed for expenditures by taxpayers for the purchase or construction of most business property (with the exception of buildings). Under COWPTA, an additional 11 percent investment tax credit was made available for qualifying small-scale hydroelectric expenditures.[2] To qualify for the 11 percent investment tax credit, the expenditure must be made for hydroelectric facilities at a dam completed before October 18, 1979, or at an existing water flow other than at a dam, such as rivers, water conduits or irrigation ditches. The expenditure must be made for "qualifying property" which is defined to include generating equipment (up to the transmission stage), powerhouses, fish passageways, penstocks, the cost of repairing or restoring generating equipment, and the cost to reconstruct or rehabilitate a dam.

Qualifying expenditures must be made between January 1, 1980 and December 31, 1985. A three-year extension for qualifying expenditures is available if the project is on the Federal Energy Regulatory Commission (FERC) docket by December 31, 1985. The tax credit is limited to the taxpayer's tax liability or $25,000 (whichever is less) plus a percentage of the taxpayer's current tax liability, in excess of $25,000. (70% of the excess in 1980; 80% in 1981; 90% in 1982 and subsequent years.) The tax credit may be carried back for up to three years, or carried forward for up to seven years.

The full 11 percent additional energy investment tax credit is available for expenditures on generating facilities having a maximum capacity of 25 MW. The tax credit is reduced proportionately for expenditures on facilities having a maximum capacity of up to 125 MW and does not apply to expenditures for facilities with a maximum capacity exceeding 125 MW. In the case of joint ventures with utilities the 11 percent energy investment tax credit is also available to public utilities for qualifying expenditures on hydroelectric facilities.

The primary drawback of an investment tax credit is that it does not appeal to an investor who does not have a substantial tax liability. However, the size of the tax credits, a combined total of 21 percent, could encourage risk capital formation for small-scale hydroelectric development by investors seeking tax shelters.

Prior to the passage of the Economic Recovery Tax Act of 1981 (ERTA),[3] investment tax credits were of limited use to an investor who did not have sustantial current tax liability. With the passage of ERTA, the carrover period for unused investment tax credits was extended to 15 years. This would apply to investment tax creidts earned for tax years ending after December 31, 1973.[4]

The 11 percent energy investment tax credit is reduced if the project utilizes subsidized financing. The amount of the reduction is proportionate to the amount the project is subsidized by federal, state or local programs. Loan guarantees are not considered subsidized financing. This prohibition is generally known as the "double dipping" prohibition.

ERTA also made complicated changes to the "at-risk" requirements for investment tax credit qualification. Tax credits for a small-scale hydroelectric project are limited to the amount a taxpayer has "at-risk" in the project, i.e., the amount for which the taxpayer is personally liable plus any equity contributed by the taxpayer. An investment is not considered to be "at-risk" if the taxpayer is protected from loss of the invested amount (i.e. through nonrecourse financing such as loans guaranteed by government agencies), if the taxpayer is not personally liable for repayment, if a lender has an interest other than that of a creditor in a small-scale hydroelectric project, or if the lender is related to the taxpayer.

Exceptions to these "at-risk" requirements are generally referred to as the "safe harbor" rules. Nonrecourse financing is considered to be "at-risk" if the taxpayer is personally liable for 20 percent of the borrowed amount, if the property acquired with the borrowed amount came from an unrelated person, if the lender is neither the seller of the property nor related to the seller of the property, and if the lender is unrelated to the taxpayer.[5]

Nonrecourse financing which does not meet these requirements will be considered "at-risk" if the taxpayer is personally liable for 25 percent of the borrowed amount.[6] Tax credits for expenditures under the "safe harbor" rules will vary as the amount "at-risk" varies. Expenditures must of course be for "qualifying property." The ERTA requirements apply to property placed into service after February 18, 1981, except for property acquired under a binding contract entered into before that date.[7]

An Accelerated Cost Recovery System (ACRS), which supplements the existing system of depreciation, was also contained in ERTA.[8] Under ACRS, the cost of "recovery property" can be recovered over 3, 5, 10 or 15 year periods depending on the classification of the property. No distinction is made between new and used equipment and salvage value is disregarded. With certain limitations, existing straight-line methods of depreciation may still be used and may be more appropriate in specific situations.

Property having a three year cost recovery period includes automobiles, light-duty trucks, research and development equipment, and personal property with a present class life[9] of four year or less.[10] Five-year property includes most other equipment, except long-lived public utility property, and appears to include small-scale hydroelectric property meeting the "qualifying facility" requirements of PURPA.[11] Ten-year property includes public utility property with a present class life greater than 18 but not more than 25 years, manufactured homes and real property with a present class life of 12.5 years or less.[12] Fifteen-year property includes public utility property with a present class life exceeding 25 years or real property with a present class life of more than 12.5 years.[13]

The combination of tax credits and the Accelerated Cost Recovery System will expand the tax benefits available to a small-scale hydroelectric developer. It is quite possible that these expanded tax benefits will exceed a developer's tax liability. A procedure is contained in ERTA whereby a small-scale hydroelectric developer can sell the tax benefits resulting from the development while retaining both legal and beneficial title to the property.[14]

Under this procedure, a developer could "sell" the property to a corporation[15] seeking the developer's tax benefits. The "buyer" of the property must pay a minimum of 10 percent of the cost of the property[16] and would, typically, give the "seller" a note for the remaining 90 percent. The "seller" would then lease the property from the "buyer" with the payments on the lease exactly equalling the payments on the "buyer's" note. At the end of the lease term, the "seller" could repurchase the property from the "buyer" for a nominal amount.[17] The length of the lease term is limited to 90 percent of the depreciable life of the property under existing regular depreciation regulations or to 150 percent of the existing Asset Depreciation Range midpoint life.[18]

In essence, the 10 percent minimum payment would be the amount paid by a "buyer" to a "seller" for the "buyer's" use of the "seller's" tax benefits. This could result in expanded financing opportunities for a small-scale hydroelectric developers.

Colorado has authorized the use of county and municipal development bonds to assist private hydro development. If such "Industrial Development Bonds" (IDBs) are issued to finance development, tax-exempt status may be obtained under certain Internal Revenue Service requirements or through a special provision of COWPTA.[19] The "small issue" exemption[20] generally limits the amount of IDBs to $1 million. Under a special election procedure, bonds of up to $10 million may also be exempted. Ninety percent of the proceeds from the sale of IDBs must be spent on basic project purposes. Even more stringent restrictions apply to $10 million IDBs.

Size and use restrictions do not apply to IDBs issued to finance the "local furnishing" of electricity.[21] To meet the local furnishing requirement, a developer must furnish electricity to anyone in the service area desiring electricity and it must appear likely that the facility will meet the needs of a large segment of the population in the service area. But under the "two county rule," energy may not be sold beyond the boundaries of two contiguous counties.[22]

The eligibility requirements for IDBs under the COWPTA exemption are quite specific and require strict compliance. Public ownership of the facility is necessary. A long-term lease of the facility to a private developer may be considered an inappropriate shift of ownership. Besides public ownership, public use must also be established. In addition, only dams constructed before October 18, 1978 and owned by a municipality by the next year are eligible for

COWPTA exemption. Finally, the bonds may not be held by a major user of the facility.

If the requirements of the Internal Revenue Code (including the COWPTA exemption) are met, then income derived from investments in Industrial Development Bonds sold to finance small-scale hydroelectric facilities will be exempt from federal taxation. Expenditures of the proceeds from the sale of IDBs must meet the same eligibility requirements as expenditures receiving the 11 percent investment tax credit. The percentage of the interest which will be exempt from federal taxation decreases proportionately for investments in bonds used to finance facilities having a maximum generating capacity of between 25 MW and 125 MW and ceases for facilities having a generating capacity in excess of 125 MW.

The Internal Revenue Code also permits the deduction of certain expenses from a taxpayer's gross income. Though these deductions are not specifically intended to encourage small-scale hydroelectric expenditures, their availability should be noted:

- A deduction from gross income is allowed for expenses resulting from the operation of a business.[23] For a small-scale hydroelectric developer, this would include legal fees paid for the acquisition of necessary permits and licenses,[24] as well as other normal operating expenses.

- Certain types of property may be depreciated and deducted from gross income over the useful life of the property according to various schedules.[25] Certain legal and engineering fees paid for both property acquisition and for land preparation in relation to dam construction may be deducted over the useful life of the property.[26] If fees are part of normal start-up costs of the organization, they must be amortized; engineering and design fees related to the equipment, may be depreciated. Similar fees paid for the acquisition of a flowage easement may also be deducted.[27]

- Finally, deductions available to a small-scale hydroelectric developer in excess of the developer's tax liability may, with certain adjustments, be applied against gross income in subsequent tax years.[28]

Colorado Law

Colorado law allows a 10 percent tax credit on expenditures for certain types of "energy property."[29] Unfortunately, the definitions of "energy property" contained in the statute do not include small-scale hydroelectric property.[30] Including hydroelectric property in the statutory definitions of energy property would require future legislative action.

The only apparent provision in Colorado's tax law which might encourage investment in small-scale hydroelectric facilities is the allowance that a taxpayer's federal adjusted gross income will generally be considered that taxpayer's income for the purposes of Colorado income taxes. As was discussed in the preceding section, ordinary business expenses and certain types of depreciation can be deducted from federal adjusted gross income. Since these types of deductions reduce a taxpayer's adjusted federal gross income, they would also reduce the Colorado income.

Footnotes

[1]Crude Oil Windfall Profits Tax Act of 1980, P.L. 96-223 (April 2, 1980) (hereafter referred to as COWPTA).

[2]Id. at Title II, Part II, Sec. 222(e).

Economic Recovery Tax Act of 1981, Pub. L. No. 97-34 (August 13, 1981) (hereinafter referred to as ERTA).

[4]26 U.S.C. Sec. 46 (1).

[5]26 U.S.C. Sec. 46(c)(8)(B)(ii).

[6]26 U.S.C. Sec. 46(c)(8)(F)(ii).

[7]ERTA, supra note 3 at 211(i)(5).

[8]26 U.S.C. Sec. 168.

[9]"Present class life" defined, 26 U.S.C. Sec. 168(g)(2).

[10]26 U.S.C. Sec. 168(c)(2)(A).

[11]26 U.S.C. Sec. 168(c)(2)(B).

[12]26 U.S.C. Sec. 168(c)(2)(C).

[13]26 U.S.C. Sec. 168 (c)(2)(D), (E).

[14]26 U.S.C. Sec. 168 (f)(8).

[15]"Corporation" includes a corporation, a partnership of which all partners are qualifying corporations, or a grantor trust whose grantors and beneficiaries include only corporations or partnerships. 26 U.S.C. Sec. 168(f)(8)(B)(i).

[16]26 U.S.C. Sec. 168(f)(8)(B)(ii).

[17]26 U.S.C. Sec. 168(f)(8). One should note the absence of repurchase regulations.

[18]26 U.S.C. Sec. 168(f)(8)(B)(iii).

[19]COWPTA, supra note 1 at Title II, Part IV, Sec. 242.

[20]26 U.S.C. Sec. 103(b)(6).

[21]26 U.S.C. Sec. 103(b)(4)(E).

[22]26 U.S.C. Sec. 1.103-8(f)(2)(ii).

[23]26 U.S.C., Sec. 162, cited in Developing Hydropower in Washington State, prepared by the Office of Water Programs, Department of Ecology, State of Washington in Cooperation with the Washington State Energy Office and the U.S. Department of Energy, Region X (Document No. WAOEMG-81-02; WDOE-81-1; January, 1981), p. 21.

[24]Id.

[25]26 U.S.C. Sec. 167.

[26]Rev. Ruling 72-96, cited in Developing Hydropower in Washington State, supra note, p. 21.

[27]Rev. Ruling 71-121, cited in Developing Hydropower in Washington State, supra note, p. 21.

[28]26 U.S.C. Sec. 172. See also Developing Hydropower in Washington State, supra note 24, p. 21.

[29]CRS 39-22-512 (1) (a).

[30]CRS 39-22-512 (5) (a). The definition of "energy property" in the Colorado code is taken from the Internal Revenue Code. See 26 U.S.C. Secs. 48 (1), (3) and (5).

CHAPTER X: EQUIPMENT SELECTION AND CONSUMER PROTECTION

A hydroelectric developer will be involved in a number of activities simultaneously. The process of developing hydroelectric facilities requires the developer to obtain federal, state and local permits and licenses, to obtain a water right, to formulate power sale and purchase agreements, to secure financing and to acquire necessary equipment. To the maximum extent possible, these activities should occur concurrently. If they occur sequentially, the resultant delays could substantially increase the total cost of the project.

Equipment Selection

There are a number of equipment suppliers currently involved in hydroelectric generation. Some of these suppliers have been in the business of marketing generation equipment for years, while others have entered the market only recently. A developer should investigate a supplier's expertise and experience in supplying equipment similar to that required. The Colorado Small-Scale Hydro Office has prepared a manual of over 80 engineering and manufacturing firms which contains specific information on their small-scale hydroelectric expertise. A list of these firms and their services are found in Appendix B on page 109. More detailed information on each firm may be obtained by visiting the Colorado Small-Scale Hydro Office in Room 718, 1313 Sherman Street in Denver, Colorado, 80203. Equipment selection should be reviewed by any consulting engineering firm which the developer may have retained.

Many different types of turbines are available. The type of turbine required depends on the specific hydrologic characteristics confronting the developer. Once the appropriate turbine has been selected, it will need to be coupled with a generator and possibly a speed changer, governor, or other type of operational equipment. A developer may want to weigh the use of standardized equipment, (which may cost less but perhaps be less efficient) against the use of specialized equipment designed to best match a site's specific characteristics (which will be more efficient but perhaps cost substantially more.)

A developer may also want to determine whether the equipment offered by a supplier will actually be that which will be delivered to the developer. Equipment may be advertised which has neither been assembled nor tested. Specifications regarding installation and operation are essential and may not be available for newly developed equipment. The developer should compare the total range of services and equipment offered by a number of suppliers.

In addition to the turbine and the generator, other types of equipment will be required. Interconnection, transmission, or distribution equipment will be necessary to transmit the output of the generator to either a user or to a transmission grid. Different types of safety equipment will be required, as well as equipment to perform maintenance operations. The developer may wish to use standardized equipment to the maximum extent possible to reduce the costs associated with custom-made equipment. The Colorado Public Utilities Commission has recommended that the minimum standards and quality of facilities, consistent with safety, be required of facilities of 25 kW or less. Meters are to be purchased from the utility.[2]

The developer will probably wish to solicit bids from a number of suppliers for the needed equipment. Though this may be a time-consuming process, it will allow the developer to compare the characteristics and prices of equipment and services offered by a number of different suppliers. The developer may wish to include a requirement of installation supervision or assistance as well as operational instruction when soliciting bids from equipment suppliers.

Selection of Services

Site owners may choose one of the following: a) to act as a "general contractor," subcontracting for engineering, legal, construction, financial, etc. services; or b) to select a hydro developer who will assume responsibility for these taks.

In either case, the hydro developer is a relatively unknown commodity, and site owners have fewer of the traditional avenues to aid their selection of services. It should be remembered that the recent resurgence of small scale hydro development is only three to four years old. Much of the expertise needed to develop hydro sites dates back no further. Histories of developers or professional experts who have taken a hydro site from inception to production of energy are only now being established. Although engineers and lawyers have professional organizations which impose quality control standards, there are no such organizations for small scale hydro developers. In addition, the nature of the competition encouraged by federal government's incentives has resulted in more emphasis on quantity (i.e., how many sites to be developed) rather than quality (i.e., how well those sites are to be developed). The best tools, therefore, are simply common sense and astute comparative shopping.

Before shopping for services, you should know what it is you wish to accomplish. Educate yourself on the development process; do not rely on the developers/subcontractors to do this for you. Specify exactly what services and for what period of time. Know the details of the site involved. This will produce clear comparative figures and minimize time spent.

Always solicit two or more (preferably three) offers of service. Ask for references, with special emphasis on projects within Colorado that are similar to your in type and size. Contact with these references should inquire into such matters as:

- Was the service in line with the price?
- Was the project completed on time and within budget? Who was responsible for cost over-runs, if any?
- Was the equipment properly sized for the site?
- Was the permitting process properly carried out?
- Was a good price for the power negotiated?
- Was the agreement between the site owner and the "expert" fair, understandable, and easy to carry out?
- Was the site owner left feeling dependent on further work from the "expert?"

Colorado differs from other states in its requirements and power sale rules. Make sure the developers/subcontractors know these rules. Ask specific questions to determine if the firm has the capability and flexibility to perform on your unique site. If the financial stability of the company will be critical to the development of your site, request data on their financial background, or procure a Dunn and Bradstreet rating. Check with accredited professional fraternities, where possible.

Consumer Protection

Federal law (the Magnuson-Moss Warranty Act)[3] requires that all limitations of warranties attached to the sale of a product be fully disclosed to the buyer of the product. Under this law, a supplier of equipment could not enforce a warranty limitation against a developer unless the developer was fully informed of the limitation.[4]

A contract between a supplier and a developer will generally be subject to Colorado law. With limited exceptions, either a supplier or a developer (as the parties to a contract) can enforce the terms of the contract against the other. If there is no contract, the sale of equipment by the supplier to the developer will be governed by the Uniform Commercial Code as adopted in Colorado (the Colorado Commercial Code).

There are four types of warranties contained in the Colorado Commercial Code which may apply to the sale of goods: 1) a warranty of title; 2) express warranties; 3) an implied warranty of merchantability; and 4) an implied warranty of fitness for a particular purpose. All of these warranties may be eliminated by a supplier through appropriate disclaimers.

Under a warranty of title, a supplier guarantees that title to the property conveyed is good and transfer of the property is rightful.[5] Disclaimers of this type of warranty must be very specific. The measure of a developer's damages if this warranty is breached is generally the difference between the value of the property with and without the encumbered title.[6]

An express warranty can be created by a supplier, regardless of whether the supplier is a merchant, in one of three ways:[7] 1) any affirmation of fact or promise by the supplier[8] (e.g., the capacity of a turbine); 2) any description of goods by the supplier[9] (e.g., blueprints or technical specifications); and 3) any sample or model of the goods to be sold[10] (e.g., a demonstration of a generator's variable speed performance). For an express warranty to exist, it is essential that the supplier's affirmation, promise, description or sample be a part of the basis of the bargain agreed to by the supplier and the developer. There are a variety of remedies available to the developer if a supplier breaches an express warranty.

If a supplier is a merchant dealing in the type of goods a developer wants to buy, a warranty of merchantability is implied.[11] Under this section of the Colorado Commercial Code, a supplier guarantees that the goods as sold are "fit for the ordinary purposes for which such goods are used."[12] Unless properly disclaimed, a supplier selling a generator guarantees the generator will function in the manner in which such generators normally operate. A developer has a number of different remedies available should the goods sold by the supplier fail to meet implied warranty of merchantability standards.

If a developer relies on a supplier's expertise in selecting necessary equipment, and if the supplier knows of the developer's reliance, then any sale of such equipment carries an implied warrant of fitness for the particular purpose for which it was intended.[10] This implied warranty can be created regardless of whether the supplier is a merchant. As with the implied warranty of merchantability and unless properly disclaimed, a developer has a wide range of remedies for breach of warranty should the supplier's product not be fit for the particular purpose for which they were intended.

If a supplier deliberately deceives a developer, the developer may also have a cause of action under the Colorado Consumer Protection Act.[13] This act, which is basically a deceptive sales practices act, prohibits the making of false statements about the nature or quality of goods. If a developer feels that a supplier has been deceitful, the developer may file a complaint with the Attorney General or with a district attorney. Both the Attorney General and a district attorney are authorized to seek an injunction against the supplier to prevent such deceptive sales practices as well as damages up to a maximum of $10,000. The act also allows the developer to file a civil action against the supplier.

There are other federal and Colorado consumer protection statutes of general interest to a small-scale hydroelectric developer using credit financing. These provide for full disclosure of credit terms, as well as other protective mechanisms.[14]

Reliance on any of the above protective measures should not be necessary if adequate and thorough agreements were negotiated initially and the developer explores thoroughly the credibility of the supplier before any final transactions are signed. Federal and Colorado consumer protection laws exist to resolve those disputes, which the parties to a contract did not, or could not, anticipate.

Footnotes

[1]Colorado PUC Decision C82-73, Rule No. 4.050.

[2]Id. Rule, No. 4.801.

[3]Magnuson-Moss Warranty--Federal Trade Commission Improvement Act. Pub. L. No 93-637, 88 stat. 2183 (January 4, 1975) (relevant portion codified at 15 U.S.C. 2301-2312).

[4]The disclosure requirements of the Magnuson-Moss Warranty Act supersede those of the Colorado Commercial Code.

[5]CRS 4-2-312.

[6]CRS 4-2-714.

[7]CRS 4-2-313.

[8]CRS 4-2-313 (1)(a).

[9]CRS 4-2-313 (1)(b).

[10]CRS 4-2-313 (1)(c).

[11]CRS 4-2-314.

[12]CRS 4-2-314 (2)(c).

[13]CRS 6-1-101 et seq.

[14]For example, the Federal Consumer Credit Protection Act (the "Truth-in-Lending" Act) and the Uniform Consumer Credit Code are both tangentially related to small-scale hydroeletric financing.

Appendices

APPENDIX A: MUNICIPAL OPTIONS FOR PUBLIC/ PRIVATE DEVELOPMENT OF HYDROPOWER

Some Colorado municipalities may own potential hydro sites, either in abandoned hydro facilities or in conjunction with their water supply system. Over the years numerous dam sites have reverted back to municipal ownership for many reasons, and many municipalities are now faced with the decision of whether to pursue the development of these sites. The purpose of this section is to provide some insights into the use of private initiative and dollars as an alternative to public sector development.

In most cases, the public development of a hydroelectric site will require municipal employees to manage and participate in the development plans for the site. Generally, development will take a minimum of one year, and possibly as long as two or three before the project is actually built. Such commitment of staff time to a hydroelectric project may prove difficult for municipalities now struggling to meet other operating budget constraints. In addition, the commitment to fund a municipal project requires the use of some of the municipality's borrowing capacity. Such a commitment may not be feasible or may be less attractive in the face of other more critically needed projects.

In addition, private developers have certain tax advantages available to them which will make development of a site by them more attractive than development with public financing. While it is true that municipalities may borrow funds at a tax free rate, such financing does not offset the substantial advantages available to a private developer. Under the current tax laws, a private developer may claim a ten percent investment tax credit, as well as an additional 11 percent energy tax credit, for a total tax credit of 21 percent of the major expenses of a small-scale hydroelectric project. In addition, small-scale hydroelectric projects are eligible for accelerated depreciation and, on average, this means that about 50 percent of the project can be written off during the first three years of the project's life. In addition, the interest paid by private developers is tax deductible, thus bringing their cost below the tax free municipal rate.

Where a municipality with limited borrowing capacity wishes to turn the site over to a private developer, the two could create a limited partnership. In such an arrangement, individual investors in high income brackets would contribute approximately 30 percent of the project in cash equity and sign recourse notes for the remaining 70 percent. These notes and the project revenues would provide the collateral for a long term debt. The investor benefits by receiving a tax savings during the first year equal to the actual cash equity investment. Future tax benefits are also passed through to the investor. Eventually, when the project is refinanced or sold, the limited partners receive the benefits as capital gains and not ordinary income. Such arrangements may permit the development of a project which could not be financed through the public sector. Municipalities should explore this route prior to abandoning plans for development.

The municipality gains a relatively risk free asset which will generate a positive cash flow in the form of a royalty payment. In addition, it will have none of the financial risk and will not have to spend any funds from the operating budget for on-going maintenance and management of the project.

Information derived from "Developing A Site," Peter McGrath, The Energy Bureau Conference, Washington, D.C., April 27-28, 1981, pages 7-8.

APPENDIX B

ENGINEERING & MANUFACTURING FIRMS
COLORADO

CHART B-1

COLORADO FIRMS AND SERVICES OFFERED

Services Offered / Engineering and Manufacturing firms	FEASIBILITY: Preliminary Site Analysis	FEASIBILITY: Feasibility Studies	FEASIBILITY: Preliminary Permit & License Application Assist.	ENGINEERING SERVICES: Final Design & Specs: Materials, Equip., Constr.	ENGINEERING SERVICES: Cost estimating	ENGINEERING SERVICES: Procurement	ENGINEERING SERVICES: Scheduling	ENGINEERING SERVICES: Marketing & Financial Surveys	ENGINEERING SERVICES: Inspection & Expediting Equip. & Mat'l Purchase	ENGINEERING SERVICES: Site Rehabilitation & Renovation	EQUIPMENT: Selection	EQUIPMENT: Manufacture	EQUIPMENT: Sales	CONSTRUCTION: Act as General Contractor	CONSTRUCTION: Provide Construction Management	OPERATION: Plant Start-up	OPERATION: Operation Instruction	OPERATION: Continuous Plant Operation	OPERATION: Repair & Maintenance	OPERATION: Other (See listings in manual of firms)
Aguirre Engineers, Inc.	●	●		●					●										●	
Allis-Chalmers	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●		●	
Alternate Energy Company	●	●	●	●	●	●	●		●	●	●		●	●	●	●	●		●	
American Research Corp.	●	●	●		●		●	●												
ARIX	●	●	●	●	●	●	●	●	●	●	●				●	●	●			
Armstrong Engineers & Assoc.	●	●	●	●	●	●	●			●	●				●	●				
Ayres, Owen & Assoc., Inc.	●	●	●	●	●	●	●			●	●									
Bates Consulting, Inc.	●	●	●	●	●	●	●	●	●	●	●			●	●	●	●			
Boyle Corporation	●	●	●	●	●	●	●	●	●	●	●				●	●	●			
CH2M Hill	●	●	●	●	●	●	●	●	●	●	●				●	●	●			
CTL Thompson, Inc.	●			●						●										
Camp Dresser & McKee Inc.	●	●	●	●				●		●	●									
Centennial Engineering, Inc.	●	●		●	●	●	●	●	●		●				●	●	●			
Chen & Associates, Inc.	●	●		●											●					
Claycomb Engineering	●	●	●	●	●	●	●	●	●	●	●				●	●	●			
Coe, VanLoo & Jaschke Eng.	●	●	●	●	●	●	●	●	●	●	●				●	●	●			
Cooper & Clark, Consulting Eng.	●	●	●	●	●		●		●	●					●		●			
Dames & Moore	●	●	●	●	●	●	●	●		●	●									
DeVore, Lincoln Testing Lab.	●	●		●																
Earth Sciences Associates	●	●	●																	
Electrical Systems Consultants		●	●	●	●			●			●									
Energy Resource Consultants	●	●	●		●			●												
Engineering Hydraulics, Inc.	●	●		●																
Engineering-Science	●	●	●	●	●	●	●	●	●	●	●				●	●	●	●		
Envirosphere Company	●	●	●	●	●	●	●	●	●	●	●				●	●	●			
Geo-Hydro Consulting, Inc.	●	●	●																	
Geo Testing Laboratories, Inc.	●	●	●	●	●		●		●						●					●
Harza Engineering Company	●	●	●	●	●	●	●	●	●	●	●				●	●	●			●
Henningson, Durham & Richardson	●	●	●	●	●		●		●		●				●	●	●			
Hydroelectric Constructors, Inc.	●	●	●		●	●	●	●	●	●	●			●	●	●	●	●		
Hydropower Consultants	●	●	●	●	●	●	●	●	●	●	●	●			●	●	●	●	●	

Source: "Colorado Siteowners Manual of Engineering & Manufacturing Firms/Small Scale Hydro Services," Colorado Small Scale Hydro Office, June 1981.

CHART B-1
(cont.)

COLORADO FIRMS
AND
SERVICES OFFERED

Engineering and Manufacturing Firms / Services Offered	FEASIBILITY	Preliminary Site Analysis	Feasibility Studies	Preliminary Permit & License Application Assist.	ENGINEERING SERVICES	Final Design & Specs: Materials, Equip., Constr.	Cost estimating	Procurement	Scheduling	Marketing & Financial Surveys	Inspection & Expediting Equip. & Mat'l Purchase	Site Rehabilitation & Renovation	EQUIPMENT	Selection	Manufacture	Sales	CONSTRUCTION	Act as General Contractor	Provide Construction Management	OPERATION	Plant Start-up	Operation Instruction	Continuous Plant Operation	Repair & Maintenance	Other (See listings in manual of firms)
Hydropower Development Company		●	●	●			●	●	●	●	●	●		●							●		●		
Hydro-Triad, Ltd.		●	●	●		●	●	●	●	●		●		●											
International Engineering Co.		●	●	●		●	●	●	●	●	●	●		●					●		●	●			
Jex-Piland Eng. and Geologists		●	●			●	●	●	●	●	●	●		●					●		●	●	●	●	
Koch. Donald, P.E.		●	●	●																					
Law Engineering Testing Company		●	●	●			●		●			●		●											
McCall-Ellingson & Morrill, Inc.		●	●	●		●	●		●		●								●		●				
Miller, Ted D. Associates, Inc.							●	●						●	●	●								●	
Our Own Mfg. & Machine Shop							●	●			●				●									●	
PRC Engineering Consultants		●	●	●		●	●	●	●	●	●	●		●					●						●
Regional Systems Services Group		●	●	●			●			●				●											
Resource Consultants, Inc.			●																						
Rice, Leonard Consulting Eng.		●	●																						
Ricketts and Rindahl, Cons. Eng.		●	●	●		●	●	●		●		●		●					●		●	●			
Robillard & Associates, Inc.		●	●	●							●														●
Rocky Mountain Geotechnical		●	●	●								●							●						
Sato, J. F. and Associates, Inc.		●	●	●		●	●	●	●	●	●	●		●					●						
Simons, Li & Associates, Inc.		●	●	●		●	●	●	●	●	●	●		●					●						
Simons, W. L. & Associates		●	●	●		●	●	●	●		●	●		●								●			●
Skelly and Loy Eng. Consultants		●	●	●			●	●	●	●		●							●						
Stone & Webster Eng. Corp.		●	●	●		●	●	●	●	●	●	●		●				●	●		●	●		●	●
Swanson-Rink and Associates		●	●			●	●	●	●	●	●	●									●	●			
Tipton and Kalmbach, Inc.		●	●	●		●	●	●	●					●					●		●	●			
Tudor Engineering Company		●	●	●		●	●	●	●	●	●	●		●					●		●	●			
Ueblacker Associates, Inc.		●	●	●		●	●	●	●	●	●	●							●						
Weidmann Engineering		●	●	●		●	●	●	●	●	●	●		●					●		●	●			
Western Energy Planners, Ltd.		●	●	●			●	●	●	●	●			●					●						
Wheeler, W.W. and Assoc., Inc.		●	●	●		●	●			●		●		●								●			
Woodward-Clyde Consultants		●	●	●		●	●																		
Wright-McLaughlin Engineers		●	●	●		●	●	●	●		●	●		●							●	●			
Zorich-Erker Engineering, Inc.			●																						

Source: "Colorado Siteowners Manual of Engineering & Manufacturing Firms/Small Scale Hydro Services," Colorado Small Scale Hydro Office, June 1981.

ENGINEERING & MANUFACTURING FIRMS

OUT-OF-STATE

CHART B-2

OUT-OF-STATE FIRMS AND SERVICES OFFERED

Engineering and Manufacturing firms / Services Offered	FEASIBILITY: Preliminary Site Analysis	FEASIBILITY: Feasibility Studies	FEASIBILITY: Preliminary Permit & License Application Assist.	ENGINEERING SERVICES: Final Design & Specs: Materials, Equip., Constr.	ENGINEERING SERVICES: Cost estimating	ENGINEERING SERVICES: Procurement	ENGINEERING SERVICES: Scheduling	ENGINEERING SERVICES: Marketing & Financial Surveys	ENGINEERING SERVICES: Inspection & Expediting Equip. & Mat'l Purchase	ENGINEERING SERVICES: Site Rehabilitation & Renovation	EQUIPMENT: Selection	EQUIPMENT: Manufacture	EQUIPMENT: Sales	CONSTRUCTION: Act as General Contractor	CONSTRUCTION: Provide Construction Management	OPERATION: Plant Start-up	OPERATION: Operation Instruction	OPERATION: Continuous Plant Operation	OPERATION: Repair & Maintenance	OPERATION: Other (See listings in manual of firms)
Alaska Wind & Water Power	●	●	●	●	●	●	●				●		●							
CRS Group Engineers	●	●	●	●	●	●	●	●	●	●	●				●	●	●			
Canyon Industries	●	●		●	●						●	●	●				●		●	
Converse Ward Davis Dixon	●	●	●	●	●	●	●	●	●	●	●					●	●			
DREES & Co. GmbH				●	●	●	●	●	●		●	●	●			●	●		●	
Evans Engineering	●	●		●	●	●	●	●	●	●		●			●	●	●	●	●	●
GSA International Engineers	●	●		●	●	●	●	●	●	●	●	●	●		●	●	●		●	●
Gilbert Gilkes & Gordon Ltd.	●	●			●	●					●	●	●		●	●	●		●	
Harper, Mike, P.E.	●	●	●	●	●	●	●	●	●	●	●	●		●	●	●	●	●	●	●
Jyoti, Ltd.	●	●		●	●	●	●				●	●	●	●	●	●	●		●	
KaMeWa					●						●	●	●			●	●		●	
Leffel, James & Company				●	●	●			●	●	●	●	●		●	●	●		●	
Main, Chas. T., Inc.	●	●	●	●	●	●	●	●	●	●	●				●	●	●		●	
Master, David B. Associates	●	●	●	●				●			●									
Meinikheim Machines	●	●			●						●	●	●							
Natural Power, Inc.											●	●	●							
Small Hydro. Systems & Equip.				●	●	●	●	●	●		●	●	●		●	●	●			
Turbomeccanica DØSol SA	●	●		●	●		●		●	●	●	●	●	●		●	●		●	
Western Energy Associates		●		●										●		●		●		●
Windworks, Inc.												●	●							

Source: "Colorado Siteowners Manual of Engineering & Manufacturing Firms/Small Scale Hydro Services," Colorado Small Scale Hydro Office, June 1981.

Small Power Producers Qualifying Status. Public Utilities Commission - Colorado Public Utilities Commission Decision No. C82-73.

Information required includes name, address, all owners, and location of facility. A brief description must be given, including the primary energy source to be used, the power production capacity, and the percent of ownership by any public utility company or holding company, or by a person owned by either. Any notification regarding Qualifying Status from the Federal Energy Regulatory Commission must be submitted.

When the above information is submitted and if the project is in compliance with the three required criteria of a) uses renewable resources as a primary energy source (water); b) has a power production capacity of 80 MW or less; and c) is owned by a person not primarily engaged in generation or sale of electric power (except power from the small power facility itself), status as a Small Power Producer is automatically assumed. No notification will be received.

Contact: Harry Galligan, Executive Secretary
Public Utilities Commission
500 State Services Building
1525 Sherman Street
Denver, Colorado 80203
(303) 866-3154

Determinations Regarding Fish and Wildlife. Division of Wildlife - 16 USC §§760 (c)-760(g) and 16 USC §§661-66(c).

Required by the Fish and Wildlife Act of 1956 and the Fish and Wildlife Coordination Act as ammended. No substantive permitting requirements are imposed on the applicant; the Federal Energy Regulatory Commission (FERC) requires coordination with the state Division of Wildlife. A study may be recommended with specifics outlined. A recommendation against a study may also be made.

Contact: Jack R. Grieb, Director
Division of Wildlife
6060 Broadway
Denver, Colorado 80216
(303) 825-1192

<u>Coordination Regarding Historical and Archeological Resources.</u> State Historical Preservation Office -CRS 1973, 24-80-1 101-108.

Information requested is project location (including map); description of proposed work; description of improvements and conditions at the site and impacted area; existing and potential ground disturbance; survey of (or reference to) historical and archeological sites, if available.

Contact: Arthur C. Townsend
State Historic Preservation Officer
Colorado Heritage Center
1300 Broadway
Denver, Colorado 80203
(303) 866-2136

<u>Approval Regarding Project Effects on State Recreation Sources.</u> Division of Parks and Outdoor Recreation - CRS 33-30.

Approval is granted by the Colorado State Park Board for any changes affecting land owned by the state Department of Parks and Recreation or any changes affecting recreation management properties. Information required: location maps and specific site maps, reclamation plans, drawdown and operational plans, construction and extraction methods. Park Board approval is contingent on approval from the property owner and conformance with other required local, state and federal regulations.

Contact: George T. O'Malley, Jr., Director
Division of Parks and Outdoor Recreation
1313 Sherman Street, Room 618
Denver, Colorado 80203
(303) 866-3437

401 Water Quality Certification. Water Quality Control Division - CRS 11-25-8.

Information required: applicants name, address, phone; details of procedure to be used with emphasis on water quality impacts; location; affected watercourse; project schedule; discharge details; and whether or not six other state and federal agencies have been contacted. Request application form from either Water Quality Control Division or Corps of Engineers Office. This process is required only where the corps 404 permit is required.

Contact: Kathleen Reilly
Permit Section
Water Quality Control Division
4210 East 11th Avenue
Denver, Colorado 80220
(303) 320-8833 ext. 3482

Floodplain Information. Federal Emergency Management Agency, Division of Insurance and Mitigation - Federal Executive Order 11988, January 25, 1978, and Colorado Executive Order 8504, October 1, 1977.

Intended to prevent any rise in the flood level by requiring mitigative measures for development activities in floodplains, including manmade changes to improved or unimproved land in floodplains. Such measures must be taken in any location covered by the Federal Flood Insurance Program. Colorado executes this process by enabling counties to establish floodplain development requirements. Cities and counties may enforce these requirements under the zoning laws, the building and engineering departments, or as a separate aspect of their permitting process. Initial contact should be made with the proper authority at the city/county level. Further information may be obtained from the Colorado Water Conservation Board, or the Federal Emergency Management Agency.

Contact: Larry Lang
Colorado Water Conservation Board
1313 Sherman Street, Room 823
Denver, Colorado 80203
(303) 866-3441

or

Jerry M. Olson, Director
Federal Emergency Management Agency
Division of Insurance and Mitigation
Building 710, Denver Federal Center
Denver, Colorado 80225
(303) 234-6582

National Pollutant Discharge Elimination System (NPDES) Permit. Colorado Department of Health, Water Quality Control Division - CRS 1973, 25-8-501 through 508 and CRS 25-8-101 et seq. as amended.

Information required: name, address and phone of facility owner; legal description of facility location; type and quantity of discharge; and additional information such as maps or sketches. Request NPDES application from the Water Quality Control Division.

Contact: Jeb Love
Permits Section
Water Quality Control Division
4210 East 11th Avenue
Denver, Colorado 80220
(303) 230-8333 ext. 4163

Site Approval of New Sewage Treatment Facility. Colorado Department of Health, Water Quality Control Division - CRS 1973, 25-8-704.

Information required: brief statement of reason for selecting site size and type of treatment facility; location including description and maps; information on ownership; other treatment plants in the area, and zoning; signatures from local government, Board of County Commissioners; local health authority, city/county planning authority, regional planning agency, Council of Governments, state geologist. Request WQ-3 form from the Water Quality Control Division.

Contact: Ron Schuyler
Section Chief, Field Services Section
Water Quality Control Division
4210 East 11th Avenue
Denver, Colorado 80220
(303) 320-8333 ext. 3459

Approval of Location and Construction of Water Works. Department of Health, Water Quality Control Division - CRS 1973, 25-1-107 and 109, 24-4-104-105, and Primary Drinking Water Regulations for Colorado, 1977.

Information required is proof that risk from earthquakes, floods, fires or other disasters is insignificant; that the site is not in a 100 year floodplain (except for intake structures). Plans and specifications must be submitted with a written request for review. Submit information to Water Quality Control Division. Drinking Water Section approval may include conditions. Decision may be appealed to Executive Director of Department of Health.

Contact: Richard J. Karlin
Drinking Water Section
Water Quality Control Division
4210 East 11th Avenue
Denver, Colorado 80220
(303) 320-8333 ext. 3322

Dam Safety Approval. Division of Water Resources - CRS 1973, 37-87-105.

Plans and specifications for the dam or dike and related structures must be prepared by a registered professional engineer in Colorado in accordance with the state engineer's office regulations. Supporting data such as geotechnical reports and hydrological reports are required. Other data and calculations may be requested during review. Contact DWR to obtain regulations and discuss project.

Contact: Alan Pearson, Chief
Design Review Unit, Dam Safety Branch
Division of Water Resources
1313 Sherman Street, Room 818
Denver, Colorado 80203
(303) 866-3581

Right of Way and/or Lease. State Board of Land Commissioners - CRS 1973, 36-1-136 as amended.

Information required includes map of proposed route, plat and legal description of area prepared by Registered Land Surveyor. Public entities can obtain leases and/or Right of Ways; private entities can negotiate similar transactions. Request Application Form SLB-38 from State Board of Land Commissioners. Fee required.

Contact: William J. Killip II
Engineering Technician
State Board of Land Commissioners
1313 Sherman Street, Room 620
Denver, Colorado 80203
(303) 866-3454

Open Burning Permit. Department of Health, Air Pollution Control Division - CRS 1973, 25-7-123. Regulation No. 1, Section I.C.1.

Information required includes burning site, debris to be burned, date of burning, etc. Request Permit Application Form APC-24 from Air Pollution Control Division.

Contact: John M. Clouse, Chief
Stationary Sources Section
Air Pollution Control Division
1101 Bellaire Street
Denver, Colorado 80220
(303) 320-4180

Emmission Permit. Air Pollution Control Division - CRS 1973, 25-7-114. Regulation No. 3.

Applicant supplies beginning date of new source, date of anticipated start-up, date of actual start-up, any change or modification of facility which may increase or change nature of emission, and beginning date of monitoring system performance. Request permit application from Air Pollution Control Division.

Contact: John M. Clouse, Chief
Stationary Sources Section
Air Pollution Control Division
1101 Bellaire Street
Denver, Colorado 80220
(303) 320-4180

Special Transport Permit. Department of Highways - CRS 1973, 42-4-409.

Information required is route to be used by vehicles, dates and numbers of trips; size, weight and description of vehicle and load; number of axles and axle spacing; vehicle license and ID number. Normal oversize or overweight are handled at the time of application, usually within 10 minutes. Excessively large loads (over 175,000 pounds) must be checked through a computer and may require up to a month for processing. Obtain application from local or state Department of Highways.

Contact: Doug Shaffer
Staff Maintenance Superintendent
Colorado Department of Highways
4201 East Arkansas Avenue
Denver, Colorado 80220
(303) 757-9536

<u>Access Control Permit.</u> Department of Highways - <u>CRS 1973, 43-2-147.</u>

Information required is property owner's name, location, and use of access; type of traffic; and type of business to be conducted. Application, in some cases, may be submitted to local jurisdiction for approval or denial. It must meet local zoning and building requirements. If approved at local level, it will be forwarded to the Department of Highways for approval. Obtain application from Department of Highways office located in Denver, or local Department of Highway office.

Contact: Doug Shaffer
Staff Maintenance Superintendent
Colorado Department of Highways
4201 East Arkansas Avenue
Denver, Colorado 80220
(303) 757-9536

Permit for Explosive Materials. Division of Labor, Public Safety Section - CRS 1973, 9-7-101 et seq. as amended.

Applicant submits list of any such previous permit(s) and expiration date(s); name, address, phone; type and location of storage facility; and purpose for which explosives will be used. Completed application must be notorized at local sheriff's office. Applicant must be finger-printed. Application then should be sent to Department of Labor. Obtain application form from Department of Labor. Fee of $10.

Contact: Bill Cimino, Chief Inspector
Public Safety Section
Division of Labor
1001 East 62nd Avenue
Denver, Colorado 80216
(303) 289-5641

Water Right. District Water Courts - CRS 1973, 37-92-101 et seq.

Information required includes description of beneficial use; location, amount, consumptive use; date of appropriation; survey of site; explanation of prior adjudications.

See page 152 for location of Division Water Courts.

The best reference for information on the majority of federal permits is the "blue book" entitled, Procedures to Apply for Hydropower Licenses and Preliminary Permits, March 1981. These may be obtained by contacting the Federal Energy Regulatory Commission (FERC) office in Fort Worth, Texas or Washington, D.C.

FERC Preliminary Permits

The exact specifications for filing a preliminary permit application are contained in FERC Order No. 54, which is included in the "blue book," and 18 CFR 4.80-4.83. The following information is required:

a) Location of project.

b) Name, address and telephone of applicant.

c) Requested term of permit (not to exceed 36 months).

d) The name and address of the owner of the dam and facility, including federal agency, where applicable.

e) Exhibit 1 - a description of the proposed project with as much detail as the applicant can provide.

f) Exhibit 2 - a study plan and work schedule for the investigations and other activities to be carried out under the permit. This includes dates for a final feasibility decision, and for a license application date.

g) Exhibit 3 - a statement of cost and financing, along with any available information concerning the ultimate market for the project power, and financing sources to carry out the necessary studies.

h) Exhibit 4 - a map or maps showing the geographical location of the project, the physical relationships of its principal features, and a proposed project boundary, and any portion of the project affected by Wild and Scenic Rivers or Wilderness areas.

The original and eleven copies are sent to FERC. Full-sized and reduced prints of all maps and drawings should also be included.

FERC Licenses

-Short-form license-Minor Projects and Major Projects with installed generating capacity of 5 MW or less.

This license application is obtainable from FERC in Order No. 11 and Order No. 185. It calls for an initial statement, including a brief project description and construction dates, description of the owner, and information regarding certain state requirements. Exhibit A gives a project description and mode of operation information. Exhibit E requires a report on the environmental resources and impacts of the project. Exhibit F requires general design drawings. Exhibit G requires a map of the project. In cases involving new dam or impoundment construction, an Environmental Report is required, replacing Exhibit E.

-Major Projects at Existing Dams in excess of 5 MW.

This category is for developers who seek: (1) an initial license for an existing hydroelectric project, (2) a new license for an existing project, or (3) an initial license for a proposed hydroelectric facility. The application requires an initial statement and seven exhibits.

The initial statement provides certain basic information, including the nature of the application, the names and business addresses of the applicant and its authorized agents, the nature of the applicant, and the name and location of the project. The applicant is also required to state that he has complied with the laws of the state where the project is located with respect to obtaining property rights and the rights to appropriate, divert, and use water for power purposes, and with respect to obtaining authorization to engage in the business of producing, transmitting, and distributing power and any other approvals necessary to accomplish the purposes of the requested license.

Exhibit A provides a description of the physical structures and features of the project. The exhibit also includes a tabulation of any lands of the United States that are enclosed within the project boundary.

Exhibit B provides a statement of project operation and resource utilization. The exhibit calls for a description of the available resource (flow and head) and a technical description of the proposed use of the water resource for the generation of power. The applicant must also explain how he intends to dispose of the power. Finally, the applicant must describe any plans for future hydroelectric development on the affected stream.

Exhibit C provides a construction history and a proposed construction schedule for the project. The construction history, which need only be filed if the applicant is seeking an initial license, calls for a tabulated chronology of construction for the existing project structures and facilities, including the dates construction or installation is to begin and be completed and the dates commercial operation is to start.

Exhibit D provides a statement of costs and financing. If the applicant seeks a new license for a project, and is not a municipality or a state, it must provide an estimate of the amount that would be payable if the United States exercised its right to take over the project upon expiration of the initial license. Estimated costs of any proposed new development and estimated annual operating costs must also be provided, as well as information concerning the value of project power to the applicant and the sources and extent of financing and annual revenues available to meet the estimated costs.

Exhibit E provides a report on the environmental resources of the project, the impacts of the project on those resources, and the measures proposed to mitigate the impacts or to protect and enhance the resources. The exhibit must include reports on: (1) water use and quality, (2) fish, wildlife, and botanical resources, (3) historical and archeological resources, (4) recreational resources, (5) land management and aesthetics, and (6) literature consulted.

Exhibit F consists of general design drawings of the principal project works. The drawings must show a plan, elevation, and profiles and sections for each structure, and must be accompanied by sufficient information concerning structural strength and stability and other controlling factors to demonstrate that the structures are safe and adequate for their stated functions.

The final exhibit, Exhibit G, is a map of the project. The map must show the geographical location of the project, the physical interrelationships of project works and other features, a project boundary enclosing the project works and all lands and waters necessary for project purposes, and any lands of the United States that are within the project boundary.

For exact specifications for this license application, see FERC Order No. 59 (included in FERC's "blue book") or 18 CFR 4.50-4.51.

-Major Projects at New Sites

For a major project license, an application must be completed with exhibits A through W. This requires the completion of all studies and design work, the selection of all construction equipment, the procurement of all land and water rights, and the securing of state permits. Unless there is a Finding of No Significant Impact, Exhibit E will become the basis for a full Environmental Impact Study which may require one to two years to complete. A list of the exhibits is included in Table D-1; for exact specifications, see 18 CFR 4.40-4.42 and 18 CFR 131.2.

TABLE D-1

Exhibits Required for FERC License Application
Major Projects

A. Description of Project

B. Statement of Project Operation and Resource Utilization

C. Proposed Construction Schedule

D. Statement of Project Costs and Financing

E. Environmental Report

F. General Design Drawings

G. Map of Project

Source: 18 CFR 4.41 (1980) amended by FERC Order No. 185, Final Rule, issued November 6, 1981

-Conduit Facilities.

Section 30 of the Federal Power Act gives FERC the authority to exempt small conduit hydro facilities from all or part of the normal licensing requirements. To qualify a project must be on a conduit, canal, pipeline, etc., used primarily for domestic, agricultural, or industrial purposes. It must not utilize a new dam for the increased head necessary for power generation; the power house cannot be on federal land; and the project capacity cannot exceed 15 MW. The application is similar to the short-form license application, except that it requires less information than the short form. Under FERC regulations, applications will be considered on a case-by-case basis, and will be acted upon within 90 days of notifying the applicant that an acceptable application has been received. If notification is not received within 90 days, the application is considered approved.

The application consists of an introductory statement and four exhibits. The introductory statement identifies the applicant and locates the project. Exhibit A is a description of the conduit, the purposes for which it is currently used, and the proposed mode of operation. Exhibit B is a general location map showing land ownership and the location of the physical structures of the facility. Exhibit E is an environmental report that must include, in some detail, the setting of the facility, expected impacts and proposed measures to mitigate them, a description of alternative means of obtaining the equivalent amount of power that is to be provided by the proposed facility, and evidence that the applicant consulted with state and federal fish and wildlife agencies and any determinations of these agencies. Exhibit G is a set of drawings of the facility structures and equipment. This must include a plan, elevation, and profile view of the power plant and any dam to which the plant would be attached. More detailed and exact specifications can be found in the Federal Register of April 28, 1980 (45 FR 28085), in 18 CFR 4.90-4.94, or obtained from FERC (Order No. 76).

-Projects Less Than 5 MW.-Case-by-Case

FERC recently adopted procedures for exempting certain projects not exceeding 5 MW from all or part of the licensing requirements under Part 1 of the Federal Power Act. The exemption will be granted on a case-by-case basis. To be eligible the following conditions must be met: (1) the project owners must have a property interest sufficient to permit development; and (2) there must be an existing dam, or a "natural water feature" must be used without a dam or a manmade impoundment. According to the rule, public notice will only have to be published once, and FERC will circulate a notice of application for exemption to interested agencies. The agencies will have 60 days to respond. FERC will have a 120 day time limit to either grant or deny the exemption unless this is suspended because it is deemed that more time is necessary.

The application for exemption consists of an introductory statement and four exhibits. The introductory statement requires information on the name, address, and status of the applicant; the name and location of the project; and the sections of Part I of the Federal Power Act for which the exemption is requested. Exhibit A must describe the hydro project and its proposed mode of operation. Exhibit B is a general location map of the proposed project. Exhibit E is an environmental report which must include a description of the environmental setting, a description of the expected environmental impacts, and letters or documentation showing that the applicant consulted or attempted to consult with state and federal fish and wildlife agencies before filing the application. Exhibit G is a set of drawings showing the proposed and existing project works. Exact requirements can be found in the Federal Register of November 18, 1980 (45 FR 76115), in 18 CFR 4.101-4.108, or obtained from FERC (Order No. 106).

Projects Less Than 5 MW - Generic

They categorically exempt projects meeting the criteria below, as opposed to the case-by-case exemptions. This may be obtained from FERC (Order No. 202). The proposed regulations include:

1. projects with a proposed installed capacity of 100 kW or less and

2. projects with a proposed installed capacity of 5 MW or less and certain specified physical characteristics and environmental effects. To be eligible, the proposed project must be one which:

    a. involves an existing dam;
    b. will not increase the normal maximum surface elevation of the impoundment after repair or reconstruction of the dam;
    c. will not entail any change from the prevailing regime of storage and release of water from the impoundment;
    d. will not divert water from the waterway for more than 300 feet from the toe of the

dam to the point of discharge into the waterway;

e. does not involve construction of a primary transmission line which:
   - has a design capacity of more than 69 kv; or
   - is more than one mile long and located on a new right-of-way;

f. utilizes only a dam at which there is no significant existing upstream or downstream passage of fish;

g. will not violate Environmental Protection Agency (EPA) or state water quality standards;

h. does not involve construction on or alteration of any site included in or eligible for inclusion in the National Register of Historic Places;

i. does not involve construction in the vicinity of any threatened or endangered species or critical habitat designated in Department of Interior regulations; and

j. is a whole project and not just part of a larger water project.

To utilize this categorical exemption, a project sponsor will be required to submit to the FERC a Notice of Exemption, accompanied by certification from state and federal agencies which supports the conclusion that the project meets the requirements listed above. The form of such a filing will be provided later as "Form of Notice of Categorical Exemption, Proposed 18 CFR §4.112(c)."

Applications for permits, licenses, or exemptions may be received from and are submitted to:

Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

Additional Federal Permits and/or Consultation

Bureau of Land Management.

If a project is located on BLM lands or affects BLM lands because of its close proximity, the developer must contact the appropriate BLM office to obtain approval.

Contact: George Francis, State Director
Bureau of Land Management
Colorado State Office
2000 Arapahoe Street
Denver, Colorado 80205
(303) 837-4325

Maryln Jones
District Manager
Bureau of Land Management
Highway 550 South
P.O. Box 1269
Montrose, CO 81401
(303) 249-7791

Lee Carie
District Manager
Bureau of Land Management
P.O. Box 248
455 Emerson
Craig, CO 81625
(303) 824-8261

David Jones
District Manager
Bureau of Land Management
764 Horizon Drive
Grand Junction, CO 81501
(303) 243-6552

Mel Clausen
District Manager
Bureau of Land Management
3080 East Main Street
Canon City, CO 81212
(303) 275-7494

Bureau of Reclamation.

Any hydro project utilizing or affecting sites under the jurisdiction of the Bureau of Reclamation must contact the appropriate Bureau office. The Bureau, in May 1981, signed a memorandum of understanding with the Federal Energy Regulatory Commission regarding the jurisdictional responsibilities for powerplant design approval, project access rights, and construction inspections. Annual use charges should be discussed. The state of Colorado includes three Bureau jurisdictions.

For general information:

Bruce Glen, Energy Coordinator
Division of Planning Technical Services
Bureau of Reclamation
Building 67, Room 1398
Denver Federal Center
West 6th Avenue and Kimpling Street
Denver, Colorado 80225
(303) 234-3321

For river basins on the Western Slope:

Regional Director
Bureau of Reclamation
Upper Colorado Region
P.O. Box 11568
Salt Lake City, Utah 84147
(801) 524-5566

For the Rio Grande River Basin:

Regional Director
Bureau of Reclamation
Southwest Region
714 S. Tyler, Suite 201
Amarillo, Texas 97101
(806) 728-9400

For river basins on the Eastern Slope:

Regional Director
Bureau of Reclamation
Lower Missouri Region
P.O. Box 25247, Building 20
Denver Federal Center
Denver, Colorado 80225
(303) 234-4441

U. S. Army Corps of Engineers.

The Corps of Engineers has jurisdiction over any project which is proposed for a navigable waterway (Section 10, River & Harbor Act of 1899), or which involves the discharge of any dredge or fill material into waters of the U.S. (Section 404, Clean Water Act as amended of 1977).

In general, the Corps does not require a separate Section 10 permit in cases where FERC exercises licensing jurisdiction. However, the Corps does review and comment on FERC applications as a part of the FERC's prelicense consultation process to ensure the protection of navigational interests. Very few waterways in Colorado are considered navigable requiring Section 10 permits. For projects involving the discharge of dredged or fill material into U.S. waters a 404 permit is required in addition to any FERC license.

Section 404 and Section 10. The permit application is made on a general form and takes on the average, two months but may take as long as six months to have approved. It requires information on the nature and location of the proposed activity; the time span involved; and the status of other federal, state, and local permits. The Corps, upon receipt of the application, issues public notice and requests comment.

The FERC license application should be on file. After 30 days, the agencies will respond with approval, request a hearing, or request a hold. Comments are also requested from local, county, and state agencies. After approvals from agencies are granted and the final NEPA EIS is approved (if required), the permit may be issued.

Contact:

For the Western Slope and for general information:

Rodney L. Woods
Chief, Regulatory Section
U.S. Army Corps of Engineers
2784 Crossroads Blvd., Suite 111
Grand Junction, Colorado 81501
(303) 243-1199

For the Northeast quadrant of the state:

Ralph Miller,
Chief, Regulatory Section
U.S. Army Engineer District Omaha
6014 USPO & Courthouse
215 North 17th Street
Omaha, Nebraska 68101
(402) 221-4133

For the Southeast quadrant of the state:

Andrew Rosenau
Chief, Regulatory Section
U.S. Army Engineer District Albuquerque
P.O. Box 1580
Albuquerque, New Mexico 87103
(505) 766-3225

Department of Interior - Environmental Division.

All hydropower developments involving property owned by a DOI agency must be coordinated through the DOI Environmental Division. The Region VIII contact for this procedure is:

Contact: Robert Stewart
Regional Environmental Officer
Department of Interior
Bulding 67, Room 688
Denver Federal Center
Denver, Colorado 80225
(303) 234-3120

Environmental Protection Agency (EPA).

Federal agencies making decisions on hydroelectric project licenses are required to comply with the National Environmental Policy Act (NEPA). For minor projects and for the additions of hydroelectric facilities to existing dams, the project proponent is initially required only to provide enough environmental information for FERC to make a determination of environmental significance.

If the project is determined to be environmentally significant, a full Environmental Impact Statement (EIS) is required. Major projects usually require an EIS. When an EIS is required, it is written by the FERC staff using the information provided in the license application (Exhibit W or the Environmental Report). When necessary, FERC will require that additional studies and information be provided. See FERC's regulations related to NEPA: 18 CFR 2.80-2.82 (note that revisions to these regulations have been proposed-Federal Register of August 27, 1979, 44 FR 50-052—and are expected to be adopted in the near future).

Contact: Regional Administrator
Region VIII
Environmental Projection Agency
Lincoln Tower Building, Room 900
1860 Lincoln Street
Denver, Colorado 80203
(303) 837-3895

National Park Service.

If a hydro project is located in or near:

a. a unit of the National Park System;

b. a "designated" or "study" river in the National Wild and Scenic Rivers System;

c. a river listed on the Nationwide Rivers Inventory;

d. a river listed in the 5(a) Rivers Inventory

contact must be made with the National Park Service. Each of the above categories has differing requirements regarding the location of hydro projects within their boundaries.

If it is unclear whether any of these designated areas are affected by a particular hydro site, a list may be obtained from either the Colorado Small Scale Hydro Office, the Colorado Natural Areas Program, or the National Park Service.

Contact: Ken Czarnowski, Branch Chief
Rivers, Trails, & Landmark Program
National Park Service, Rocky Mountain Region
P.O. Box 25287
Denver Federal Center
Denver, Colorado 80225
(303) 234-6443

Fish and Wildlife Service (FWS).

Under the authority of the Fish and Wildlife Coordination Act (48 Stat. 401, as amended, 16 USC 661, et seq.) the Department of the Interior, Fish and Wildlife Service, is required to determine the potential impacts to fish and wildlife resources of proposed water development projects to be constructed under federal assistance or permit and to outline measures for mitigating or compensating damages to those resources. They usually do this through the process of reviewing Federal Energy Regulatory Commission and Corps of Engineers permits.

The Endangered Species Act of 1973, as amended, establishes a comprehensive program to conserve endangered and threatened species of fish, wildlife, and plants. Any species in danger of extinction or likely to become in danger of extinction, is eligible for listing by the Department of Interior as an endangered or threatened species. Once listed, the law mandates that all federal agencies are required to protect an endangered or threatened species. When an applicant applies for a FERC license, FERC will contact FWS regarding the presence of threatened or endangered species. If such species exist at the site, FERC is responsible for completing a "Biological Assessment." FERC will generally require the developer to cover the costs of the Assessment. If FERC determines that the hydro project may affect the threatened/endangered species, they will make a Formal Request of FWS for a "Biological Opinion". FWS will issue such an opinion including recommendations and alternatives. FERC will then make a final determination. If the project is on private land and involves no Federal action (such as FERC permits or licenses), this process is not required, except in the case where a developer should directly harm a threatened or endangered species in a substantial manner (referred to as "taking").

The National Wildlife Refuge System administered by the FWS authorizes hydro development in wildlife refuge areas if such projects, including transmission lines, access roads, etc., do not conflict with management of the refuge. Developers should consult early with the FWS to determine whether easements, permits and leases can be obtained for hydro development on Wildlife Refuge and National Fish Hatchery System lands.

Contact: Dr. Grady Towns
U.S. Fish & Wildlife Service, Region 6
P.O. Box 25486
Denver, Colorado 80225
(303) 234-5586

U.S. Forest Service (USFS).

In the event that a small scale hydropower project involves the use of or otherwise affects lands administered by the U.S. Forest Service (some Wild and Scenic Study Rivers are under the jurisdiction of the Forest Service) the developer must contact the appropriate headquarters office of the forest involved. Information at the regional level and locations of the headquarters offices are available from the Rocky Mountain Region office.

Contact: Craig W. Rupp,
Regional Forrester
U.S. Forest Service, Rocky Mountain Region
11177 W. 8th Avenue
Lakewood, Colorado 80225
(303) 234-3711

Other federal and state agencies may need to be contacted, depending on ownership or management of lands involved. These are detailed in Chapter 6, entitled "Environmental Effects," and in Appendix F on page 145.

APPENDIX E: EXAMPLES OF MANAGED AREAS IN COLORADO REQUIRING DEVELOPER CONSULTATION

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*	Bureau of Land Management
*	Experimental Areas
*	Experimental Forests
*	Experimental Ranges
(1)	Federally Owned Dams and Reservoirs
(2)	Five-a [5(a)] Rivers
(3)	Instream Flow Adjudications
*	Indian Reservations
*	Land Utilization Projects
*	MAB-Biosphere Reserves
*	National Audubon Society
*	National Grasslands
*	National Monuments
*	National Parks
*	National Recreation Areas
*	National Scenic Trails
*	National Wildlife Refuges
(2)	Nationwide Rivers Inventory
*	Nature Conservancy Lands
*	Primitive Areas
*	Research Natural Areas
*	State Forest
*	State Natural Areas
*	State Recreation Areas
*	State Parks
*	State Wildlife Areas
*	State Owned Land
*	U. S. Forest Service Lands
(2)	Wild & Scenic Rivers (designated or proposed)

*Information regarding locations of these managed areas and respective agencies to contact can be obtained from the Colorado Natural Areas Program, 1313 Sherman Street, Room 718, Denver, Colorado 80203 (303) 866-3311.

(1) Contact Bureau of Reclamation or the U.S. Army Corps of Engineers.

(2) Contact the National Park Service to determine if a Wild & Scenic River, a Nationwide River Inventory river, or a 5(a) River is involved.

(3) Contact Colorado Water Conservation Board.

APPENDIX F: AGENCY CONTACTS

FEDERAL

Bureau of Land Management
Colorado State Office
2000 Arapahoe Street
Denver, Colorado 80205
(303) 837-4325

District Manager
Bureau of Land Management
Highway 550 South
P.O. Box 1269
Montrose, Colorado 81401
(303) 249-7791

District Manager
Bureau of Land Management
P.O. Box 248
455 Emerson
Craig, Colorado 81625
(303) 824-8261

District Manager
Bureau of Land Management
764 Horizon Drive
Grand Junction, Colorado 81501
(303) 243-6552

District Manager
Bureau of Land Management
3080 East Main Street
Canon City, Colorado 81212
(303 275-7494

Bureau of Reclamation
Division of Planning Technical Services - BUREC
Building 67, Room 1398
Denver Federal Center
Denver, Colorado 80225
(303) 234-3321

For river basins on the Western Slope:

Upper Colorado Region
P.O. Box 11568
Salt Lake City, Utah 84147
(801) 524-5566

For the Rio Grande River Basin:

Southwest Region
714 South Tyler, Suite 201
Amarillo, Texas 97101
(806) 728-9400

For river basins on the Eastern Slope:

Lower Missouri Region
P.O. Box 25247, Building 20
Denver Federal Center
Denver, Colorado 80225
(303) 234-4441

U. S. Army Corps of Engineers

For Western Slope and general information:

U. S. Army Corps of Engineers
Regulatory Section
2784 Crossroads Boulevard, Suite 111
Grand Junction, Colorado 81501
(303) 243-1199

For Northeast quadrant of the state:

Chief, Regulatory Section
U. S. Army Engineer District Omaha
6014 USPO & Courthouse
215 North 17th Street
Omaha, Nebraska 68101
(402) 221-4133

For Southeast quadrant of the state:

Chief, Regulatory Section
U. S. Army Engineer District Albuquerque
P.O. Box 1580
Albuquerque, New Mexico 87103
(505) 766-3225

U. S. Department of Energy
Region VIII
Assessments & Integration
1075 South Yukon
Lakewood, Colorado 80226
(303) 234-2472

Environmental Protection Agency
Region VIII
Lincoln Tower Building, Room 900
1860 Lincoln Street
Denver, Colorado 80203
(303) 837-3895

Federal Energy Management Agency
Division of Insurance & Mitigation
Building 710, Denver Federal Center
Denver, Colorado 80225
(303) 234-6582

Federal Energy Regulatory Commission
Office of Electric Power Regulation
825 North Capitol Street, N.E.
Washington, D.C. 20426
(202) 376-9171

Department of Interior
Regional Environmental Officer
Building 67, Room 688
Denver Federal Center
Denver, Colorado 80225
(303) 234-2329

National Park Service
Rivers, Trails, & Landmark Program
Rocky Mountain Region
P.O. Box 25287
Denver Federal Center
Denver, Colorado 80225
(303) 234-6443

FEDERAL (cont.)

U. S. Fish & Wildlife Service
Region 6
P. O. Box 25486
Denver Federal Center
Denver, Colorado 80225
(303) 234-5586

U. S. Forest Service
Regional Forrester
Rocky Mountain Region
11177 West 8th Avenue
Lakewood, Colorado 80226
(303) 234-3711

STATE

Colorado Small Scale Hydro Office
Colorado Water Conservation Board
1313 Sherman Street, Room 823
Denver, Colorado 80203
(303) 866-3441
Coordinator: Barbe Chambliss
Assistant: Opal Anderson

Air Pollution Control Division
Stationary Sources Division
1101 Bellaire Street
Denver, Colorado 80220
(303) 320-4180

Colorado Water Conservation Board
1313 Sherman Street, Room 823
Denver, Colorado 80203
(303) 866-3441

Colorado Department of Highways
Staff Maintenance Superintendent
4201 East Arkansas Avenue
Denver, Colorado 80222
(303) 757-9536

State Historic Preservation Officer
Colorado Heritage Center
1300 Broadway
Denver, Colorado 80203
(303) 866-2136

State Board of Land Commissioners
Engineering Technician
1313 Sherman Street, Room 620
Denver, Colorado 80203
(303) 866-3454

Colorado Natural Areas Program
1313 Sherman Street, Room 718
Denver, Colorado 80203
(303) 866-3311

Division of Parks and Outdoor Recreation
1313 Sherman Street, Room 618
Denver, Colorado 80203
(303) 866-3437

Public Utilities Commission
1525 Sherman Street, Room 500
Denver, Colorado 80203
(303) 866-3154

Division of Labor
Public Safety Section
1001 E. 62nd Avenue
Denver, Colorado 80216
(303) 289-5641

STATE (cont.)

Water Quality Control Division

401 Permits:

Permit Section
4210 East 11th Avenue
Denver, Colorado 80220
(303) 320-8333 ext. 3482

NPDES Permit:

Permits Section
4210 East 11th Avenue
Denver, Colorado 80220
(303) 320-8333 ext. 4163

Sewage Treatment Facilities:

Section Chief
Field Services Section
4210 East 11th Avenue
Denver, Colorado 80220
(303) 320-8333 ext. 3459.

Water Works Construction:

Section Chief
Drinking Water Section
4210 East 11th Avenue
Denver, Colorado 80220
(303) 320-8333 ext. 3322

Division of Water Resources

Dam Safety:

Design Review Unit
Dam Safety Branch
1313 Sherman Street, Room 818
Denver, Colorado 80203
(303) 866-3581

Water Rights - Division Offices

Division I - Greeley:

Room 208 8th & 8th Office Building
Greeley, Colorado 80631
(303) 352-8712

Division II - Pueblo:

1906 West Northern Avenue
Pueblo, Colorado 81004
(303) 542-3368
(303) 542-8099

Division III - Alamosa:

P. O. Box 269
Alamosa, Colorado 81101
(303) 589-6683

Division IV - Montrose:

P. O. Box 456
Montrose, Colorado 81401
(303) 249-6622

STATE (cont.)

Division V - Glenwood Springs:

P. O. Box 396
Glenwood Springs, Colorado 81601
(303) 945-5665

Division VI - Steamboat Springs:

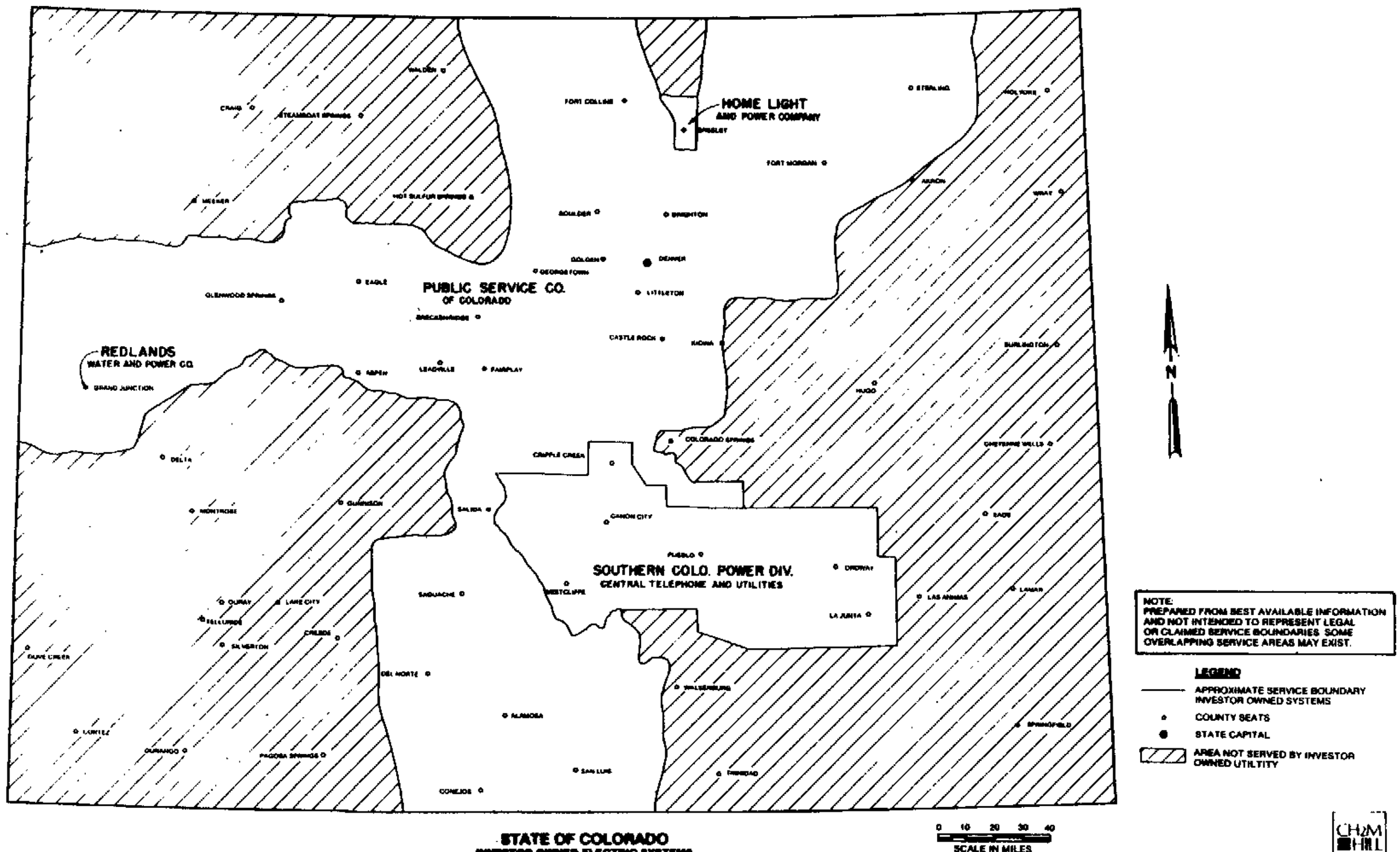
P. O. Box AE
Steamboat Springs, Colorado 80477
(303) 879-0272

Division VII - Durango:

P. O. Drawer 1880
960 East 2nd Avenue
Durango, Colorado 81301
(303) 247-1845

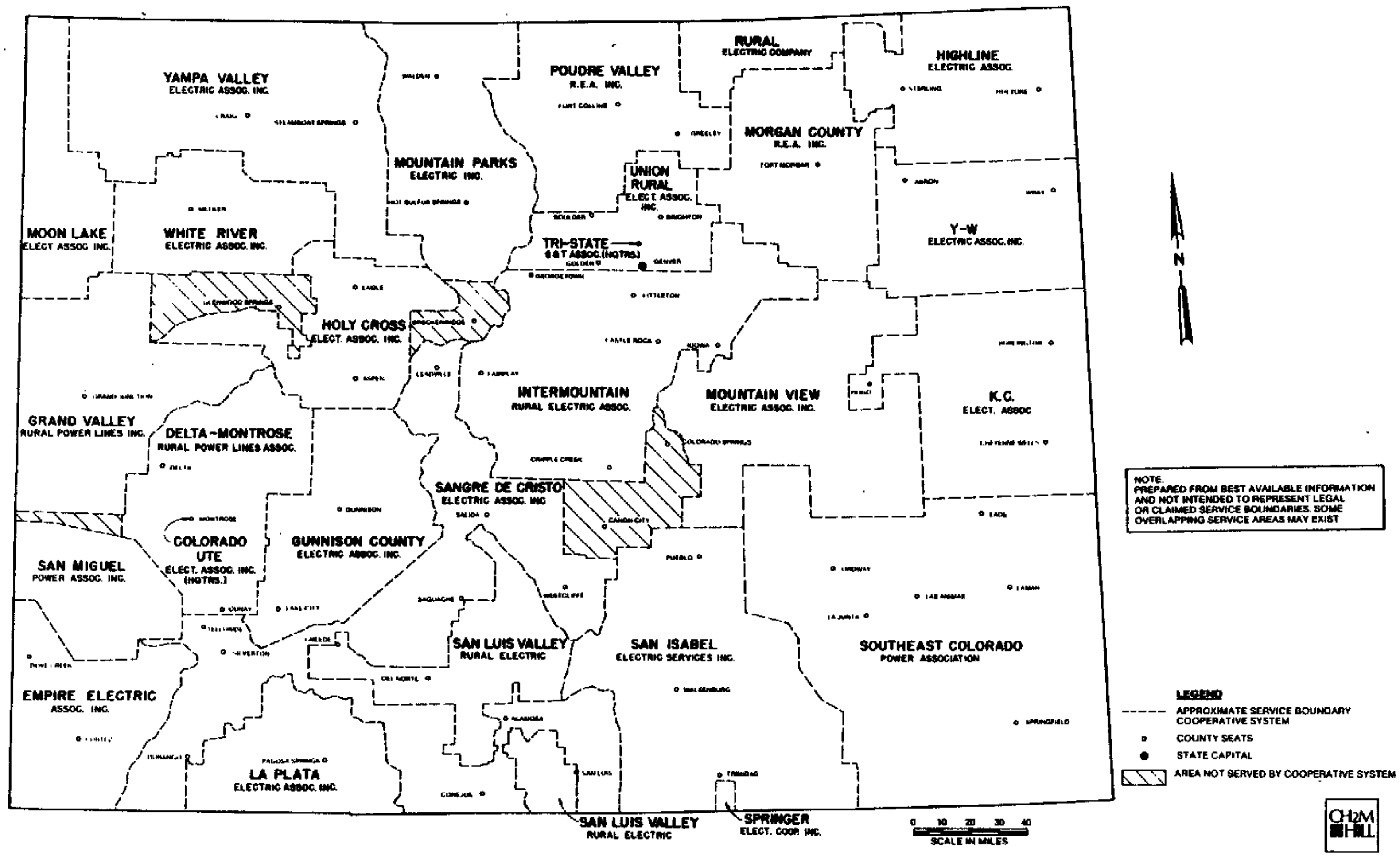
Division of Wildlife
6060 Broadway
Denver, Colorado 80216
(303) 825-1192

APPENDIX G: COLORADO UTILITY JURISDICTIONS

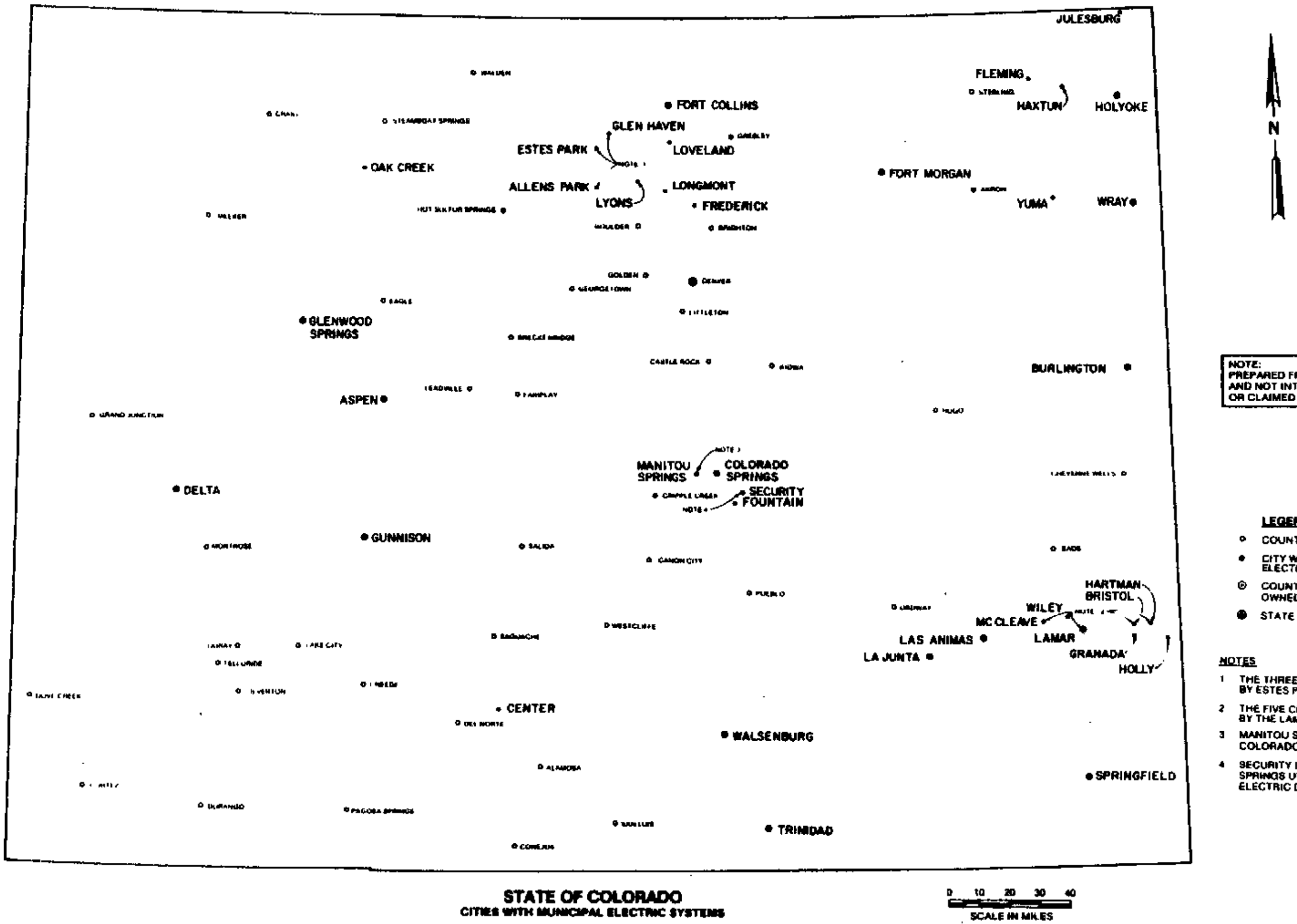


STATE OF COLORADO
INVESTOR OWNED ELECTRIC SYSTEMS

CH2M HILL



STATE OF COLORADO
COOPERATIVE ELECTRIC SYSTEMS



NOTE:
PREPARED FROM BEST AVAILABLE INFORMATION AND NOT INTENDED TO REPRESENT LEGAL OR CLAIMED SERVICE BOUNDARIES

LEGEND

- COUNTY SEATS
- CITY WITH MUNICIPALLY OWNED ELECTRIC SYSTEM
- COUNTY SEAT WITH MUNICIPALLY OWNED ELECTRIC SYSTEM
- STATE CAPITAL

NOTES

1 THE THREE CITIES INDICATED ARE SERVED BY ESTES PARK LIGHT & POWER DEPT

2 THE FIVE CITIES INDICATED ARE SERVED BY THE LAMAR UTILTIES BOARD

3 MANITOU SPRINGS IS SERVED BY COLORADO SPRINGS UTILITIES DEPT

4 SECURITY IS SERVED BY BOTH COLORADO SPRINGS UTILITIES DEPT AND FOUNTAIN ELECTRIC DEPT

STATE OF COLORADO
CITIES WITH MUNICIPAL ELECTRIC SYSTEMS

CH2M HILL

APPENDIX H: RECOMMENDED AVOIDED COST RATES FOR SMALL POWER PRODUCTION AND CONGENERATION SALE OF POWER TO COLORADO REGULATED UTILITIES

On November 24, 1980 testimony was presented to a Hearing Examiner of the Public Utilities Commission regarding the Proposed Rules of the Colorado Implementation of Public Utilities Regulatory Policy Act (PURPA) Sections 201 and 210.

On May 6, 1981 the Recommended Decision of the Hearing Examiner to the Public Utilities Commission was issued. Attachment 2 of this document details the recommended avoided cost rates for each regulated utility. These are outlined in Table H-1 on the following pages.

Commission approval of the recommended rules and rates is still pending and finalized rates are not available as of the publication date of this manual. Updated information will be provided once the Commission has acted.

Table H-1 recommending utility specific rates has been removed in its entirety (previously pages 158, 159, and 160). The reason for this is stated by the Public Utilities Commission in their Decision No. C82-73:

> it is not appropriate to set forth or adopt a specific methodology for determining avoided costs nor is it appropriate to adopt utility specific avoided cost rates for Colorado jurisdictional utilities who purchase energy and capacity from small power producers and cogenerators.

TABLE H-1, cont.

Utility	Demand	Energy	Peaking
San Miguel Power Association, Inc.	.03069 $/kwh	.013166 $/kwh	
Sangre De Cristo Electric Association, Inc.	.03069 $/kwh	.013166 $/kwh	
Southeast Colorado Power Association	.03069 $/kwh	.013166 $/kwh	
Southern Colorado Power Company	7.26 $/kw-month	.009997 $/kwh	
Springer Electric Cooperative, Inc.	.03069 $/kwh	.013166 $/kwh	
Tri-County Electric Cooperative, Inc.	.03069 $/kwh	.013166 $/kwh	
Union Rural Electric Association	.02977 $/kwh	.0128 $/kwh	
Wheatland Electric Cooperative, Inc.	.03069 $/kwh	.013166 $/kwh	
White River Electric Association, Inc.	.03069 $/kwh	.013166 $/kwh	
Y-W Electric Association, Inc.	.02977 $/kwh	.0128 $/kwh	
Yampa Valley Electric Association, Inc.	.03069 $/kwh	.013166 $/kwh	

Source: Attachment 2, to Decision no. R81-801, Colorado Public Utility Commission Rules Imprlementing Sections 201 and 210, PURPA Small Power Production and Cogeneration Facilities, May 6, 1981

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Arbitrage bonds - Bonds issued by a public entity at a specific interest rate, the returns of which are invested at a higher rate.

Avoided cost - The incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or facilities, such utility would generate itself or purchase from another source.

BLM - Bureau of Land Management (U. S. Department of Interior).

CFR - Code of Federal Regulations.

CFS - Cubic feet per second.

CI - Cost Index.

CNAP - Colorado Natural Areas Program (State).

COE - Corps of Engineers (U. S. Army).

COWPTA - Crude Oil Windfall Profits Tax Act (Federal).

CRS - Colorado Revised Statutes.

CWCB - Colorado Water Conservation Board (State).

Capacity value - That part of the market value of electric power which is assigned to dependable capacity.

Capitalization - Consists of the total liabilities of a business including both ownership capital and borrowed capital.

Cash flow - The net profits of a business plus the charges of the accounting period for depreciation, depletion, amortization and extraordinary charges to reserves not paid in cash. This is the cash generated in a period if all other accounts do not change. In addition, decreases in assets, increases in liabilities and new capital added are sources of cash while increases in assets and decreases in liabilities and net worth are applications of cash.

Construction loan - A loan usually negotiated at the same time as the long-term debt which provides the necessary funds to take a project through the construction period. After that point, the long-term lender typically provides the capital to retire the construction loan.

Cost of service contract - A contract wherein a pricing formula is established that covers the costs of the particular project, including the return on the investor's equity.

Cost of service payment - Payments which include operation and maintenance, debt service, normal return on equity, administration and other fixed fees.

DNR - Department of Natural Resources (State).

DOW - Division of Wildlife (State).

DWR - Division of Water Resources (State).

Debt capital - Money that is borrowed rather than invested by equity investors.

Debt equity ratio - The ratio of the outstanding debt of an organization to the market value of the equity invested. For partnerships and corporations that are not publicly traded, the equity is usually valued at the amount of contribution.

Debt service - The sum of the interest due on the outstanding principal for a loan.

Double barrel bonds - Bonds supported by both revenues and general obligation.

Double-dipping - Using separate moneys from the same source to accomplish one task.

EIS - Environmental Impact Statement.

Energy value - That part of the market value of electric power which is assigned to energy generated.

Equity investor - A person investing money, land, or services and receiving in return shares of interest or common stock.

Exceedance - The amount of flow exceeding the average annual flow of a water way.

FERC - Federal Energy Regulatory Commission (U. S. Department of Energy - formerly Federal Power Commission).

FLPMA - Federal Land Policy and Management Act U. S. Department of Interior).

FmHA - Farmers Home Administration (U. S. Department of Agriculture).

FR - Federal Register.

FWS - Fish and Wildlife Service (U. S. Department of Interior).

General partner - The person(s) who controls a business and manages the use of its assets. The general partners are personally responsible for the liabilities of the business and eligible for the flow through of the business tax consequences.

GWh - Gigawatt hours.

Gigawatt - One million watts.

Head - The gross head is the difference in elevation between the headwater surface above and the tailwater surface below a hydroelectric power plant, under specified conditions.

Headrace - A watercourse that feeds water into a mill, water wheel, or turbine.

Headwater - The waters at the upper surface of a dam or penstock.

IDB - Industrial Development Bond. For tax purposes an IDB is an obligation, proceeds of which are used in trade or business of a private individual. In computing gross income, the interest received from an IDB will be included.

IOU - Investor Owned Utility.

Interconnection - A transmission line joining two or more power systems through which power produced by one can be used by the other.

Kilovolt (kV) - One thousand volts.

Kilowatt (kW) - One thousand watts.

Kilowatt-hour (kWh) - The amount of electrical energy involved with one kilowatt demand over a period of one hour. It is equivalent to 3,413 Btu of heat energy.

Leveraged lease - A financial arrangement in which the developers/lessors of a project borrow on the credit of the lessee whose payments for the lease cover the debt service plus a generally nominal equity return.

Limited partnership - A partnership involving a passive investor lacking control over management who can participate in the business' profits and losses but whose personal liability is limited to the amount of the investment.

Marginal tax bracket - Refers to the rate at which income is taxed in the highest bracket in which the taxpayer is situated.

Megawatt (MW) - One thousand kilowatts.

Megawatt-hours (MWh) - One thousand kilowatt-hours.

Mine-mouth - Located at the mouth of a mineral extraction mine.

NACHP - National Advisory Council on Historic Preservation.

NEPA - National Environmental Policy Act.

NPDES - National Pollutant Discharge Elimination System.

PUC - Public Utilities Commission (State).

PURPA - Public Utility Regulatory Policies Act (Federal).

Peaking power - Power provided at the time of highest demand on a utility system.

Penstock - A pipe or conduit used to carry water to a water wheel or turbine.

Present value - The value today, or in some initial period, of a future payment or cost when discounted by a rate reflecting the rate of change of value over time, e.g., the future value in one year of $1.00 with a return of r is $(1 + r). The present value of a future $1.00 discounted by r is $\frac{1}{1+r}$.

Public offering - Refers to the general sale or offer for sale of securities such as stocks, bonds and debentures. The public offering of securities requires registration with the SEC.

QF - Qualifying Facility.

REA - Rural Electrification Administration (U. S. Department of Agriculture).

REC - Rural Electric Cooperatives.

Revenue stream - All the incoming cash generated by a trade or business over time.

Run-of-the-river - A hydro project using the flow of water in its natural, undiverted course.

SHPO - State Historic Preservation Officer (State).

Small issues exemption - An industrial development bond which, for reasons of the size of issue, qualifies for tax exempt status.

Subordinate debt - Debt which yields priority in liquidation to other (senior) debt of a business. Usually, such debt is not subordinate to general creditors, but only to senior debt owed to a financial institution.

Tailrace - The part of the millrace below the water wheel or turbine through which the spent water flows.

Tailwater - The spent waters at the lower surface of a dam or penstock.

Take or pay contract - A contract where the buyer must take delivery, at a fixed sum or price, or pay that sum. It is often, if not usually, used for the contract where the buyer must pay whether or not the delivery is made.

Tax credit - Credit against moneys owed on income tax.

USC - United States Code.

USDOE - U. S. Department of Energy.

USFS - U. S. Forest Service (U. S. Department of Agriculture).

USGS - U. S. Geological Survey (U. S. Department of Interior).