Low-Head Hydro

--An examination of an alternative energy source

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Moscow, Idaho
September, 1978

Introduction

by the Hon. John Evans, Governor of the state of Idaho

The great challenge for us today, as a state and a region, is to fashion a balanced energy future, making the most appropriate and reasonable use of all our resources. Low-head hydroelectric technology can give both public and private decision makers another very valuable tool to use in arriving at that critical balance for the future.

While nationally hydroelectric generation contributes only 15% of our electric energy, until very recently it had been the basis of the Northwest's energy resources. It has provided us with a clean, abundant, and ever-renewing source of power since the first small dams were installed before the turn of the century. But times today are different. It is apparent that both public and private utilities have almost come to the end of the era when great new high dams are either acceptable to the public or are worthwhile from a cost-benefit comparison. Although some new sites do remain, they are more expensive, harder to develop, and involve a whole series of complicated environmental questions.

It is also important to remember that national public policy has excluded the possibility of much hydroelectric development in the region by opting to preserve some rivers in a wild, free flowing state.

That combination of circumstances presents us today with several options in providing additional electrical supplies for the region. The most widely discussed course, and in many ways the easiest route, is to continue supplementing our hydroelectric generation with power from new thermal plants, using either coal or nuclear fuels.

Drawbacks of nuclear, thermal

That has been the direction the region has begun to pursue, and while it has provided power, some of its distinct drawbacks are today becoming apparent. Increased concern is being shown over nuclear plants, and much citizen sentiment is opposing the development of coal-fired facilities.

For both Idaho and the region, I feel a wiser and more prudent course is to maximize the potential of all our hydroelectric resources within reasonable environmental guidelines.

All existing high dams where the total generating potential has not been developed must be brought on line. In addition, a new scheme of regional power distribution is necessary. The current marketing practices of the Bonneville Power Administration deny access to much of our electric energy to many citizens. Those marketing and forecasting practices will work contrary to the best interests of the Idaho customers of private utilities, even if those currently empty penstocks in federal dams are equipped with turbines and generators.

The utilization of our low-head potential is necessary to complement other sources of energy. Low-head becomes more and more important as we increasingly realize that there is no one solution to our energy problems, but that a solution must be based on making the appropriate use of all resources at the appropriate times.

Low-head advantages

Low-head hydroelectric technology offers great advantages. Probably the greatest of these are its environmental acceptability, its flexibility, and its potential to keep electrical rates reasonable. Low-head installations do not inundate great stretches of our rivers; they can be tailored to meet local needs within the distribution system; and while the cost of thermal fuels escalates, the cost of a low-head installation, once built, remains relatively constant. The increased use of low-head hydroelectric technology also has the advantage of reducing pressure to develop new high dam sites in the face of environmental objections.

I have been very pleased at the progress that has been made in Idaho and in the region in developing low-head hydro. A number of significant events have occurred lately, perhaps the most noteworthy is the impending installation of bulb turbines at the Idaho Falls low-head sites.

Recently, the Boise Project Board of Control has received a grant to study low-head potential along its dams and canals, and the Idaho Power Co. has submitted several applications for low-head projects to the Idaho Public Utilities Commission. A series of those Idaho Power projects would be along the south fork of the Payette River in Garden Valley, and provide an acceptable alternative to flooding that beautiful valley with one large dam.

For all its advantages, there are still a number of barriers standing in the way of utilizing low-head technology as an integral part of our energy future in Idaho and the region. Those restraints are both technical and institutional. However, with a concerted effort they can all be overcome, and I encourage your efforts. I also stand ready to assist you, along with the Idaho Department of Water Resources and our Office of Energy.

No distinction

There is the critical question of permits and licenses. Although recently changes have been suggested on the federal level, there is virtually no distinction made between the various types of hydroelectric generating facilities when it comes to applying for licenses. Because of the complexity and delays of licensing, utilities are discouraged from applying for low-head permits because it entails as much effort as a permit for a major high-head project. There is a distinct need for legislation and new procedures that simplify licensing procedures for low-head projects, while continuing to provide adequate review and safeguards.

Low-head hydro is a once-obsolete idea whose time has come again. Low-head hydroelectric generation holds great promise for Idaho and the whole Pacific Northwest. I am sure that this seminar will be a very important step in making that promise into tomorrow's gift to our energy future.

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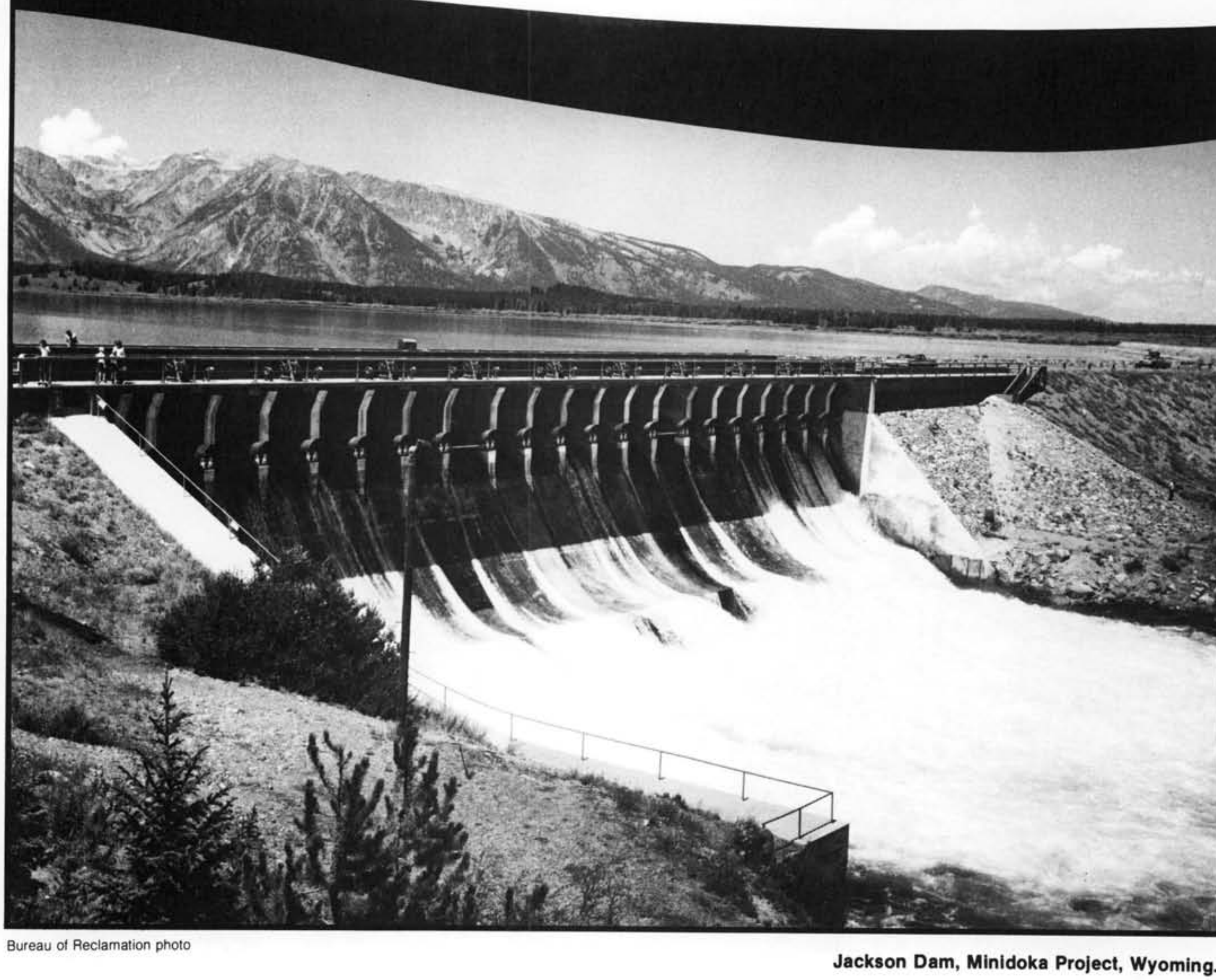
An Overview



Bureau of Reclamation photo

Jackson Dam, Minidoka Project, Wyoming.

The Impact of the World's Energy Problems on Low-Head Hydroelectric Power

by Ellis L. Armstrong

There are some basic fundamentals we must carefully consider in evaluating the energy problems of the world. First, let's look at the world's population. Today, we number over four billion. By the year 2020, barring catastrophe, according to the United Nations median projections, we'll number about nine billion, as shown in Figure 1. The OECD Countries (Organization for Economic Cooperation and Development) which are the industrialized free nations - Western Europe, North America, Japan, Australia, and New Zealand - now total about 18% of the world's population. By the year 2020, it will be about 11%. The Centrally Planned Countries U.S.S.R., Eastern Europe, China - now make up about one-third of the world's population and by 2020 will be one-fourth of the total. The Developing Countries, which are the remaining countries, now involve a little over one-half of the people in the world, and by 2020 will total about two-thirds. These six billion people of the year 2020 cannot be ignored if we expect to stick around very long.

Figure 2 shows the sharing of the world's gross national product; it is now about five trillion dollars a year. By 2020, median projections indicate it will be about four times as large - about twenty trillion dollars. (Both figures are in 1972 U.S. dollars). The OECD Countries share of the GNP is now 63%, and it will decrease to about 54% by 2020. The share of the Centrally Developing Countries will increase

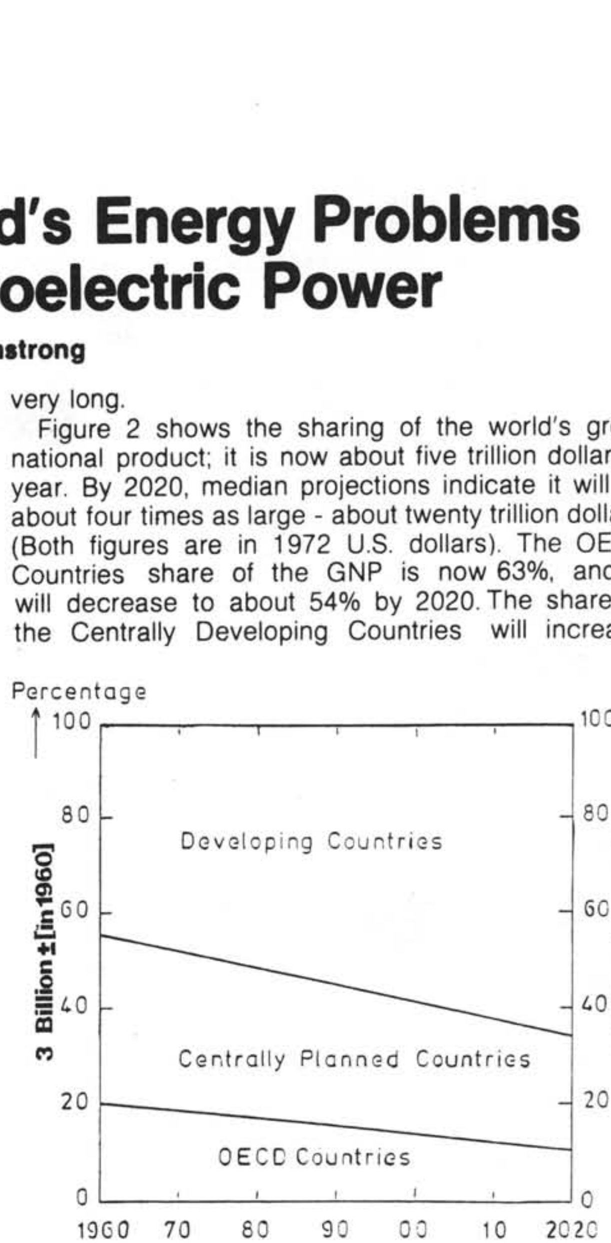


Figure 1. Population shares of world groups, 1960-2020.

Ellis L. Armstrong is a consulting engineer in Salt Lake City. He was the U.S. Commissioner of Reclamation 1969-73, chairman of the United States National Committee of the World Energy Conference, 1972-74, and chairman of the Hydraulic Resources group of the International Energy Conservation Commission of the World Energy Conference 1975-78. From 1958 to 1961 he was U.S. Commissioner of Public Roads, and from 1954-57 was project engineer for construction of the U.S. portion of the St. Lawrence Seaway.

He was an engineer with the government, in design and administration dealing with water, energy, and transportation, from 1934 to 1954.

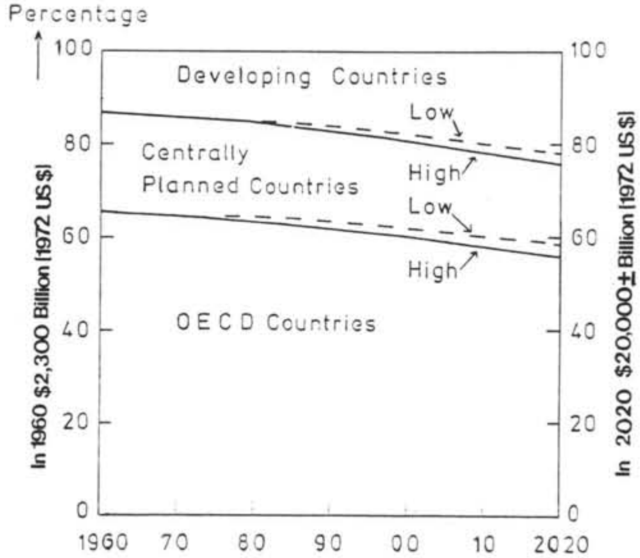


Figure 2. GNP shares of world groups, 1960-2020.

from the present 15% to about 25% by 2020. These projections are based on reasonably solving the energy problems. This may be too optimistic, but it does give a base for study.

The per capita GNP of each country varies almost directly with the per capita consumption of energy. This isn't surprising as goods and services are provided by the expenditure of energy. With adjustments made for the difference in topography and geography, the area per capita, and the differences in energy needs of the different products of the country, the relationships almost fit a straight line. While the United States consumes about one-third of energy expenditures today, it also produces about one-third of the world's goods and services.

Twenty years ago coal provided nearly half of the world's energy. Quantities have remained about constant since, but now account for only one-fourth of today's energy uses. In 1960, the world used about 60 million barrels of oil per day equivalent, and today this has increased to about 120 million barrels per day. Keep in mind, this includes all of energy sources measured in terms of oil equivalent. Most of the increase in total energy use has come from the increased use of gas and oil. We have become heavily dependent on oil, and that is our main problem. Today on a worldwide basis, we're using oil at the rate of about 60 million barrels per day.

When oil was discovered in Titusville, Pennsylvania in 1859, the problems encountered were somewhat similar to the problems we have today. Various extremist groups, the "Nadarites", "environmentalists" and "concerned scientists" of the day, were violently opposed to taking oil out of the 57-foot well. They claimed that it was there for a purpose, and that purpose was to fuel fires of Hell. If it were taken out, then the wicked would fail to receive the punishment they so richly deserved.

Upheavals

If there were unlimited supplies of oil, our energy problems would be limited. It is quite likely that oil production, worldwide, will peak out at about 80 million barrels per day about 1990, as shown on Figure 3, and then drop off rather sharply to half that production by the year 2020. The band on the chart covers the area of uncertainty on the basis of present data. You can see that the oil demand will exceed supply some time about 1990, less than 15 years from now, and this is but a little more than the lead time required to get a nuclear plant or a large coal-fired plant on the line. If other energy sources are not developed to fill the widening gap between demand and supply, we most likely will face drastic economic and social upheavals.

The data on Figure 3 illustrate what I consider the most likely eventuality barring world catastrophe. However, even considering adverse economic difficulties, the time when the demand exceeds that supply is only moved ahead about ten years. These analyses assume continuation of nuclear and coal-fired plants in line with the present plans. They assume increases in the efficiency and in conservation to the extent that the economy is not greatly affected adversely, and that the price for oil will remain at the present rate for another eight years, and then will increase to about $20 per barrel. There have been a large number of scenarios analyzed by the International Energy Conservation Commission, as well as other groups, and these projections appear most likely. You can see the wide gap between demand and supply that will be developing by the end of this century. While there are many uncertainties, these data reflect what I think are the best projections at this time.

False security

The chart also illustrates one of our present serious problems. You will note that the world now has the capability of producing about 20 percent more oil than is necessary to meet the demands. We have a temporary oil glut that gives a false sense of security that is misleading and tends to prevent positive action that is essential now if we are to avoid future chaos.

There have been a number of recent articles concerning natural gas that indicate there may be great reserves of this energy resource. Statistically, there are probable large reserves that have not yet been defined. However, they are mainly in remote areas such as the desert sand areas of the Middle East, or the Arctic. Costs of developing and transporting the gas from the remote areas will probably be prohibitive for decades.

The situation in regards to coal presents problems of magnitude also, even though we must depend primarily on coal and nuclear fuel to fill the gap as oil and gas reserves are exhausted. The extraction of coal requires high technical efforts as well as high expenditures of both capital and labor. On a worldwide basis, it doesn't appear likely that the coal producing countries, such as the United States, U.S.S.R., Poland, and Germany will be able to do much more than meet their internal demands, let alone the needs of other countries. Preliminary data indicate that only Australia will be able to export appreciable quantities of coal. Liquefaction and gasifaction of both mined and in situ coal offer some help, but many technological improvements are needed to reduce costs.

Figure 4 illustrates the recoverable energy available from the exhaustible energy resources in the United States. It shows that coal and uranium, with some help from oil shale, will need to fill the gap as the oil and gas reserves are exhausted, and while other sources of energy such as nuclear fusion, solar, biomass, and geothermal are brought along to commercial production on a scale that will have appreciable effect.

Problems with uranium

The light water reactors operating on a once-through cycle with uranium as the primary fuel, are a commercial reality and are now contributing 3% to 4% of the world's electrical supply. The problem with uranium is illustrated by the United States' situation. The best estimates of uranium resources indicate the supply is adequate to fuel the present nuclear plants and those that can be brought into production by 1990 during their lifespan of about 40 years. Beyond that there are serious uncertainties regarding the supply, even though the problem has received extensive study. Only a small fraction of the available energy — less than one half of one per cent — is obtained from the fissioned uranium in the once-through cycle. Completing the nuclear fuel cycle with enrichment and the breeder reactor, could provide fuel for several centuries, as indicated on Figure 4. For instance, the fissioned once-through uranium already in storage at Oakridge contains more energy than all the coal reserves in the United States.

Statistically there is a lot of uranium yet to be discovered, but it is mostly well underground and difficult and expensive to locate and develop. Most experts are convinced that the breeder reactor is a must, especially for those countries which must rely almost entirely on imports of energy, such as Japan and Western Europe. The big concern with plutonium and its control is one of the areas that does require continuing attention. However, I believe the risk here is far less than the alternative of energy shortage.

In considering other energy sources, such as geothermal, we must keep in mind the magnitude of the energy needs and the long lead time that is required for commercial production of consequence. Solar energy will make a contribution in space and water heating and provides some hope for generation of electricity. I saw some figures the other day that if mirrors covered the state of Arizona so that the solar energy could be intercepted and converted into electricity, by the year 2000 it would supply less than 10% of the electricity needed in California. I haven't checked these figures out, the efficiency assumed appears questionable, but this does indicate the magnitude of the problem.

Nuclear fusion has developed to the bench-model stage with control of the plasma by magnetic means or by laser beams. The big problem is containing the one hundred million degrees centigrade temperature necessary for fusion. Lithium is the key immediate fuel, (lithium converts to tritium, and tritium and deuterium interact to produce energy) and presents engineering problems that are formidable. It appears that the earliest commercialization will be about the end of this century. Then perhaps another 50 years will be required to

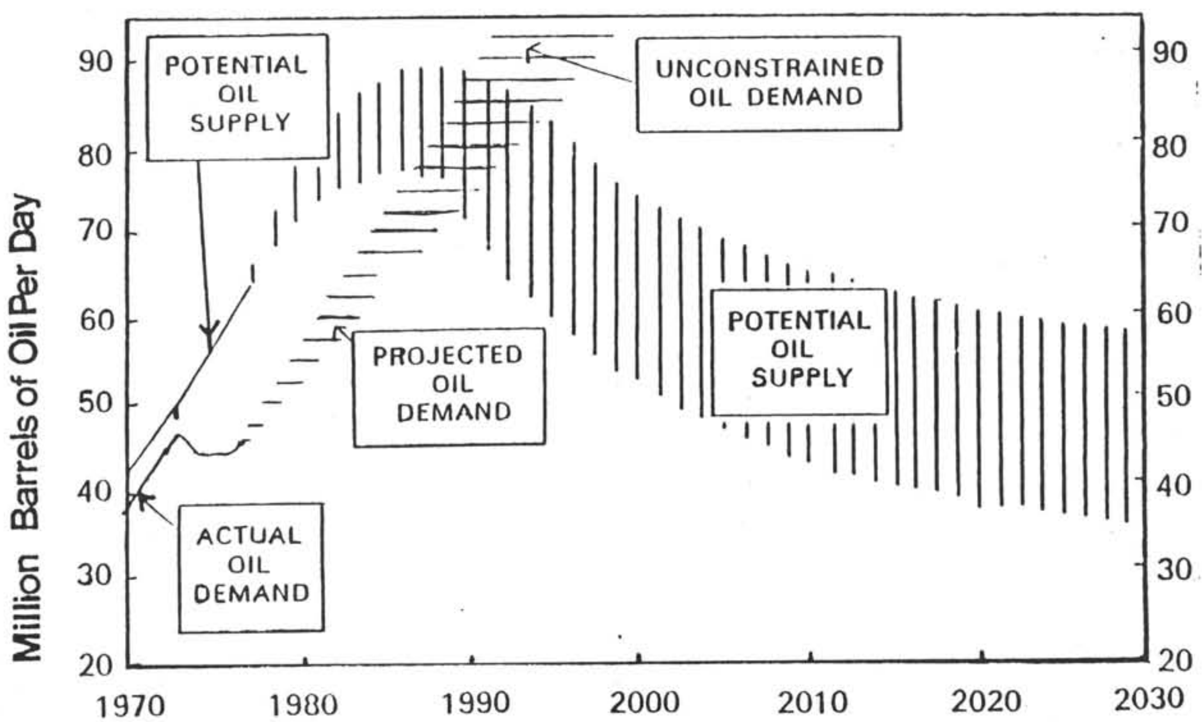


Figure 3. Potential oil production compared to worldwide demand, 1970-2030.

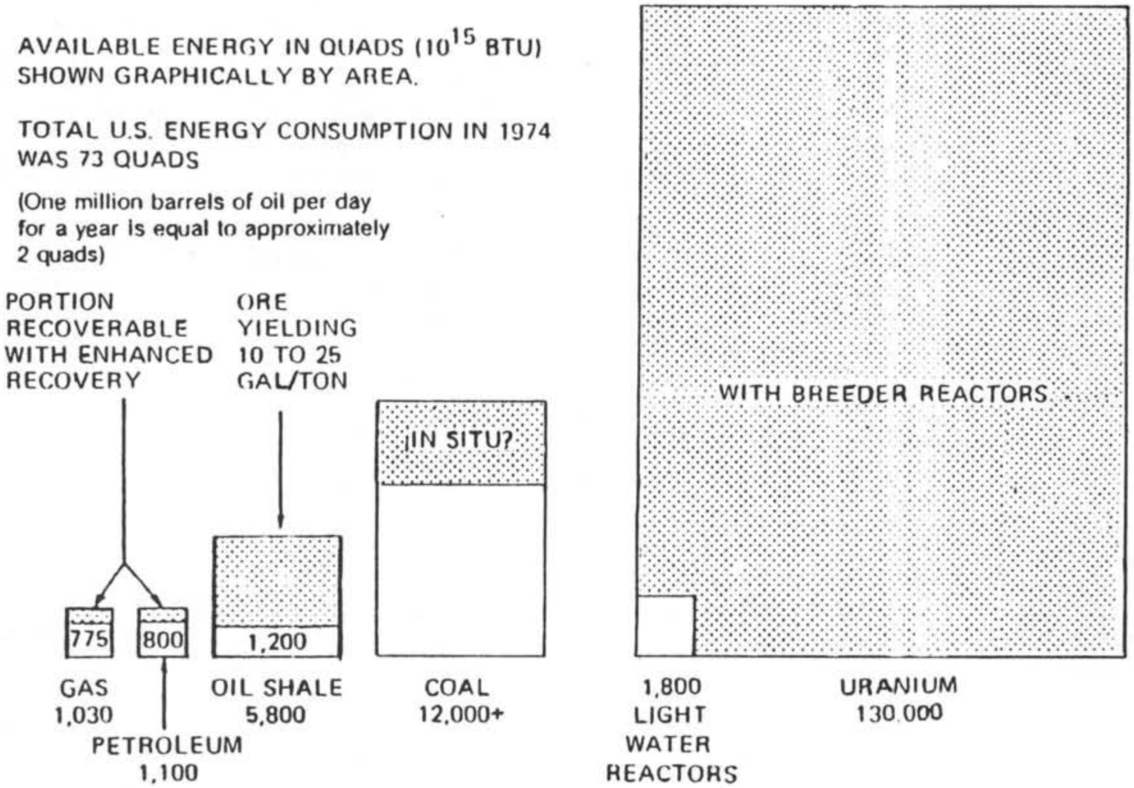


Figure 4. Energy available from the exhaustable energy resources in the United States.

directly utilize deuterium, the isotope of hydrogen, which is a component of sea water. When and if we get to that point, and I believe we will if our civilization stays intact long enough, then our energy problems will be solved.

Other energy sources, such as wind, biomass, ocean temperature gradients, and tides can make contributions, but appreciable commercial production from these sources is limited, and many decades ahead. All this makes necessary the fullest use possible of the hydroelectric potential.

The message of the various Conservation Commission study groups is that positive decisions and appropriate actions are required now to avoid the risk of serious energy deficiencies within the next two decades and beyond. While the forecast is not doomsday, it does require successful action towards conservation and efficient use of energy along with vigorous development of all forms of energy supply. And this applies to the maximum utilization of the continually renewable hydroelectric energy, and full consideration of low-head hydro development.

Hydroelectric energy

At present, hydraulic energy provides about 23 percent of the total electrical generation on a worldwide basis. The installed capacity is now approximately 375,000 Mw, which is about 17 percent of the total potential likely to be developed as reported in the 1976 World Energy Conference survey of energy resources. Figure 5 illustrates the hydraulic resources of the various areas of the world that are now producing electricity, the amount under construction, and the total potential that is considered likely of development. This latter amount of 2.2 million Mw, at 50% plant capacity factor, is about 12 percent of the total hypothetical, world gross potential, which is the total energy in all stream flows if it were developed with 100 percent efficiency.

The study of the Conservation Commission estimates that by the year 2020 the amount of hydroelectric power developed will be about 5 times the present capacity, about 80 percent of the identified installable capacity. The increasing cost of energy fuels will make more hydroelectric projects economically attractive that previously have been considered unfeasible. This is especially true of low-head hydro. However, counteracting this will be the concern for free flowing rivers which has recently accompanied growing affluence, the developments in potential reservoir sites that will make them unavailable, and the increasing requirements for water to serve functions which preclude generation of power.

In the United States, hydroelectric generation now provides about 15 percent of the electricity used. A total of 1,430 hydroelectric power plants include approximately 60,000 Mw of conventional generating capacity and 10,000 Mw of pumped storage capacity. The conventional is 35 percent of the total hydroelectric power considered developable in

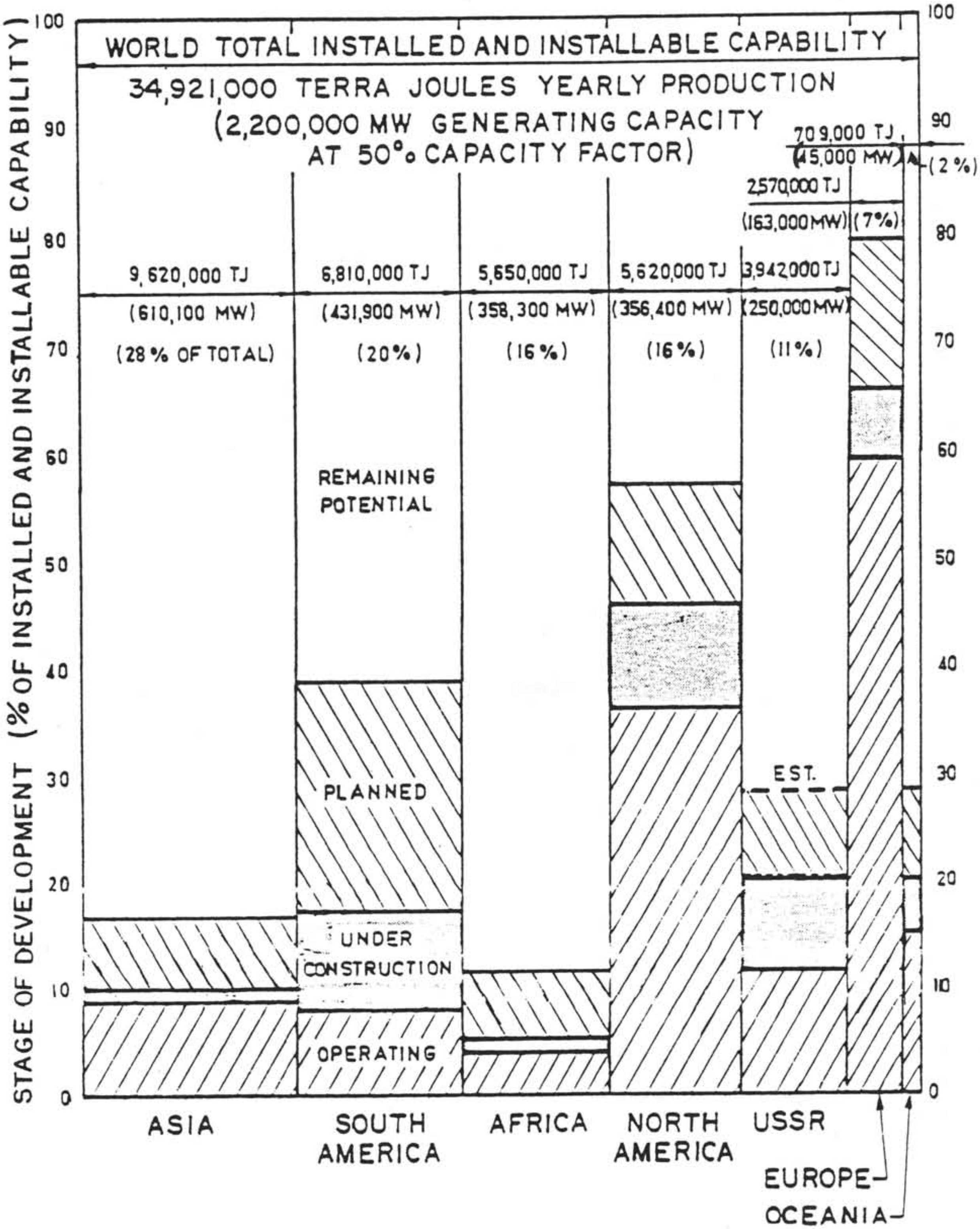


Figure 5. World hydraulic resources.

plants greater than 5 Mw. It is expected that by 2020 the amount developed will at least double, especially if low-head hydroelectric generation increases as expected.

Advantages of low-head hydroelectric power

Low-head hydroelectric energy is a non-polluting resource continually renewable by the energy of the sun creating and sustaining the hydrologic cycle. No heat is released, and while reservoirs can create problems, they are minimized with low-head installations. With balanced management they can be an enhancement, and where existing dams are renovated as part of the development, small-head hydro can be a major plus to the existing environment. Its long life and the low operation and maintenance costs, especially with present-day remote control facilities, make it essentially inflation-proof.

It can be a catalyst in the economic development of remote areas. In such areas, when the quantity of power produced is small, operations can be quite simple, and thus local labor can generally be utilized with a minimum of training. Generally, local materials can be used for most of the construction. Also, the time to construct a low-head plant and put energy in the line is about two to four years depending on the size and complexity, and thus can be pushed to meet immediate needs.

Further, the full utilization of low-head hydroelectric energy in remote areas can be enhanced by the improving technology for energy storage. In the past, batteries have been utilized. A much more efficient way appears to be using the energy by means of an electrolyzer to break water down into hydrogen and oxygen. The hydrogen can then be used as a fuel for heating, lighting, or operating combustion engines or, by means of a fuel cell, used to provide electricity during peak demand periods. The oxygen produced has many uses also.

The reliability and flexibility of hydroelectric power make it adaptable for injection into an existing large distribution system, and as an emergency source if and when the large system encounters problems. The technology is proven, although some improvements can be expected which will reduce costs. It can be an integral part of optimum utilization of water resources in a river basin.

Development of low-head hydro power

In the United States, as in most other countries, the Industrial Age began with low-head hydraulic power utilized to operate thousand of grist and lumber mills, and then various factories. The water energy was used directly at the site by mechnical hookups to waterwheels of various types. Many of the towns and cities in the Northeast grew up around these mill sites. Abount 1850, turbines, such as the one developed by James B. Francis, began to replace the overshot and breastwater wheels, and as demand grew for power, water was brought by canals to the point where power was to be used.

After 1860, water power development lagged as suitable sites within the limitations of mechnical power transmission were mainly developed, and the more flexible steam engines were being improved in dependability and economy. With the advent of electricity in the 1880's, the flexibility of electric power became evident. America's first hydroelectric plant was a low-head installation at Appleton, Wisconsin, built in 1882, and produced 12.5 kw from a direct current generator driven by a small vertical turbine. Developments followed rapidly and most of the waterwheels were converted to generating electricity.

During the 1930's and 1940's, the economy of scale of large generation plants, generally powered with fossil fuels, made small hydroelectric plants less attractive economically, and many of the older and smaller plants were abandoned. For instance, in the New England states, over 800 small dams which have been utilized for power generation have been abandoned or are in varying degrees of disrepair. Further, potentials for hydroelectric generation at many dams being constructed were not developed. A recent study by the Corps of Engineers' estimated that about 55,000 Mw of additional capacity could be developed at existing dams; of this total about 27,000 Mw are at sites with potential less than 5 Mw, generally low-head.

Other than the electrification of the early waterwheel mill sites, primarily in the New England states, the development of low-head hydroelectric power has received little attention in the United States. Hydropower development in the west and south has received input primarily from the large Federal water resource projects, such as those of the U.S. Bureau of Reclamation and the Tennessee Valley Authority. There have been only one or two firms involved with manufacturing low-head turbines and related equipment. However in Europe, low-head hydroelectric development has been utilized extensively and there are a large number of firms involved in providing equipment. The World Energy Conference energy resources data indicate that China has developed over 50,000 hydroelectric installations during the past decade, with an average capacity of less than 50 kw.

The present world energy problems, with declining finite energy fuel resources, has put new and greater emphasis on renewable energy resources and this is expected to impact favorably on the development of low-head power. Economics are becoming more advantageous, and obligation to provide energy from non-polluting, renewable sources, wherever possible is becoming greater.

Problems of low-head hydroelectric developments

Major deterrents to the development of low-head hydroelectric power in the United States include: economic problems, high cost of fulfilling numerous requirements of regulatory agencies, difficulty in obtaining permits, the need for hydrologic information to determine power potential, water rights and various laws making hydroelectric development difficult to achieve, other conflicting demands on the water supply, lack of standardized equipment that would reduce costs, and difficulties in providing a dependable market for the relatively small quantity of power produced. While these difficulties vary widely depending upon specific locations, most of them can now be resolved in light of the present world energy problems.

Potential developments which have been ruled out by economics in the past now must be reevaluated. The economic determinations made by comparison with the least-cost alternate sources, because of future uncertainties, are commonly evaluated at current levels for both capital and operating costs. Such an approach is against hydro, with its high capital costs and low operating costs, and usually favors thermal alternatives which have lower investment but much higher operating costs. At present, an oil or coal-fired generating plant just being completed will cost about $400 per kilowatt. A hydroplant to be considered competitive must cost about $1800 per kilowatt or less, depending upon the overall specifics.

The shortcomings of present analysis methods are illustrated by Figure 6. If the cost of fuel oil was $20 per barrel at the time a plant started into operation, and this is likely to be the cost by the time a plant, starting with planning now, will encounter when it is ready to operate; and with an escalation of 5 percent per year in the cost of the fuel, then the value of a hydroelectric kilowatt would be about $3,400 more than that of the oil-fired kilowatt. This is based on 8% interest and a 35-year life for the thermal power generating station and 50 years for the life of a hydro plant.

A recent study indicated that a new thermal plant

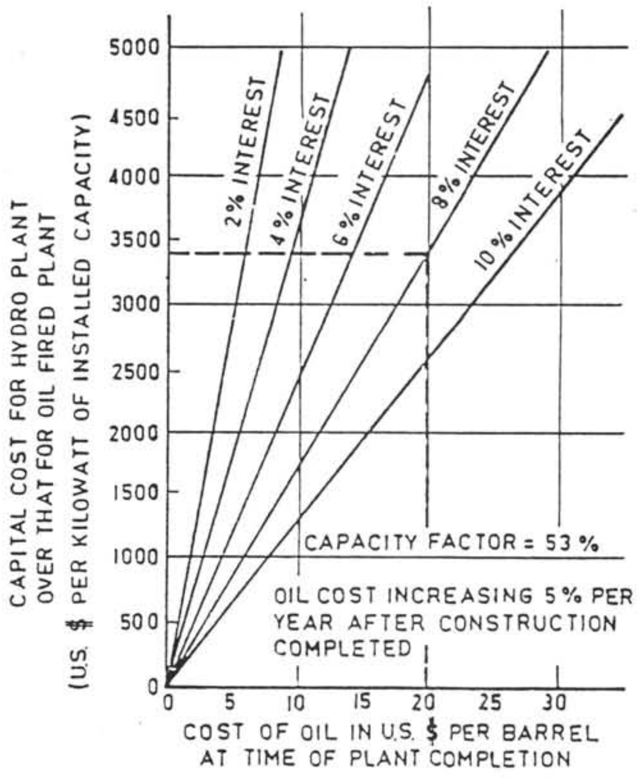


Figure 6. Additional capital costs economically justified for a hydroelectric plant over that of an oil-fired electric plant with different oil costs and rates of interest for financing.

starting into the planning stage now, will cost about $900 per kilowatt by the time construction is completed. The chart is based on the same capacity factor for the two comparison plants. While oil-fired and hydro plants in an electrical system would likely have differing load curves, for a specific plant the comparison is valid, although with lower capacity factors, the differences will not be as great. Differences in cost of operation and maintenance, lower with hydro plants are considered in the chart, but they along with all other factors must be considered in a specific site analysis. While the chart is simplistic, it does emphasize the need for a different approach on our economic analysis that takes inflation into account. Further heavy weighing must be made in favor of an energy source not using finite fuels.

Cost reductions will result from simplification and standardization of equipment that will promote mass production; from possible decrease in complexities of constructing waterways, and from improvement in turbine and generator designs making full use of low-head technology developed in Europe. The front-end cost of engineering can be reduced by standard-type plans, adapted to a specific site.

Efforts are being made by various governmental agencies to reduce the effort involved in licensing low-head hydroelectric projects. Certainly low-head small projects don't justify the same extensive and lengthy submittals of the largest developments. There are occasional indications that reason may prevail, but much remains to be done with various institutional constraints.

Present day hydrologic data generally are readily available from the federal Geological Survey working in cooperation with various state agencies. Water-right problems are complex, but generally adjustments are likely to be worked out in the overall public good. Sound, factual information is a requirement. In some areas legislation may be needed and such areas need to be identified early. At any rate, it is becoming increasingly important that utilization of water resources must be multi-purpose in nature.

Marketing the power from low-head generation has problems, but it is essential that equitable arrangements must be worked out. This requires a cooperative approach by all concerned.

Low-head hydroelectric programs

The changing economic situation with hydropower is receiving attention in industry and in government. Utilities are reconsidering small plants that were being planned for phase-out, and are reevaluating potentials which had been ruled out in the past. Equipment manufacturers are examining the potential market, and one large manufacturer, Allis-Chalmers, has developed a series of standardized units to be competitive with European equipment.

The U.S. Department of Energy has launched a series of workshop-type conferences, beginning last September in New Hampshire, followed by one in Wisconsin in May and this one in Idaho in June (1978). One in southern California is planned for this fall.

Proposals for studies of potential low-head hydroelectric facilities to be added to existing dams have been received and evaluated by the Department of Energy and 56 contracts are being let, covering a wide variety of problems and a wide geographic distribution across the nation. Various problems which will be helped by demonstration projects are being identified and a nationwide demonstration program is being formulated.

A state-of-the-art study of European turbine generators is nearing completion and should be available soon. An extensive survey of the low-head hydroelectric potential of the Columbia River Basin is underway and is expected to develop and test methodologies that will be helpful in similar studies across the nation. The initial preliminary study of the nationwide low-head hydropower potential by the U.S. Army Corps of Engineers is being updated, broadened to cover new sites, and refined. The U.S. Bureau of Reclamation is conducting studies on methods of marketing low-head hydropower; a design of interties; on pre-cast structural modules in dams and waterways in connection with low-head hydro; and on the practical lower limits of low-head installations. Most of the funding for studies underway is being provided by the Department of Energy.

National energy legislation is expected to be passed by Congress soon that is expected to provide substantial funds to support the front-end engineering studies and licensing requirements and also provide loan funds for construction of feasible projects. It is expected the legislation will provide $330 million over a three-year period. All of these activities will have a positive effect on furthering the use of the low-head hydro resources.

While the amount of electricity generated from lowhead installations is a small percentage overall, its importance is much greater. About 660 kwh at a hydroelectric plant almost anywhere, will reduce the requirement for oil by one barrel, or its fuel equivalent. The World Energy Conference study emphasizes that utilization of all energy sources, especially those not using finite fuels, must be vigorously pushed. Low-head hydroelectric potential is now receiving deserved attention, and considerable development can be expected over the next few years.

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The Role of a Private Utility in Production of Energy

by Wendell J. Satre

I have been asked to discuss with you the role of a private utility in the production of energy. We should probably define what we mean by utility for purposes of our discussion. Because the subject of this seminar obviously is related to the production of electric energy, we shall, for the most part, limit our discussion to electric utilities. Here in the Northwest we have investor-owned electric utilities and public agencies operating side by side and most of our discussion today will be applicable to either the investor-owned utility or the public agency providing utility services. However, later I shall discuss some differences between the two types of utilities, but basically we all face similar problems today.

With the types of problems which have been created for us today, many of them by laws and regulations, but some obviously supported by our customers and the public we serve, we sometimes wonder what really is expected of us and it is appropriate that we examine the role of the utility in today's society.

Last Sunday was a beautiful day and I walked to church. I passed a rather modest home where a group of children were playing in the front yard. One of the group was a little boy, probably three years old, sitting on his tricycle near the sidewalk. He was a handsome little, round-faced fellow who showed a row of short, white teeth when he smiled. As I passed by, he looked up at me, smiled and said, "Hi". I responded and walked on. With the picture of that carefree little boy imprinted on my mind, I began to wonder what kind of a future was in store for him. Coming from a family of modest circumstances, would there be sufficient financial capability so that he could acquire an education? Would his environment provide the necessary incentives? Or regardless of his educational achievements, would he be able to enjoy the relative standard of living we enjoy today? Then my mind turned to my responsibilities and how they may be related to his future. Would he be required to live in an energy-short world? If so, would it be because of depletion of resources or would it be because of artificial restrictions imposed by laws and regulations? If the adequacy of energy supplies is insufficient for him to enjoy our level of standard of living, who is at fault? And who will be blamed? There is no doubt in my mind that, if someday in the future you flip the switch and there is no electric supply to respond to your wish, utilities will be blamed.

Historically, the traditional role of electric utilities has been one of service. Over the decades we have established systems and supplies capable of carrying the loads imposed on them by our customers almost 100 per cent of the time and with hardly a flicker in voltage level. We were always there when demanded and not only were we ever-present but at ever decreasing cost until even that became a tradition, one which is hard to overcome in the minds of our customers.

The blackout

Then, in 1965, a blackout occurred throughout much of the Northeast. People across the nation became aware that electric service could be interrupted, that it wasn't magic, that even with the degree of sophistication present in 1965, it was still possible to be momentarily without energy supply. That blackout created such alarm in the minds of many of our regulators, that new regulations were imposed on the industry, regulations and reporting procedures that are still in place today.

Because electric utilities, too, purchase materials and hire labor, we have been afflicted by that horrible monster, inflation, and universally across the nation, it has been necessary to seek rate increases. Many utilities which use fossil fuels for creating their energy supplies, particularly petroleum, were faced with rapidly escalating costs in fuel supply, much of it outside the control of anyone in our own nation because the world price of oil was established by an international cartel. So the traditional role of the electric utility was perceived by many people to have changed, changed to a lower quality of service at higher cost. Actually, the quality of service remains as high as ever — instant communications just makes more people aware of problems when they do develop — and electric service is still the best value in the household budget.

The household slave

Let us examine for a moment the uses made of electricity in the average home. Lighting immediately comes to mind and while it is a very important use, it consumes a minor part of the total used. In the average home, particularly in the Northwest, we will cook your food, run your refrigerator, do your washing, dry your clothes, do the ironing, vacuum the floors, heat the water, provide entertainment in the form of television and radio, keep you on schedule with your electric clocks and perform a whole host of other miracles by operating the many appliances which you plug into the ever ready receptacle. Recently I counted up to 70 motors in my own home and it is not an ostentatious home either. I do have a little woodworking shop and, of course, there are motors driving drills and saws. If you count the motors in your own home, don't forget the clocks, the stereo, the refrigerator, the garbage disposer, the timeclock on your electric range, maybe the garage door opener and the furnace fan. Throughout the Northwest, electric heating is widely used. Add up all of those uses, including some for electric heat, too, and we will do all of that work for you for only about 2 per cent of the household income. The average household spends three times as much for recreation as they spend for electric service.

If you compute the actual physical capability of a human, the amount of electricity that we use in our homes today is equivalent to the output of almost 200 people per home. That is almost impossible to believe but even in the most humble home, it is easy to conceive that the electricity used performs jobs equal to at least fifteen or twenty slaves and electric utilities provide that kind of service for 2 per cent, or about 1/50th of one person's income. That is the traditional role of the electric utility. That is the role we are playing today.

Government as adversary

Over the years the utility role has not been one of partnership with government. Today when there should be a maximum of cooperation in order to provide the necessary energy supplies, government has become an adversary. From the time Edison first developed the electric lamp bulb almost one hundred years ago, technical development in the industry has been almost entirely by private business. Government has played almost no role in the improvement of technology, in the reduction of costs, and in the improved quality of service. Only in recent years has government made any contribution at all toward development.

Some forty or more years ago, perhaps stimulated by the great Depression, publicly owned distributors of electric energy began to develop at an increasing rate. Some people perceived that if their utility supplier could be relieved of the payment of taxes, if it had lower financing cost due to a capability to issue tax-free securities, and particularly if it could be the beneficiary as a preference customer of low-cost federally generated hydro power, then surely that would result in lower electric rates to customers. The Federal government stimulated the formation of public agencies for the distribution of electricity. The Tennessee Valley Authority was created and their subsidized rates were held up as a yardstick against which all utility rates were to be measured. For a time it appeared that perhaps the investor-owned utility would disappear and the plank in the Socialist Party platform which called for government ownership and distribution of electric supplies may be realized.

Maybe it was because improving technology made it possible to continually reduce rates; maybe it was because the growing affluence in our society created a quieting effect; or maybe it was because people began to recognize the substantial benefits of privately owned business — at any rate for many years the desire to create new publicly owned power systems seemed to subside. Now new conflicts are developing, stimulated by increased rates made necessary by the inflated costs of doing business.

Costly environmentalists

Previously I mentioned that electric utilities today are facing problems seemingly insurmountable. Our

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biggest problems are associated with the creation of new electric supplies. The ability to construct large hydroelectric projects has been almost eliminated, partly because many are already developed and partly because of increased environmental concerns. A good example of the latter is the proposed development of the Middle Reach of the Snake River between Idaho and Oregon, which a group of our companies sought for over a period of twenty years. Finally, an act of Congress precluded development in favor of retaining the area in its pristine state. At the time the Act was passed in Congress, I calculated that the difference in cost of energy created by the Middle Snake Project and the lowest cost alternative meant that customers of the utilities in the Northwest would be subsidizing the trip of every visitor to the canyon in that area to the extent of $10,000 per trip. Now it may be worth it — maybe our customers want to do that. I am not in position to make that judgment but I believe that is the type of judgment that our people should make — that they should have the information available to them so that they can balance the effects of development versus nondevelopment and not be stampeded into an attitude of preservation just for the sake of preservation.

We are not finding it much easier to develop new electrical supplies by using coal as a resource. Government legislation and regulation have made it difficult to mine coal and in some cases the leasing of coal on Federal lands has been stopped by edict. Even if mining the coal is possible, burning it is made extremely difficult by laws and regulations.

Delay at $400,000/day

I should like to cite an example: The Colstrip No. 3 and No. 4 Project is a project in eastern Montana in which five Northwest electric utilities are involved. Applications for permits were made in 1973, about five years ago. We still do not have the necessary permits to proceed with construction and there are continuing delays by litigation in both state and Federal courts. At the time we applied for permits, the estimated cost of the project was approximately $400 million. Today the estimated cost is between $1.2 and $1.4 billion. If you're interested in calculating the escalation in costs over the five-year period, you will find that the cost has escalated more than $400,000 per day. That is per day, not per week or per month. This is Wednesday noon. At that same rate, by Friday night this week the project would have escalated another $1 million. We now have over $100 million invested in the project and we still do not have permits to proceed with construction.

Utilities have experienced similar difficulties in the development of nuclear power stations. Some people still believe that a nuclear power plant can explode just as did the bomb which we dropped on Hiroshima in World War II. A nuclear power plant cannot explode. Nuclear power stations have the best safety record of any device ever built. Not one member of the public has ever lost his life due to the operation of a nuclear power plant. Nevertheless, people are still concerned. People are concerned about the handling of the waste product and I believe the government long ago should have made a decision on the handling of waste material. Of course, there was good enough reason to postpone a decision because the quantity of waste material is so small that it was not unreasonable to plan to store the material, awaiting the development of new or improved technologies for the utilization of waste. Today the public is demanding a decision and the assurance that nuclear wastes can be stored without danger. I believe that nuclear wastes should be stored where they can be retrieved because I am convinced that new technological developments will make it possible to extract a higher percentage of the energy left in the waste products and it would be a shame to dispose of them in a manner which would make their retrieval impossible.

Intervention run wild

Because of these concerns and because our loosely drafted laws permit, nuclear plants have been delayed interminably. Other nations can build a nuclear plant in five years. It takes us twelve years. Something must be done to limit the interventions, to limit the delays which can result through legal maneuvering or costs will continue to escalate but the more critical result will be that our ability to carry the increasing loads imposed on our systems will rapidly diminish.

Today utilities are being criticized from every angle, accused of inflating their load forecasts in order to justify the construction of more power plants. I assure you that we do not, and I repeat do not, inflate our load forecasts. Utilities desire to build only the plants necessary to satisfy the requirements of our customers.

Historically, we have done a good job estimating loads. I believe utilities today are better able than anyone else to estimate the loads of the future. Our estimates, of course, will be wrong — so will all other estimates. We are dealing with new factors today, the factors of conservation and price elasticity. We are doing the best job we can, trying to anticipate the extent to which our customers are willing to conserve. We are trying to determine price elasticity; that is, how much will consumers reduce their use as price increases? We are approaching these problems with all sincerity. We use econometric models, too. A model is only as good as its inputs. There can be honest differences among us as to what values should be used for the various inputs. But we also have tried to weigh the results of overestimating versus underestimating. If we overestimate and find that we are wrong, we can slow down construction or at worst, we may have to carry the costs of a plant for a year. But if we underestimate and do not provide for the requirements of future customers, we will not be able to provide the necessary power for the economic development which means jobs for our young people joining the work force. Today we are prone to consider only the costs of doing something. We seldom balance those costs against the cost of doing nothing.

The result?

The managers of utilities today are beginning to wonder, "What should be the extent of our effort?" When it becomes obvious that costs are escalating dramatically due to delay, when it is obvious that some of our customers want no growth and use every tactic available to impede construction, when it is obvious that governments continue to impose increasing numbers of roadblocks, should we quit in the face of such opposition? I can assure you that there are times when the temptation is great. Then, we ask ourselves the question, "What will be the result? What will happen when the lights go out? Will there be chaos? Will there be rioting because of high unemployment rates? Will there be demands to nationalize the electric industry because of our failure to provide service? The results of failure are unacceptable. We must find the means of providing the supplies necessary to create jobs for our children as they mature.

Utilities — public and private alike — have what is known as a utility responsibility. We have the responsibility and attempted to acquire fuel supplies of to anyone who applies for service. We do not have the authority to pick and choose, the authority to determine who needs how much or the authority to deny service if we think the proposed use is frivolous or not of high priority. Utility managers do not treat that responsibility lightly. In many cases, we have gone beyond the normal responsbility and attempted acquired fuel supplies of our own in order to assure service to our customers.

In addition to acquiring fuel supplies, most utilities, public and private, are contributing to the Electric Power Research Institute to conduct research on a national and coordinated basis for maximum efficiency. Current programs of EPRI call for the investment of approximately $180 million a year. Many gas utilities are carrying on similar programs, programs of exploration and development to find new supplies to serve their customers and, as an industry are involved in research programs through the Gas Research Institute. Gas utilities are also building storage projects to provide more efficient utilization of the supplies available. Frequently, regulatory bodies take the short-range viewpoint and discourage utilities from performing these functions, ignoring the long-term benefits of assured supplies.

A fork in the road

Maybe we have come to the fork in the road. Do we continue our traditional role or do we abandon the concepts that have built the most reliable and efficient electric system in the world?

A traveler in Texas came to a fork in the road. There were no signs and as he sat there wondering which fork to take, a cowboy rode by. He told the cowboy, "I'm trying to get to Silverton. Does it make any difference which road I take?" The cowboy replied, "Not to me, it don't." Too many people are like the Texas cowboy — they are unconcerned about the route we follow today. There are two paths available to us. We can remove roadblocks, making it possible to continue to develop and provide the supplies our people will need or we can continue to create obstacles making it more difficult until the public will call on the Federal government for the solution.

There is a vast difference in the approach taken by private business or by government. Government has a "can't do" approach. We see the results of that philosophy in the present energy legislation making its way through the Congress. Most of the legislation is negative. It imposes additional controls. It assumes no solutions. There is one positive aspect of the legislation and that is the deregulation of natural gas. But, basically, government adopts the "can't do" approach, imposing regulations and restrictions rather than providing the incentives necessary to solve the problem. Such an approach can only result in higher cost. Asking the Federal government to do a job that we can do for ourselves is like giving yourself a blood transfusion from one arm to the other through a leaky tube. Giving the government an opportunity to expand bureaucracy cannot possibly result in a better, more efficient process. Furthermore, if the Federal government gains control of the electric industry, they will have control of the means of production throughout the country.

The 'can do' approach

Private business adopts the "can do" approach. The "can do" approach means solutions. It means incentives. It means lower costs. The profit system is still the best incentive to achieving more efficient operations and lower costs. The role of government should be the role of watchdog and the role of providing assistance to private business. Private business means improved technology and technology is the best tool we have available to us today to solve our energy problems.

If government becomes the sole supplier of electric energy, who will present a second viewpoint? Therefore, we can only conclude that the role of the private utility today must be the same as the role it has played in the past. In order for it to play its role efficiently, for the business to remain healthy, to enable it to provide the service required to fulfill its responsbility, we must remove the roadblocks in the way today. In the decision-making process we must balance development versus environment. We must support technological development. Technology is not dead. How many of you ten years ago would have conceived of wearing a digital watch today or how many of you could possibly have conceived of a multi-functional electronic calculator you could carry in your shirtpocket? The American people have not lost their capability. If we can develop the technology to put a man on the moon in a few short years, we can develop the technology to solve our energy problems if given the opportunity. If we are given that opportunity, the private electric utility will continue its traditional role of efficient service at low cost. I think that is what our customers want.

Low-Head Hydro and The Energy Problem

by Norman M. Clapp

After this first day of intensive examination of the many detailed aspects of low-head hydro-electric potential, technology, and feasibility, perhaps it is both appropriate and useful to step back for a moment and take a look at its place in the larger picture of our national energy problem. It is that relationship to our national energy needs which accounts for the revival of public interest in the potential development - or redevelopment - of such hydro installations. That is really why we are here at this seminar.

Let me commence with what I would assume to be some self-evident truths about energy.

First, an adequate supply of energy is essential to a standard of living or quality of life which is acceptable in terms of present-day expectations. Mechanical energy is a multiplier of human labor. The farmer who today produces enough food for 56 persons with the help of mechanical energy in one form or another would scarcely be able to keep himself and family alive if he had to rely entirely on the unassisted human exertions he and his family could supply. The same is true of the factory production worker.

The heat which is produced in the release of energy is likewise not only essential to human comfort and well-being, but an essential factor in the production of goods and services. The gross national product is directly and highly correlated to the supply of energy used.

Second, it follows that the economic growth necessary to provide for a still-expanding population, as well as the release of sizable portions of our society from poverty levels of existence, will require increased supplies of available energy.

More Energy Required

The exact rate of energy usage necessary to support any given rate of economic growth with sound conservation is the subject of some debate among the statisticians, but the overwhelming preponderance of expert judgment concedes that economic growth will require some measure of increased energy supply.

I dismiss from serious consideration the position of some that we can dispense with further economic growth. This is a callous, elitist notion, which if seriously intended, is totally insensitive to the needs and aspirations of the vast majority of American people. If seriously implemented, it would produce social stresses which would, in all likelihood, tear the political, economic, and social fabric of this nation to shreds.

Finally, the role of energy is so vital to our standard of life, the stability of our society, and the security of our citizens, we must be careful to provide not only a level of supply equal to current needs, but one that will provide for a prudent safety margin or reserve to cover

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contingencies.

What is our present energy situation, and what do we have in prospect for the future?

We in the United States, some 215 million of us, presently consume annually more than 74 quadrillion BTUs of energy. This is the equivalent of 13.5 billion barrels of oil, or in electrical terms, the equivalent of 7¾ trillion kilowatt hours. Of this total usage, 47.3 percent is drawn from oil, 27.4 percent from natural gas, 18.5 percent from coal, 2.7 percent from uranium in 1976 and closer to 4 percent last year, and 4.1 percent from hydropower.

The end uses of that energy have been electrical generation, 28.9 percent; transportation 26.3 percent; industrial use 24.9 percent; and residential and commercial use, 19.9 percent.

It is estimated that last year we produced over two trillion kwh of electrical energy from a total plant capacity of 523,687 Mw. It is further estimated that 38.7 percent of that capacity was coal-fired; 38.4 percent was from gas- and oil-fired capacity; 9.3 percent was nuclear-fueled; and 13.4 percent was hydroelectric.

Historically, our annual consumption of energy from all sources since 1950 has grown at a rate of 3.5 percent up to 1973. With the impact of the foreign oil embargo in 1973-74, followed by the economic recession of 1974-75, this rate of growth was significantly altered, at least temporarily. In 1974-75 it actually decreased at an average rate of roughly 1.7 percent. In 1976, however, with our limited economic recovery, it increased again to approximately 3 percent. The present indications for 1977 show a somewhat stronger rate of increase for last year.

Similarly, the demand for electricity, which up to 1973 had been growing at an average annual rate of slightly over 7 percent, was jolted out of its usual pattern. In 1974 it increased by only one percent. By 1976 it had recovered to a rate of 4 percent. And last year, according to industry estimates, it was back at the historic growth rate of 7 percent.

Looking to the future, the electric industry is projecting load growth averaging 5.5 percent annually in the next five years, and tapering off to 4.9 percent by 1990.

Danger Underestimated

In my judgment, there is serious doubt as to the adequacy of these load projections. Already the declining supplies of natural gas have forced significant new conversion to electrical energy in the industrial energy market. The share supplied by natural gas dropped from 37.6 percent in 1972 to 30.1 percent for the first six months of last year. So far the largest shift from natural gas has been to fuel oil, which supplied 13.9 percent of the market for the first six months of last year compared with 9.8 percent in 1972, but electricity's share of the industrial market has also increased from 15 percent in 1972 to over 17 percent during the first half of 1977.

With the prospect of further increases in the cost of fuel oil, the increasing industrial reliance upon electricity may very well accelerate, and it is unclear as to how well the load projections of the electric utilities have reckoned with this very real possibility.

Moreover, to the extent that national energy policy forces industry to move away from reliance on oil in its effort to increase the utilization of coal, much of that conversion is bound to be to coal as transformed into electricity. The direct use of coal by industry will necessarily be limited by the high cost of the equipment required to meet environmental standards and burn coal cleanly. Conversion to coal will be economically feasible only for relatively large industrial plants on a direct use basis.

All of this leads us to the heart of our national energy problem: i.e., providing adequate and reliable sources of available energy for our common needs in the years ahead.

What supplies are available? What sources can we afford to rely on?

Urgent problem

This is a problem of extreme urgency -- right now - because it takes time to implement the solutions, and there are many limitations upon our choices. Some of those limitations are inescapable. Others, said to relate, are of our own making.

President Carter's national energy plan submitted to the Congress a year ago projected a need for additional energy supplies growing at an annual rate of 2.5 percent under his plan to maintain a 4.2 percent rate of growth in the national product. This would mean an energy use of 95 quadrillion BTUs in 1985, compared to 74 quads in 1976.

The National Electric Reliability Council's future load projections and reserve forecasts contained in its annual review of last July indicate the industry is planning to bring on line, between 1976 and 1986, 300,000 Mw of new capacity to meet total expected summer peak loads of 683,601 Mw in 1986. At the time of the report last July, 20 percent of that new capacity was not yet under construction.

And then the report added this ominous note: if all the coal-fired plants not under construction are delayed one year because of changes in environmental regulations and those for which there was as yet no corporate commitment are delayed two years; if the nuclear plants under construction are delayed as much as one year in securing operating licenses and those still facing construction permit proceedings are delayed two years; and if the annual rate of peak load growth has been underestimated by only one-half of one percent -- all nine Reliability Council regions in the country will fall short of reliable generating capacity beginning with the Southeastern region in 1979, the Mid-America pool in 1980, the East Central and Southwestern areas in 1981, the Northeastern and the Mid-Continent areas in 1983, Texas and the Mid-Atlantic areas in 1985, and the Western area in 1986.

Given the current performance of our regulatory processes, those delays are more than likely, and given the probability that industrial conversion from natural gas and fuel oil to electricity will actually be greater than the Council anticipated in its projected annual growth of 5.7 percent for the United States as a whole, those projected power shortages are a very real prospect.

This poses a very special problem of relatively immediate marginal capacity shortages, which gives the potential of low-head hydro-electric development, with its relatively short lead-time requirement, a very special relevance.

No single answer

Neither small nor low-head hydro, by any stretch of the imagination, can be regarded as a single answer to our national energy problem. But if it is pursued vigorously, beginning right now, it can make a badly needed marginal contribution to our lagging energy growth in the short run and save us from dangerous shortages in the next few years.

The Army Corps of Engineers' report last year estimated that 54,600 Mw of additional electrical generating capacity is available for development right now in existing dam structures. 5,100 Mw of that can be achieved through improved efficiency of existing turbine-generator installations. 15,900 Mw are estimated to be available by adding turbine-generators to existing hydro-electric stations. And 33,600 Mw can be developed by installing power stations at existing dams presently not used to generate electricity.

Full development of that potential is the equivalent of replacing oil-fired capacity using 266 million barrels of oil annually, at a rate of 727,000 barrels per day. The magnitude of this oil saving, it is interesting to note, is seven and a half times the oil saving which the President's plan estimates would be saved by installing solar heating in 2½ million homes by 1985.

With oil-fired electrical generating costs now running at a reported 4 cents per kilowatt hour, and promising to go higher, the economic feasibility of this potential hydro capacity appears to be assured, except in unusual circumstances.

The technology is proven, the sites are there, the need is evident, and the economic feasibility is becoming clearer month by month. The swing factors now in determining whether these resources will be pressed into service to meet our energy needs without further delay are institutional and financial.

Leadership needed

Here we need the strong and aggressive leadership of the Federal government to get this program moving. We need the active initiative of the Department of Energy with a sense of commitment from the President to dramatize its urgency. This is a critical, immediate phase of defense against possible impending energy shortage, to buy time for the longer-range adjustments and time to bring larger souces of energy into production.

We need the kind of financial catalyst two distinguished members of the Congress, Sen. John A. Durkin of New Hampshire and Representative Richard L. Ottinger of New York, have proposed. Through their initiative and insistent efforts an authorization of $330 million for a three-year, low-interest guaranteed loan program to finance project development has reportedly been agreed upon by the Congressional conferees working over the President's energy package. An appropriation, as well as authorization, is needed. Unless the Administration and the leadership of the Congress make a special effort to fund the program in this year's appropriation bills now before the Congress, another year or more could be lost in building the momentum behind this program.

We need some significant and successful projects underway to break the barrier of inertia and reassure the skeptics. We need to prove, by actual performance, that these sites, long overlooked, do offer a valuable addition to our electric power sources. We need to confirm the expectation that the costs of production, long outside the pale of feasibility in comparison to past alternate fuel costs and the economies of large scale operation, are now within the range of feasibility when compared to a new and higher range of alternate costs. We need to demonstrate how these projects can be integrated into the operations and economics of existing power supply systems -- or be dedicated to specific, individual loads with adequate back-up for maximum efficiency and economy.

Exemptions up to 15 Mw

We need expedition and simplification of the licensing procedures, as Mr. Ronald Corso, Deputy Chief of the Federal Energy Regulatory Commission's division of licensed projects, has long been urging. The Federal Energy Regulatory Commission has now taken the first step in that direction in proposing new and simplified rules for projects under 2,000 horsepower. This is a welcome step in the public interest. It ought to be extended to projects up to 15 Mw. If that takes legislation, the need should be taken to Congress for action.

We need the cooperation of the electric industry in integrating these additional power sources into their systems under fair, equitable, and workable arrangements.

And, finally, we need the understanding and support of the public generally, as well as the various special-interest public groups, of the unique advantages this energy program offers. The adverse environmental impacts are minimal. There is no air pollution. The reservoirs are already there. The dams are built. In many instances, their maintenance and safety will undoubtedly be better provided for if the dam is a working dam producing revenue, than if it is an idle dam left on the doorstep of a local recreation organization or municipality, to be cared for out of hard-to-get tax dollars.

This is sound conservation -- taking a dam that is already there and putting it to fuller use, making it serve more efficiently, with greater benefits to the community.

This is conservation of the highest order. To ignore or permit the neglect of this potential is wasteful, stupid, and, I might add, bad public policy.

The crisis is real

In conclusion, let me offer some very brief personal observations on the national energy crisis we face. It is not just a problem; it is, indeed, a crisis, a very real one. The full magnitude of the impending crunch is not yet upon us, but it constitutes a present crisis because of the long lead time required for major corrective action. If we wait for it to happen, it will be too late to deal with it without great loss and human hardship. It will take years, perhaps a generation or two, to recover from its effects.

I am not talking about just occasional brownouts or blackouts. I am talking about energy starvation and what that will do -- not just to the economy, but to people. I am talking about what it will do to the living standards of people, in determining how warm they can stay -- or can afford to stay -- in the winter, what it will do to their jobs, what it will do to the prices they have to pay for food and the necessities of life. I am talking about what it will do to wages and personal incomes.

I know there are those who speak glibly of more jobs with less energy; a more labor-intensive economy, it is called. That is another name for working harder and producing less. In the overall accounting, incomes must be equated with productivity. If our total production is reduced or constrained because of energy shortages, and there is less to go around to serve the needs of people generally, its effects come home to the individual either in lower pay for his own output, in the depreciation of his real income through inflation and higher prices, in the scramble for goods in short supply, or all of them together in some combination or other.

We've been warned.

And we have been warned. For the last three winters we have been under substantial curtailments of natural gas service in major regions of the country. As I pointed out, natural gas represents roughly one-fourth of our energy reliance. While the adjustments that these curtailments have been forced upon the people of the areas affected, have fallen generally upon industry, and have attracted only limited national attention during two of those winters, the havoc it caused in the winter of 1976-77, with widespread closing of schools, factory shutdowns, and forced unemployment offered the American people a foretaste of what energy shortages can mean.

The supply of electrical generating capacity is beginning to pinch as well, but for different reasons. It got only passing attention in the press, but the fact is that the entire southeastern area of the country was on the brink of a major power shortage last winter when demands on the TVA system soared above TVA's total available generation capacity, and it had to scour the eastern seaboard and midwest for reserve energy to import on a temporary basis to meet the emergency. This is the area, you will recall, that the National Electric Reliability Council warns may face a chronic capacity deficiency condition beginning next year, 1979.

For eight years now we have been consuming natural gas faster that we have been able to find it. Since 1973 the actual production has been declining year by year, until last year when it barely held up to the previous year's level. This is not because of lack of exploration. The industry has been drilling more test holes than in any period since the salad days of the developing interstate pipelines back in the 1950s. They have been drilling more, but just finding less.

Our domestic oil production has levelled off. Oil, as I mentioned earlier, accounts for almost half of our energy supply. So we are getting more and more of it from the troubled world overseas. Whereas in 1950 we were importing only 14 percent of our national oil requirements, now we have to get fully half of it from foreign sources. The hazards of this condition are not only physical and political, but economic as well. The price of imported crude has increased threefold since 1973. We are now paying $45 billion a year for imported oil. It takes a lot of wheat and cotton to pick that up in the international exchange market.

Coal we have in relative abundance, but we are not getting it mined at anywhere the rate necessary to meet the goals set by President Carter.

And nuclear energy, which, aside from hydro-electric generation, is the most economical source of electricity and least offensive environmentally, is under continuing public attack, which is making expansion of its use increasingly difficult and expensive.

Lag time

Add to that the simple fact that whereas 10 years ago it took 3 to 5 years to plan and build a coal-fired electric generating plant and 5 to 7 years a nuclear plant, the anticipated lead time today is now 7 to 10 years for a coal-fired plant and 12 to 14 years for a nuclear plant. And some of the projected nuclear-fueled projects have been abandoned altogether because of public fear and opposition.

These are the ingredients of our energy crisis, and I, for one, am deeply concerned about our ability to solve it -- in time.

I am concerned about the general lack of public awareness of it seriousness, the splintering of public commitment to the broad issues by all the various special-interest, single-issue groups and the easy faith that conservation or some technological solar fix is going to solve it all without any need for hard or unpleasant choices.

I certainly recognize the desirability of sound conservation of energy. We have been wasteful and still are. We can conserve significant amounts of energy, and we are getting results particularly in the industrial sector. But conservation alone is not going to take care of the problem.

Solar energy can also make a contribution but there is no credible evidence that it will be the panacea so many people hope it will be.

I am concerned about the social unconcern of many of our experts as they ply their professional specialties. The economists, at least those present-day descendants of Adam Smith who say demand can be tailored to supply by simply jacking up the price to a true economic value proved in the marketplace, are shirking their social responsibilities in this dilemma just as much as the industrial managers who plump for total deregulation as the answer, or the old-style "damn the torpedoes" engineers who refuse to look at environmental costs as a necessary consideration of present day resource development.

And then I am deeply concerned about the inability of our government to lead, to reach decisions, and get on with the tasks at hand. We study, we temporize, we debate, we set up new procedures and new agencies to act as special watchdogs for new elements in the energy equation. In our government of checks and balances we have developed so many checks we no longer seem to be able to balance.

It has been estimated that the budgetary expenses of various Federal regulatory agencies have risen from $1.6 billion in 1970 to $7 billion and another study reported that the private sector spent more than $62 billion in 1976 to meet Federal regulatory requirements. Delay alone is a costly item in today's inflationary world. The implication of these figures in terms of increased costs to the American consumer speaks for itself.

Adversaries

I am not suggesting either a surrender of public interest in regulation of vital energy policy and implementation or the abandonment of due process, but we have multiplied the forums for testing and retesting the conflicting elements of vital energy decisions to the point of threatened breakdown of the process. We have institutionalized the adversary process to the point where it threatens the ability of government to shape a coherent energy policy and assert the leadership public interest demands in this complex and critical field.

President Carter has properly called for a national effort on energy as a "moral equivalent of war." Obviously we are still not institutionally equipped or psychologically prepared to deal with the energy on a "war" footing. It boggles the mind to contemplate fighting a war with all of the hobbles and constraints we are burdened with in dealing with energy needs. We would be occupied before the first public hearings were completed -- to say nothing of subsequent court tests.

As we face the national energy crisis today, and as we will perforce have to continue to face it in the years ahead, the biggest question of all is going to be our ability to get together and work together, not against each other as adversaries, to settle on the answers to our problems and put them into action. It will be an acid test of our democratic form of government, for -- make no mistake about it -- energy is so crucial to people's well-being that if democratic government fails to provide satisfactory solutions to our energy problems, the backlash may well jeopardize the future of our democracy itself.

This is the challenge we face. The potential of low-head hydroelectric development offers significant and critical contribution to the most immediate supply problems. The task, however, does not stop there.

As a nation, we have to get our total energy act together.

Some Problems Facing Low-head Development

by C. Stephen Allred

Idaho has been dependent primarily upon hydro power for its power supplies since the late 1880's. The first power supplies in Idaho were from low-head power. As early as 1887, the first unit was a 30-foot-head, 30 kw installation in the Boise Valley.

As economies of scale dictated, the production of power came from larger and larger plants until today we have major high-head plants within the state. We still have a lot of high-head sites, but most of those sites have been eliminated for one reason or another.

As we look forward toward new power supplies, we are pretty well limited to look at either such things as low-head hydro, exotic power sources such as geothermal where we have some potential or coal or nuclear.

The problems

In looking at the development of low-head hydro, we have experienced a lot of problems. We have tried to implement some projects but we have not been successful. We also are watching many others in the state who are trying to implement low-head hydro. I'd like to talk a little bit about some of the problems that appear to be hindering those efforts.

Certainly one of the greatest problems that we see being experienced by both our own projects and those of others is the problem of people. How do you convince someone who already has a facility that that facility should be used for low-head hydro purposes?

People are concerned as to what that might do with regard to their water rights, the restraints that it may place upon them as far as their ability to continue to operate their system as they have in the past, and many times just the resistance to having someone else involved in their system. We see a great lack of understanding as to what low-head hydro is and what its effects are. In many cases it's viewed as a utopic solution to all of our power problems, and of course we know that is not true. We have the problem of anytime that we are looking at low-head hydro we are usually looking at a water supply that is dedicated for other purposes. How do you use that water supply for low-head hydro purposes without proposing changes in the way that it is made available to current users? It is a difficult problem.

There are areas in the state of Idaho where the flow regimes are such that they match to some extent electrical loads and can be operated as river-run plants. There are also areas in Idaho where there are rather large storage capacities and the operation of those storage capacities could be changed somewhat so that water could be made available to downstream low-head plants under a different flow regime.

Who has authority?

Authority is another area where in Idaho we experience difficulty. Generally in the state, most of our hydro power in the past has been developed by private utilities. Those private utilities are faced with extensive pressures from new demands as they look to the future, demands which in order to be satisfied would require many typical low-head plants. Likewise, most of the facilities where those low-head installations could be installed are owned by people other than the private utilities. As we look at the authority of those who own the facilities to install hydro plants on them, we find that that authority is not well established. At the state level the only authority that exists for operation of hydro plants is within my own agency, the Department of Water Resources, and the Water Resource Board. Recently the legislature has provided some very limited authority to cities who already have existing plants to replace those plants through the use of revenue bonds and also to irrigation districts to construct facilities on existing dams. But other than these organizations, the authority to become involved in hydroelectric production is fairly well limited. Of course private entities and utilities, assuming that they can receive authority through the various approval processes, can and do have authority to install facilities.

Tax-exempt status needed

Funding is a major problem. In the past most of the hydro power facilities have been developed by private interest with private funding sources. As we look at those sponsors who now control facilities where you might install low-head power we find that funding is not generally available to them. Normally in the public funding area, and particularly the funding sources that these sponsors might go to, revenue bonds have been a favorite form of financing. However we're finding with the IRS interpretation, particularly with regard to tax exempt status as applied to generating facilities, we're having difficulty in obtaining tax exempt status on those revenue bonds. There is legislation in congress in a couple of different forms that would seek to change that and to insure that water facilities used for the production of power by non-profit entities would be tax exempt.

Environmental problems certainly are a consideration, and I think it's something that the public generally has overlooked. I'm concerned that we have sold low-head hydro to the public with the assumption that it will not be environmentally disruptive. And certainly that is probably the case where we install facilities on existing dams, under existing flow regimes. But as we look in Idaho the possibility of that supplying our needs we find that the total that can be generated in existing facilities is not a very significant amount compared with our total needs. So as we look at low-head hydro it probably means new facilities being constructed, new diversion facilities, new impoundments, with their associated environmental effect. I suspect that as we look at new low-head facilities and the power that we can obtain from those facilities as compared to alternative means, the environmental impacts may be just as great per kilowatt hour produced with low-head hydro as they are through the alternative sources. I'm concerned that as we get into specific projects and as information comes out we're going to get a reaction, questioning our credibility when we have said that low-head hydro is not environmentally disruptive.

Red tape

I think that regulatory red tape is the most frustrating problem we face. Many of us recognize that it is impossible for anyone, including ourselves, to get a decision out of the governmental organizations and structures that we have created over the past few years. And I don't blame that entirely on the bureaucrats. I blame that as much on the lawmakers as anyone. Laws have been passed without regard to laws that were previously enacted, and there has been no real correlation from one act to the other. And as a result we have fragmented the decision-making ability of government to the point that no one can make a decision and no decision can ever be final. And as a result I don't know how any sponsor can ever comply with all the requirements and obtain all the necessary permits in any kind of a timely fashion that will make low-head hydro cost-efficient.

In looking at what can be done, the situation certainly isn't hopeless, there are a lot of things that can be done. I think that the two primary areas that have got to be attacked in Idaho, and certainly in other places also, are the institutional questions and the social questions of how do you implement these things? I think that the technical, the hardware questions, will come as projects are implemented. I have no concern about the feasibility of low-head hydro. In most cases the technical feasibility is there. All you have to do is look at the fast-increasing costs of alternative means of power production.

Shortages loom

Okay, how do we get at the picture in Idaho and get on with building low-head plants? It appears to me that in Idaho we're faced with a situation where in the mid- to late-1980's our utilities, public and private, will not be able to meet the loads that they are going to be faced with. I'm concerned that when that happens we will typically react in a crisis atmosphere where we will not have alternative means ready to go on line, and we'll implement some alternatives that are not in the best interest of our people, and certainly not in the best interest of our environment.

Low-head hydro can contribute to meeting our future needs if we can get implementation within a reasonable time period. I don't consider it to be the only alternative. But if it is viewed as the only alternative, say that by 1985 we have to have another 500 megawatts on line from low-head hydro, and each installation may produce 5 to 10 megawatts. If we assume 10 megawatts, then we would need 50 individual installations by 1985. If we're

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He has a B.S. and an M.S. in Agricultural Engineering from the University of Idaho.

looking at 5 megawatts, that's 100 installations on line by 1985. As I look at the institutional and social problems of putting 100 or even 50 or 25 installations on the line in the next seven years I wonder how that can ever happen.

How it can happen

Well, it can. I think there are two areas that can make it happen. Number one, you can't expect 50 different sponsors to put 50 projects on line in a seven-year period. Somehow we've got to build the mechanism to consolidate the sponsors and the actions that are necessary to get the facilities on the line. The studies that are being done now by the university and others will refine the data that we have had previously on low-head hydro sites, and further define the feasibility.

It's then a question of how to accomplish it. I think we've got to have some coordinating group to accomplish the development and to do it in a very aggressive manner. Obviously just the logistics of constructing 25 or 50 or 100 plants are tremendous. Secondly, the financing must be solved. If we continue to rely upon the revenue bond market for low-cost financing for hydro facilities, its obvious that it's not going to be done very efficiently and timely in 25 or 50 or 100 different bond sales. The costs are going to be extremely high for that many small sales of bonds, and just the logistics of accomplishing that many separate bond sales for hydro power are going to be almost impossible.

I think that those are the two items that we have to concentrate on in Idaho to try to insure that if we go the low-head hydro route we go in a large enough manner to make a difference in the 1985-1990 time frame.

I think that in Idaho, low-head hydro can play an important part. I think the technology is there, although certainly it can be improved, and is being improved. The feasibility is there. The funding is there if it can be put together in such a manner as to be made available within a reasonable time frame. The authority is there, assuming that we can find ways to get around the red tape. The desire is there, if it can be consolidated into a force that can move to accomplish it. And the sites are there.

I think low-head hydro is a great possibility, and is going to be an important part of our future energy picture in Idaho. The Department of Water Resources is concerned about finding solutions that will make low-head development occur, and we intend to pursue it.

What Idaho Power Has Learned

by W. D. Arms

Systems management considerations with regard to low-head hydro are primarily economic considerations. In order to set the stage for my fellow panel members here, I will briefly provide an overview of some of the economic factors related to low-head hydro, pointing out some of the caveats which set little red lights blinking in the Corporate planning mind. And I will attempt to put into perspective how low-head hydro suddenly sounds like a magic answer — at least in the public mind — to fulfill increasing energy requirements.

Early in the 1940's, utilities in the northwest saw the need for integrating systems to develop a low-cost, general capability to serve their customers. The formation of the Northwest Power Pool in 1941 was the forerunner of nearly all power pools in the United States as they are known today. When this group was formed as a voluntary organization, all of the northwest utilities, including private, municipal and federal, went together to pool their power and to help their neighboring utilities to provide reserves — to provide assistance when needed — and, in effect, put together one of the greatest utility systems known at that time.

This management decision has helped to develop this northwest country with low-cost power. But now, time is running out. The power pool can scarcely supply the need of any deficient system. And so, it becomes necessary for Management to look for power generation of its own in order to meet its own needs.

Power production in recent years has led many utilities to consider additions to existing hydro installations. As an example, as far back as 1950 Idaho Power Company redeveloped its power potential on the Malad River. They replaced a 5,000 kw power plant with a 7,500 kw unit and a 13,500 kw unit, thereby developing the full potential of the river which, is relatively low-head and does not use extensive dams to store water.

In fact, utilities were considering these additions well before the terms "low-head hydro" or "bulb turbine" became buzz words in the media. These terms are now bandied about by people who have little or no understanding of the basic economics of providing electricity.

Commissions Reluctant

While the terms low-head hydro, bulb turbines and such are exciting to the political atmosphere and to the people who are not initiated into the world of economics, it must be pointed out that regulatory commissions are most reluctant about increasing costs to customers for any reason.

Systems management considerations for low-head hydro installations must center around methods which may be found to hold down operating expenses. The overriding decisions made by management will be geared to the economic climate under which any low-head plant can be brought into the overall system operated by a particular utility.

W.D. Arms is Vice President-Engineering with the Idaho Power Company of Boise. He has had a 40-year career in power operations and construction work in southern Idaho, including 30 years in the field as an electrical superintendent. He is a member of the Executive Committee of the Western Systems Coordinating Council and is on the Engineering Advisory Board of the University of Idaho.

He graduated from the University of Idaho in 1937 with a degree in Electrical Engineering.

While we favor low-head hydro where it is practical, here are some problems which we must recognize and talk about in detail:

•Sites are not generally available where stream flows are adequate to produce power in significant quantities.

•Low-head projects of any type are extremely vulnerable to flunctuations in stream flows. In some cases, generation could fall from peak capacity to nearly zero in the space of only two or three months. This is a very important consideration.

•Each plant requires separate installation of transmission facilities, substations and monitoring equipment. This increases costs dramatically and compicates the every day management and operation of the overall system.

•Lead time can be long. It can take two years to get permits to construct and two to three years of construction time for any project. You do not merely grab a bulb turbine off the shelf and plug it into your system.

•Low-head hydro can be very expensive. The sites we've filed on at Idaho Power hopefully will produce electricity at prices competitive with coal or nuclear plants. But power from other sites we've investigated would cost more — up to twice the cost of coal-produced electricity.

•Utility systems having 500 to 1300 Mw plants of single units cannot afford to allocate very much manpower in operating small, low-head plants of 15 to 75 Mw capacity. It takes almost as many people to operate a 15 Mw, low-head hydro plant as it does to operate a 1,500 Mw high-head hydro plant.

•The protection that goes into keeping a small plant operative is approximately the same protection that goes into keeping a large plant operating.

•Through federal legislation and pressures by minority environmentalists, two of the major sources of hydro electric power in the State of Idaho have been "locked-out" of production.

a) One is the Middle fork of the Snake River which is now in the National Recreation Area and on which a moratorium was placed for construction of power facilities.

b) The other is the Salmon River which is a Wild and Scenic River. While it has a great deal of power potential, it would be impossible to develop any of the hydro that would be available.

This, in short measure, develops some of the economic bases under which management considers the systems it puts in. I'm sure the members of our panel will address the controls, the electrical systems and the methods of integrating small hydro units into rather complex dimensions in total System Management.

Bulb turbine

As you may have heard or read, for heads up to about 60 feet, the bulb turbine can be superior to the conventional Kaplan turbine in terms of efficiency and economics. The bulb turbine is a compact, self-contained, operationally-flexible installation. But there are some limitations to its use. One disadvantage is that its inertia is less than that of other types, including vertical-shaft Kaplan turbines, so that its use is limited to systems where there are other power sources available to maintain an electrically stable system. And this limitation is, of course, very definitely a Systems Management consideration.

The inertial qualities of bulb turbines, the electrical systems from bulb turbine installations, which are often remote, must be considered. It would do very little good to install a low-head hydro project on a remote river if it was impossible to build the necessary transmission to bring the power out of that area. Since establishment of areas such as the NRA and the Wild and Scenic rivers, it is becoming increasingly difficult to provide transmission across designated federal lands. Each special interest group has a reason for protesting any disturbance of the status quo.

In recent months, Idaho Power has filed for water rights on a number of low-head projects, including projects that would make use of either bulb or conventional turbines. On paper, these appear to provide a sizeable amount of electricity. But in reality, because of limitations in water supply, their actual generation will provide energy approximately equal to only one year's load growth.

We are looking at eleven hydro sites with a combined total of 431 Mw of capacity, a total investment of approximately $473 million and an operating cost of 37 mills per kwh.

Example

Barber Dam near Boise often has been cited as an example of a good location where a low-head unit could be installed. The Water Resource Board made a proposal to the Idaho Legislature calling for rehabilitation of the dam and installation of turbines with a capacity of 3.2 Mw. The Legislature, however, rejected that proposal because law makers believed the cost was too high.

At Idaho Power Company, we are still adding new generators at some existing dams such as American Falls in order to try to squeeze as much power as possible out of our hydroelectric facilities. But there aren't very many places where new dams can be built. Idaho has more miles of rivers protected under the National Wild and Scenic Rivers System than any other state.

Economics involves the study of scarcity. The fact is that water — once abundant in the northwest — now is scarce. It is scarce due primarily to the Wild and Scenic River System and it also is scarce due to the increasing demands of agriculture and a growing population.

So you see, economics really is at the forefront in any discussion of the development of low-head hydro. The decision was made to keep those rivers wild and scenic — not just for ourselves, but for our children as well. Those rivers are a natural resource, and what you do with that natural resource involves a choice: either you dam them up or you do not. That's a choice, and that's pure economics. But the youngsters for whom we have arranged this legacy of scenic beauty are in fact already part of today's — and tomorrow's — energy problem. If they are going to stay here in the northwest and enjoy the heritage we've built, they're going to need jobs and houses — and electricity.

If viable solutions to integrating such small units are found, then low-head hydro can become a significant factor in developing additional power resources for the northwest, but every aspect considered must be based chiefly on economics and not on engineering technology alone.

A whole lot of little low-head hydro electric plants scattered around here and there otherwise could mean relatively few megawatts but a great many mega-headaches!

The WWP View

by Donald L. Felgenhauer

The Washington Water Power company is interested in all possible forms of electric generation. New sources of generation are continually needed to supply the needs of our growing region. Because of economics of large scale, we have traditionally used "large" hydroelectric projects to meet the load. We have built our own projects and participated in projects built by public utility districts in the state of Washington.

At this point in time, all of the economically feasible and environmentally acceptable large hydro sites in the Northwest have been developed. In recent years, coal-fired power plants have been used to satisfy the additional load growth. Both nuclear and coal-fired plants are under construction to satisfy the future needs of our customers.

Long licensing delays for several of the region's large thermal projects have caused the costs of these projects to skyrocket. These increased costs, along with the resulting energy shortages caused by the delays, have resulted in WWP re-evaluating other forms of generation. We have embarked on a program of defining sources and obtaining energy from small hydroelectric and thermal sources.

The company is working with the city of Spokane, studying the feasibility of installing an additional 1 Mw unit at the Upriver Power Station, located on the Spokane River. Upriver Power Station is owned by the city of Spokane and has a present capacity of 4Mw. During most of the year, water is now being spilled at that project.

In cooperation with the Pend Oreille County Public Utility District, application for a license is being prepared for construction and installation of two 8 Mw units at Sullivan Creek in northeastern Washington. This will be a high-head installation, fed by a natural lake.

We are also exploring the possiblity of obtaining small amounts of thermal generation from burning wood wastes at existing forest product manufacturing plants in our service area. We are looking at both plants specifically for electricity production and plants which use steam which will later be used in the forest product manufacturing process. The latter type of plant is called "co-generation".

Plans

"Small" is not bad. WWP is interested in any form of electric generation, if it is environmentally acceptable and economically competitive with alternate methods of generation. The time frame required between conception and production seems to be extending each year. Time is money, and construction delays increase the unit cost of electricity to the company, and ultimately the consumer.

I thought you might be interested in the procedure that our resource planning engineers use to evaluate the alternatives when new generation is needed. Specifically, let us evaluate the possibility of a small low-head project.

Donald L. Felgenhauer is the Hydrology and Computer Applications Engineer for Washington Water Power Co., Spokane, Washington. He has been employed by WWP since 1964, working in the resource planning, Intercompany Pool, hydrology, and systems operations sections of the Power Supply Dept.

He graduated from Washington State University in 1964 with a B.S. in Electrical Engineering.

I will use a typical streamflow in north Idaho and the WWP system to demonstrate the procedure Figure 7 is a graph of the shape of the streamflow going into Coeur d'Alene Lake. This is representative of a "typical" year. Since the Spokane River system drainage is primed by snow-fed streams, the shape of the curve is quite variable, especially when compared to the shape of WWP's average monthly load, as a percent of the annual average load. This load curve is also in Figure 7. One can readily see the advantages of storage reservoirs for the purpose of hydroelectric generation. This shape is representative of most small streams in the Northwest between the Cascades and the Rockies.

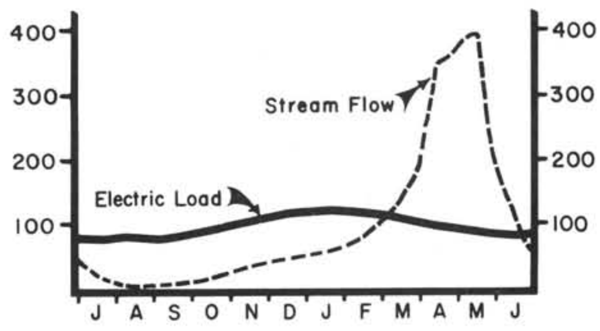

Figure 7. Percent of annual average.

For purposes of discussion, let us make the following assumptions about the low head project under consideration:

- 30 feet of head.
- Run-of-river operation (no daily or seasonal storage).
- Average river flow is 1700 cfs.
- River flow shape as in Figure 7.
- "Minimum" dam structure (narrow rock canyon).
- "Unattended" station operation.
- Close to a load center with load comparable to the generation.
- No customers will be interrupted if the plant does not operate.

Figure 8 shows the expected average generation from this project as a function of the installed capacity. A 4 Mw station would handle the annual flow (if there were enough storage to make the flow uniform throughout the year). One can see that without storage on a stream such as this, the incremental energy obtained from an incremental unit of capacity is quite small. For example, increasing the capacity from 10 to 11 megawatts increases the average annual energy approximately 0.25 megawatt.

Figure 9 is an estimate of the cost of the station, compared to the installed capacity. These estimates are "rough" and are for a "bare-bones" station without frills as described above. Note that the total plant cost shows a fixed cost even with no electric generating capacity. This represents the cost of installing the dam. For each additional unit of capacity added, the costs increase. The unit cost curye drops rapdily with the first few megawatts, then levels off.

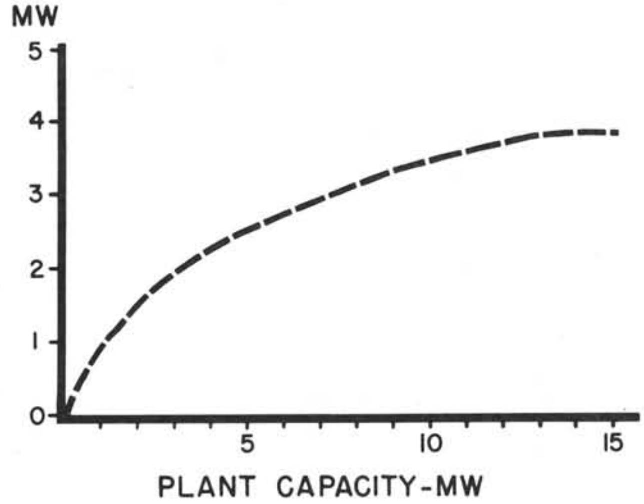

Figure 8. Average annual generation, - Mw.

Optimum capacity

Figure 8 and Figure 9 are combined to obtain the information in Figure 10. Generating costs are shown for low-head hydro capacity ranging from one to 16 megawatts. The average cost curve shows the average cost of generating electricity at various plant sizes. In this example, the minimum average cost is for a 5 Mw plant. The incremental cost curve shows the generating cost for the last megawatt installed. For example, the additional energy received from increasing the plant capacity from 6 to 7 Mw will cost approximately 7.5 cents per kilowatt hour. All other things being equal, it would be economic to build the low-head project if its average cost curve went below the cost curve for the least cost alternative resource.

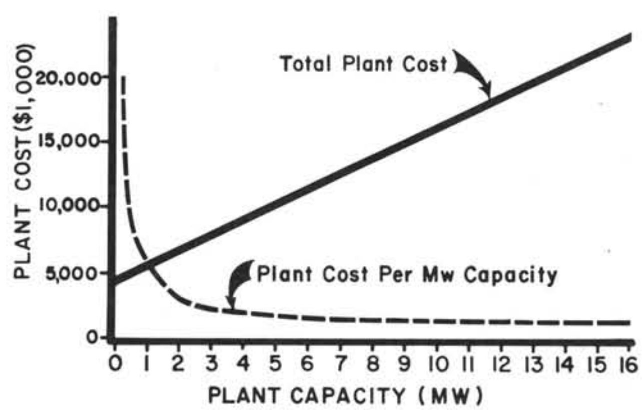

Figure 9.

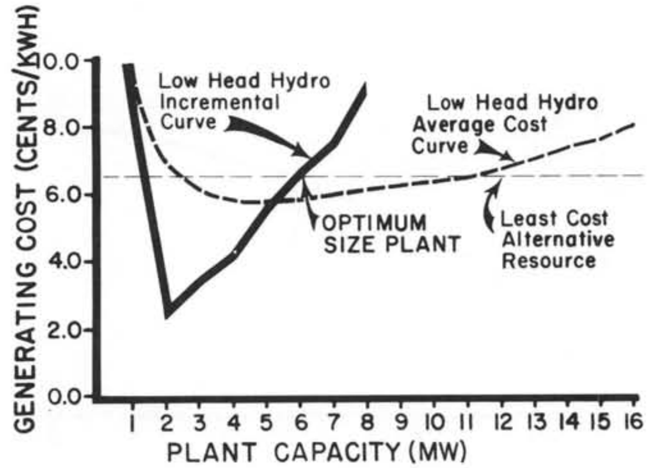

Figure 10.

The optimum plant capacity would be at the point where the incremental cost curve crosses the cost curve for the least cost alternative resource. In the example, the optimum plant capacity is 6 Mw. If an additional megawatt were required to supply our customers' requirements, it would be less expensive to purchase 1 Mw of the other resource.

I would like to emphasize that these curves are not for a specific location. They are intended only to illustrate the procedure that is used. All forms of generation, including low-head hydro, are constantly being re-evaluated by our resource planning engineers as their relative costs change.

A low-head hydroelectric station on our system would probably operate unattended with periodic inspections by an operator. The station would be shut down automatically in case of any electrical or mechanical malfunction which would endanger the equipment. When the plant shut down, the operator or maintenance personnel would be dispatched to determine the cause of the shut-down, repair the damage, and start the units.

Remote control equipment would probably not be economical; however, provisions could be made to provide remote alarms for out-of-tolerance conditions. The generation would also be such a small percentage of the total system generation that the electrical integrity of the power pool would not be endangered by the loss of the station.

Streamflow variations considered

The extreme variability in streamflow throughout the year and the loss of efficiency for part load operation would probably necessitate the installation of several small units at the station, instead of one large unit. When the operator made his routine visit to the station, he would put enough units online to handle the streamflow at the time. Automatic equipment would change the loading for small changes in flow. If the streamflow substantially decreased after the visit, automatic logic would be provided to shut down individual units in succession. If streamflow substantially increased after the visit, the additional water would be temporarily spilled by an overflow spillway. Large increases in streamflow would require the presence of an operator to start additional units. The operator would also probably have to live on-site during periods of high streamflow to take care of ice, trash, etc.

Small low-head hydro projects have many environmental "pluses" when compared to other methods to generate electricity. Low voltage distribution lines can usually adequately transfer the power to a load center. The natural streamflow characteristics of the stream are not affected. Large land areas are not required for a reservoir.

One of the "minuses" of these small dams in our area is that facilities would probably have to be provided to permit resident and anadromous fish passage around the structure. This would add to the cost of the project and reduce the amount of water available for generation.

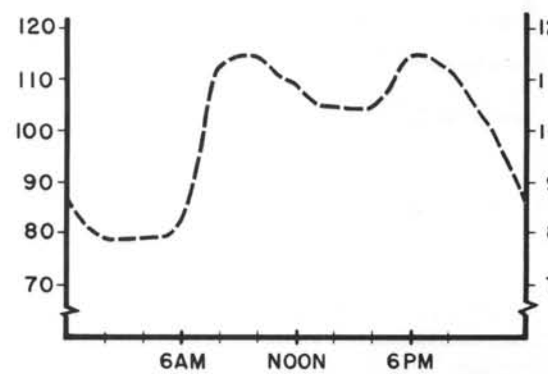

Figure 11. Electric load, percent of daily average.

Figure 11 can be shown to illustrate the effect that small run-of-river hydro projects will have on other large river systems. Figure 11 is a graph of the typical hourly electrical use of our customers. This shape does not change appreciably during the year, although it does "flatten out" during extreme cold weather.

High-head changes

Since a small run-of-river hydro station does not have any storage facilities, it cannot "follow" the pattern of the electrical load use throughout the day. The small station must be "base loaded" and used to satisfy part of the 70-80 percent "base load". This means that the small hydro station cannot share in the generation fluctuations needed to meet the load. Other hydro projects (with daily storage) must "take up the slack". Therefore, any new generation source which is "base loaded" causes existing large hydro generation stations to vary their discharge to a larger extent throughout the day.

Because of the inability to fluctuate generation, the assured capacity of the project would be the amount of generation available at the time of the maximum system load. This would occur in August (low flows) or January (low flows).

If low winter streamflow only produces 1 Mw, that is all the capacity that is assured, irrespective of the size of the plant. Additional capacity will produce additional energy which may or may not be usable, but availability of such capacity is not assured during peak load conditions. That means that other generating stations must be built to serve loads in excess of the low winter energy capability of a run-of-river plant. This is a major cost item that reduces the economic feasibility of these types of plants.

In summary, the Washington Water Power company is very interested in low-head hydro generation. We do have an obligation, however, to ensure that each generating resource built is the best alternative available at the time. This requires a careful examination of the legal, environmental, engineering, and economic aspects of each project.

The Hydro Choice — High, Low or No?

by W. H. Riggsbee

In the past few years, many utilities have been actively exploring the possibilities of increasing the output at existing hydro sites by replacing or supplementing existing generating units. In the Pacific Northwest, practically all the economically feasible and environmentally acceptable high-head hydro dam sites have been developed. Current plans at existing hydro sites calls for additional capacity to be built at higher costs of energy.

In order to develop future hydro sites, be they high or low-head, the following management consideration must be addressed:

1. Need for power,
2. Methods of meeting those needs,
3. The general considerations which should govern any resource development,
4. The environmental impacts,
5. The economics of the project.

1. Need for power in the Pacific Northwest

The Pacific Northwest Utility Conference Committee (PNUCC) is a committee composed of major generating utilities in the Pacific Northwest and has been functioning since the mid 50's. This committee has established a Subcommittee on Loads and Resources which each year prepares a long-range projection of loads and resources for the West Group of the Northwest Power Pool encompassing the loads in the area roughly included in the Bonneville Power Administration's service area excluding the area served by the Montana Power Company and the Idaho Power Company. The projection covers a 10 year period beginning on July 1, following the date of preparation. This document is prepared through the combined efforts of virtually all of the major electric utilities in the Pacific Northwest.

This forecast shows the estimated loads of the West Group of the Northwest Power Pool both in terms of peak kilowatts and in terms of annual kilowatt hours for each year in the 10-year period. Projections for the next ten years beyond 1988 were calculated in-house and are discussed below.

The total West Group energy requirements are expected to grow from 16,072 average megawatts (Mw) in 1978-1979 to about 35,000 Mw in 1996-1997. The overall annual growth rate at present is about 4.2 percent; the growth rate after 1980-1981 is projected to be 4 percent. Peak load is expected to grow from 24,600 Mw in January 1979, to 56,000 Mw in January 1997. The overall annual growth rate will be about 4.5 percent after January 1988.

The current Pacific Northwest electric energy generation resources are predominately hydro, augmented by thermal plants. By 1988, over 13,000 Mw of thermal plant capacity is scheduled at this time and new hydro will not be a significant fraction of the total additions. Thus, the Pacific Northwest system is making a transition from the current hydro-dominated system to a mixed hydro-thermal system in the next several

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decades.

In the near term, the need for power is best identified in the West Group Forecast as a 0-2,000 Mw average energy deficit from 1977-1978 through 1987-1988. In the long term, energy deficits begin to increase in 1988-1989 while peak deficits begin to show in 1990-1991. Energy deficits build up from about 1,000 Mw in the later 1980's to over 12,000 Mw in the early 1990's to over 20,000 Mw in the late 1990's. If these projections are correct, the future needs will have to be met with large increments of energy.

2. Methods of meeting the needs available to the utilities in the Pacific Northwest

In order to eliminate energy deficits, the utilities will need to add resources at an average rate of about 350 Mw per year with peak requirements on the order of 500 Mw per year. Thus, a resource which satisfies the energy requirements and has a design load factor of 70 percent would probably satisfy the peak requirements as well.

Numerous methods or alternatives are presently available for providing additional electricity in the Pacific Northwest. Those methods currently available are:

- Baseload hydroelectric plants or groups of small hydro plants
- Combined cycle plants
- Pumped storage hydroelectric plants
- Baseload coal plants
- Intermediate load coal plants
- Light water nuclear reactors (LWR's)
- Purchase part of a power plant built by another utility

All but the first two are systems considered practical as future sources of large quantities of electricity.

The new technologies currently being researched and developed and their commercial availability dates for the Pacific Northwest are:

Type	Commercial Availability
Low temperature vapor-dominated geothermal systems	1986
Wind generators	1986
Fuel cells	1987
In situ coal gasification	1990
Fusion	After 1995
LMFBR	After 1995
GCFBR	After 1995
HTGR	After 1995
LWBR	1985
Municipal Waste	1987

Although, baseload hydroelectric plants are listed as current electricity supply methods, the actual availability is questionable due to severe opposition to the environmental effects of site development and operation. Many small (0 - 50 Mw) plants may be built, but the total capability obtained in this manner is not expected to have a significant effect on the need for additional plants. One solution would be groups of small hydro sites plus some of the new technologies.

3. The general considerations which govern any resource development

The basic consideration which governs any resource development is priority. Which out of all the possible technologies available in the Pacific Northwest has the highest priority? In order to answer that question, the Supply System is currently assessing the current energy technologies plus the technologies of the future and their commercial availability.

At the present time, all of the technologies are being reviewed and assessed to answer the above question. The hydroelectric program is no exception, the current program consists of evaluating all potential hydro sites in the Northwest. This program will evaluate all conventional hydro sites, which include high and lowhead facilities, plus a number of unconventional hydro projects.

4. The environmental impacts which are associated with alternatives

In terms of impacts associated with current and new technologies, the best approach is to divide them into the effects they have on depletable resources versus non-depletable resources. The most attractive technology available with non-depletable resources is hydroelectric power, be it small or large. The most attractive technology which uses depletable resources is coal-fired power followed by nuclear power.

A coal fired plant, (800 Mw size) would use about 2.35 million tons of coal annually to produce an equivalent amount of power from a hydro plant of the same size. A nuclear plant would require about 245,000 tons of uranium ore per year to produce an equivalent amount of power for the hydro plant. Furthermore, both thermal plants will require substantial amounts of water; between 10.3 and 12.6 million gallons per day for plants of this size.

With respect to the thermal plants, there will be certain problems associated with environmental pollution, and the transport of energy from energy source to load center. Aside from these issues, on the surface, the hydroelectric power appears very attractive, yet the large baseload hydro is nonexistent. Small hydro appears to be one answer to lessening the impacts of adding new power.

5. The economics of a project as compared to the economics of development of alternative projects

The costs for most hydroelectric facilities vary according to the size, shape, and location of the project. Although the cost of hydro projects represent a large expenditure of capital over a multiyear period, hydroelectric facilities have in the past offered the most economical source of electric power in the Pacific Northwest.

Future development of new hydroelectric resources is estimated to range as low as $400 per kilowatt of installed capacity to about $1,500 per kilowatt. The outlook for these future units is uncertain when all management considerations are evaluated.

The capital costs of the coal and nuclear alternatives assumes each to be 1,000 Mw units. The total range of capital cost for the coal plant with various options is $795-939 million without scrubber and $1,030-$1,170 million with scrubber. The nuclear plant has a range of capital cost of $1,343-$1,381 million.

For the future, the most likely power generation types may be coal or nuclear plants. In the long term, some of the technologies, such as groups of small hydro, fuel cells, geothermal and wind may be the technologies selected to meet the needs for the Pacific Northwest.

2

Economics

Barber Dam, Boise, Idaho.

Bureau of Reclamation photo

The Need For Better Forecasting

by Walter R. Butcher

As everyone knows, the electricity supply business has been undergoing some revolutionary changes. Costs of power plants, fuel and delivered electricity are all escalating rapidly. There is stiffening opposition to all conventional supply options and spreading intrusion into the affairs and decisions of utilities. Under the circumstances, it is not surprising that more and more attention is being devoted to a determination of just how far growing electricity demands will carry this situation.

There is a wide range of opinions about what future electricity demands are going to be or should be made to be and considerable controversy has arisen between proponents of different opinions about the future of electricity. So, it is with some trepidation that I address this controversial topic of "determining the need for electric energy."

Demand forecasting

Forecasting involves determining (predicting) what the demand for electricity is going to be. Demand management involves determining (causing) demand to be more nearly what it should be.

Demand forecasting is an unavoidable part of any enterprise. Thomas Edison and everyone involved with electricity supply since has had to form some opinion about future demands for electricity. Some based their forecasts on little more than an assumption or a hunch, and others used elaborate forecasting methods. Some proved to be very accurate, and others were bad guesses. Some didn't even realize they were forecasting.

At the present time, we are in an era of greatly increased attention to forecasting. In the Pacific Northwest, there have been four major independent studies of electricity demand forecasts for the region since 1975[1]. There have been two separate studies for the state of Oregon alone[2] and several special forecasts for individual utilities or for project service areas. At a larger scale, nationwide forecasts are being presented at more and more frequent intervals.

Not only is the number of separate demand forecasts growing, but also the sophistication of the analyses is increasing. It used to be common to prepare forecasts using some mixture of simple growth extrapolation and the informed judgment of utilities' sales divisions. Econometric and/or end use analyses of varying sophistication are invariably used in the independent studies and most of the larger utilities now make some use of these techniques in their own forecasts. However, growing numbers and advancing sophistication have not prevented disagreement over demand forecasts. People disagree, heatedly, about whether forecasts are too high or too low. The battle rages in rate hearings, plant siting hearings, regional power planning and policy deliberations, the media and every appropriate or inappropriate forum. Utilities, industrialists, environmentalists, consumer advocates and politicians have all entered the fray.

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Why the sudden fuss and flurry?

It used to be different. For many years, prior to about 1973, no one showed much interest in forecasting power demands except the utilities. They went quietly about the business of planning and preparing for the future using forecasts based on simple extrapolation of trends, knowledge of informed individuals and judgment about what rate would fit best with hopes for the future of the utility and the region. For a long time, methodologies of this sort were accepted within the power supply industry and outside it as well, because the consequences of a mistake were not too threatening. The utilities seemed to be doing a pretty good job, and, anyway, who could possibly do any better?

Interest in forecasting began to spread about 1973 along with growing national concern about an "electricity crisis" due to rapidly escalating construction and financing costs, opposition on environmental grounds to both coal and nuclear thermal plants, shortand long-run supply problems for oil and natural gas, deterioration of reserve capacity to handle unusual demands, etc. In the Pacific Northwest, possibilities for hydroelectric production from the remaining undammed reaches of the Snake, Clearwater, Salmon, Columbia and other large rivers were lost to interest in preserving free-flowing streams and the region entered the difficult transition from very cheap hydroelectric power to the expensive and controversial coal and nuclear plants that have already created so many financial and political problems for our less riverblessed brethren. These supply-side difficulties stimulated a lot of rethinking about how the electricity supply system could cope with future growth in use of electricity. Even utility executives began, understandably, to wonder whether growth was really worth all the headaches and bruises that they absorbed in their attempts to expand system capacity to serve anticipated growth in demand.

During this same time period, the rate of growth in electrical consumption has been slowing, taking some of the pressure off of supply expansion. In the Pacific Northwest, the average compound rate of growth in electrical consumption had been 6.3 percent per year during the period 1961-66. It dropped to 5.8 percent per year for 1966-71 and further to 4.7 percent per year growth during the period 1971-76. For the four years from 1973 to 1977 electrical energy sales grew at an average annual rate of only 2.2 percent per year. Even eliminating the drought-constrained year of 1977 changes the lagging demand growth picture very little. During the three years from 1973 to 1976 the growth rate averaged only 3.6 percent per year.

Slow to adjust

The demand forecasts of the utilities have been slow to adjust to this changing demand situation. A review[3] of the Pacific Northwest Utilities Conference Committee's annual West Group Area forecasts[4] shows that the following year's actual load was lower than forecasted in eight out of the 10 years from 1965-74. From 1968 on, it has been necessary to systematically revise forecasts for future years downward when each year's new set of forecasts is turned out. For example, the 1968 forecast predicted a 12-month average firm load in 1974-75 of 14,081 megawatts. By February 1974 the forecast for the 1974-75 power year had been lowered 8 percent to 12,971 megawatts. The actual load in the power year that began five months later was five percent below the projection. The same pattern has continued and become more pronounced since 1974. Each successive set of forecasts is lower for the coming year than was the forecast for the same year that had been prepared only 12 months earlier. Furthermore the forecasts for more distant future years are lowered by a larger amount, reflecting an expectation of a lower longterm growth rate.

The downward revision of load forecasts is in the direction preferred by the usual opponents to the utilities' future plans. However, it has not taken the heat off the utilities' forecasts. The problem now is that the credibility of the utilities' forecasting methodology has been seriously compromised. Forecasts that had to be revised downward so many times seem likely candidates for still more downward revision before those far off years for which power supply systems are now being planned. So attacks have continued, causing the utilities and regional policy makers to seek a better, more acceptable or defensible method of projecting future demands for electrical energy.

A "better way" to project electricity demands?

Dissatisfaction with the available semi-official forecasts of electricity demand has stimulated lots of activity in the field of load forecasting. In the Pacific Northwest, the independent forecasts mentioned earlier and two comprehensive reviews of existing forecasts and forecasting methodologies[5] have increased our understanding of how to make demand growth projections. I want to suggest four principles that can help increase the chances that projections will accurately predict energy needs in a future that is significantly different from the past.

First, the projections should be disaggregated for as many subcategories of demand as possible. There should be separate estimates for industrial, residential, commercial, etc. If at all possible, projections should be further disaggregated to major industrial sectors, to principal types of commercial and public buildings and to types of housing units. It is also desirable, where possible, to estimate demand separately for different end uses such as electric space heating, appliances, etc. Disaggregation improves the ability to forecase the aggregate effect of predictable micro-changes such as a shift in economic structure from heavy industry toward production of finished goods and services.

Second, the projections should be "composed" by combining estimates of number of electricity using units with separate estimates of the amount of electricity used per demanding unit. For example, a projection of the number of occupied housing units should be combined with a separate projection of the average killowatt hours of electricity used for general appliance operation. Similarly, projections of production or employment in particular industries should be combined with separate estimates of power use per employee or per ton of product. This approach makes it possible to apply whatever is known about both growth in the numbers of electricity demanding units and in the "energy intensity" rather than dealing with the much less specific total amount demanded in some use category.

Users do respond

Third, the projections should include an allowance for the changes in demand that arise due to changes in economic variables such as the price of electricity, prices of alternate energy sources, consumers' incomes, and real costs of substitutes for energy. Several studies have shown that there is economic incentive for household and business users to adjust electricity consumption when prices and incomes change. Moreover, they have shown, convincingly, that users do in fact respond to those incentives. A projection that takes no account of economic factors will certainly be mistaken during the coming era of changing real cost of electricity and electricity substitutes.

Fourth, and finally, for demand projections to have a good chance of being accurate, they need to use good data and good analytical techniques. Good demographic and economic base projections and good analyses of demand response to economic variables are of vital importance. A highly disaggregated and sophisticated demand projection model can turn out unbelievable forecasts if the underlying base projections and response functions are also unbelievable.

The non-utility projections for the Pacific Northwest with which I am most familiar are the WSU and NEPP projections. Both of these projections attempt to follow the four principles for a good forecasting that I listed above. Both studies disaggregated demand components as much as possible, including separate forecasts for several industries and major household appliances. Both combined projections of energy user numbers and energy use intensity rates to get aggregate amounts demanded. Both incorporated response of energy demand to prices of energy and energy substitutes. Finally, both relied on official or semi-official projections for population, economic growth and other external factors.

Bad load growth estimates

Utilities' load growth projections generally do not conform very closely to the characteristics of a better projection that were sketched out above. In the Pacific Northwest, some utilities apparently just predict future total load levels — the ultimate in aggregated and simplified forecasting. Others make separate estimates for a few broad customer or end use categories. Only a very few utilities give explicit consideration to demand response to changing power rates and other economic variables. As a result, we know that their projections will fail to reflect the effect on electricity demand of some predictable changes in the regional economy and residential living patterns. They also will fail to pick up the substantial demand-dampening effect of inevitably higher energy prices.

Critics are concerned that the flaws of the conventional approaches almost certainly result in a bias toward over-projections in the face of changes such as those that began in the early 1970's. Furthermore, there is also widespread belief that the utilities would like to have demand projections that are as high as possible, so as to make it easier to win approval for new plants. Hence, there is suspicion that biases may be entering into the assumptions on which the projections are based as well as through the methodology itself. Small wonder that they are still subjected to criticism and counterattack.

Detailed structure

These independent studies produced projections under several sets of basic assumptions. In the WSU study, an assumption of low population growth rates (Census Series E) and high response to price resulted in a regional electricity demand growth rate of only 1.5 percent per year from 1971 to 2000. If population grows significantly more rapidly in the PNW than current birth rates would produce and demand is less responsive to price, then the projected electricity growth rate is 2.6 percent per year. In the NEPP study, the forecasted rates of growth were 1.4 percent per year with population and economic growth rates similar to the lower assumption in the WSU study. With a population growth rate of 1.3 percent per year for the PNW, the NEPP obtained their most likely forecast of a 2.9 percent per year rate of growth in regional energy demands. NEPP also prepared a high forecast based on very rapid growth of population, economic activity and incomes. That forecast was 4.3 percent per year growth in electricity consumption.

The detailed structure of these models makes it possible to identify some of the reasons why they project demand growth at rates well below those that prevailed in the 50's and 60's and below even the most recent of the utilities' regional forecasts. One reason is that these studies incorporate a projected shift of employment toward services and industries that are not electricity-intensive. Another factor is projected tapering off of growth in residential and commercial demands as low population growth rates eventually retard new household formations and existing households reach saturation with the appliances that account for most electricity use. Finally, demand reductions in response to forthcoming price increases is another growth dampening factor. These all seem to be reasonable and highly expectable occurrences. Models that account for these factors provide the best way to project the future demand for power.

What is more important than "better" projections?

The more carefully researched, independent projections tend to agree on a long-run growth rate of around 3% per year. But there still are sharp disagreements over what demand levels ought to be used in long-run plans for electricity supply. The utilities and major industrial customers argue that we really should be planning for higher growth rates, around 4.5% or 5% per year. On the other side, people with strong concerns about environmental conditions and the consequences of growth would prefer that plans be geared to even lower rates of growth in electricity demand, trending toward zero growth in the long run.

It would be a mistake to try and resolve these differences by developing even more elaborate projections that would be more conclusive and convincing. Remaining disagreements are based more on differences in objectives (in what is sought and hoped for) than on differences in projection (i.e., in what is expected). Utilities believe that their own business and the economy will be better off if there is rapid growth in electricity consumption. Thus, they hope that electricity consumption will grow so that their hopes for growth will be realized. Other people believe that the environment and the long run interests of society would be better off if there was less growth. Thus, this group hopes that electricity consumption will grow slowly, discrepancy between the marginal cost of electricity thereby reducing pressures on the environment and resources.

Both sides are entitled to their points of view about what rate of growth in electricity consumption would be best for the country or the region. It is very important that the desirable and undesirable aspects of high and low rates of growth be brought forth and carefully considered. But, arguing for projections at "their" desired rate of growth seems to be an inappropriate place to press for one's view of a better future. After all, projections are intended to be predictive rather than idealistic. Getting a projection changed to a more ideal rate does not change underlying demographic, economic and technologic forces that are the ultimate determinants of growth in power demand. Changing a projection to fit one's own ideal may be nothing more than simple wishful thinking, unless forecasts are self-fulfilling.

Are demand forecasts self-fulfilling?

The general premise of projection is that various economic and other factors will determine future demands for power and that forecasts are a bystander's best guess as to what is going to happen. However, both high growth and low growth proponents are concerned that forecasts are more than just innocent bystanders. Utilities realize that forecasts on the low side will prevent them from expanding power supply capability as rapidly as they feel may be needed. Then, if the projection turns out to have been too low and future demand is higher than planned for, it will be too late to build the capacity needed to meet the loads. Under those conditions not much could be done except to ration the available power among customers. Usage will have been determined by the forecast that constrained planning. The economic impacts of this kind of forced reduction in power demand may be quite significant.

On the other hand, low growth advocates are afraid that a high forecast will be used to justify building additional capacity which, once built, will be available for use at very low, marginal operating cost. If demand does not materialize as forecasted, the utility can minimize its losses by offering to sell power from the surplus facilities at cut rates. Anything above the costs of operation will be of some help in paying off the sunk capital costs for plant construction. This bargain priced surplus power will bring forth interested customers who then will buy more than they would have at normal prices. Total power usage will be higher and again forecasts will have determined demand.

So, it is possible for forecasts to be a factor in determining consumption to be at least partially self-fulfilling. But, I would argue that this should not be. Electricity consumption ought to be determined by a decision to use power in all applications and usage rates for which value gained or cost saved by the user is greater than the cost of supply. Underbuilding or overbuilding because of plans based on erroneous or biased forecasts should not be a factor.

Possible solutions

There are some directions for power planning that can help to reduce the chances of erroneous forecasts determining future consumption. Briefly, those directions are:

1. Improving the accuracy and objectivity of forecasts so that there will be less need for a reserve margin to hedge against the possibility of unexpected growth and less chance of a biased forecast becoming the basis for future plans.
2. Shortening the time required for constructing supply facilities would make it possible to use shorter, and hence more reliable, forecasts as a basis for deciding whether to build or not. A reduced construction lag also would make it possible to operate closer to the projection with less reserve margin scheduled to cover unexpected growth contingencies.
3. Building low capital cost facilities would make it feasible to have standby reserve generating capacity with minimal pressure to make bargain priced sales of power from the facility in order to recover some of the capital cost.
4. Developing contingency arrangements in advance for handling possible unexpected demand growth or supply delays can make it possible to get through a shortage at minimal cost and hence make it feasible to plan less reserve margin. Contingency arrangements could include elements such as more interruptible contracts (perhaps in several classes), increased interties with other regions, "shortage" pricing schemes, etc.

How to deliberately alter future growth in consumption?

Action has traditionally been directed toward increasing consumption of electricity. Increased consumption could be stimulated by measures such as: (1) rate structures that cause price to be less than marginal cost for the portions of demand that are most subject to change — declining block rates, promotional rates and preferential rates to industry; (2) subsidies for electricity supply — low interest public funds, tax exemption on income, facilities and bonds; (3) advertising and sales promotion; and (4) recruitment of electricity intensive industries and processes.

The directions of these hopes are clear. The power supply industry feels that there are definite advantages to be gained from use of more electricity. A principal concern is that economic prosperity is closely associated with electricity consumption. Our own history and cross-country comparisons show a definite energy/economy correlation. But, this does not mean that a slowing in the growth of electricity demand will necessarily be linked with a slowing or decline in jobs and economic production and incomes. Correlation does not mean necessary causation. There are examples of societies, like Sweden and West Germany, that enjoy economic prosperity at least as high as ours but consume much less energy. Furthermore, a look into our own industries and life styles reveals ample opportunity for adopting processes and measures that use less energy. Capital, labor and better technology can all be substituted for energy. in producing the same level of material consumption.

On the other hand, individuals who are concerned about environmental degradation and the ills of growth fervently hope that demand will grow more slowly. If growth is slow, building of new facilities can be delayed and environmental and social costs avoided.

Rate changes

More recently, attention has turned to several steps that can be taken to reduce realized rates of growth in electricity consumption. One important policy decision is what will be done about electricity rates. There are two aspects. One is adjusting rates to reflect the marginal or incremental cost of power supply. Economists agree, as unanimously as they ever do about anything, that the most efficient allocation of our resources between producing power plants and producing other goods will be achieved if we charge the power user the marginal cost of supplying an additional unit of power. If the user pays anything less than marginal cost there is a natural tendency to use more power and hence incur more power supply costs than would be optimal.

In the Pacific Northwest, the difference between price and marginal additions to power supply are in thermal plants at a cost of more than 20 mills per kwh. The average cost of power now is around 5 mills per kwh (plus costs of delivery and service) and with prices set at average cost, customers are responding by using lots of a product that is priced far below the marginal cost of additional supply. If electricity were priced at marginal cost in the Pacific Northwest, demand growth would fall as customers would adopt energy conservation and substitute other sources for electricity. The Northwest Energy Policy Project estimated that pricing electricity at Long-run Incremental Cost would reduce total 1990 electricity consumption by 27% from the amount projected under continuation of pricing at average cost. Thus adoption of LRIC would be an important determinant of electricity consumption and hence of the need for additions to the power supply system.

Outside of the Pacific Northwest the greatest discrepancy between the marginal cost of electricity and rates is in peak demands. It costs much more to add peaking capacity to a thermal based system than it does to supply more base load where the capacity is already present. Overall economic efficiency would be enhanced if customers' rates for use during peak periods were much higher to reflect the cost involved. Again, there is evidence indicating a significant response which would be reflected in lower peaks, higher system load factors and less need for additional generating capacity to handle load growth.

Another important policy issue is what to do about energy conservation. Energy conservation is an elusive concept that means different things to different people. A particularly confusing entanglement exists between energy conservation and customer response to increasing energy prices. People adopt energy conservation measures, like insulating their houses, mostly because they realize that they will save money by saving energy. When energy costs rise they stand to save even more money and hence more conservation will be profitable to adopt. So, to some extent, conservation is one adaptation to higher price. But there are sound grounds for believing that profitable conservation opportunities go unexploited due to lack of knowledge, breakdowns in the cost/rewards arrangement (such as between tenants and landlords), institutional constraints (such as building, lighting and ventilation codes), high cost and unavailability of financing, etc. There is a need for policy changes to correct these situations. Estimates that we prepared for the Pacific Northwest indicated that information programs to fill some of the gaps in knowledge about conservation could save 6% in Pacific Northwest electricity consumption by 1985. Adding financial incentive programs would increase the savings to 9%, and relatively mild regulatory changes would boost it further to an 11% saving from projected demands.

Conclusion

How should we determine the need for electric energy?

1. We should determine what the demand for electric energy is going to be by using projection models that are disaggregated, detailed, price responsive and linked to the best available demographic and economic projections. These models generally indicate rates of

growth that are lower than those that have been experienced in the past, lower than hoped for by utilities and higher than hoped for by many environmentalists.

2. We should try to break the linkage that allows forecasts to be self-fulfilling by making better, independent forecasts and by increasing capacity for low cost adjustment to unexpectedly low or high growth.

3. We should continue the discussion of growth-determining policies and decide which pricing policies, conservation programs, etc., are in the best interest of the people of the region.

FOOTNOTES

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Economics of Small Hydroelectric Projects

by James V. Williamson

With respect to the title of this seminar, I have difficulty with the semantics of "low-head" which is quite often applied to small hydroelectric development. While much of the small hydro development now underway in the country is indeed low-head, there are many developments which are being considered which have heads greater than the 20-meter limit currently being used by the Department of Energy and yet are possibly more economic than many of the low-head installations which are now receiving consideration. Quite often an upstream installation with higher head will provide the necessary reservoir regulation so that lower head installations downstream can be developed with capacity dependable in the peaking mode, rather than being strictly for generation of secondary energy.

With few exceptions, the hydroelectric sites in the country which have not been developed should be considered as peaking installations (low plant factor), in order for them to be economically competitive to alternatives. This results from the projected high value of demand (peaking) in the future, particularly on the east coast where such generation is normally oil-fired. There is some potential for "energy" installations, with plant factors in the range of .5 to .6 on the larger rivers. This is usually low-head, run-of-river, but dependable capacity can be developed during low stream conditions by operating in the low plant factor range, and by suitable exchange agreements with other utilities to fully utilize the output in this manner. Even so, the output from such an "energy" plant can be expected to be used in the upper part of the load curve in order to achieve maximum economies rather than displacing power from large base load thermal generation.

Hydroelectric projects are capital intensive, and hence are very sensitive to the financing terms for the capital investment to construct them. The variable annual costs of operation of such a project are only 10% to 15% of the total cost including the debt service. In this respect such projects differ significantly from thermal generation. Hence it is very important to obtain the best borrowing terms for financing of such projects.

Municipal tax exempt financing is of course the most attractive source, and is no doubt the reason why municipalities are leading in efforts to develop small hydro throughout the nation. Conversely, it is more difficult for investor-owned utilities to develop these projects because of their inherent higher cost of borrowing and taxable status. The effect of financing terms is amply demonstrated by the two assumed cases of financing a typical project which is well advanced in the development stage.

Case A examines the feasibility of this project with municipal financing and Case B is for financing of the same project through the Rural Electric Administration (REA) with higher interest rates and shorter term. The project is on the east coast and hence is competing with an oil-fired generation economy.

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He received a Bachelor of Civil Engineering degree from Melbourne University, Australia, in 1943.

Description of project

A plan of the project is shown in Figure 12. It includes a total of six powerplants (Nos. 1 through 6). Plant 1 will be located at the toe of a new 165-foot-high earth dam which will provide regulation on the river for peaking operation of the five downstream low-head (30-feet) plants. Plant no. 1 will have three units, with a nominal total installed capacity of 15,000 kw operating under a 150-foot head. Figure 13 shows details of the dam and powerplant arrangement for Plant 1.

Five downstream plants will each have a nominal installed capacity of 3,000-kw operating under heads ranging from 30 to 35 feet. Hence all of these generating units will be of the same size for economic reasons Plants 2 and 3 have powerplants adjacent to the dams. Plant 1 will require a new concrete dam to be constructed and Plant 3 entails raising an existing concrete dam some 11 feet. Details are shown in Figure 14. Plants 4, 5 and 6 will differ in the arrangement of Plants 2 and 3 in that each will involve various lengths of penstock connecting the reservoirs with a downstream powerhouse.

For Plant 4 the existing dam will be abandoned because of its deteriorated condition, and a new dam, about 4 feet higher than the existing dam, will be constructed downstream. For Plant 5 the existing dam will be raised 2.5 feet, and for Plant 6 the existing dam crest elevation will be unchanged. (See Figure 15.)

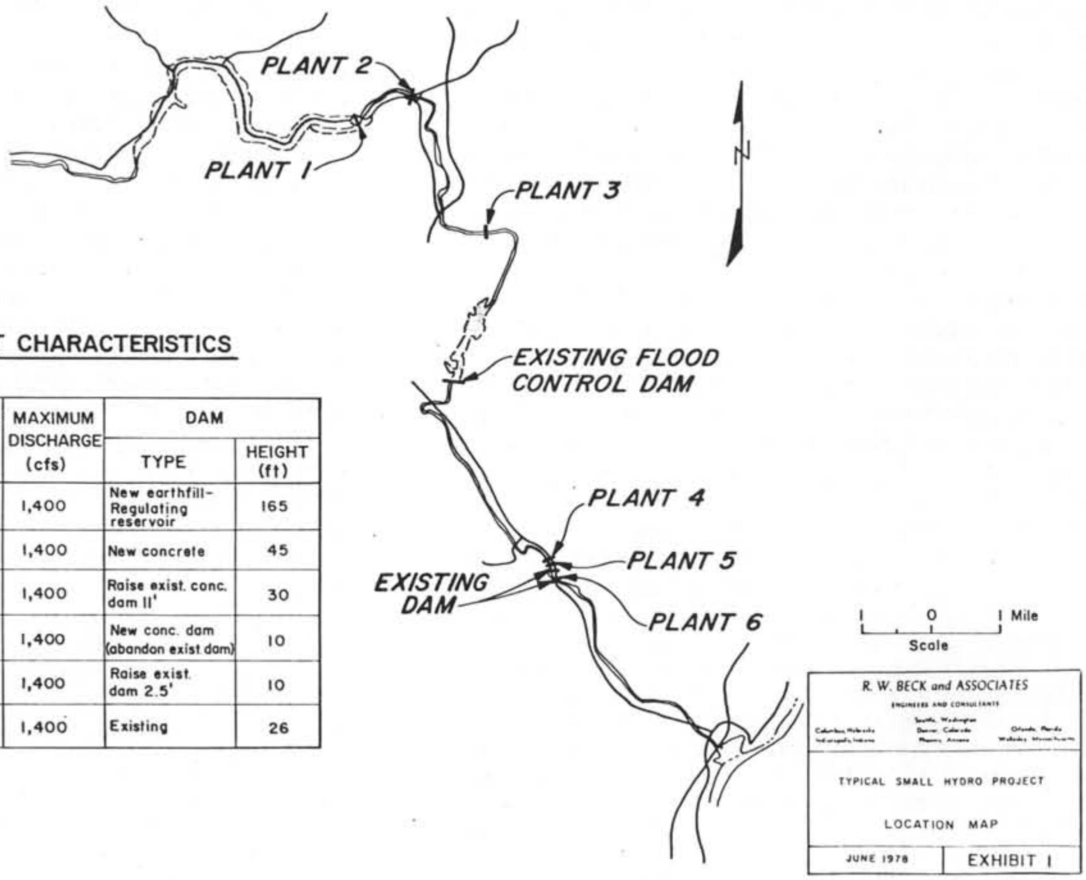
The turbines for Plant 1 will be Francis type with a vertical setting and a steel lined scroll case. The generators will be open air-cooled type with a speed of 360 rpm. The turbines for all of the downstream low head plants will be fixed-blade propeller type with a semi-spiral scroll case and a straight conical draft tube. The generator will be open air-cooled type with a speed of 144 rpm.

The studies referred to herein were generally done in 1976, and are based on the project entering into service in late 1982.

Reservoir operation and power output

Reservoir operation and power studies were conducted for a period of 44 years of hydrological record. Normally the project will operate during peak load daytime periods and will release up to approximately 1,400 cfs at Plant 1. This release will pass throught Plant 2 and 3 into the existing flood control reservoir downstream and will normally occur for 12 hours or less each day. Generating flows during the off peak periods will occur only when the average monthly stream inflows exceed 600 to 700 cfs and the reservoir is full, which will be principally in March, April and May.

During the winter months of November through February the reservoir can be drawn down 17 feet to El. 748, and during the summer months of May through October the reservoir will be maintained at El. 753 or above. Operation studies show that if the reservoir at Plant 1 is maintained at a lower level than a minimum El.



POWER PLANT CHARACTERISTICS

PLANT	INSTALLED CAPACITY (kW)	AVERAGE HEAD (ft)	MAXIMUM DISCHARGE (cfs)	DAM	
				TYPE	HEIGHT (ft)
1	15,000	150	1,400	New earthfill-Regulating reservoir	165
2	3,000	34	1,400	New concrete	45
3	3,000	35	1,400	Raise exist. conc. dam 11'	30
4	3,000	30	1,400	New conc. dam (abandon exist dam)	10
5	3,000	31	1,400	Raise exist. dam 2.5'	10
6	3,000	34	1,400	Existing	26

Figure 12.

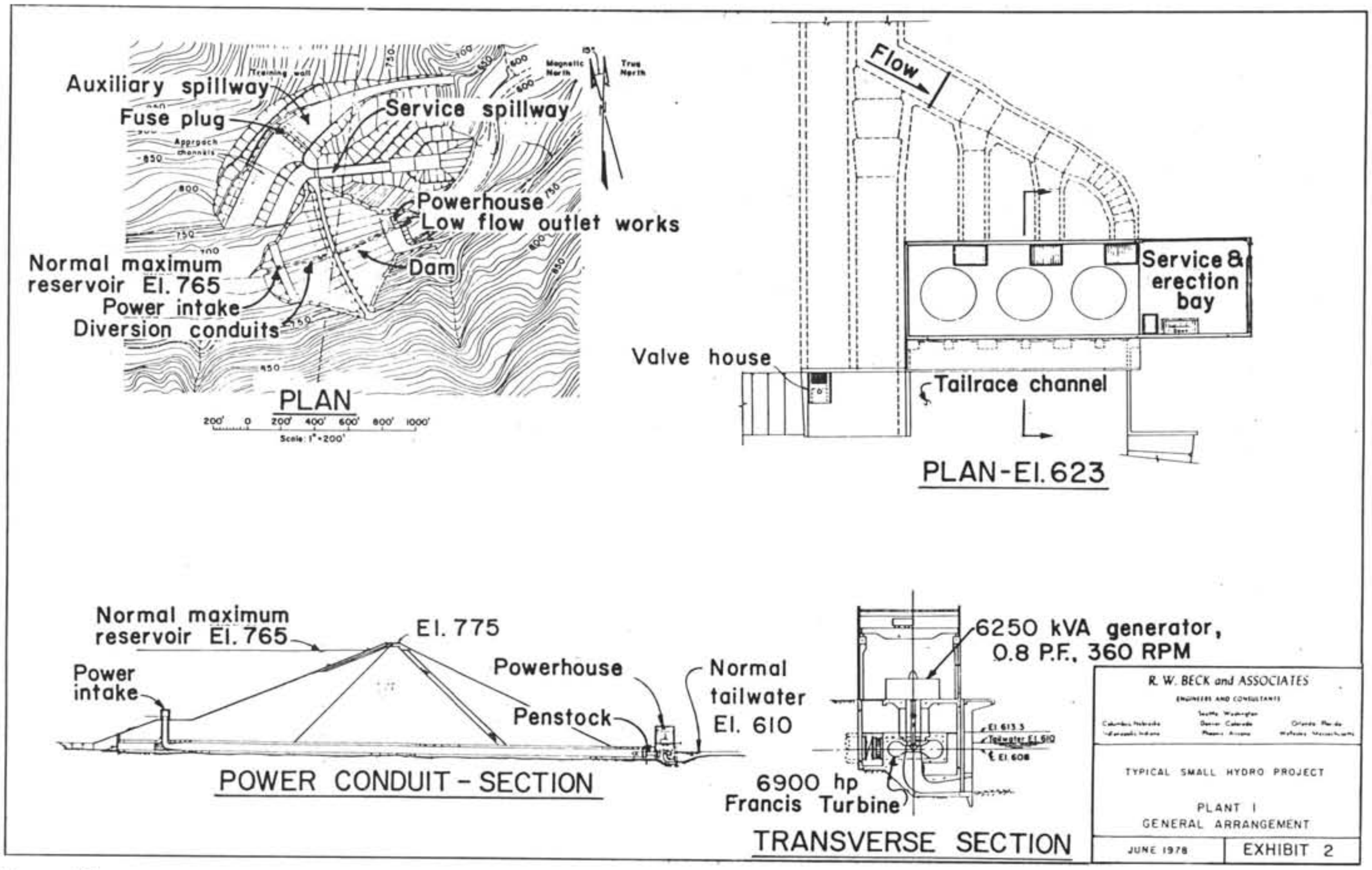


Figure 13.

748 during the year, very little annual energy is gained and dependable capacity is of course lost. Regulation of the daily flows can be obtained from the storage at Plant 3 and additional regulation would be gained in normal passage of the water through the existing downstream flood control reservoir, so that the same flow will also be available to Plants 4, 5 and 6 during peak load periods.

During periods of nongeneration a minimum flow will be released for stream-flow maintenance, fish and wildlife and scenic purposes.

The 44-year average energy generated by the entire project is 45,730,000 kwh annually delivered to the load centers. In the most adverse hydrological year the annual generation is 18,910,000 kwh, and in the second most adverse year it is 29,930,000 kwh. It is considered reasonable to assume that the energy output during the second lowest flow period is firm and the economic feasibility studies were preformed on this basis.

The dependable capacity (demonstrated capability) for the project was determined based on the power pool rules prevailing in the vicinity. The capability for each generating unit is based on the year of median flow during the last 20 years. The last week of January of this year was checked to produce a minimum of two consecutive hours of daily capability for each weekday, and the dependable capacity is based on the lowest resultant reservoir level which was determined to be El. 759. On this basis, Plant 1 would have a capacity of 15,800 kw and the other five units a total of 15,600 kw, to arrive at a total dependable capacity for the project of 31,400 kw as delivered to the load centers.

Based on the average annual energy generated, and the dependable capacity, the annual plant factor of the project is 16.6% On the basis of the energy generated during the second flow year (firm energy), the annual plant factor is 10.9%

Economic analysis

To establish the economic feasibility of the project, comparison was made of the project with the most economic alternative sources of generation to meet regional peak loads. The analysis was made as a comparison of annual costs of the project with the annual cost of the most economic alternatives producing the same amount of power, which represents the annual value or benefit from the project. These two such alternatives are; (1) construction of a simple cycle oil-fired combustion turbine with the same output as the project, and (2) continuing power purchases from the current power supplier.

The combustion turbine generic alternative would be located near the load centers. The economic comparison was made on the basis of annual costs for the first ten years of operation of both the project and the combustion turbine alternative to establish a short term break-even point. The economic life of the project is assumed to be 50 years and the combustion turbine is assumed to have an economic life of 25 years.

The ten-year comparison was made on a present-worth basis. The annual value of the power output of the project is based on the respective costs of capacity and energy from the combustion turbine alternative. The project would deliver an estimated total of 45,730,000 kwh of which 29,930,000 kwh is calculated to be firm energy. The additional 15,800,000 kwh of the energy (45,730,000 - 29,930,000 kwh) would replace energy in the region that would otherwise be generated by older oil-burning, steam-electric power plants, and 29,930,000 kwh would be delivered as firm peaking energy at 10.9% plant factor.

Annual capacity costs for the combusiton turbine alternative for 1982 are estimated to be \$53.05/kw and \$55.94/kw for delivered capacity for municipal and REA financing, respectively. Firm energy costs are estimated at 65.15 mills/kwh and the value of secondary energy is established at 44.37 mills/kwh in 1982. Table 1 shows the estimated first year project benefits calculated on this basis.

The prevailing costs of demand and energy for the second alternative of continued power purchases were escalated to the time frame under consideration. The comparison with the project is again made for the first ten years of operation, on a present-worth basis. The 1976 wholesale purchase power demand cost was \$76.22/kw and the energy rate 12.0 mills/kwh. These values become \$114.40/kw and 18.0 mills/kwh in 1982, when escalated at 7% annually, which is the same escalation rate used for costs of all alternatives. The first year project benefits for this alternative are shown in Table 1.

Case A - Municipal financing

The estimated project annual costs for this case are shown in Table 2 and for Case B - REA financing - in Table 3. The determination of economic feasibility is based on 50-year revenue bonds (the same term as the economic life), with repayment over a 47-year period and interest at 6.5%. Hence the basis for the economic feasibility is the same as the financial feasibility in this case.

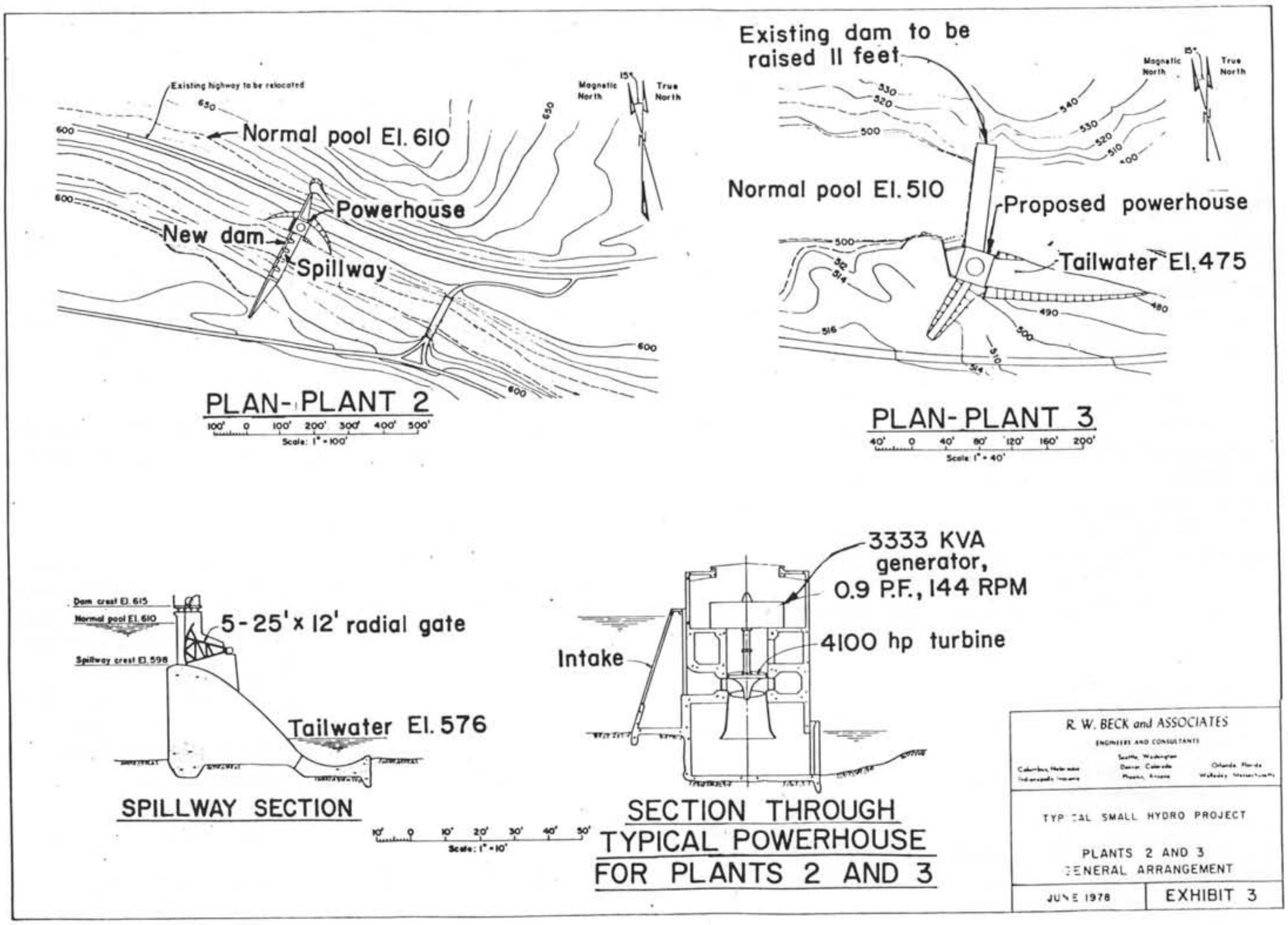


Figure 14.

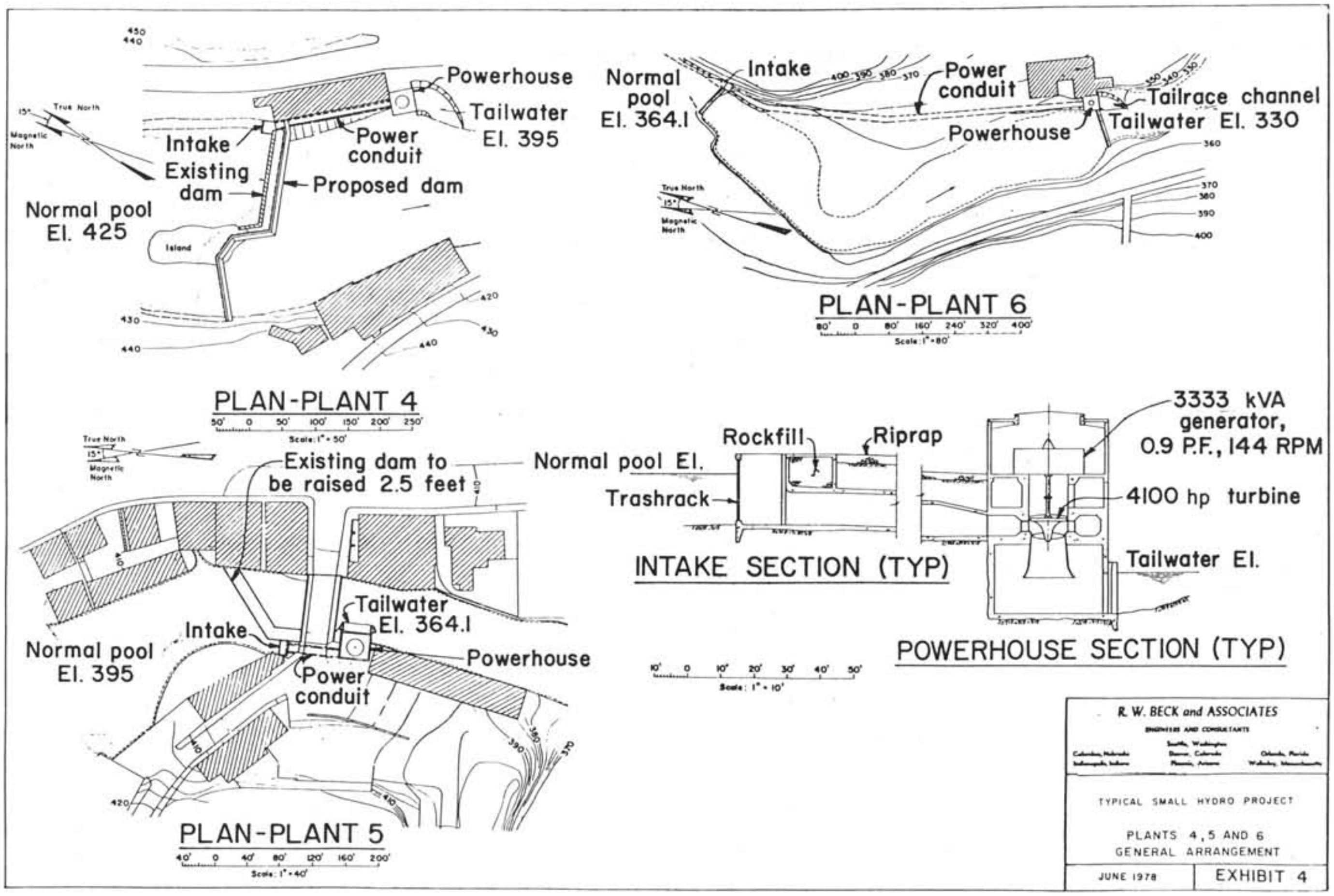


Figure 15.

The economic feasibility of the project is determined by comparing the benefits and costs over its useful life. Table 4 shows a comparison of the project costs and the combustion turbine alternative over the first 10 years of operation. As shown, during the first four years of project operation the annual cost of the project would exceed the annual costs of the combustion turbine alternative. However, since a larger portion of hydroelectric costs are fixed in comparison with alternative sources of power, project benefits exceed project costs after the initial four years of operation and continue to increase for the remaining 46 years of the economic life of the project.

Table 5 shows a comparison of the project cost with the estimated future average system power costs over the same 10-year period. As can be seen, the alternative of combustion turbine generation is the least costly, and hence is used to demonsrate the final economic feasibility of the hydro project.

Based on the annual surplus or deficits amounts for the project compared to the combustion turbine alternative as shown in Table 4, it is determined that during the first 10 years of project operation the project

Table 1. (right) Total first year project benefits. Typical small hydro project.

Combustion Turbine Alternative

Case A - Municipal Financing			
Capacity - 30,100 kw[1] at $53.05/kw	=	$	1,597,000
Primary Energy - 29,930,000 kwh at 65.15 mills/kwh	=		1,950,000
Secondary Energy - 15,800,000 kwh at 44.37 mills/kwh	=		701,000
TOTAL PROJECT BENEFITS	=	$	4,248,000
Case B - REA Financing			
Capacity - 30,100 kw at $55.94/kw	=	$	1,684,000
Primary Energy - 29,930,000 kwh at 65.15 mills/kwh	=		1,950,000
Secondary Energy - 15,800,000 kwh at 44.37 mills/kwh	=		701,000
TOTAL PROJECT BENEFITS	=	$	4,335,000

Purchased Power Alternative

Capacity - 30,100 kw at $114.40/kw	=	$	3,443,000
Energy - 45,730,000 kwh at 18.0 mills/kwh	=		823,000
TOTAL PROJECT BENEFITS	=	$	4,266,000

Note:
1. Installed capacity adjusted for forced outage reserves.

Total Investment Cost:		
Total Construction Cost[1]	=	44,064,000
Net Interest During Construction[2]	=	4,500,000
TOTAL INVESTMENT COST	=	48,564,000
Total Annual Costs:		
Operation and Maintenance	=	935,000
Transmission	=	168,000
Interest[3]	=	3,472,000
Depreciation[4]	=	107,000
TOTAL ANNUAL COSTS	=	4,682,000

Notes:
1. Escalation from current costs (contractor's bid January 1976) to full commercial operation by January 1982 at 7% annually.
2. Interest at 6.5% on total capital requirements (including financing costs and reserve funds), less interest earnings on unused funds at 6.5%.
3. 6.5% annually.
4. 50-year bond term, repayment period 47 years.

Table 2. Project estimated capital and annual costs. Case A: Municipal financing. Typical small hydro project.

Total Investment Cost:		
Total Construction Cost[1]	=	$ 44,064,000
Net Interest During Construction[2]	=	5,560,000
TOTAL INVESTMENT COST	=	$ 49,620,000

Total Annual Costs:	**First Year**	**Eighth Year**
Operation and Maintenance	$ 935,000	$1,501,000
Transmission	168,000	270,000
Interest	4,473,000	4,473,000
Principal[3]	-	230,000
TOTAL ANNUAL COSTS	$5,576,000	$6,474,000

Note:
1. Escalation from current costs (contractor's bid January 1976 to full commercial operation by January 1982, at 7% annually.
2. Interest at 9% on construction funds borrowed as needed.
3. 35-year loan term, 9% interest, no principal payments for first seven years.

Table 3. Project estimated capital and annual costs. Case B: REA financing. Typical small hydro project.

would show an advantage over the alternative of about $705,000 in terms of 1982 dollars (present worth). Although the project shows a benefit-cost ratio of about only .90 in the first year of operation, over a reasonable period of ten years of operation and assuming that the cost of oil fuel escalates at 7% annually, the hydroelectric project shows economic feasibility.

The ten-year comparison of the cost of the alternatives is also shown graphically in Figure 16.

Case B - REA financing

The estimated project annual costs for this case are shown in Table 3. The determination of financial

Year	Annual Surplus (Deficit)	1982[1] Present Worth	Cumulative Present Worth
1982	(433)	(434)	(434)
1983	(325)	(307)	(741)
1984	(210)	(187)	(928)
1985	(85)	(71)	(999)
1986	47	37	(962)
1987	189	141	(821)
1988	341	255	(566)
1989	504	335	(231)
1990	678	425	194
1991	864	511	705

Note:
[1]Present worth of annual surplus or deficity based on interest rate of 6%.

Table 4. Ten-year cost comparison of project and combustion turbine alternative. Case A: Municipal financing. Typical small hydro project.

Year	Annual Surplus (Deficit)	1982[1] Present Worth	Cumulative Present Worth
1982	(416)	(416)	(416)
1983	(194)	(183)	(599)
1984	42	32	(562)
1985	296	249	(313)
1986	567	449	136
1987	857	679	815
1988	1,168	823	1,638
1989	1,500	998	2,636
1990	1,856	1,164	3,800
1991	2,236	1,323	5,123

Note:
[1]Present worth of annual surplus or deficit based on interest rate of 6%.

Table 5. Ten-year comparison of project and purchased power alternative. Case A: Municipal financing. Typical small hydro project.

Year	Annual Surplus (Deficit)	1982[1] Present Worth	Cumulative Present Worth
1982	(1,241)	(1,241)	(1,241)
1983	(1,132)	(1,068)	(2,309)
1984	(1,017)	(905)	(3,214)
1985	(892)	(749)	(3,963)
1986	(760)	(602)	(4,565)
1987	(618)	(462)	(5,027)
1988	(466)	(329)	(5,356)
1989	(407)	(271)	(5,627)
1990	(233)	(146)	(5,773)
1991	(47)	(28)	(5,801)

Note:
[1]Present worth of annual surplus or deficit based on interest rate of 6%.

Table 6. Ten-year cost comparison of project and combustion turbine alternative. Case B: REA financing. Typical small hydro project.

feasibility in this case is based on an assumed 35-year loan term and interest rate of 9%. The loan conditions include interest payments only for the first seven years of project operation. Beginning with the eighth year the principal would be retired on the level debt service basis over the next 35 years.

Table 6 shows a comparison of the project annual costs and the combustion turbine alternative, which is again the least costly alternative, over the first 10 years of operation. As shown during the first 10 years, the annual cost of the project would exceed the annual costs of the combustion turbine alternative.

The combustion turbine alternative is found to be the least costly alternative for the final economic feasibility. Hence the results from Table 6 indicate that the hydro project is not economically feasible when the economics are based on a financial feasibility analysis using REA loan conditions.

The ten year comparison of cost of alternatives is also shown graphically in Figure 16.

Conclusions

It is concluded that the typical hydro project herein shows economic feasibility with municipal financing, but not with higher interest rate, shorter term, REA financing. The least costly alternative to the hydro project is the generic alternative of constructing an oil-fired simple-cycle combustion turbine alternative with the same output as the project.

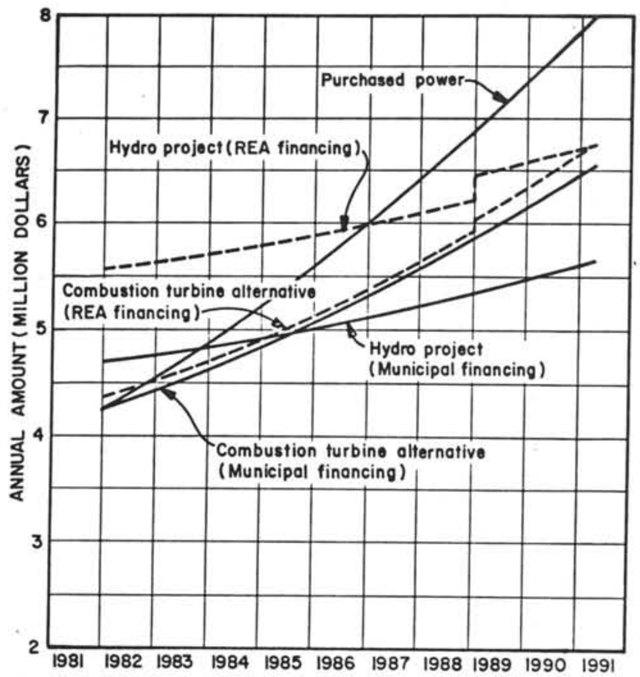


Figure 16.

Following his speech, Mr. Williamson was asked the following question.

Q: Your last remark was the key remark: "If we can get the oil". Then maybe there's maybe one more question we should address ourselves to — it's 15 dollars for our own costs with high cost pipelines in Alaska and so forth, and Saudia Arabia can change their cost of oil at any time. Mr. Williamson, or other members on the panel, do you have any handle on the costs per barrel of oil where this economic situation may change from what you've just shown us — Is it $20? Is it $25? — where all of these so-called marginal situations may come on the line?

Williamson: Well, I can't answer you quantitatively. Again I want to point out that if you look at the value of the capacity in the Northeast situation, quite often when you're talking now about purchase alternatives, it might be 80% of the total value of the project, so it's not going to make a heck of a lot of difference, with that kind of a peaking project, whether the cost of oil is $15 a barrel or $20 a barrel. What the utilities are doing is charging you a demand charge which is really related to construction of very expensive base load capacity which is either coal fired or nuclear fired. And when you get 75 to 80% of your benefit of the project in demand, and you're looking at purchase alternatives which normally govern — and this was an unusual case where the generic alternative of combustion turbine and oil fired did govern — when you're looking at purchase which have this high demand value, which is the case, wherever you have oil fired economy, or when you've got a large amount of base load generation, then it won't make a lot of difference whether you've got $15 or $20 a barrel in my opinion.

Some Basic Considerations

by David C. Willer

Although most of my remarks will be directed toward economics of low-head hydroelectric projects, there are also other, possibly more important reasons for the interest in small hydroelectric plants, such as a desire of people to develop environmentally acceptable, nonpolluting, renewable resources to enable conservation of our non-renewable resources.

In this presentation on the economics of low-head hydroelectric projects I will present some basic economic considerations for both buyers and sellers of power.

The first category is the small municipality, the Rural Electrification Administration utility or the Co-op which is in the position of having to purchase at least some power for its consumers.

The second category is the public irrigation or water district which has the potential for becoming a power producer, simply because it owns an existing dam, canal or pipeline with undeveloped hydro potential which may have been constructed primarily for flood control or water supply.

Both buyers and sellers face different economic considerations. Tudor has been engaged by both entities, so we have learned to see the economic picture from a variety of viewpoints.

Large electrical utilities are generally not interested in developing small hydroelectric projects simply because - economically - they must concentrate on large power producing projects.

Since the Arab oil embargo in 1973, the wholesale price of electricity to small municipalities and electric co-ops has increased at an unprecedented rate. A portion of the increase in California may also be due to the last two drought years and reduced stream flow. For example, the city of Ukiah in May, 1973, purchased its

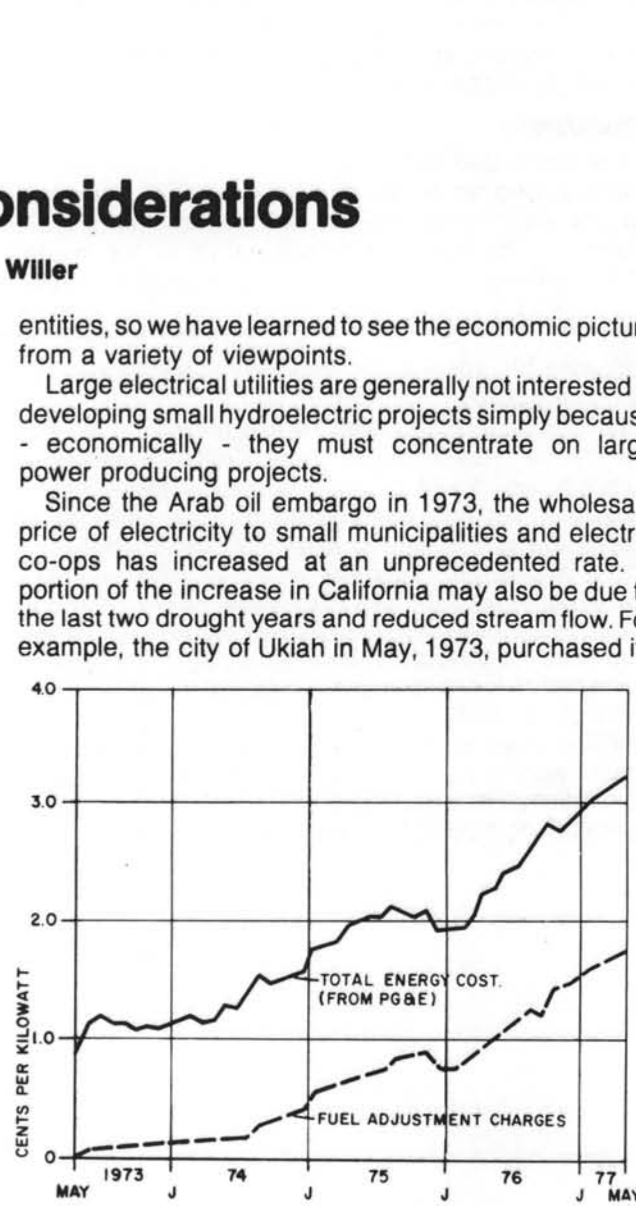


Figure 17. Cost of Purchasing Power - City of Ukiah.

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He graduated from the University of Iowa with a B.S. in Civil Engineering in 1952 and from the University of Southern California with an M.S. in Civil Engineering in 1958.

total needs for distribution to residents for 9 mills per kilowatt-hour. By May, 1977, the wholesale price of purchased power had risen to 33 mills per kilowatt-hour. (See Figure 17.)

One community's solution

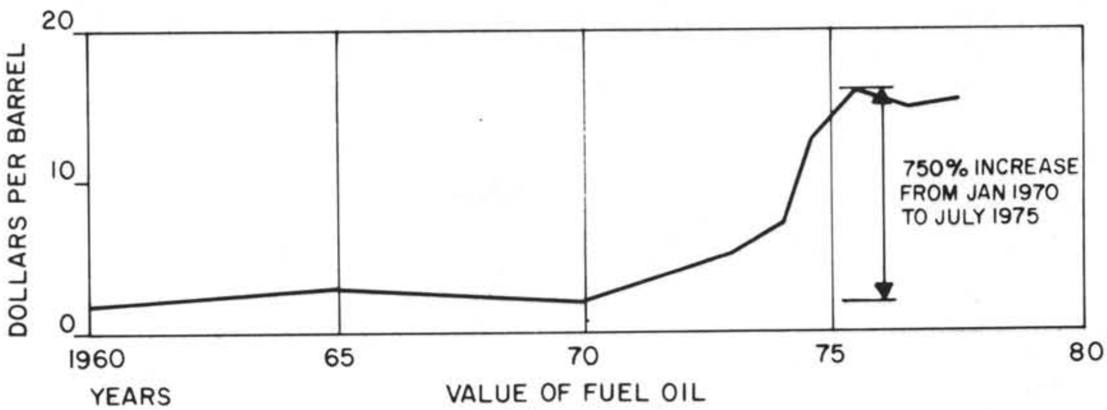
The supplier of their wholesale power in Northern California, Pacific Gas and Electric Company, has experienced power production increases at an unprecedented rate, primarily because of the cost of fuel oil. In the early 1970's, PG&E purchased fuel oil for $3 per barrel and could produce energy for 4.5 mills per kilowatt-hour. (See Figure 18.) At the present time, low sulphur fuel oil, the only kind that can be utilized because of air emission standards, costs about $15 per barrel and the resulting energy cost is 20 to 22 mills per kilowatt-hour.

The city of Ukiah recently engaged Tudor to investigate alternatives to the prospect of having to continue to purchase electrical energy at PG&E wholesale power rates. We recommended that they satisfy a portion of their electrical needs by constructing a small hydroelectric plant at an existing Corps of Engineers flood control and water conservation structure on the Russian River, only about two miles from the center of Ukiah. (See Figure 19.) The Corps of Engineers has endorsed the idea. The proposed 4,000 kw plant will supply about one-fourth to one-third of the city's present energy needs. The cost of producing power would be about 16 to 18 mills per kilowatt-hour, or only one-half the cost to purchase energy today.

In general there are many similar communities now investigating alternative sources of power. One problem which some REA's and co-ops face is that they once signed "sole source of supply" agreements which prohibit them from developing small hydroelectric projects in their own "back yard." As a result, they are locked in and will have to continue to purchase power from large coal-fired or nuclear generating stations at a rate yet "undetermined" in many cases.

Small municipalities and REA's face another important consideration when reviewing the economics of building a small hydroelectric project versus continuing to purchase power wholesale. That is the possibility of hedging against inflation in power costs. The cost of power produced from the small hydro project should remain fairly constant over the life of the project.

As an example, let us assume that a small municipality has the alternative of constructing a 6,000 kw hydroelectric plant at an existing dam to provide part of its needs. Assume a capital cost of $5 million. That



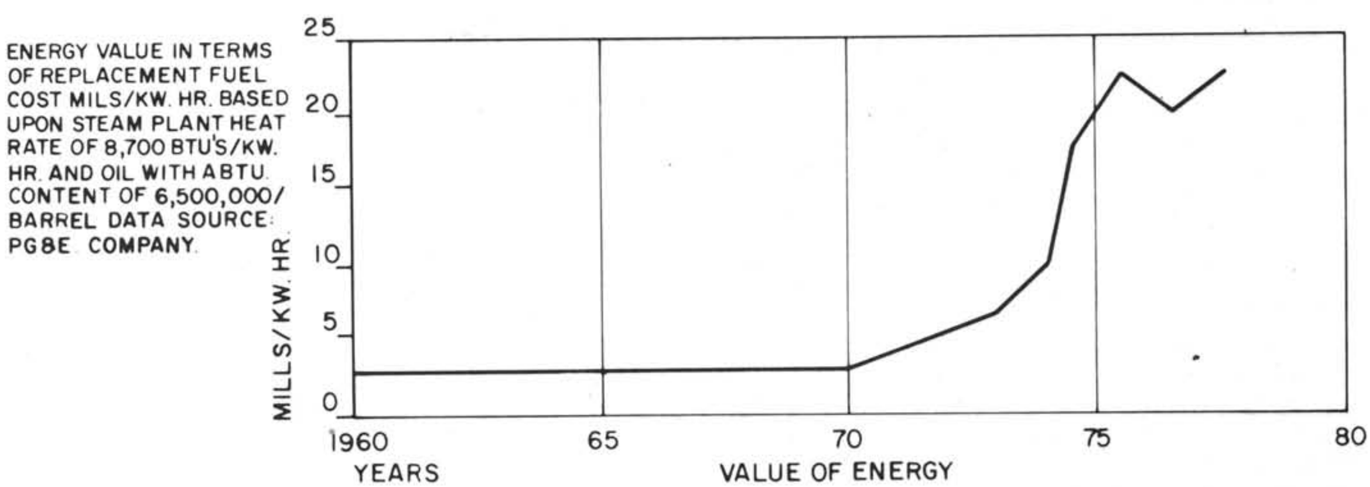


Figure 18. Energy Value - Cost of Fuel Oil.

Figure 19. Lake Mendocino - Corps of Engineers.

amounts to $833 per kilowatt which is a reasonable cost for a power plant of this size at an existing dam. Also, assume that the hydroelectric plant would produce on an average of 20 million kilowatt-hours per year. The annual cost of the plant would be about $350,000. That amount would be for revenue bonds (assume 40 years at a 7 percent interest rate) to construct the facility and $50,000 per year for operation, maintenance, and replacement. Each year after the first year of operation, assume that the operation and maintenance cost of the small hydroelectric project would escalate at 5 percent per year. (See Table 7, columns 1 and 2).

The alternative to construction of the small hydroelectric plant is to continue to purchase that portion of the power wholesale. At certain times of the year the hydroelectric plant could not operate, so the municipality would need to continue to purchase power but could reduce its energy consumption by the amount produced by the small hydroelectric plant.

If this turned out to be 20 million kilowatt hours at 20 mills, the city would reduce its purchasing needs by $400,000. Table 7, column 3, also shows this continuing purchase cost, assuming it also would increase in price at 5 percent per year.

In the first year, the cost of producing power at a small hydroelectric plant versus purchasing from a wholesaler of electrical power amounts to a benefit cost ratio of 1.0 to 1.0. That is, it would cost $400,000 to either produce or purchase. There is no particular advantage at this point. However, each year thereafter it becomes cheaper to generate a portion of their needs and in the 40th year, the cost of energy from the small hydro plant would be only $685,288 versus $2,681,900 to purchase.

Also, when the present worth of the annual costs of the small hydroelectric plant for a 40-year period is compared to the present worth of the purchased power as shown on Table 7 in columns 5 and 6, it can be seen that the benefit-cost ratio, when inflation is considered, amounts to 1.77 to 1.00 and is heavily weighted in favor of the small hydroelectric project installation.

Development of a small hydroelectric project is a built-in check against future escalating power costs and such inflationary prospects should always be considered in economic studies.

Wholesaling

Now let's talk about the economics of small hydroelectric projects where owners, such as irrigation districts, water districts or other special-purpose districts want to generate hydro power and wholesale it to a distributor. In most cases, the special district wants to recover their cost of the new installation and realize an incentive profit. The power generated from the falling water in these cases is often incidental to some other purpose, such as releases for irrigation or domestic

SMALL HYDRO

YEAR	COST STREAMS		BENEFIT STREAM	PWF 1/	PRESENT VALUES	
	DEBT SERVICE	O&M COST +5.0%	POWER PURCHASE +5.0%	@7.0%	COSTS	BENEFITS
1	350000	50000	400000	0.9346	373832	373832
2	350000	52500	420000	0.8734	351559	366844
3	350000	55125	441000	0.8163	330703	359987
4	350000	57881	463050	0.7629	311171	353255
5	350000	60775	436203	0.7130	292877	346656
6	350000	63814	510513	0.6663	275742	340176
7	350000	67005	536038	0.6227	259690	333818
8	350000	70355	562840	0.5820	244650	327578
9	350000	73873	590982	0.5439	230559	321455
10	350000	77566	620531	0.5083	217353	315427
11	350000	81445	651558	0.4751	204976	309550
12	350000	85517	684136	0.4440	193375	303764
13	350000	89793	718343	0.4150	182498	298087
14	350000	94282	754260	0.3878	172300	292515
15	350000	98997	791973	0.3624	162737	287047
16	350000	103946	831571	0.3387	153767	281682
17	350000	109144	878150	0.3166	145393	276417
18	350000	114601	916807	0.2959	137459	271250
19	350000	120331	962648	0.2765	130050	266180
20	350000	126348	1010780	0.2584	123097	261205
21	350000	132665	1061319	0.2415	116570	256322
22	350000	139298	1114385	0.2257	110441	251531
23	350000	146263	1170104	0.2109	104685	246830
24	350000	153576	1228610	0.1971	99278	242216
25	350000	161255	1290040	0.1842	94198	237689
26	350000	169318	1354542	0.1722	89424	233246
27	350000	177784	1422269	0.1609	84936	228866
28	350000	186673	1493383	0.1504	80717	224608
29	350000	196006	1568052	0.1406	76748	220410
30	350000	205807	1646454	0.1314	73015	216290
31	350000	216097	1728777	0.1228	69501	212247
32	350000	226902	1815216	0.1147	66194	208280
33	350000	238247	1905977	0.1072	63080	204387
34	350000	250159	2001275	0.1002	60148	200567
35	350000	262667	2101339	0.0937	57384	196818
36	350000	275801	2206406	0.0875	54780	193139
37	350000	289591	2316726	0.0818	52324	189529
38	350000	304070	2432563	0.0765	50008	185986
39	350000	319274	2554191	0.0715	47823	182510
40	350000	335238	2681900	0.0668	45760	179098
TOTALS	14000000				5990765	10597337

1/ INTEREST RATE - 7%

$$\text{BENEFIT-COST RATIO} = \frac{10597337}{5990765} = 1.77$$

Table 7. Economic comparison (dollars).

water from a dam or pipeline, or irrigation water being checked in a canal. Also, in the case of small hydro plants at diversion dams or river, they may be permitted to generate power only from the natural flow of the stream. Any daily re-regulation of the river flows or storage of water to meet an electrical demand may be deemed environmentally unacceptable.

Consequently, without any storage capacity or the ability to release water upon power demand, the economic worth of energy from such a project would depend directly upon the kind of energy that it would displace in the electrical load for the utility which would purchase the power. Also, the energy from the small hydroelectric project should replace the more expensive energy in the load curve of the utility.

In general, if this energy replaces fuel oil in the year 1978, you could say its value would be competitive at 20 to 24 mills per kilowatt-hour. If coal or nuclear fuel were replaced, its value would be lower. Coal costs may range from 8 to 15 mills per kilowatt-hour depending upon air pollution control requirements. Nuclear power may range from 3 to 11 mills per kilowatt-hour dependent upon whether the cost of disposing of the nuclear waste is included. The utility may wish to replace the energy at its system "mix" of fuel rather than one specific source.

It should be pointed out that all kinds of fuel for electrical generation, not just petroleum, are increasing at a rate equal to or greater than the cost of living index.

Some small hydro projects may have capacity value too, an ability to impound water and release it for power generation at a desired rate. That kind of "dependable capacity" as we call it may add to its value to a prospective utiltiy purchaser. The anticipated capacity may only be available five days a week, 52 weeks a year, or possibly six months a year on a 24-hour basis. Figure 20 shows the power demand for a typical week for a utility during its maximum nonth of the year. The figure shows that 6 Mw of capacity for this utility load which is available five days a week, twelve hours a day, can be considered dependable. The value of capacity is normally expressed as dollars per kilowatt-year and can vary depending upon the kind of generation being replaced from a low of $35 kilowatt for an oil-fired plant to $80 per year for a nuclear plant for public owned utilities in the year 1978. For privately-owned investor utilities, these values may vary from $60 to $150 per kilowatt respectively.

Interchange

The principle of interchanging of power generation and sharing of benefits between members of a group of electrical utilities has been well-established. Special districts which may want to generate the wholesale electrical power also want to be considered a part of this group. Traditionally, the cost benefits of interchanging of power are shared equally between the utilities based upon the alternative power generation cost for the utilities.

An agreement between the Nevada Irrigation District

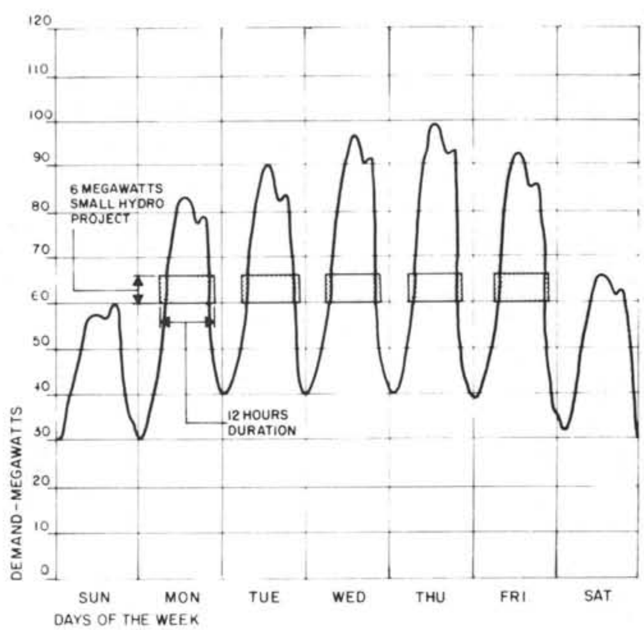


Figure 20. Power demand-typical week.

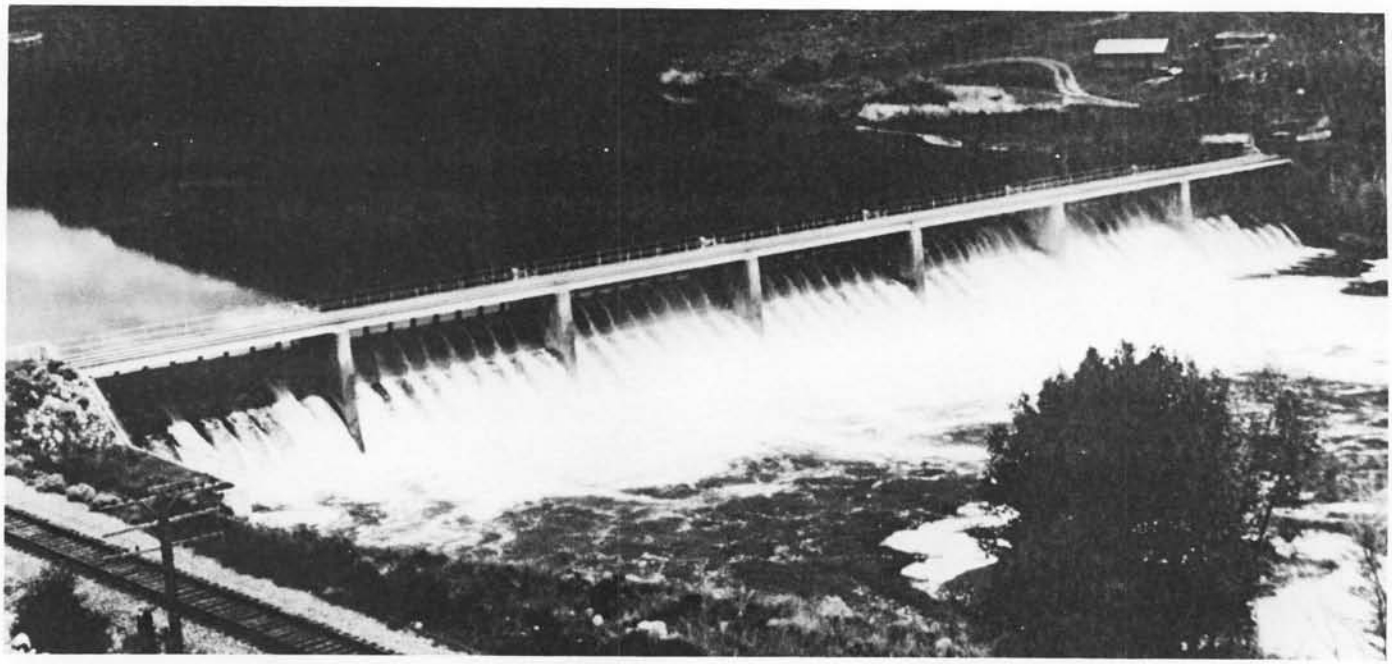


Figure 21. Broadwater Missouri Project - State of Montana.

and Pacific Gas and Electric Company in California, which Tudor helped negotiate, is an example of such sharing of benefits. In this case, the Nevada Irrigation District owns and operates Rollins Reservoir for water conservation and irrigation. The District and PG&E entered into a contract to install an 11,000 kw power plant from which PG&E would purchase the energy generated. The alternative source for PG&E was an obsolete oil-fired steam station plant which was producing power at a cost of 21 mills per kilowatt-hour.

Figure 22. Check 22.7 Drop Structure — South Columbia Irrigation District.

The new generator by Nevada Irrigation will produce power for 13 mills per kilowatt-hour. The resulting 8 mills saving will be equally divided between the two entities, by this simple pricing arrangement.

The Rollins Project will provide to the Nevada Irrigation District an average of about $300,000 incentive annual payment. That is a sound incentive for proceeding with the project. Furthermore, the costs of the alternative PG&E power source could be expected to escalate steadily and so the benefits of the new plant will increase - for both parties - in years ahead. The index of the incentive payment used in the agreement which will escalate as the value of power increases, was based upon the rate which the utility sells power wholesale to other utilities. A similar rate base could be used in the Northwest, such as for the Bonneville Power Administration rate for wholesaling an equal amount of capacity and energy. As the Bonneville power rate increases in time, the incentive payment could also escalate. Another possible index which could be used is the U.S. Department of Commerce utility component of the "Cost of Living Indices". This index is published quarterly and as the retail value for power increases, the benefit could increase proportionately.

Another Tudor client which has been successful through power purchase negotiations of this kind is the Siskiyou County Flood Control and Water Conservation District. The District, with Federal and State aid, created a recreation and flood control lake on the upper Sacramento River about 11 years ago. It was thought originally that operation and maintenance would be self-supporting from the fees paid by recreational users. In reality, the project has been costing the taxpayers of Siskiyou County an average of $100,000 per year.

Power pays for play

Tudor has proposed the installation of a small 4,000 kw plant, and we believe that the selling of power will reduce or completely eliminate their dependence upon taxation to support the recreational development. The power will be sold to the State of California Department of Water Resources, which will use the energy for pumping water in the State Water Project.

The incentive payment to Siskiyou County amounts to about 4 mills per kilowatt-hour and this will increase every three-year period as the value for similar energy increases. Our studies indicate that the project should yield initially about $90,000 per year to the District, beyond the costs of debt service, operation and maintenance of the powerplant.

Broadwater-Missouri Project in Montana, under the administration of Montana's Department of Natural Resources and Conservation, has a diversion structure on the Missouri River with no storage capacity. (See Figure 21.) Yet it lends itself to installation of generating capacity of 14,400 kw and an ability to produce 80 million kilowatt-hours per year from the average flow of 4 million acre-feet of water. The installation will cost $14.7 million and it will produce energy at a cost of only 14 mills per kilowatt-hour. The State proposes to sell the power from the proposed project including an added incentive payment to obtain funds for maintenance of other State-owned dams and possibly retire a portion of the unsecured debt for their water conservation projects.

Examples

Now let's look at a couple of examples of small powerplants on conveyance structures and outlets.

We recently prepared a preliminary design for a powerplant at South Columbia Irrigation District's Check 22.7 structure near Pasco, Washington (See

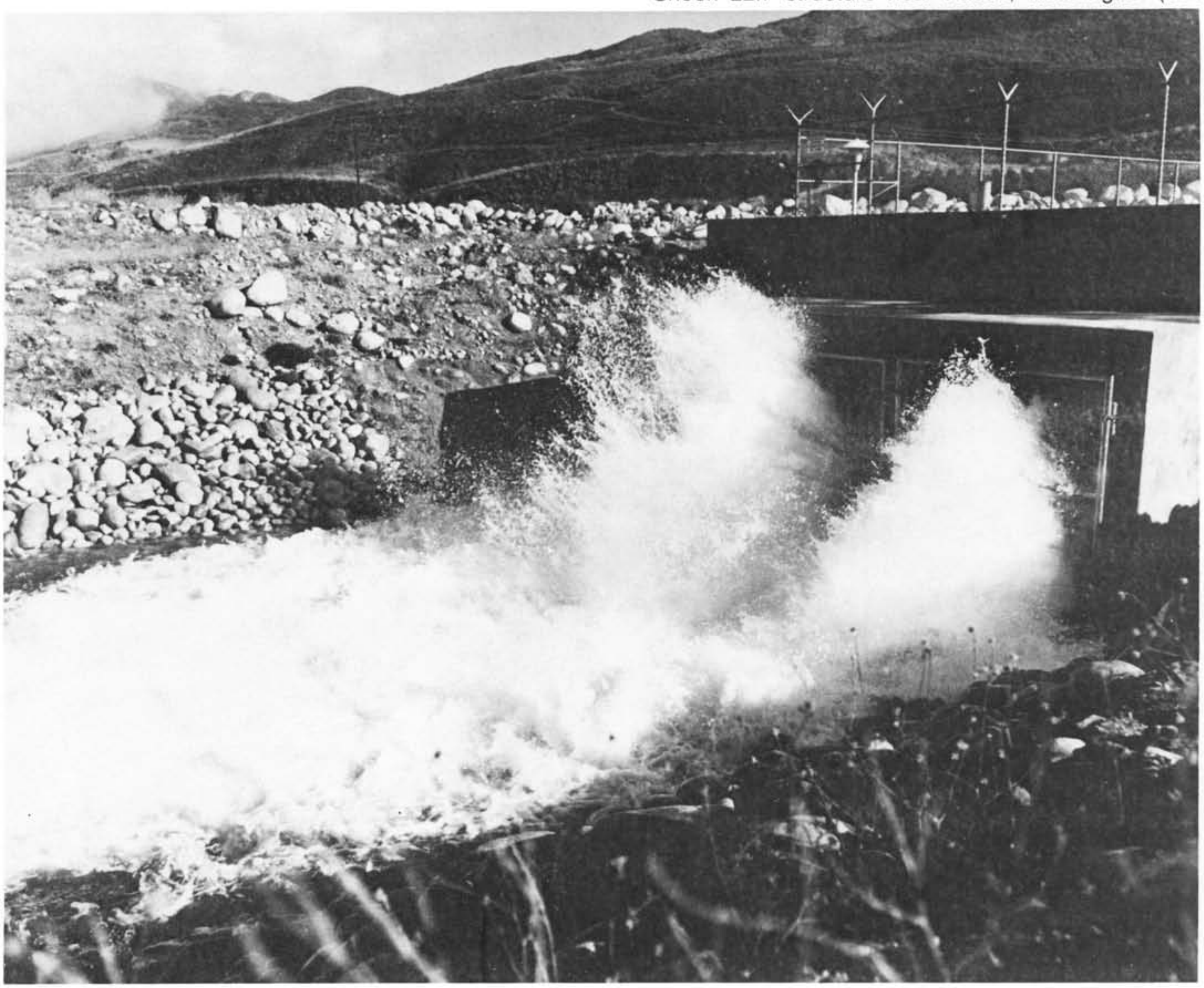


Figure 23. Waterman Outlet turnout — San Bernardino Municipal Water District.

Figure 22.) This is a case of where irrigation water is being carried from one plateau level down to another. The difference in elevation is 52 feet, and that kind of hydraulic drop justifies installation of a low-head hydro plant with a capacity, in this case, of 5,000 kw. The capital cost of this plant is about $3.1 million and the average annual generation 22 million kilowatt-hours. The cost of energy amounts to about 12 mills per kilowatt-hour.

In this example, we are proposing a tube type turbine which can be installed along the left side of the check structure with no interference with the existing check structure which must be maintained operable to pass irrigation flows if the powerplant is not operating. Other turbine-generator designs such as a Leffel-flume type or bulb type could also be used.

You can also install a powerplant at an outlet from an aqueduct. An example is the facility which we are now investigating for the San Bernardino Valley Municipal Water District at their Waterman Turnout. (See Figure 23.) This outlet discharges 20,000 acre-feet of water annually under a head of 505 feet for the purpose of ground water recharge in the Santa Ana River Basin. This turnout is the largest power producer of the four turnouts studied.

The plant we are proposing is a small Francis turbine and generator, 4,000 kw in size, which can operate in a peak mode 12 hours per day, five days a week, since the water flows into a large percolation basin. The capital cost will be about $1.8 million. The cost of generating 8 million kilowatt-hours per year will be about 18 mills per kilowatt-hour. There are no unusual engineering problems to be solved. The powerplant will be placed adjacent to the existing outlet works and the existing valve will be equipped for synchronous bypass in case of a powerplant outage. This project, along with the other three projects totalling 8,000 kw, should be constructed to save fuel oil and reduce the air emission from combustion at steam stations located in the Los Angeles basin.

I hope that these examples of what can be done - is in fact being done - will lend more credibility to the feasibility of small hydroelectric installations. As engineers we know that such projects will not solve our energy problem. Nevertheless they represent the development and utilization of a natural resource which is now going to waste. Small hydro plants can produce energy without polluting the air or water. Their construction does not impose a violent impact on the environment. The cost of power produced is nearly always competitive with that produced by other means, and is frequently lower.

As representative of one engineering organization, I can assure you that the technology for meeting a wide variety of hydro problems is highly developed and we are looking forward to increasing interest in small hydro.

Economics of Low-Head Hydro: U.S. Case Studies

by Henry H. Chen

I would like to make a few observations on the economics of low-head hydro on the basis of our recent experience with several projects.

Low-head hydro projects are typically of the run-of-river type with limited reservoir storage capacity for regulation purposes. Their role in the electric system is sometimes difficult to define because of the uncertain water supply situation. Thus their benefits may be hard to pin down. On the other hand a realistic estimate of capacity and energy benefits is essential to justify the project. Therefore, we must have a good technique to estimate benefits.

Low-head hydro projects usually have high capital costs. It would be useful to identify the characteristics of those types of low-head projects offering lower costs so that work might be concentrated on these types of projects.

Power and energy production

The first item of study of a project is to develop the power and energy potential. Our company would usually use the duration curve approach (Figure 24) for low-head projects since it is often the simplest method, and nearly as accurate as any other method. Where possible, we would like to develop flow duration curves for each month of the year, so that the energy production of each month can be estimated.

Low-head hydro suffers from wide variation in operating head, due to rise in tailwater level (Figure 25). In some cases the operating head might reduce to only a fraction of the rated head, and turbines can no longer be operational. Consequently powerplant curtailment or

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He graduated from Hong Kong University in 1956 with a B.S. in Civil Engineering and came to the U.S. the same year. He has been with Harza since 1959.

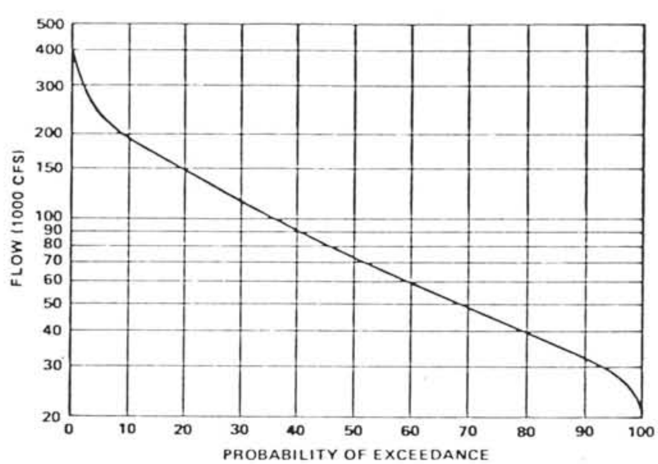


Figure 24. Streamflow-duration.

shutdown can occur under high-flow conditions.

Figure 26 shows the power potential of a project on the Mississippi River as a function of the river flow. First, power output increases with flow until the powerplant capacity is reached and the output is limited by the generator capacity. As the flow continues to increase and the tailwater rises, the output is reduced. Finally at some point, the net head is reduced to a level that the powerplant has to be shut down. The figure shows the performance with different number of units installed.

Selection of installed capacity

The proper way to select the installed capacity of a specific project is to go through an optimization analysis comparing incremental benefits to incremental costs. There is no established rule-of-thumb to select the installed capacity of a low-head project. Usually the selected capacity can be expressed as a function of the average river flow. For example we would indicate that the full-gate turbine discharge capacity would be so

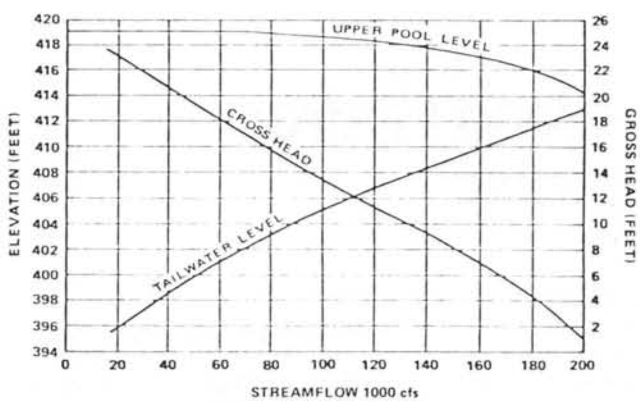


Figure 25. Streamflow vs head.

many times the average flow of the river, where the number might vary between 1 and 4.

Every river has different streamflow characteristics, every site has different physical characteristics affecting power output and costs, and every system has different relative values of capacity and energy. Therefore, it would not be appropriate to select the installation as a simple multiplication factor of the

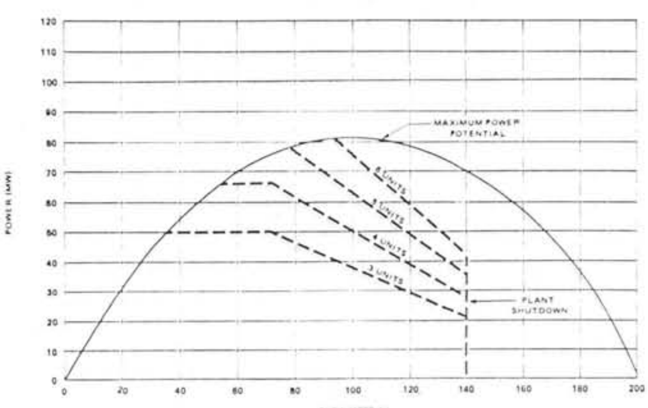


Figure 26. Power production.

average flow.

We have, however, used such an approach in reconnaissance and inventory types of studies in order to arrive at very preliminary estimates of project potentials.

Capital Costs

We all know the capital cost of a low-head project can be very high. It should not be a surprise if the capital cost exceeds $1,000 per kilowatt at the current price level. It would be a pleasant surprise if the capital cost is below $1,000 per kilowatt. One of my colleagues prepared a table (Table 8) relating the changes over the years in the estimated cost of a low-head (18 feet) hydro project on the United States-Canada border.

First, there is the definite increase over time in the capital cost of the project. Over the years, we also see the trend of moving away from the vertical propeller and Kaplan units to the horizontal tube and bulb type units. The cost savings in going to the tube unit can be identified by comparing the 1962 and the 1965 cost estimates.

The next table (Table 9) shows the distribution of costs in percent of the total cost for the various items over the years.

The high costs are due principally to high machinery costs and high cost of skilled labor in the powerhouse. Cost of excavation has not gone up as much over the years.

Year of Estimate	Description of Equipment	Installed Capacity Mw	Estimated Cost	$/kw
1948	3-4.8 Mw Propeller Units	14.4	$ 5.4 mil.	$375
1952	4-5.2 Mw Vertical Kaplan Units	20.8	$ 9.2 mil.	$441
1962	4-17.25 Mw Vertical Kaplan Units	69.0	$34.7 mil.	$530
1965	4-15.0 Mw Tube Units (fixed blade)	60.0	$25.0 mil.	$416
1976	3-15.0 Mw Bulb Units (fixed blade, no wicked gates - no governor)	45.0	$40.9 mil.	$909

Table 8. Soo Plant - Whitefish Island Alternative. History of cost estimates.

The high cost of equipment, principally turbines and generators, is borne out by our other recent studies. We have the following cost estimate for the powerplant on the Mississippi River at Lock and Dam No. 26. (Table 10.) The project is planned to have four 15 Mw tube units. The rated head is 18 feet.

Capacity and Energy Values

We conduct economic analysis by comparing the

Item	**1948**	**1952**	**1965**	**1976**
Power Canal, Dikes & Tailrace	27%	29%	21%	11%
Powerhouse Equipment	40%	42%	45%	62%
Powerhouse Civil Works	29%	25%	30%	22%
Emergency Spillway, Sluices & Miscellaneous	4%	4%	4%	4%

Table 9. Soo Plant - Whitefish Island Alternative Distribution of item costs in % of total cost.

	$ Million	**Percent**
Powerhouse and Intake	16.2	40.3
Powerhouse Equipment		
Turbines and Generators	20.0	49.8
Other	3.0	7.5
Transmission	1.0	2.5
Total Direct Cost	40.2	100.0
Contingencies	8.1	20.1
Engineering and Overhead	7.7	19.2
Interest During Construction	5.6	13.9
Total Capital Cost (1974 price level)	61.6	153.3

Table 10. Estimated capital cost 60 Mw hydro powerplants.

hydro project with alternative generation providing the same service. This is not as simple as it sounds since different types of projects do not provide the same service. What we do is therefore to perform the analysis by identifying alternative projects which would provide the same amount of incremental capacity to the electric system to meet increases in demand. Next we would then determine the increase in system energy costs for each alternative. The capital cost and the difference in energy costs over the project service life are then combined to obtain an indication of the total cost of an alternative.

This leads us to the traditional approach of determining the capacity and energy costs, or values. The only point is we should look at the capacity and energy values as increments to the system's.

Capacity Value

First, we need to determine the necessary installed capacity which would provide the equivalent amount of capacity to the basic hydro project. In the past, we would attempt to estimate the dependable capacity of a hydro project under the critical water supply conditions. The dependable capacity would then be the basis upon which we would determine the equivalent amount of capacity from the "dependable capacity" approach in some cases.

The electric systems of the United States are becoming larger with time. They are often supplied by a large number of generating stations. It is the combined capability of these plants to supply a system that determines the adequacy of the system. Often the hydro plants constitute but a small part of the total system installed capacity. A hydro plant may at times be "unavailable" because of low-flow condition, or "low-head" condition. During periods it is not available, the system may count on other powerplants in the system. The hydro plant is more reliable than thermal plants and requires less time for maintenance. The thermal units have to be taken out of service for weeks each year for maintenance purposes.

Consequently, we would evaluate the value of the capacity on the basis of the "availability" of the project. If the project is available 80% of the time, it can be assigned a capacity value equal to 80% of the full capacity value.

This approach was adopted in studies of the redevelopment of the Safe Harbor and Holtwood Projects on the Lower Susquehanna River for the Safe Harbor Water Power Corporation. We think it should be applicable to most low-head hydro projects serving a large electric system.

Energy value

Today, we would want to evaluate the "incremental system fuel cost" with alternative generation projects added to the system. Such a cost would depend on the make-up of the system, or the generation mix.

Relatively simple computer models can be developed to estimate the incremental system fuel costs with

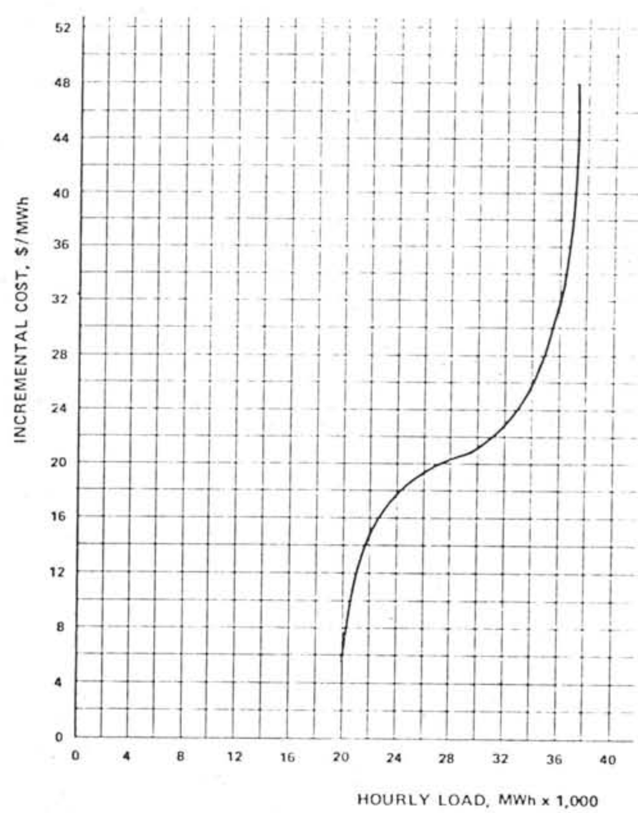


Figure 27. Example of incremental fuel cost curve.

alternative generating plants. This was done for our studies of the Safe Harbor and Holtwood Projects. The computer program would dispatch the hydro project on the system on an hourly basis for each month of a future year against an incremental fuel cost curve which defines the generation mix as well as the costs of energy from the plants (Figure 27).

In essence, the hydro plant is dispatched in the system to achieve optimum operation or minimum energy cost of the system as a whole. Thus the optimum mode of operation of the hydro plant under existing and expanded conditions would be developed, and a realistic estimate of the future benefits of hydro energy production is obtained.

The hydro plants have limited storage capacity. They would normally operate on a daily, and at most a weekly cycle in coordination with other limited-energy projects. These other limited-energy plants are primarily pumped storage plants. Thus the dispatch of the hydro plants within each day is very important. Depending on the hour of the day and the day of the week, the energy value can vary by a factor of 4. We developed the computer program logic so that the value of the hydro energy would be maximized while the plants would observe all the operating constraints of available reservoir storage capacity, tailwater levels, and generating capacity and efficiency.

Economic analysis

The economic analysis can be performed when all costs which would differ between alternatives are identified and estimated. These would include the capital cost, the operation and maintenance costs, the incremental system fuel costs, and the residue values. The cost streams over the years for each alternative are developed.

The hydro projects have high front-end costs but lower annual costs as compared with the thermal alternatives. The time value of money is commonly factored into the analysis by "discounting" future costs to the present, to obtain a single present value for comparison. This is commonly called the present worth analysis, or life-cycle analysis.

	Including Inflation	Inflation at 6%	Excluding Inflation
Discount Rate or	8%	6%	1.9%
Interest	12%	6%	5.5%
Increase in Real Cost			
Oil and Gas	9%	6%	2.8%
Skilled Labor	7%	6%	1.0%

Table 11. Effect of inflation on discount rates and on future costs.

Future costs tend to increase with time for two reasons. First the "real" cost increases with time because certain items such as oil and gas are scarce. Second, inflation tends to cause all cost items to increase over time in relation to the dollar. It is very important to use the proper discount rates to properly account for inflation.

Table 11 provides an example of two different sets of values which can be used in an economic analysis. In recent work, it was necessary for us to use different numbers and to modify the basic approaches to meet the criteria of our clients. The investor-owned utilities use the "annual revenue requirements" to derive the annual costs of its investment. Usually they want to include taxes in the cost.

Currently, the annual revenue requirement for an investor-owned utility is some 12 to 17% of the capital investment. The federal government uses the "federal interest" rate. The current federal rate is 6⅝%. Obviously, both rates are heavily influenced by current inflation rates. Therefore, if these rates are to be used, we should allow future benefits to increase with time. Proper accounting of inflation will help to accurately estimate the benefits of hydro plants.

Following his paper Mr. Chen was asked several questions. An Allis-Chalmers official also replied.

Q: I've heard today very recently the discussion of how hydro power development is capital intensive and also we all know examples of hydraulic turbines lasting two to three times the design life, so maybe this is telling us something: — maybe we're over-designed, a little bit too conservative. Maybe this is reflecting our lack of competition, lack of mass production, lack of imaginative uses and new materials, computer design. What about the lack of research and development in a relatively stagnant technology? So, I would like to throw that out and would appreciate any comments from the economics people or the turbine manufacturers.

Chen: We must remember that for low-head hydro we are dealing with a lot of water. We need big machines. You look at them, they are all big, and we need a lot of materials in it, and therefore there is a reason for equipment having high costs, higher than we are normally associated with in high-head projects. On the other hand, I do believe that there is room, and maybe I should ask the manufacturers to tell us that; there is room for improvement in costs, especially when we get into standardization, going to package-type units, trying to come up with shelf items such as combustion turbines. You know, combustion turbines have all been packaged, and this is one reason why the cost per kilowatt of combustion turbines is that low because they really mass produce them. And I think that as low-head hydro becomes more prevelant in the United States and more people go into it, that there would be real incentives for the manufacturers to invest in the plants to produce them on a mass scale.

Q: You have that chart on the cost of the small units/machines with their controls, but it was only representative. Is that kind of information available that's pretty much up-to-date dollars, so that we can begin looking at 2 megawatts-and-under, the unit-installed cost with their controls?

Chen: Well, machines vary from one type to another and what we try to put together is something, at least what I try to put together is something which demonstrates the point I wanted to make. But to get real cost, you have to go to the manufacturers. Again, I don't know if anyone from Allis or Leffel are here, maybe you can help me?

Pfafflin (Allis-Chalmers): Let me give you two examples of typical mini-hydro plants for which we have designed the equipment, for which we have designed the powerhouse, for which we have complete, and in my judgment accurate, overall costs of the installation. One is a 38-foot-head plant with a capacity of 1,500 kw. The cost per kw is about $800 for this complete plant at an existing dam site where the dam is indeed in good condition. The other example for which I have the facts at my fingertips involves a 28-foot-head plant with a 1,000 kw unit complete powerhouse. Again, the dam in existence, the installed capacity for the whole project is somewhere between $1,300 and $1,350 per kw. And for those who believe there is insufficient competition among the manufacturers of hydraulic turbines, I want to tell you that there are 25 companies in the world building large hydraulic turbines. The facilities of those companies were utilized 50 to 70% during the last several years, and if you think that utilization of manufacturing capacity in the 50 and 70% class doesn't generate competition, I've got news for you.

Economic Comparison of Five Hydroelectric Projects in Idaho

by A. Ragnar Engebretsen

Hydroelectric energy is clean and renewable and will always have a place in the overall energy program of this country. However, hydro projects are capital intensive and are subject to much government regulation, so it is more than ever necessary to plan and design potential projects carefully and judiciously.

The purpose of this paper is to identify some of the river characteristics and site conditions which have a bearing on economic feasibility. An economic comparison is presented of the following five developments, all located in Idaho: Idaho Falls and Wiley Projects on the Snake River, Lucky Peak on the Boise River, the south Fork of Payette River and the North Fork of Payette River. The head developed by these projects ranges from 20 feet at Idaho Falls to more than 1000 feet on the North Fork of Payette River. The emphasis is on comparing types of developments rather than on reviewing planning or design aspects. Transmission lines have not been included in the comparison; all projects terminate at the high voltage bus at the powerplant substation.

A. Ragnar Engebretsen is the Principal Planning Engineer of International Engineering Co. Inc. of San Francisco. During the past 30 years Mr. Engebretsen has been engaged in all aspects of hydroelectric power development, including systems operation, technical and economic evaluation of resources, and the planning, design and construction of project features. He has worked on investigations, studies, and designs of many hydroelectric projects both within the U.S. and abroad.

Mr. Engebretsen has also had extensive experience in the planning and design of irrigation and drainage projects, having worked on agricultural development projects for three years in Bangladesh and for almost two years in Peru.

He has a B.S. in civil engineering from the Institute of Technology, Norway.

The comparison is based on recent studies performed by International Engineering Company (IECO) for the City of Idaho Falls, for the Boise Board of Control (Lucky Peak) and for Idaho Power company. These studies are all at feasibility or prefeasibility level, except for Idaho Falls which has been committed to final design. The writer has taken an active part in all of the studies except the study of Idaho Falls.

Idaho Falls

This project is a redevelopment of three existing low-head power plants on the Snake River in and near the city of Idaho Falls. The plants are old and have deteriorated to a point where redevelopment has become necessary. The plan of development provides for the installation of a bulb turbine at each of three new power plants constructed at the site of the existing plants. Associated structures include low concrete diversion weirs and spillways, and low earthfill embankments for flood protection. Very little will remain of the existing facilities. Foundations are generally good, rock is present at shallow depths.

The available head at each plant is about 20 feet. The three bulb-turbines will be identical and rated 7,200 kw. Each will have a discharge capacity of about 5,000 cfs, which is slightly less than the average river discharge at this point.

U.S. Department of Energy has shown an active interest in the project and has committed $7.4 million to its development as a demonstration project. The experience gained is considered to be useful for the implementation of many similar projects in the United States.

South Fork Payette River

This project will develop about 500 feet of head on the South Fork of Payette River in a 15-mile reach downstream from the confluence with Deadwood River. The location is about 40 miles north of Boise. The river is undeveloped except for a reservoir on Deadwood River used for irrigation releases during the summer. Average river discharge is about 1,350 cfs. In the upper nine miles of the reach, the river flows in a narrow and deep canyon with steep side slopes. The valley is much wider in the lower six miles; the river however, is flowing in a narrow channel ranging in depth from 70 to 100 feet. The geology is considered to be favorable for dam construction; rock is generally exposed on both river banks and at shallow depth in the river channel.

The initial development concept was based on using bulb-turbines in a series of low dams. High dams were ruled out because they would have significant impact on the environment and would also require extensive relocation of an existing highway on the right bank. A development by tunnels would not be economical due to the flat, 0.7 percent, gradient of the river.

The first plan comprised eight dams, which would develop a total head of 470 feet in steps ranging from 50 feet to 65 feet. The power plants would be of the run-of-river type; the reservoir would be maintained at a constant elevation. Each dam would be a concrete gravity type with the spillway occupying the entire width of the river channel at most sites. Two bulb-turbines would be located in a cavern underneath the ogee section of the spillway with access through a shaft at the right abutment. All 16 turbines would be identical, rated 4,520 kw at 60 feet head and would each have a discharge capacity of about 1,000 cfs. A minimum of two units were required at each dam because of the large variations in the river discharges.

During the course of the study, independent research and information received from turbine manufacturers indicated that the head would be near the upper limit for bulb turbines of this size. One particular disadvantage was the deep setting required to avoid excessive cavitation. Therefore, it was decided to use conventional vertical Kaplan turbines rather than bulb turbines in this case. In all other aspects the initial plan was maintained as described above, and the drawings and cost estimates were prepared on that basis.

However, the overall economics of this eight-dam concept was somewhat disappointing. A comparison between the various sites showed that the higher head plants were consistently more economical than the lower head plants, indicating the possibility that fewer and higher dams could result in improved overall economics. Further investigations and studies revealed that a four-dam development would be technically feasible and would require only minor relocation of the highway. The impact on the environment would be not much different than with the eight-dam development. Therefore, an alternative plan was developed, consisting of two dams, each providing 120 feet of head, in the upper part of the reach, and two dams, each providing 85 feet of head, in the lower part of the reach. Otherwise the design concept is similar to the concept described for the eight-dam development. Based on economic studies, using the flow duration curve of the river to estimate energy production, the plant discharge capacities were selected 3,200 cfs at the two upper sites and 2,600 cfs at the two lower sites. The studies indicated a clear economic advantage in providing larger capacity at higher head. The four turbines for the two upper sites are rated 14,000 kw; the four turbines for the two lower sites are rated 8,000 kw.

Wiley Project

The Wiley Project is located on the Snake River about 80 miles southeast of Boise, near the town of Bliss. It would develop the head between the existing Bliss Reservoir and the tailwater of the existing Lower Salmon Power Plant. The river at this point is well regulated by upstream reservoirs. The average discharge is about 10,300 cfs.

Geological explorations of the Wiley Site in the 1950's revealed that the foundation would require much excavation and treatment to provide a safe design. As a result the project was given low priority and was not reactivated until a couple of years ago.

The Wiley Project, as presently conceived, would develop about 80 feet of gross head. The power plant would be of the run-of-river type, operating at a constant reservoir elevation. Total plant discharge capacity would be about 15,000 cfs which is similar to the capacity at both Lower Salmon and Bliss. The selected turbine installation consists of one Kaplan unit rated 29,000 kw, and two propeller units, each rated 26,000 kw. Thus, the total installed capacity would be about 81,000 kw. The main dam would be an embankment about 100 feet high, constructed from excavated material and from borrow. The concrete spillway and the power intake structure would occupy about 30 percent of the total crest length. The reservoir would be contained within the walls of the canyon.

Lucky peak power development

The Lucky Peak Dam, located on the Boise River about 12 miles east of Boise, was completed by the U.S. Corp of Engineers in 1955 for the purpose of flood control and incidental irrigation. No special provisions were made for possible future development of power. Releases for irrigation and flood control are made through the outlet works, consisting of an intake in the reservoir, a 1,200-foot steel lined tunnel and a concrete manifold outlet structure. The releases are controlled by a hollow jet valve and six hydraulically operated steel slide gates. The capacity of the outlet works is about 30,000 cfs at maximum reservoir elevation. The available head for power ranges from 235 feet at maximum reservoir elevation to 135 feet at minimum reservoir elevation.

The releases from the reservoir vary considerably with the seasons. They are generally low in the period November through January and high in the period April through September. The average discharge is about 2,700 cfs. The basic concept for development of power at Lucky Peak Dam is to pass the water released from the reservoir through hydraulic turbines rather than through the existing outlet works. No changes in the present release pattern are proposed for the purpose of power and energy production. The powerhouse would be located near the existing manifold outlet structure at the base of a ridge forming the left abutment of the dam. Two alternatives are possible for the conveyance of water from the reservoir to the turbines:

1. Using the existing intake and tunnel. This would require improvement of the present steel liner and a new steel penstock and manifold which would connect the existing outlet penstock with turbines.
2. Constructing a separate intake and tunnel from the reservoir to the powerhouse.

Using the existing intake and tunnel would result in the lowest construction cost. However, a separate tunnel has certain operational advantages by providing a second large outlet from the reservoir and has been selected for the cost presentation herein.

The turbines at Lucky Peak would be required to operate under a wide range in discharge and in head. Based on preliminary power studies, an installation of three 21,000 kw units plus three 4,000 kw units was found to be suitable and was selected. All turbines would be of the Francis type, and rated at 188 feet head.

North Fork Payette River

This project would develop about 1,600 feet of gross head on the North Fork of Payette River in a 13-mile reach starting two miles downstream from Smith's Ferry and ending near the confluence with the South Fork at Banks. In this reach the river is confined to a steep V-shaped valley, flowing at an average gradient of 2.5 percent. The rock in this area is granitic and is generally exposed at both banks of the river. The river channel is filled with relatively shallow deposits of stones, gravel and sand. A highway and railway are located near the river at opposite banks through out the reach.

The river is regulated by the Cascade Reservoir for the purpose of irrigation and flood control and has an average discharge of about 1,500 cfs.

The present concept is to develop this reach by tunnels in two steps: (1) an Upper Development providing 1,020 feet of gross head and (2) a Lower Development providing 580 feet of gross head. Each development would consist of a low diversion weir, a headrace tunnel with an underground surge tank at the downstream end, a pressure shaft, an underground powerhouse, a tailrace tunnel, a switchyard, access tunnels and roads. All major features would be located underground to minimize the impact on the environment. Visible at the surface would be only the diversion weirs, the access tunnel and tailrace tunnel portals, the switchyards and the transmission lines. Total length of the waterways would be 41,000 feet for the Upper Development and 23,600 feet for the Lower Development.

Three Francis-type turbines would be installed in each power plant. The turbines for the Upper Development are rated 57,500 kw at 940 feet head. The turbines for the Lower Development are rated 32,500 kw at 530 feet head. The maximum discharge capacity at each plant would be about 2,550 cfs. Sufficient flow would be passed over the diversion weirs to maintain a live, attractive stream.

Economic comparison

An economic comparison of the projects described above is shown in Table 12. The most important item in the table, on which all other values are based, is the estimated capital cost. Therefore, the derivation of this cost will be explained in some detail.

The estimated total construction costs shown in the table were taken from recent reports prepared on the various projects. All costs were updated as necessary to the price level as of April 1978.

Costs for engineering and administration, which were added to the constructgion costs to obtain total investments required, were assumed to amount to 12 to 15 percent of the construction costs. On the South Fork there will be much repetition in design and construction, which will tend to reduce the percentage for engineering costs. On the North Fork, tunnel construction represents more than 50 percent of the total cost. This also will tend to reduce the overall percentage for engineering costs.

Interest on funds expended during construction was added to investment costs to obtain the total capital costs. The annual interest rate was assumed to be 9 percent. The construction times assumed varied from two years for Lucky Peak to four years for the North Fork of Payette River.

The estimated costs of energy shown in the table are simply the total annual costs divided by the average annual energy produced. Actual annual costs were not used in this comparison because they depend on financing conditions and government regulations which vary considerably from one project to another. Municipalities, such as the City of Idaho Falls, may obtain financing at a lower cost than a public utility, and are also exempt from taxes. For the purposes of this paper, annual costs were in all cases assumed to be 12 percent of total capital costs. This percentage does not include taxes and was obtained as follows:

Item	Percent of capital cost
Capital recovery or return on equity	10.0
Replacements and O&M	1.5
Insurance and general expense	0.5
Total	12.0

The average annual energy was in all cases estimated from flow duration curves and with the plant discharge capacities as given previously.

Other items in the table have been explained previously or are more or less self-explanatory.

Discussion of results

The results of the above economic comparison can be summarized as shown in the table presented below. The projects are listed in order of indicated economic viability.

Project	Principal characteristics
Lucky Peak	Medium head at existing dam. Average water availability.
North Fork Payette	Medium to high head tunnel development. River slope 2.5%. Less than average water availability.
Wiley	Low to medium head on a regulated river with above average discharge. Below average foundations.
Idaho Falls	Low head on river with average water availability. Good foundations. High equipment cost.
South Fork Payette	Low to medium head on river with relatively low discharge. Good foundations. Low equipment cost.

The following general observations can be made from the results obtained:

1. Development of power at existing dams for flood control and/or irrigation may be the most economical means of producing additional hydroelectric energy, except possibly in cases of low dams and low discharges. Since the energy production would be seasonal, it is necessary to check that the energy can be used effectively in the system.
2. Rivers yet undeveloped, having a gradient of 2.5 percent or more, may be developed economically by tunnels. This type of development can be economical even on rivers with low discharge. Equipment cost is relatively low.
3. Reaches on main rivers which until now have remained undeveloped due to high construction cost resulting from poor foundations, may now be economical because of improved technology and higher cost of energy from alternative sources.
4. Redevelopment of existing low-head power developments can be economical. However, equipment cost is relatively high. Also, there may be various constraints which would tend to increase costs. Small plants with low discharges, would be marginal at best.
5. Low-head developments on rivers with relatively low discharges and flat gradients are economically the least attractive of the cases studied. Both equipment cost and construction costs are relatively high.

One common characteristic of all the cases studied is that no change is proposed in the present discharge patterns of the rivers. They are essentially all run-of-river

Item	Idaho Falls (3 plants)	South Fork Payette 8-Dams	South Fork Payette 4-Dams	Wiley	Lucky Peak	North Fork Payette (2 plants)
Head Range	20	50-65	85-120	80-85	130-230	580,1020
Number of Units	3 x 1	8 x 2	4 x 2	3	6	2 x 3
Total Capacity (MW)	21.6	66	85	81	75	258
Total Capital Cost ($ Million)	36	100	77	100	52	217
Cost per kw ($)	1667	1515	906	1235	693	843
Equipment cost per kw ($)	870	590	307	252	250	194
Average Annual Energy (GWh)	169	298	302	480	295	1264
Annual Cost ($ Million)	4.3	12.0	9.3	12.0	6.2	26.0
Cost of Energy (mills)	25	40	31	25	21	21

NOTE: The above annual costs and energy costs are for the purpose of economic comparison only. Indicated actual annual cost and energy costs, reflecting current financing conditions and taxes, are as follows:

Item	Idaho Falls (3 plants)	South Fork Payette 8-Dams	South Fork Payette 4-Dams	Wiley	Lucky Peak*	North Fork Payette (2 plants)
Annual Cost ($ Million)	3.25	16.6	12.8	16.6	-	36.0
Cost of Energy (mills per kwh)	19	55	42	35	-	28

* Not yet determined.

Table 12. Economic comparison of five potential projects in Idaho.

projects that have little if any impact on the character of the river.

Finally, it is necessary to emphasize that environmental and recreational aspects have been considered only to the extent that the location and the design of the various project features have been selected with a view to minimizing the impact on the environment. When these aspects and transmission costs also are considered, the order of preference may be different than indicated by economic evaluations only.

Marketing Low-Head Hydroelectric Power

by Perry W. Reams

The estimated cost of electric power from large central thermal electric power plants after 1985 is in the range of 30 to 45 mills/kwh (public and private ownership, joint ownership). Twenty mills/kwh is a conservative estimate of the cost of power from low-head hydroelectric power plants constructed by public agencies (PUDs, etc.). Thus, low-head hydroelectric power appears to be an economically appealing power source. And, by most standards, they are environmentally acceptable.

Electric power load growth in the Pacific Northwest is projected at an annual growth rate of about 4 percent. The Bonneville Power Administration (BPA) encourages the development of all economically feasible and environmentally acceptable low-head hydroelectric facilities within its marketing area to share the burden of meeting this increasing demand.

Within the limits of its legislative mandate, and the operating limits of the Federal Columbia River Power System, BPA will participate in planning studies and enhance the marketability of this energy by storing, advancing, loadshaping, and participating in the transmission of the energy from such plants.

At the present time, the average cost to the ultimate consumer of electric power generated by the Federal Columbia River Power System and marketed by a public agency is less than 20 mills/kwh but by 1983 this power will be completely allocated. The public agencies must then develop or otherwise acquire new electric energy resources to meet their load growth. Low-head hydroelectric projects appear to be an economically favorable option to meet a portion of this future demand, but the number of sites is limited and additional large thermal plants will also be needed.

Generally speaking, a low-head hydroelectric plant will be primarily a non-firm energy resource. It is a run-of-river plant without storage capability and subject to variable streamflows or it can be a plant subject to seasonal availability of water, such as at canal drop sites. The question is, how can the full potential of these small and variable energy resources be marketed?

At present, the potential low-head hydroelectric plant sites in the Pacific Northwest and their streamflow data are unknown. However, the Idaho Water Resources Research Institute is coordinating a study to identify sites and gather streamflow data on these sites in the States or Oregon, Washington, and Idaho. That report will be available in the near future.

Problems

It is the intent of this discussion to point out that fully utilizing the energy output from low-head hydroelectric plants is not merely a matter of locating a plant site and building the plant. Marketing the variable energy from most such plants will require support from a large bulk power generating and transmission system and even then there is no assurance, using traditional techniques, of total utilization of their output.

Perry W. Reams has been a staff engineer on the Power Resources Branch of the Bonneville Power Administration since 1967. He has spent the past 32 years in the electric utility field, including seven years as a lineman and line-crew foreman and ten years as the Electrical Distribution Engineer with the Clark County PUD in Vancouver, Wash.

He graduated from the University of Washington in 1957 with a B.S. in Electrical Engineering.

The historical Snake River streamflow data from near the site of the proposed 21-Mw Idaho Falls project provides an opportunity to identify some of the concerns associated with marketing low-head hydroelectric generation. The streamflow duration curve from that site (Figure 28) demonstrate the variability of unregulated streamflows. Other sites will vary only in the degree and duration of fluctuation.

From the flow duration curve, 1928-1972, (Figure 28) it can be seen that the maximum power production occurred only 44 percent of the time at that site. The remaining time it varies to as low as 25 percent of plant capability. This raises the question "to what amount of firm residential and commercial load can we commit ourselves in view of these variable streamflows?" Obviously, without an always-available alternate source we can only commit to the 25 percent.

The present electric power outlook leads to optimistic estimates about marketing the other 75 percent, but there is no guarantee. Assured marketing rests on the availability of a large bulk power generating and transmission system, such as the Federal Columbia River Power System, with the capability to store, to advance, to shape, and to transmit that energy to a load center. In order to completely understand the complexity of the challenge to market all the available energy from these plants, one must keep in mind that figure is a 45-year streamflow duration curve and that in any one year the actual monthly streamflow duration could be less enticing.

Another option

One is tempted to say, at this point, that surely the Federal Columbia River Power system can provide that support service, and that is true for one 21 Mw plant. However, can they support 20 (420 Mw) such plants? BPA cannot answer this question precisely at this time, but studies will be underway to obtain answers as soon as sites are identified and streamflow and other data become available.

Another option for marketing low-head generation is the industrial market with contractual arrangements patterned after a proposal now under consideration by the Weyerhaeuser Company, Snohomish, Cowlitz, and Grays Harbor County PUDs, Bonneville Power Administration, and several industries. Under this

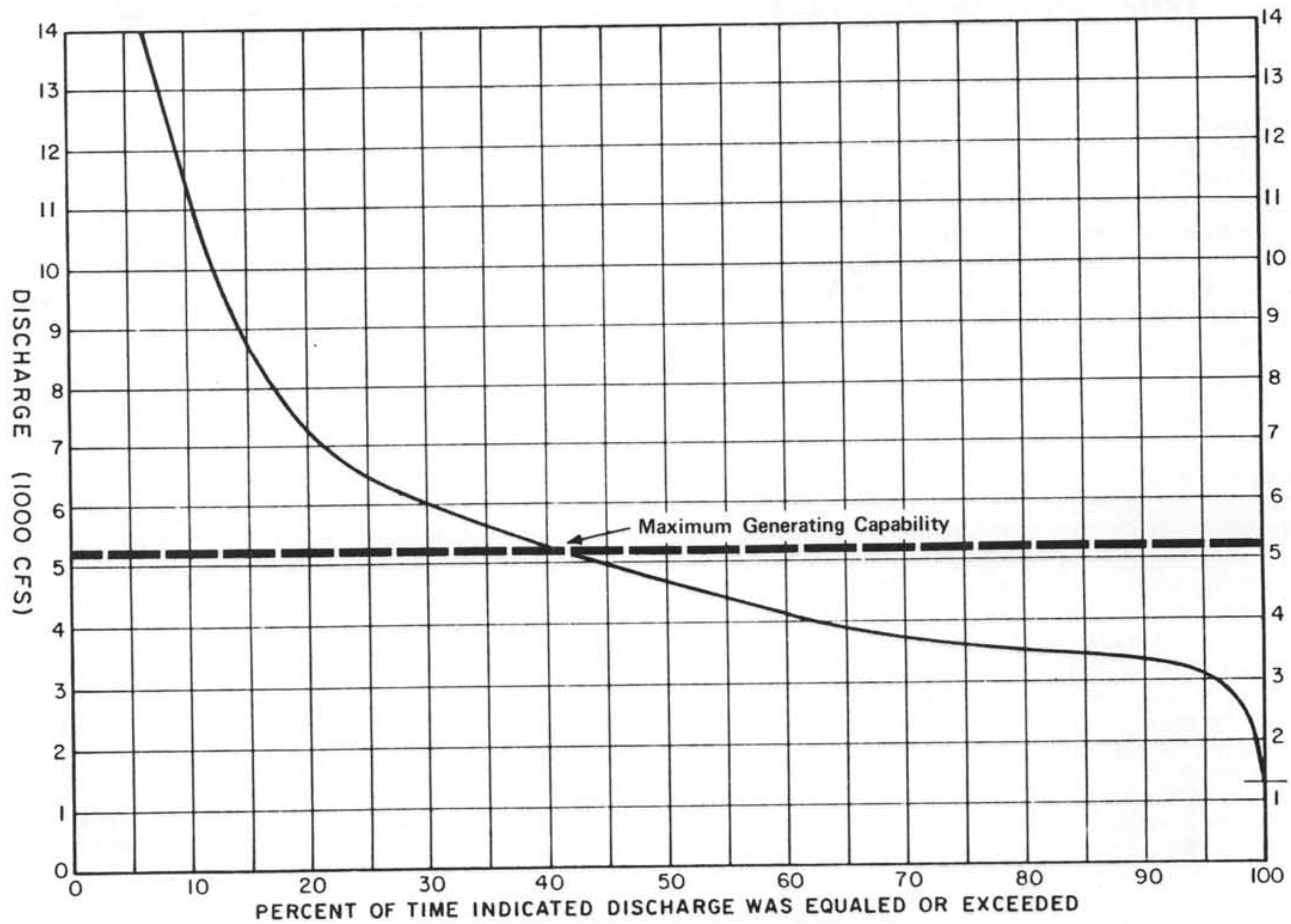


Figure 28. Flow duration curve - Snake River at Idaho Falls.

proposal Weyerhaeuser Company agrees to generate 54 average Mw's per week from head produced by woodwaste and BPA agrees to store, to advance, and to transmit that energy to the industries.

There are two exceptions to that contract that are relevant to this discussion: (1) when BPA has surplus energy available to serve that industrial load, the Weyerhaeuser energy will not be accepted, and (2) the industries guarantee a minimum annual rate of return to Weyerhaeuser Company. In the case of low-head hydroelectric plants, this type of arrangement would guarantee an economically viable investment but it does not guarantee the total utilization of the potential energy from the plant.

With respect to industrial power sales, and providing the market is there, direct sale on an as-available basis would be ideal.

Canals look good

The outlook for low-head hydroelectric plants constructed on canal drop sites is more optimistic than from run-of-river plants. They would be operated on a seasonal basis, 3 or 4 months per year, and taking into account the water available, sized in relation to the irrigation pumping and sprinkling load plus other loads peculiar to that season.

However, the economic viability of this concept as a general case, is not that obvious nor are the contractual marketing arrangements necessary for complete utilization of the generation. The author knows of no studies being made for this type of installation.

It is not the intent of this discussion to discourage the development of low-head hydroelectric plants, but rather to suggest that low-head hydro is not a panacea for relief from higher cost thermal power. Low-head hydro is primarily a nonfirm energy resource and it will tax our imagination and ingenuity to the utmost to develop a method to market this much needed, nondepletable resource.

I suggest that the extent to which low-head hydroelectric generation can become a viable resource in Pacific Northwest is limited only by our imagination and willingness to diligently seek methods to utilize the variable energy output from low-head hydroelectric plants.

3

Low-Head Turbines

David Koch photo

Electricity was first generated in Idaho at a smelter in Ketchum which installed a water wheel and small dynamo for lighting in the early 1880s, possibly in 1882. The first public use of electricity in Idaho was for street lighting at Haley later in the decade. The bi-polar generator housed here (above) is a relic of those pioneer days. It is rated at 20 kilowatts, 125 volts and 160 amperes. It was manufactured by the Edison General Electric Company in 1888 and was first used in Michigan. It is displayed at Sun Valley, courtesy of the University of Idaho.

The Straflo Turbine

by R.E. Moser

Two score and 19 years ago an American, L. F. Harza, had a great idea. He arranged a Kaplan turbine horizontally in the flow direction and wrapped the generator around the runner. This presented an optimal hydraulic design with minimum dimensions.

The advantages of Harza's idea are obvious and have been sufficiently described on all sides.

However, with the then available water turbine technology, Harza's ideas were too far ahead of their time and were only practicable within narrow limits of head and runner diameter. Since Harza's invention in 1919, many good engineers worked hard to find a proper technical solution to his ideas. After the German engineer, Arno Fischer, the Soviets worked on this during the 1950's and from 1962 to 1970 English Electric, with governmental support, carried out extensive development work on the hydraulic side and on the sealing and bearing problems.

B.E. Moser is the vice president of Sulzer Brothers Inc. of New York City and is currently responsible for the company's Industrial Equipment Division. Sulzer is a subsidiary of Sulzer Brothers Ltd. of Switzerland, manufacturers of heavy equipment.

Mr. Moser has a B.S. in Mechanical Engineering from the Juventus Institute of Mechanical Engineering, Zurich, Switzerland, and has more than 12 years' experience in hydraulic engineering.

Prior to coming to the U.S., Mr. Moser was a design and commissioner engineer for turbines with Bell Engineering Works in Switzerland. From 1965 to 1968 he was responsible for the design of a new test facility for efficiency and cavitation tests, and supervised model and acceptance tests on Francis turbines. He joined Sulzer Brothers in the U.S. in 1970.

Escher Wyss resumed their development work in 1970 based on experience with the 73 straight flow units supplied in the 1940's and 1950's and still operating satisfactorily and with the many Kaplan and bulb turbines delivered to all parts of the world.

The result is the Straflo turbine, a horizontal or slightly inclined machine, the generator being attached to the runner periphery with no driving shaft. The turbine and generator form a single unit, lying in one vertical plane, and are easily accessible for erection and maintenance. The power house design is reduced to simple shapes of minimum volume. Construction time is thereby reduced.

The distinguishing characteristic of the Straflo turbine is that the generator rotor forms a massive rim attached to the runner periphery which gives the machine various advantages:

- No driving shaft
- Compactness
- Sufficient space on the periphery to accommodate the generator, even for large outputs
- Simple, efficient cooling of the generator
- Very large natural inertia ensures stable running and damping of power fluctuations. Therefore, double regulation is not necessarily required, contrary to a bulb turbine. This is an especially desirable feature in large units.

These advantages can, however, be utilized only when suitable bearings, and seals between rim and turbine casing are applied.

Sealing arrangement

The sealing arrangement between the turbine casing

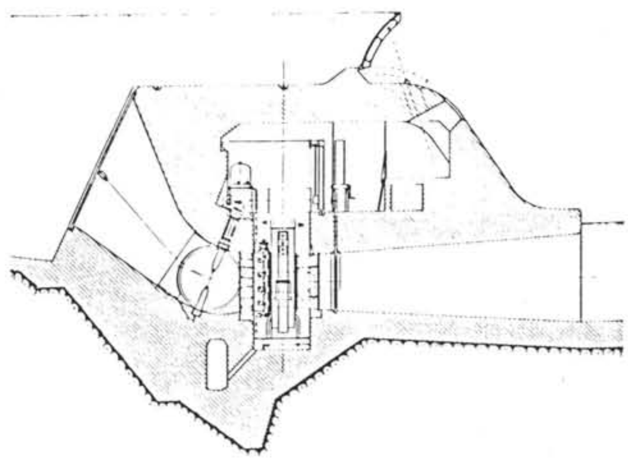


Figure 29. Submergible weir power station with straight flow turbine on the river Lech (Germany). The generator is on an outer rim of the runner.

and the rotating outer rim is one of the important points of the Straflo turbine. The purpose of these seals, which must be absolutely reliable, is to prevent the leakage of water into the generator and the power house.

The Straflo seals consist of many individual self-centering elements which are pressed against the sealing surface of the rotor without touching it.

Due to the purely axial flow, the efficiency of a Straflo turbine is higher than that of a vertical Kaplan turbine. This advantage increases with the head and is even more noticeable when, instead of a semi-spiral, a full-spiral casing is employed, as is usual for heads above 100 ft.

The rotating outer rim is, however, a source of losses because it rotates against the direction of water flow. This produces additional friction which makes the efficiency of a Straflo turbine lower than that of a bulb turbine with interior generator.

However, the water velocities at the intake to bulb turbines are about 20% higher than for Straflo turbines with same spacing. This leads to frictional losses in the intake and secondary losses in the runner which can be considerable larger than the above mentioned typical Straflo turbine losses.

During a test program lasting several years, Escher Wyss has carried out detailed studies on various test facilities. These include hydraulic optimization, determination of forces occuring within the machine and sealing and bearing tests.

The hydraulic research on Straflo turbines has been carried out on the Escher Wyss universal test rig for lowhead turbines. Since 1974, the following tests have been performed:

- Characteristic curve measurement
- Cavitation observations
- Rim influence on efficiency
- Inlet section optimization
- Draft tube optimization
- Measurement of forces and loads

The research on hydrostatic seals has been carried out since 1975 on a special test rig for axial and radial seals.

Various arrangements have been tested under the most unfavorable operating conditions, various peripheral speeds, alternating pressures, etc. Various materials for sealing elements as well as operation with sealing water containing sand have been tested.

Future tests

The results of recent research and development work will be applied on a double regulated Straflo unit with hydrostatic supports seals erected during 1980 at the Hoengg power station on the Limmat River in Switzerland. Furthermore the first of seven Straflo units with conventional bearings is due for commissioning in Belgium on December 1, 1979.

These turbines have a runner diameter of 12 ft. In the Lixhe power station the four turbines have a maximum output of 5.85 Mw each under a net head of 26 ft. The three turbines in the Andenne power station will operate under a lower head, their maximum outputs will be 3.5 Mw.

The price of Straflo turbines does not differ very much from that of a bulb turbine, but the generator is about 30% cheaper than a bulb generator and civil engineering costs are in total about 20% less compared to a power station equipped with bulb units. The efficiencies of Straflo turbines are somewhat lower than those of bulb turbines, mostly due to additional friction losses of the rim. The differences in efficiency are to be calculated in each case, depending on different parameters.

For cost reasons the Straflo turbine is certainly qualified to be selected for future low-head power stations.

Bearings

The bearing problem of the Straflo turbine has been solved, depending on the head, with two different arrangements. For low-head units the turbine and generator rotor weight is supported by standard guide and thrust bearing in the hub placed in the stay vane rings upstream and downstream of the rotor.

For high-head Straflo turbines the outer rim with the generator poles is many times heavier than the runner itself. For guiding such a heavy rotor a hydrostatic rim bearing was selected. This type of bearing was developed by Escher Wyss and is applied for various kinds of machinery.

The supporting piston is held in a cylinder mounted on a Teflon seal and free to move in all directions. The inside of this cylinder is supplied with fluid from a pressure vessel. Proportional to this pressure and the inner area of the supporting piston, the latter is pressed with the corresponding force against the rotor. The side of the supporting piston facing the rotor has four cutouts, also known as pockets, which are connected by capillary lines with the pressure chamber. In this way, a pressurized cushion is built up between the supporting

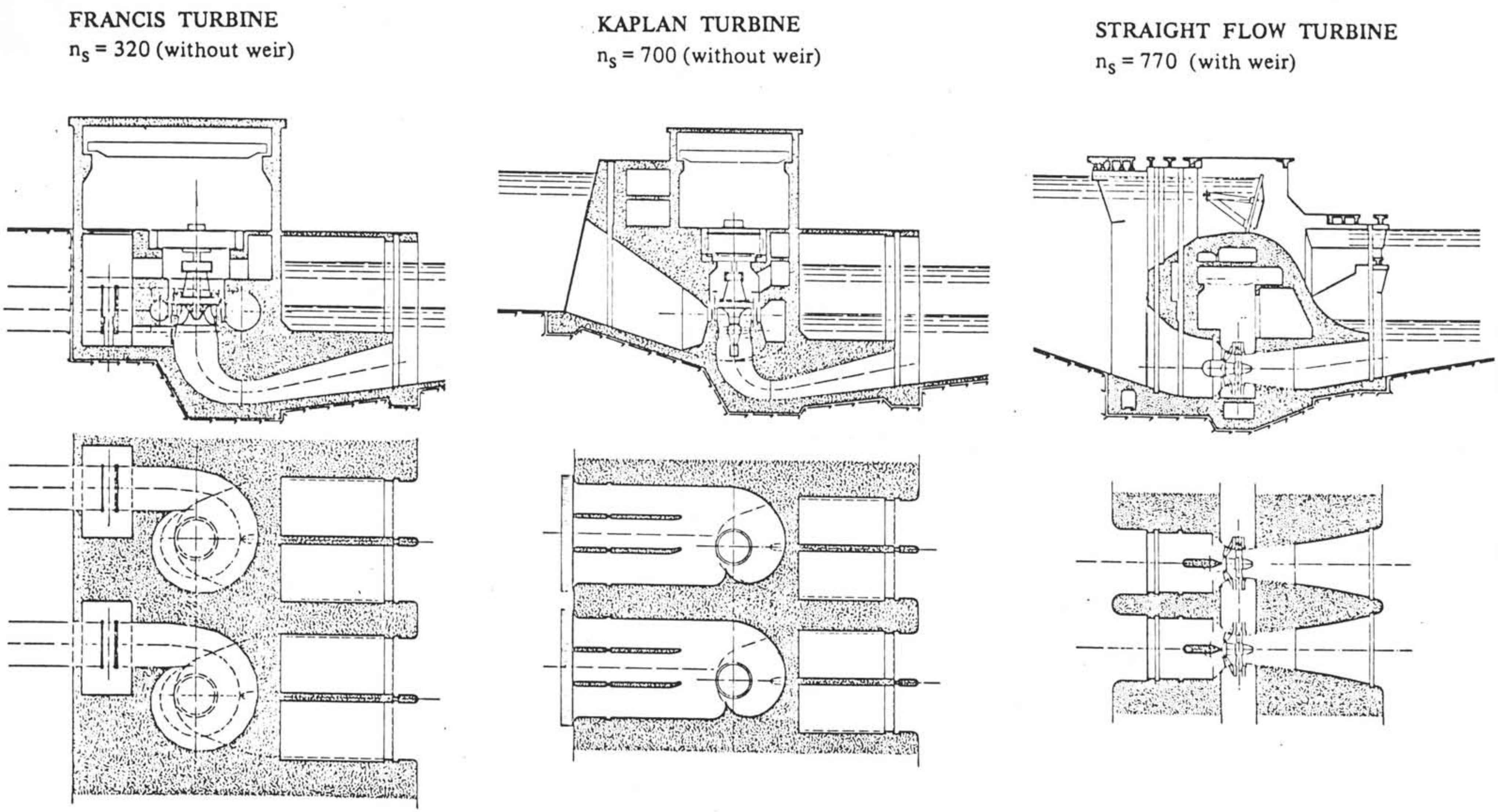


Figure 30. Dimension comparison of a Francis, Kaplan and Straflo turbine of the same output and head.

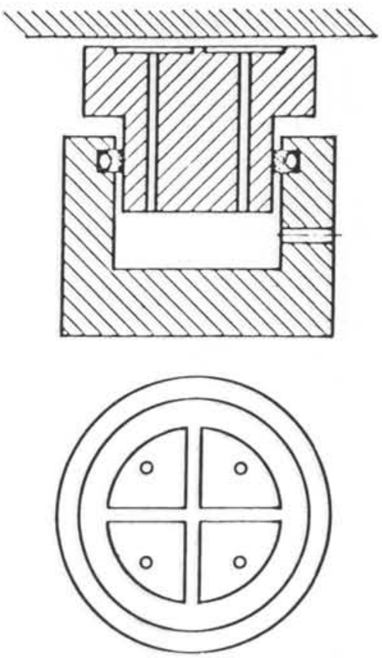


Figure 31. Diagrammatic representation of the method of operation of a hydrostatic support element in the normal position.

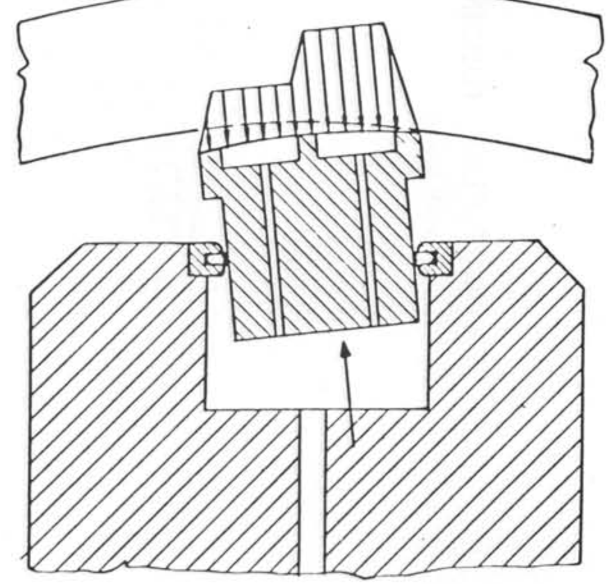


Figure 32. The functioning of a hydrostatic support element in the tilted position.

piston and the rotor. This produces a resultant force equal to the force against the rotor. As a result of this, a precisely defined gap is produced between the supporting piston and the rotor, which remains constant. The supporting piston floats between the two pressure cushions, so that it follows any displacement of the rotor.

Should the support piston tilt in relation to the surface of the rotor, one side of the gap between this surface and the piston becomes smaller and the other larger.

Due to the throttling effect of the separate capillary connections to the pockets, a pressure increase on one side and a pressure drop on the other side will occur. The resulting force from the pressure cushion is thus eccentric and produces a restoring moment which adjusts the support system until it is parallel to the running surface of the rotor.

Advantages

By a special steering device, the support elements damp dynamic forces and can also be used for centering purposes.

These hydrostatic supporting and damping elements, comprising the outer rim bearings, have the following advantages:

- The support system units are of small size relative to the large diameter of the rim bearing surfaces; these act as a series of point supports. Deformations of the bearing surfaces, in relation to the small areas of the support systems, are insignificant.
- The self-centering action of the support pistons on the bearing surface will tolerate a large amount of tilting between the rotor and the supports, both partial tilting and for the whole rotor.
- The self-centering action of the support pistons also permits maintaining very small gaps between the bearing surface and pistons. In this way, an economical relationship is obtained between pressure, flow, clearances and friction. Water may be used as pressure medium, and the losses can be small in relation to the large bearing diameter and peripheral velocity.
- The floating arrangement of the support pistons prevents contact with the rotor bearing surface. On the other hand, radial displacement or expansions and contractions of the bearing surface and of the supports are permissible.
- Manufacturing and installation tolerances become of secondary importance because both radial and concentric positioning takes place automatically.
- The radially self-adjusting support elements are always in the correct position, in contrast to shape related supports, compensating for their own deformation. Dynamic forces are damped at their onset, thus ensuring an extremely smoothly running outer rim.

The bearing research has been carried out since 1970 in the laboratories of Escher Wyss Zurich. For single element investigations a special test rig was constructed. Tests have been accomplished with various fluids and peripheral speeds.

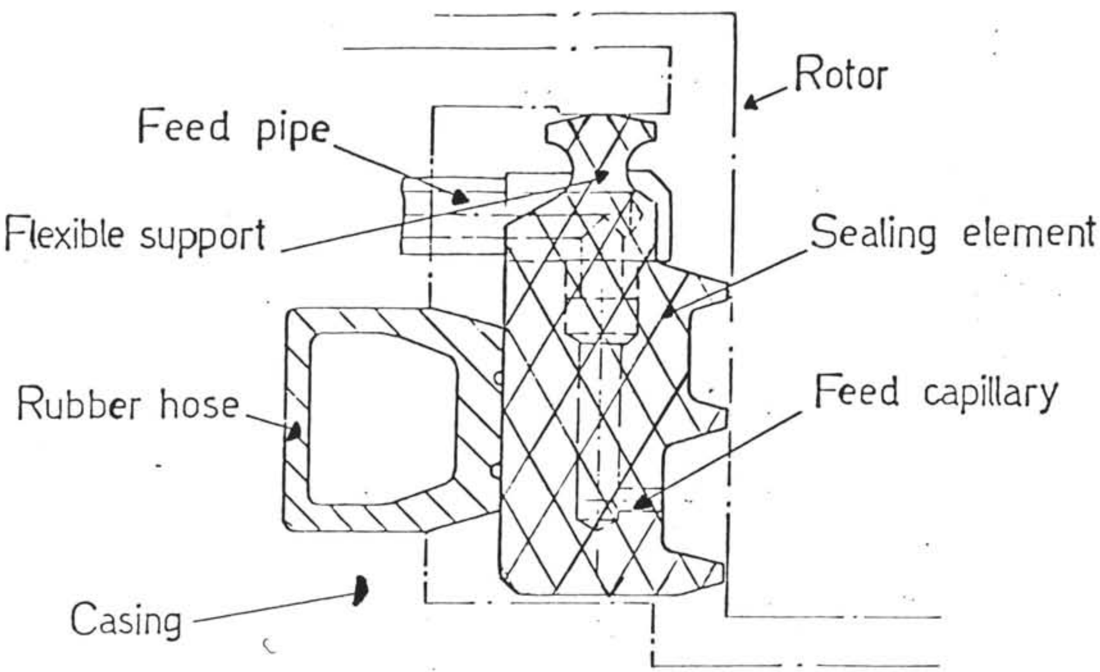
In contrast to hydrodynamic bearings, the hydrostatic bearing systems depends on an outside supply system. If this system fails, a safety system has to be used which, regardless of expenditure, makes a failure of the bearings impossible and prevents destruction of the machine. The safety system consists of reserve support elements and reserve supply systems which necessarily complicates the system. For this reason monitoring and safety devices are necessary as they are included in every governing system. It is therefore not surprising that the hydrostatic bearing system including supply and safety system is comparable in extent and price with a second turbine governing system (which also must be 100% reliable).

Seals

The ingress of water into the generator and into the hub is prevented by hydrostatic seals of the type shown in Figure 34.

These seals are easily accessible from outside the machine for inspection. The working conditions of the seals can be derived directly from the amount of water leakage. The runner shaft and the bearings will be sealed off by means of hydrostatic seals applied between the runner hub and the distributor casing on the upstream side and turbine shaft cover on the downstream side. These seals will be accessible from inside the turbine when dewatered.

These seals consist of curved segments with pockets in the form shown. The sealing elements, of special synthetic material are held together elastically without guides. Thus large axial movements can be accepted. The sealing elements are pressed hydraulically with constant pre-determined force against the rotating sealing surface. Each element has pockets on the side



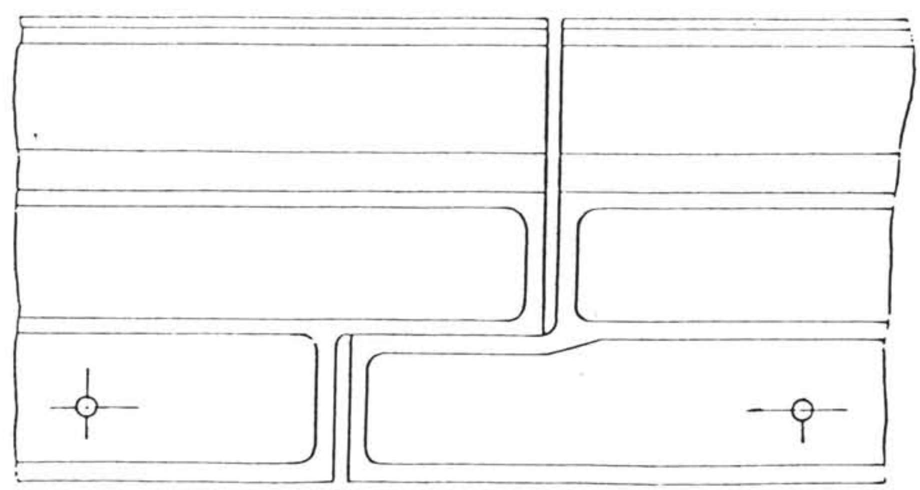


Figure 33. Arrangement of hydrostatic sealing elements between the stationary turbine casing and the rotating outer rim. The elements are pressed hydraulically against the rotating sealing surface of the rotor.

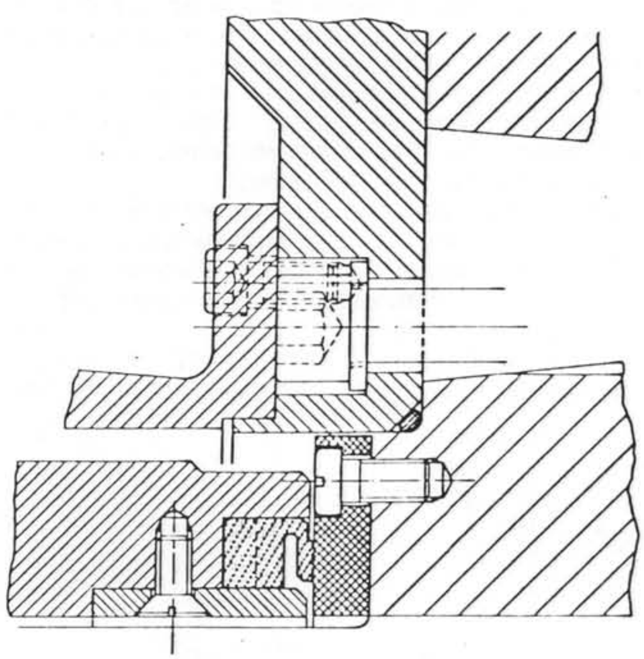


Figure 34. Contact seals between rotor and turbine casing.

facing the rotor. Each of these pockets is fed by a separate capillary with filtered water at a pressure greater than the turbine water pressure. Thus each sealing element is in equilibrium and gives closely controlled minimum clearance between the sealing element and the rotor, through which the sealing medium flows. If this gap becomes too small, the pressure in the pockets rises, forcing the element away from the rotor and correcting the gap. Conversely, if the gap opens, the pocket pressure drops so the the force pressing the sealing element against the surface increases and it is forced back toward the rotor.

The elements are stepped at the ends and are always pressed against each other by the sealing water on the rotor side and the rubber supporting hose on the other side. This rubber hose is inflated by water pressure and designed to hold the sealing elements firmly but flexibly against the rotor. The angular position of the seal contact surfaces can be so adjusted that the sealing water escaping from the seals is equally distributed on either side of the sealing surface.

The seals and support elements are supplied with filtered water to ensure satisfactory operation and least possible wear. Particles larger than 20 microns are removed by a combination plate filter and cyclone filter. The filters are self-cleaning and reserve filters are switched in automatically in the event of blockage.

Two thirds of the water supplied to the seals is recovered for recirculation.

The seals on both sides of the rim are supplied from separate pressure vessels. If the water level in one or both of these vessels falls excessively, a shutdown is initiated. Water from the fresh water supply system ensures that during the shutdown procedure the minimum required pressure is retained. Furthermore, the emergency running characteristics of the sealing elements are so good that they are able to operate for some time without sealing water, no damage occurring to either the sealing elements or the rotor sealing surface. During standstill the sealing water is shut down, the sealing elements being pressed against the rotor surface and thus functioning as standstill seals.

Conditions varied

Extensive tests have been conducted on several versions of these seals proving their reliability and durability. The test conditions were varied to include excessive speeds, loads and dynamic load variations greater than under overspeed conditions. These seals will be installed on an existing straight flow turbine (Iller stage VII).

The seals are designed so that they are fully functional and reliable even under overspeed conditions without undergoing wear.

These hydrostatic seals offer the following advantages:

a) Filtered pressurized sealing medium guarantees reliable operation and prevents damage by possibly polluted turbine water.
b) The self-adjusting seal elements maintain optimum clearance between themselves and the rotor. Thus both friction and sealing water losses are minimized.
c) The self-adjusting and elastically connected sealing elements ensure the same clearance between seal and rotor surface over the whole periphery. As contact between the seal and the rotor is impossible, high peripheral velocities cause no wear. The sealing medium escaping through the gap provides for sufficient cooling of the sealing surface and of the element supports.
d) Because the entire seal is composed of a large number of individual seals operating together, the size of the machine is irrelevant. Manufacture and installation are thus considerably simplified.
e) The equalized pressure and floating seal arrangement makes the design independent of the operating head.
f) The floating seal will tolerate axial displacement of the rotor by several millimeters, or tilting in relationship to the turbine housing.
g) The elastic supports of the sealing elements allow radial displacements or irregularities of the supports. Manufacturing and fitting tolerances become of secondary importance.

The exploitation of hydro energy should, as far as possible and reasonable, be considered a basic task to solve the energy problem. Hydro energy is renewable, and the production of hydro energy causes minimal environmental effects. In this paper it was shown that the standard of hydraulic turbines for low heads reached a very high level, but further development still makes it possible to improve the economy.

The Ossberger Cross-Flow Turbine

by F.W.E. Stapenhorst

If we now remember that after World War I, all the turbine manufacturers in the world went big, designing and manufacturing more powerful turbines every year, trying to beat each other at the same time in efficiency, we can understand that the design and manufacture of small turbines by almost all manufacturers became of secondary importance. In fact, small turbines were neglected to all intents and purposes, and only a few scaled-down units were supplied by such companies as Leffel, Allis-Chalmers and others. The types of small turbines supplied by these companies were small Francis, bulb, propeller types, etc. Members of this conference are aware of Allis-Chalmers' plans to revamp their mini tube turbines and Leffel's types of mini turbines.

With practically all manufacturers going after bigger and bigger units, the only company concentrating on manufacturing exclusively small turbines is the Ossberger Turbine Company in West Germany. Small turbines is Ossberger's only turbine business and all engineering design and development work for many years has been and is being applied to small hydro. Hence, in this field, it is not unreasonable to state that Ossberger is the leader in the world today. Over seven thousand have been manufactured and are in use all over the world, except in the United States where big hydro was the name of the game, with Grand Coulee with over one million horsepower turbines delivering over six hundred and thirty megawatts as the largest turbines in the world.

I am, therefore, grateful for the opportunity to speak about the efforts of the very specialized small turbine, the Ossberger cross-flow turbine.

The concept of the Ossberger cross-flow turbine is not new. It is of the impulse type, and was named "cross-flow" because the water physically crosses the runner twice. The cross-flow principle was invented by Mr. Michell, an Australian engineer, at the turn of the century. It was then further developed by a Hungarian engineer, Professor Banki, who is responsible for its popularity, at that time.

Principle unchanged

The real push came when Ossberger acquired the patent rights for the cross-flow turbine and concentrated on perfecting design, construction and manufacture.

The principle of the cross-flow wheel has not changed since its conception by Mr. Michell. The water in today's cross-flow turbine is directed through a rectangular jet to a cylindrical runner. The main characteristic of the cross-flow runner is that the water passes the runner blades twice - first from the outside towards the center, and then after crossing the open center, from the inside outward.

This cross-flow of the water in its secondary action outward will clean the runner blades of any debris, ice

Mr. Stapenhorst is president of F.W.E. Stapenhorst, Inc. of Montreal, the distributor of Ossberger Cross-Flow Turbines for the U.S. and Canada. He is also the president of Tyton Seal Inc., which manufactures mechanical seals, including large seals for hydraulic turbines.

Mr. Stapenhorst was educated in Germany, where he received the equivalent of a B.Sc. During World War II he was co-responsible for the development in England of the temporary runway widely used by the Allied air forces, and shared in the receipt of a British Government award for this.

and other foreign matter which may have entered the turbine.

A further feature of today's Ossberger cross-flow turbine is its capability to efficiently cope with low heads, say from three feet and going up to several hundred feet. There is no other type of turbine available today that covers the wide range of heads.

The most important property of the Ossberger cross-flow turbine which makes it particularly suitable for small run-of-the-stream operation, is its flat efficiency curve.

The Ossberger turbine efficiency will stay very high even at a fifteen percent rated flow, where Francis turbines would, in fact, not produce any power. This is achieved by the design of the guide vane. The guide vane is precision hydraulically balanced.

To accommodate high variation in flow, the Ossberger turbine guide vane is split up into two valve at the penstock at low-head installations. With the section two-thirds of the runner. At maximum flow both sections are open. At medium flow the two-thirds section is open with the small section closed. At minimum flow only the small section is open. The Ossberger cross-flow turbine will, therefore, easily outperform a Francis and other types of turbines at widely fluctuating flows. The only other turbines that come close to this performance are turbines with adjustable blades, which feature generally adds considerably to the price of the turbine. Our type of turbines can also accommodate fluctuations of head in range of plus/minus twenty-five percent.

Practicality

Because Ossberger concentrated entirely on the development of the cross-flow turbine, this turbine has become probably the most practical turbine in its range in the world today.

The multi-bladed runner is made of cold drawn steel. Each runner is precision dynamically balanced prior to its assembly into the housing. The bearings of the runner are standard roller bearings available at any bearing supplier throughout the world. The guide vane bearings are of the white metal type and a spare set of bearings is maintained by us in North America for each turbine sold by us. The shaft seal packing is also standard and is obtainable from any packing manufacturer throughout the world.

In order to regulate the tailwater level, in the turbine an automatic vacuum breaker valve is provided in the turbine housing.

The turbine is supplied with an intake transition piece between the penstock and the turbine. This is generally round to fit the end of the penstock and formed into a rectangular shape to be bolted to the turbine housing. turbine housing.

The turbine is also supplied with a draft tube. This is of a rectangular configuration to fit the turbine housing to which it is bolted with its outlet end in a round shape.

A semi-modularized design has been developed for the various diameter runners. This means that the turbines for each size runner differ only in the length of the runner and the diameter of the shaft. This feature is not only reflected in the price of the turbine, but also permits speedy deliveries in view of most other parts being standard.

The guide vane is so designed that it can eliminate a valve at the penstock at low-head installations. With the guide vane closed, the turbine housing can be opened permitting the inspection of the runner. This operation is a matter of a few hours.

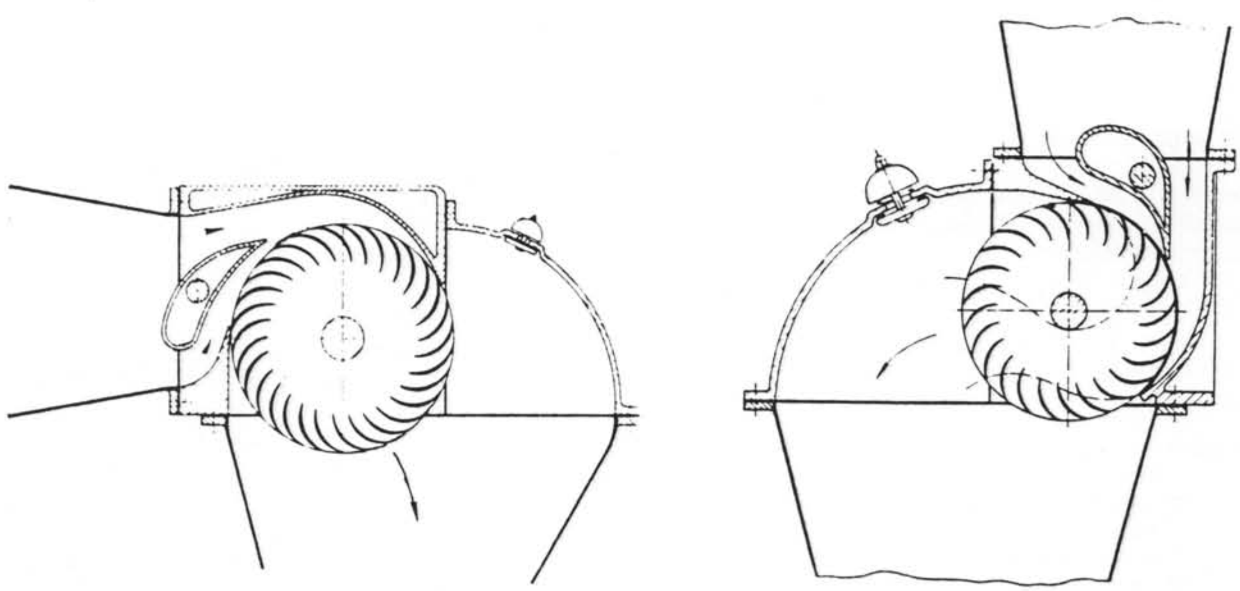


Figure 35. Flow pattern in Ossberger cross-flow turbine. Left, horizontal admission. Right, vertical admission.

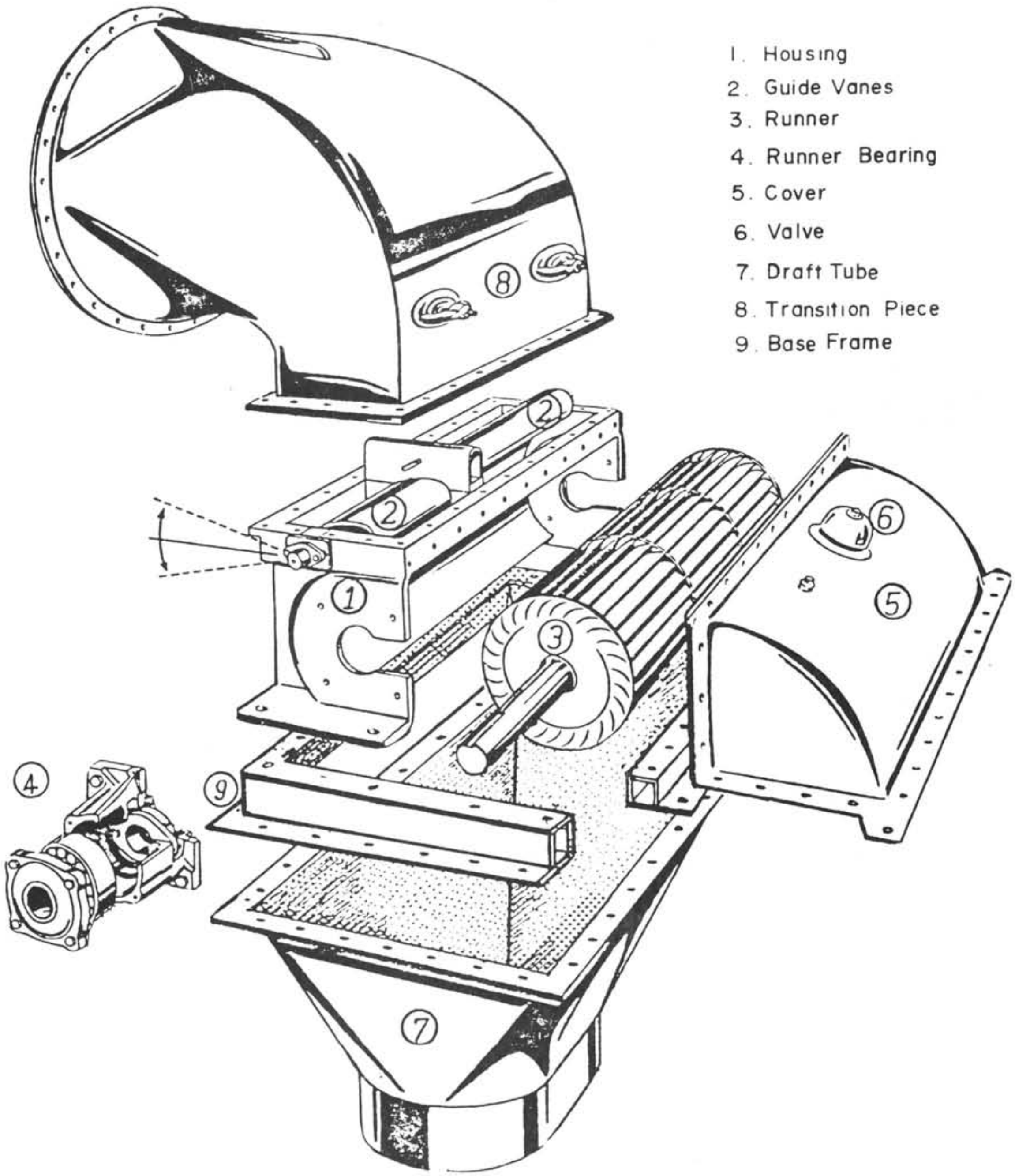


Figure 36. View of typical Ossberger turbine assembly.

The draft tube is either straight or elbow shaped. With a maximum length of 12′, selection of suitable turbine level is made easy without loss of head.

The turbine is generally supplied completely assembled, mounted to a frame. This frame is bolted to the floor with the draft tube and the transition piece screwed to the assembly at installation.

To all intents and purposes, this means that all the cross-flow turbine requires is a strong floor with a hole in it, and installation is done in a matter of days. There are no parts imbedded in the concrete.

The turbine is then coupled to a speed increaser, in most cases consisting of standard parts and to a horizontal shaft generator of a standard design.

Local components

The use of standard local equipment will reduce the cost of hardware drastically when compared to other units, especially those with vertical shafts with sensitive thrust bearings, wicket gates and other parts requiring regular maintenance.

Some of our turbine parts are already manufactured locally. All other components of the generating sets are furnished by reputable U.S. manufacturers. The West German content of a typical hardware package is only in the neighborhood of 20%. If, when, and as the demand for the Ossberger cross-flow turbine increases, we will endeavour to increase the U.S. content even more.

In most cases, small plants would be feeding into the grid of a large utility. This allows the use of induction or asynchronous type of generation which makes the equipment even more economical and simple. This system would eliminate a governor for the turbine, and the generator is an ordinary induction motor which draws excitation from the grid and is driven at a slightly higher speed than the synchronous speed.

The control for these units has been developed by Ossberger to a simple and reliable piece of equipment, named the Ossberger Regulator. Starting and stopping the generator is fully automatic, using photocells and integrated circuitry which can be programmed to include control of the water level of the reservoir to within a couple of inches.

This equipment will permit the units to automatically operate when water is available, or save the water for use during peaking hours.

For synchronous applications, a standard governor is used, such as the Woodward Type UG.

The manufacturing program of the Ossberger cross-flow turbine presently includes runners to a diameter of maximum 1,250 mm with typical data as follows:

At 10 feet	245 HP	265 cfs
20 feet	666 HP	353 cfs
35 feet	838 HP	300 cfs
55 feet	1700 HP	324 cfs

Other Ossberger units are suitable for heads up to 650′ and outputs to 5000 HP.

If more water is available and larger installations are required, the cross-flow turbines are ideally suited to be put up in multiples. In many cases, two turbines can be coupled to one generator via a suitable speed increaser.

The features of the Ossberger cross-flow turbine, apart from its low cost, can be summarized: its simplicity, its reliability and its performance combined with low cost civil works as well as extremely little maintenance.

Demonstration plant

We are about to install the Ossberger cross-flow turbine in a demonstration plant in the State of New York. We are rehabilitating a typical unused small hydro station. Two Ossberger cross-flow turbines of 980 HP each will be installed to furnish about 7,500,000 kwh per year. The head is 30′ with greatly varying flows throughout the year. The station will be completely automatic incorporating latest control devices maintaining the level of the reservoir to within a few inches of the desired level which will keep the property owners around the lake happy. It is an asynchronous installation. The energy will be fed into the grid of the local utility.

Apart from fighting tough battles with the utility over the structure of the power rate required to make such a typical venture more or less viable, we supplied over 250 lbs. of paper work into the Federal Power Commission in respect to the license. I can tell you that we have on record names of every feasible plant that grows or may grow around the reservoir as well as of all the fish that ardent fishermen may have ever dreamed of to exist in the waters. I know the types of salamanders that may crawl around the lake, I know the number of their toes and the color of their skin although I have never seen a single salamander in the area.

I, therefore, welcome Mr. Corso's statement of a "short form" of licence procedure and his efforts to get this plan approved. The trouble with the "short form" license, of course, is that a lot of people presently occupied with the bundles of paperwork require reassignment of their daily work and we ourselves suffer the loss of education by possibly eliminating all or part of our present involvement in environmental aspects in all its details.

I also appreciate the serious involvement of the Department of Energy in their efforts to bring about the birth or of many small hydro stations which are so badly needed.

Bulb Units for Low-Head Hydroelectric Generation

by Edmond E. Chapus and Choucri Haddad

Hydroelectric resources were first developed by harnessing the energy of the most economically feasible sites, those with high and medium heads, equipped with Pelton and Francis turbines. Later, Kaplan turbines were installed for lower heads. But for very low-head sites, less than 60 to 75 ft., the use of the conventional vertical Kaplan units proved often to be too costly to make the installed capacity attractive. A new design had to be found in order to improve the economic feasibility of such low-head sites. It seemed worthy to reconsider the idea of placing the turbine horizontally in the water stream and consequently simplifying the civil work and lowering its cost.

Edmond E. Chapus is President of Alsthom Atlantic, Inc., of New York City. The company is a subsidiary of Alsthom-Atlantique, a large French engineering and manufacturing firm that produces power generating equipment (hydro and steam turbines and generators, gas turbines, Diesel engines, and nuclear plants). It also builds ships, electric locomotives, and other industrial equipment.

Mr. Chapus has been in charge of Alsthom Atlantic's U.S. activities since 1958. He has also worked in Brazil, Japan, Pakistan and Iran, and handled short-term assignments in many other countries.

He has an engineering degree from Ecole Nationale Superieure des Mines, Saint-Etienne, France, and an M.Sc. in Hydraulic Engineering from the University of Minnesota.

Choucri Haddad is a Power Engineer with Alsthom Atlantic. He joined Alsthom-Atlantique in 1967 in France, where he worked on the electrical design of hydro-electric generators. He came to New York in 1976.

Mr. Haddad earned an Electrical Engineering Diploma from Ecole Nationale Superieure d'Electricite et de Mecanique, Nancy, France.

In 1943, Neyrpic and Alsthom engineers, under the impulse of the La Rance tidal project, undertook research work in this direction, placing turbine and generator inside the water conduit. They progressively developed different layouts and designs, trying to determine the best combination both economically and technically. A new and original type of machine emerged which our company named the bulb unit.

As seen from Figures 37 and 38, the bulb unit is a very compact hydroelectric generating unit in which the generator, directly coupled with a high specific speed turbine, is enclosed in a watertight steel housing shaped like a "bulb." The entire unit (turbine and generator), is placed horizontally in the water stream and completely submerged. The only connections with the outside are the governor and electrical leads through an access shaft.

This shape and design are the result of many years of intensive research, tests and operational results. Development of the bulb units proceeded by steps starting with small units.

Small bulb units

These units were designed to tap the energy of very low heads at the lowest cost. Unit capacity ranges between some 100 kw to a few thousand kw. The various site conditions led to four types of layouts, summarized as follows:

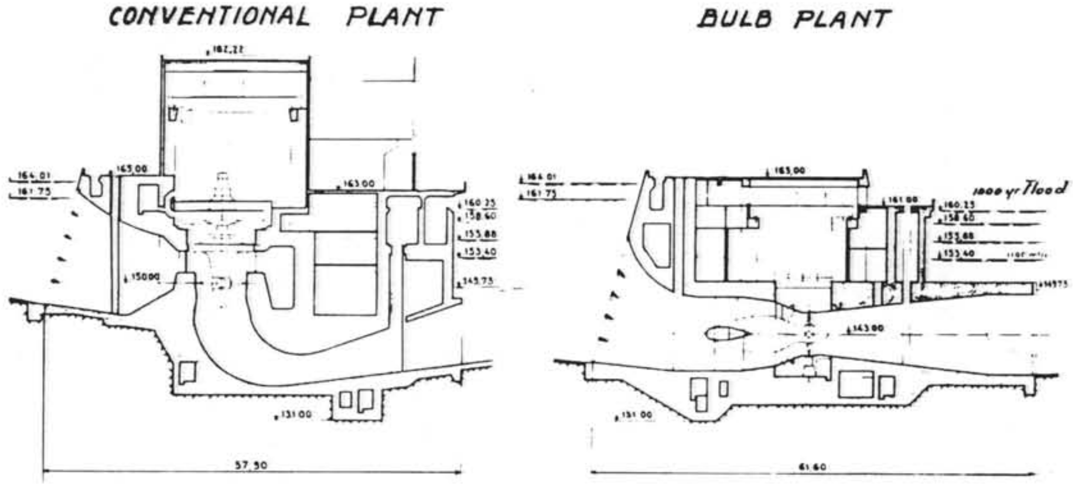


Figure 37. Bulb plant compared to conventional plant.

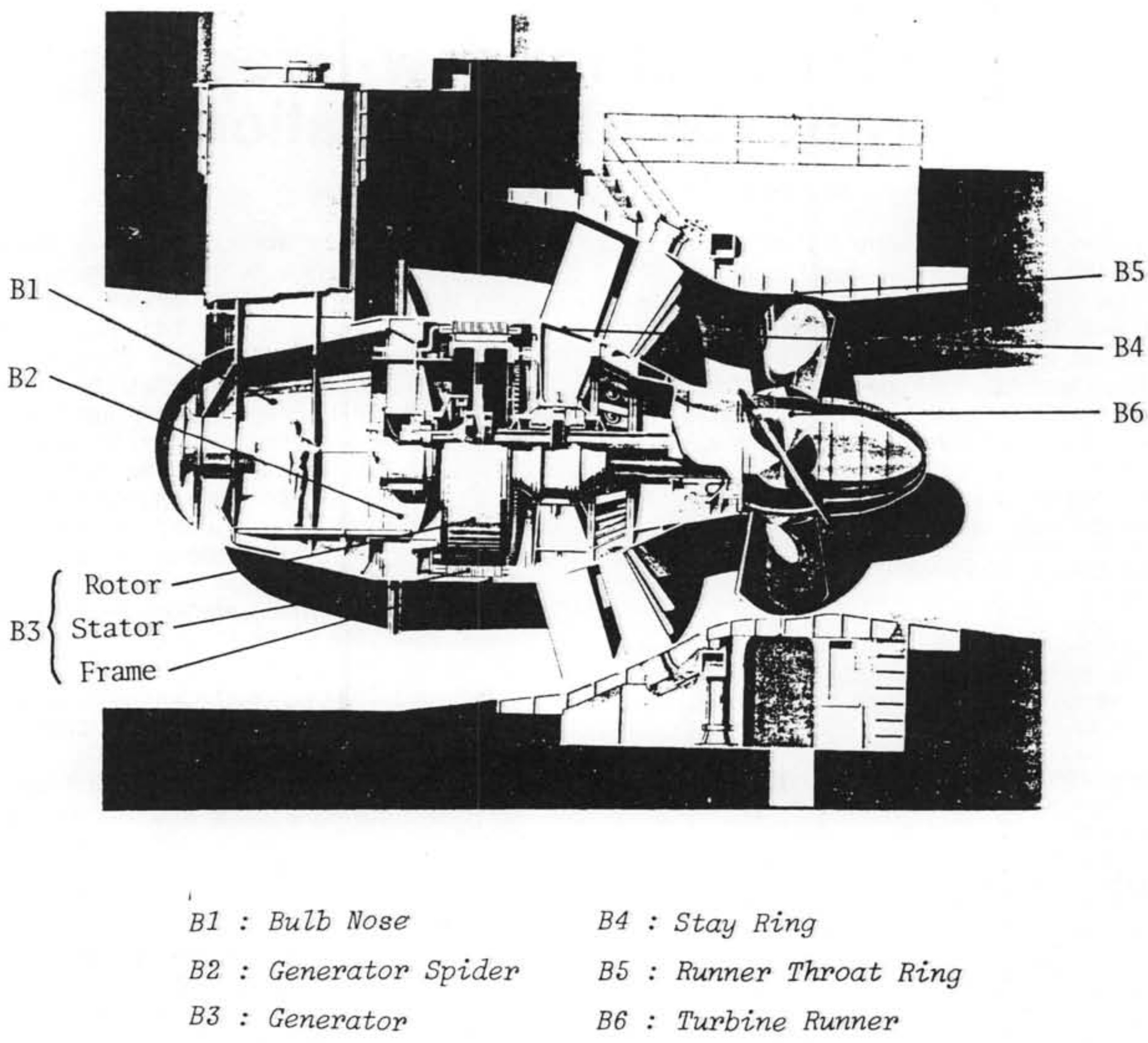


Figure 38. Bulb unit.

Layout	See Figure	Suitable for Head Range
Siphon	39	12 ft. and under
Open Chamber	40	lower range
Conduit	41	higher range
Right-Angle Drive (R.A.D.)	42	any

Site conditions, rather than head, often dictate the choice of layout. In the first three layouts the generating unit is monobloc: a fixed (or adjustable) blade turbine runner directly coupled to an induction (or synchronous) generator. In the R.A.D. layout, the turbine drives a generator outside the conduit through a right angle step-up gear. Capacity is limited by that of the gear. In any layout, erection and maintenance are very simple.

Table 13 is a list of small bulb units designed and manufactured by Alsthom-Neyrpic. It gives an idea of the head and capacity ranges.

We must point out that the successful operation of small bulb units and the numerous tests performed allowed for the design of progressively larger units.

Large bulb units

Most of these units have adjustable runner blades and wicket gates. Some have a fixed distributor and some are non-adjustable: runner blades are fixed and there are no wicket gates; they are suitable mainly for fairly constant heads. Non-adjustable units go one step further in the cost reduction of low-head equipment. Illustration of the two types of units is given in Figures 43 and 44.

Two of the principal technical problems faced in the design of large bulb units were the design of the bearings, which had to support a much higher load than in any other application and the design of the generator, which had to have a reduced diameter. Technical problems have been successfully resolved through innovative design and numerous tests. Some of the resulting construction features will be discussed later. The range of capacities and heads for these units are given in Table 14. Note the rapid increase in capacity starting around 1955 with the 5 Mw at Cambeyrac, 10 Mw at Beaumont-Monteux and 15 Mw at Argentat, to the highest capacity ever with bulb units of 54 Mw per unit at Rock Island, on the Columbia River in the State of Washington.

Features

A comparison with the conventional vertical Kaplan unit will help to point out the economic and technical advantages of the bulb unit, (see Figure 37). In a vertical Kaplan unit the water flow changes twice in direction: from horizontal to vertical at the inlet and from vertical to horizontal at the outlet. With these direction changes, a voluminous spiral case is needed in front of the turbine and an elbow draft tube behind it. By contrast, in the bulb unit, there is no change in the stream direction, a fact which eliminates the spiral case, enables the draft tube to be straight and clean, and makes better use of the water energy. The resulting advantages, both technical and economic, are numerous. They are briefly listed below.

Economic advantages

SIMPLER AND MORE COMPACT POWERHOUSE. The elimination in the bulb unit of the spiral case and the elbow draft tube results not only in better performances but also in substantial savings:

- reduction in foundation depth, powerhouse width and height.
- reduction in unit costs because shapes are simpler to form and cast.

As an example, the Rhone Valley Authority, after extensive and meticulous studies, concluded that a powerhouse with bulb units leads to the following savings compared to the equivalent Kaplan powerhouse giving the same service (energy production, reactive power, voltage, spillway capacity, etc.)

Powerhouse cost index	Kaplan vertical	Bulb adjustable	Bulb Non-adjus.
Equipment	100	85	72
Construction	100	77	52

Technical advantages

1) HIGHER SPECIFIC OUTPUT. The specific speed and specific output are considerably increased without affecting the efficiency.

2) BETTER CAVITATION CHARACTERISTICS. Bulb unit is less sensitive to cavitation than a Kaplan unit.

3) BETTER EFFICIENCY. The slight increase in the intrinsic efficiency of the turbine and the reduction of head losses at inlet and outlet result in an overall higher efficiency of the bulb unit compared to the Kaplan unit.

Operating advantages

1) SLUICE OPERATION. Sluice operation consists in allowing a certain discharge to go through the turbine while the generator is disconnected from the system. Bulb units with draft tube gates can discharge 70% of normal rated flow, a fact which allows the suppression of part of the spillway resulting in an important savings in both the equipment and the civil work, and avoidance of damaging and dangerous surges in case of a sudden disconnection.

2) REVERSIBILITY. As for the excellent adaptation of the bulb unit to reversibility or pumping, it has made possible the construction of tidal powerplant units. Consider La Rance powerplant: the units operate in both flow directions, as a turbine, as a pump, and for sluicing, a feat unimaginable with conventional Kaplan units.

Construction features

The pace in axial turbine development was controlled in great part by the technical problems that resulted from placing the turbine and generator horizontally in

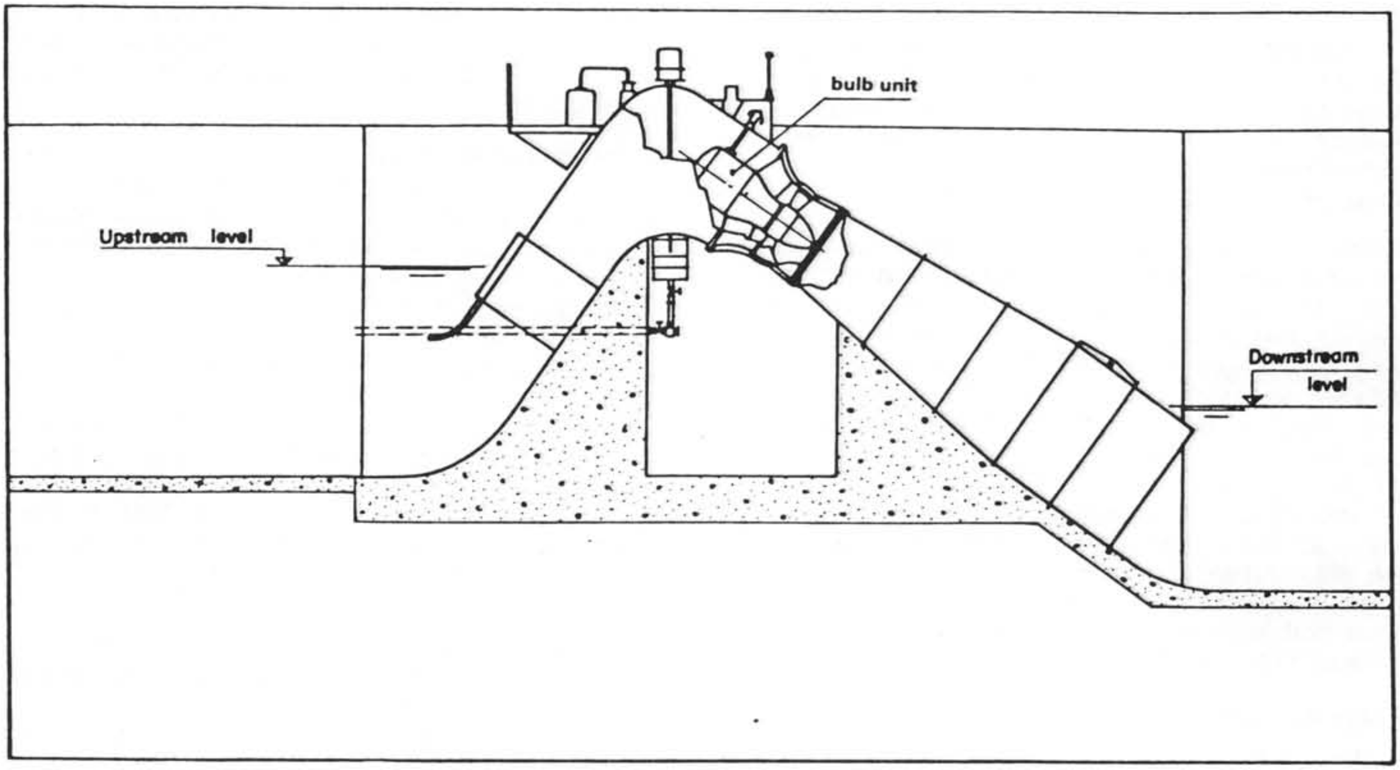


Figure 39. Siphon

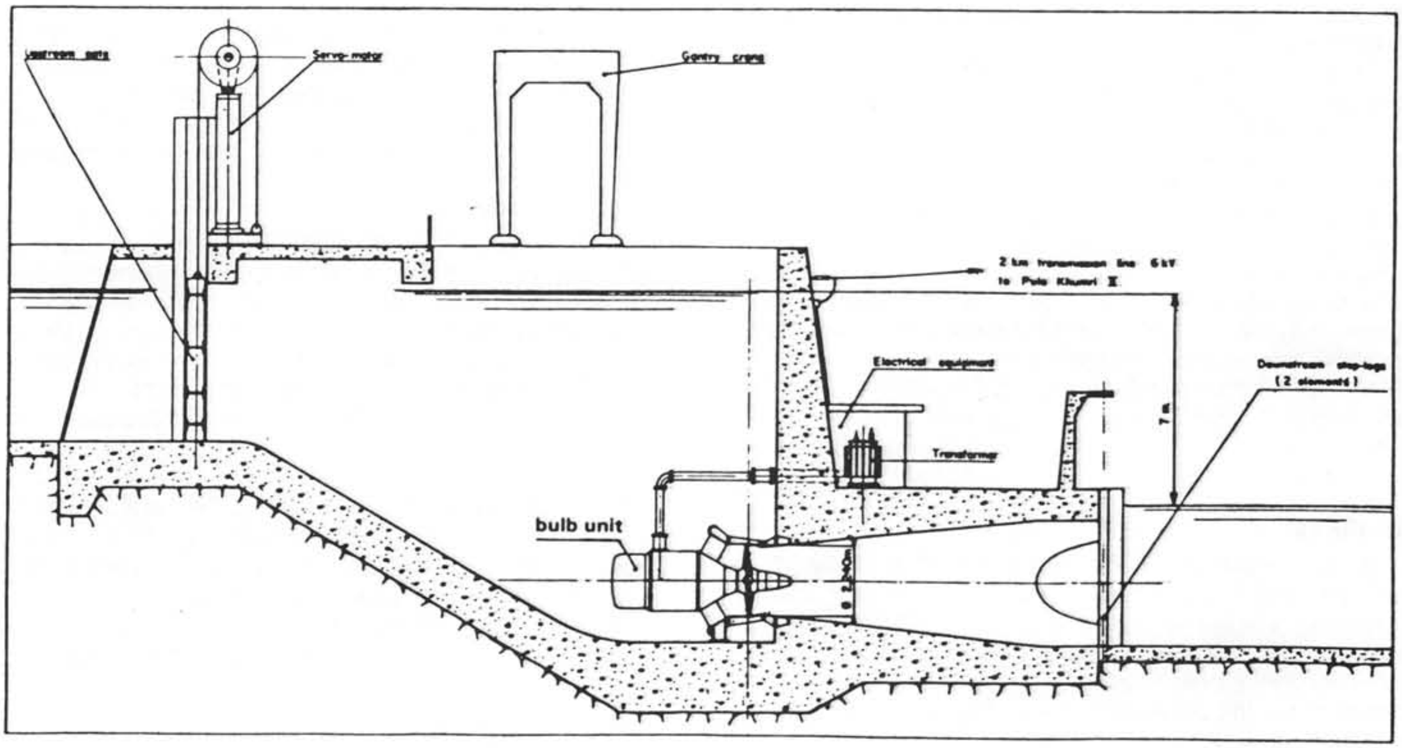


Figure 40. Open chamber.

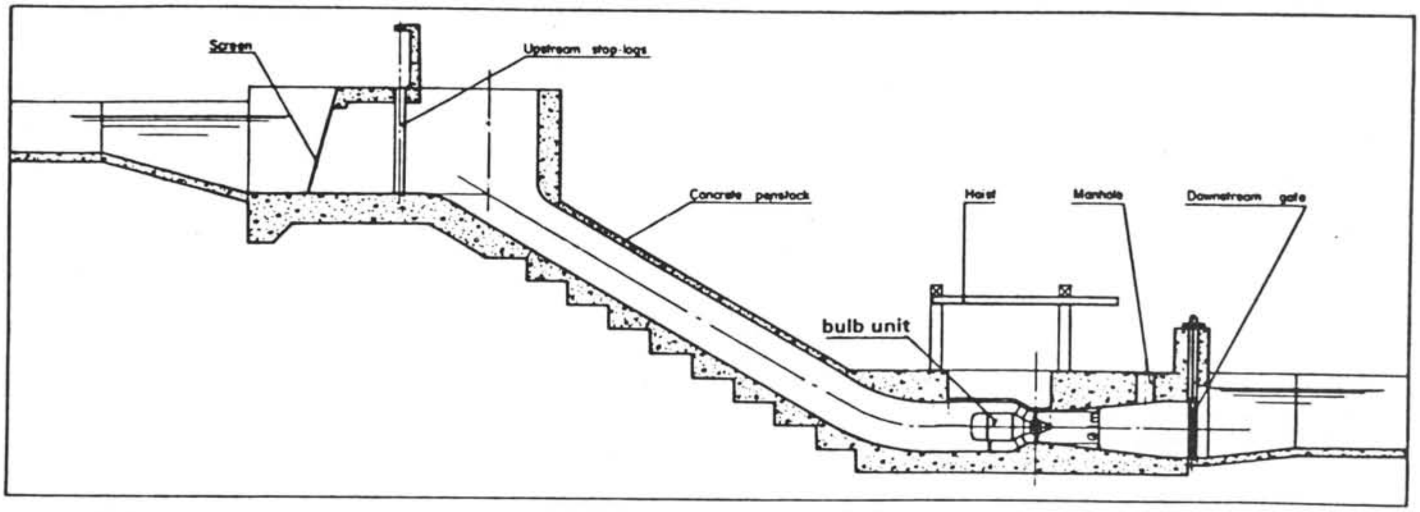


Figure 41. Conduit.

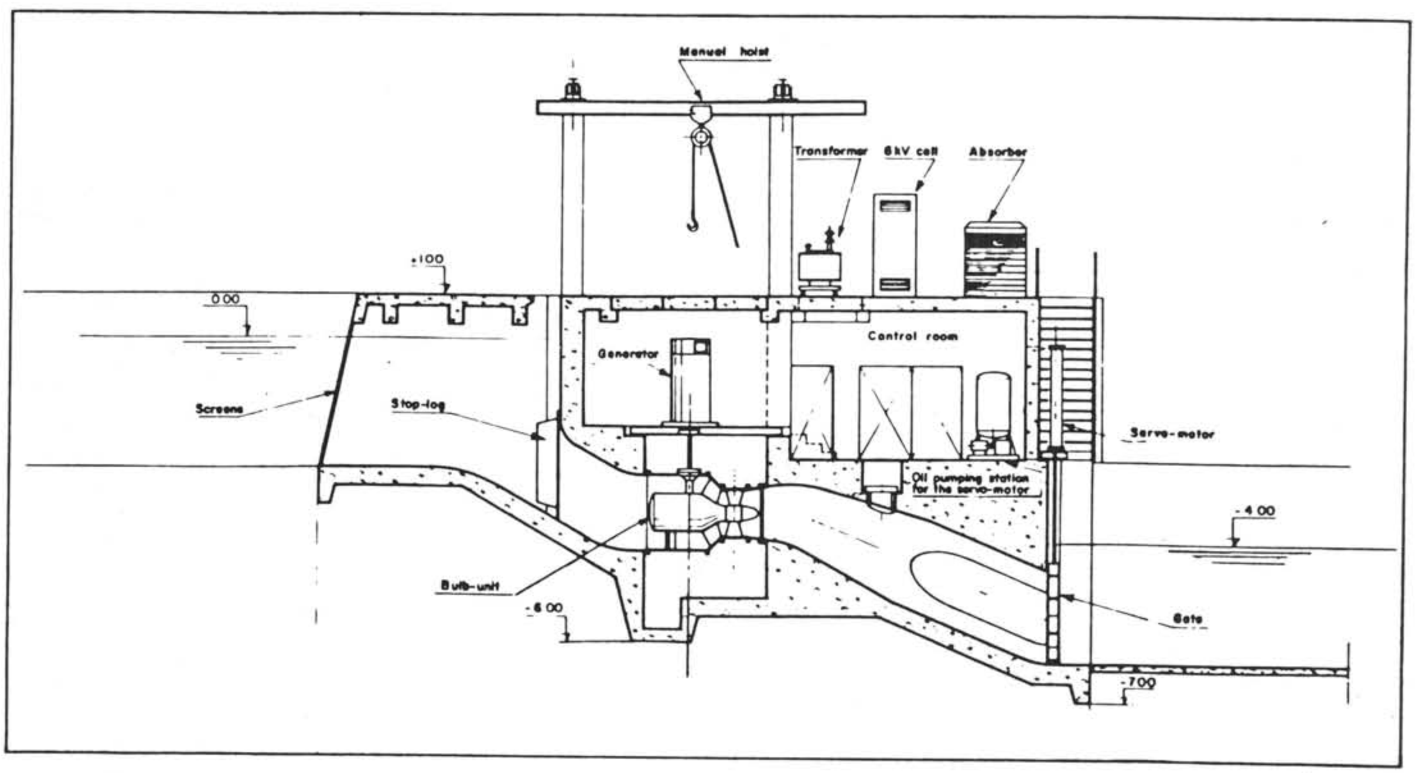


Figure 42. Right-angle drive.

Project and Country		Number of units	Nom. capacity per unit (hp)	Nominal head (ft)	Runner diameter (in.)	R.P.M.	Date of order
LA MAIGNANNERIE	France	1	69	6	44	214	1952
MARCILLAC	France	5	120	10	44	108	1957
LA CAILLADE	France	4	209	11	44	257	1955
AME	France	1	194	6	63	158	1952
LAGARDE	France	4	252	7	63	182	1955
ABZAC	France	4	230	7	68	158	1955
VERDUN	France	2	327	10	65	182	1954
RETHEL	France	2	345	10	65	182	1955
MERCUES I Un. 3	France	1	386	11	65	182	1951
ESCH S/SURE	Luxembourg	6	400	10	71	182	1959
MERCUES I Un. 6	France	1	420	11	55	250	1959
MERCUES II Un. 4 & 5	France	2	430	9	55	250	1956
RABODANGES	France	1	480	18	55	314	1956
ALBAS	France	5	575	11	71	182	1962
MERCUES I Un. 1 & 2	France	2	660	12	71	214	1964
AWE	Scotland	2	705	22	49	375	1961
CAPDENAC	France	3	1020	20	71	260	1956
BERGERAC	France	2	1075	12	57	136	1966
CASTET	France	2	1100	23	65	250	1950

In addition to the earlier units listed above, more recent units have been designed and built for Spain, USSR, Indonesia, The Philippines.

Table 13. Small Alsthom-Neyrpic bulb units.

the conduit and trying to build large units: bearings designed for very high loads, seal tightness, shaft stability under transient operating conditions, generator size, ventilation and excitation systems, etc. As mentioned before, these problems were successfully resolved by proceeding gradually with new designs, applying them first on small units, performing numerous tests and, only after that, extrapolating to higher capacities. Two of them are briefly mentioned here:

1) SHAFT AND BEARINGS. In the bulb unit the load per bearing can exceed 135 metric tons. Design and operating characteristics of such bearings are difficult to predict by calculations alone and must be supported by field tests.

2) GENERATOR SIZE. The generator diameter must be close to the diameter of the turbine in order to prevent perturbation of the water flow and maintain good hydraulic efficiency. This condition led in practice to the design of a generator whose diameter is about half of that of an equivalent conventional generator. This was successfully achieved by the engineers of our company through an original design of the field coils and the cooling system.

Maintenance and reliability

Access to the unit(s) can be achieved through vertical access shafts or a horizontal gallery running through all the units.

Maintenance in a bulb unit is simpler than in the conventional Kaplan: in particular, it is easy to dismantle the upper half ring around the runner and accede to the blades. On the generator side, an appropriate sequence of operations provides for removal of one or more poles from the rotor and one or more bars from the stator winding without dewatering the unit. As for reliability, "Electricite de France" (EDF), which has in operation more than 100 small bulb units and over 50 large ones, reported the following in 1974: the small bulb units fulfilled expectations. Many have more than 100,000 hours of operation.

The large bulb units have a very low forced outage factor. The four units at Pierre Benite, commissioned in 1966, each had over 50,000 hours of operation in 1974, despite two years of poor flow.

Some figures about annual productions will illustrate the performance of Alsthom-Neyrpic Bulb units.

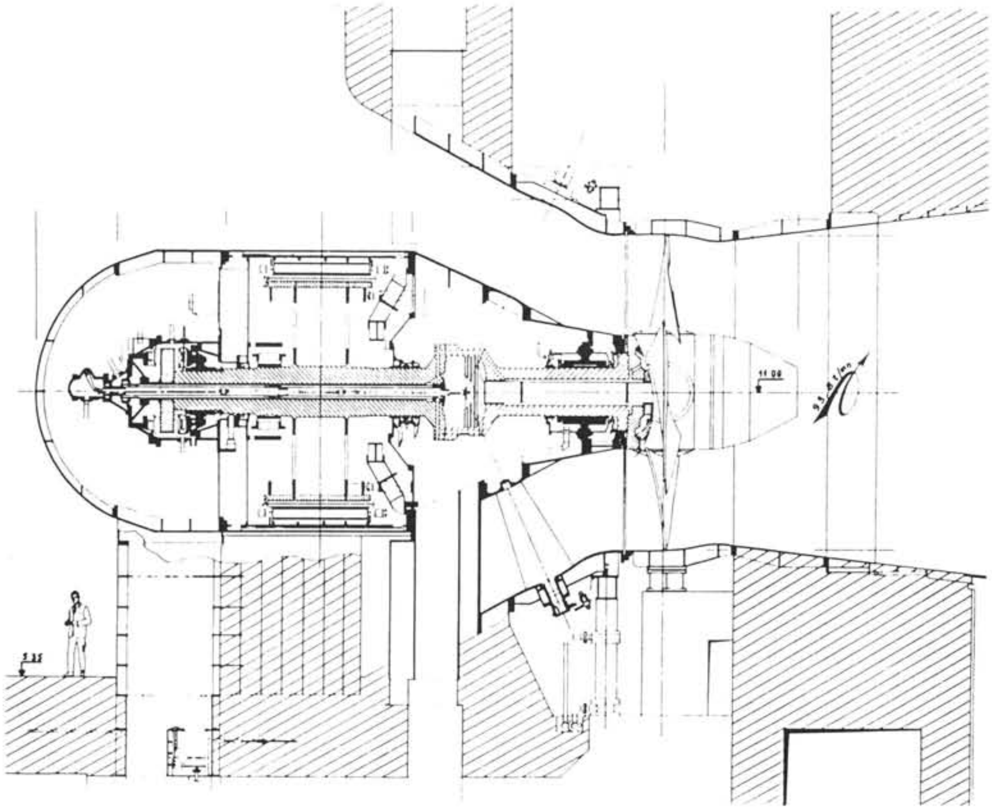


Figure 43. Caderousee I. Adjustable bulb unit.

Figure 44. Caderousee II. Non-adjustable bulb unit.

Powerplants	Annual production, Anticipated (GWh)*	Annual production, Actual (GWh)
Cambeyrac	27	Average 1960-71: 35
Argentat	102	Average 1959-71: 112
Pierre Benite	510	In 1970 : 553
Gerstheim	708	Average 1968-71: 733

* GWh: Gigawatt-hour = One million kilowatt-hours.

Conclusion

As of today Alsthom-Neyrpic have designed and manufactured more than 100 large bulb units and over 60 small ones. The capacity per unit ranges from some hundred kw to 54,000 kw. Twenty-five years of experience and progressive development, and as many years of successful operation, are the proof that bulb units can meet the challenge of the economical development of low-head hydro-electric sites.

Project and Country		Number of units	Nom capacity per unit (hp)	Nominal head (ft)	Runner diameter (in.)	R.P.M.	Date of order
CAMBEYRAC**	France	1	7,000	35	122	150	1953
NAM GANG*	Korea	2	9,500	33	118	189.5	1968
TISZA II*	Hungary	4	9,800	35	169	107	1967
SAINT-MALO**	France	1	12,220	20	228	88	1956
BEAUMONT MONTEUX	France	1	12,400	41	150	150	1955
LA RANCE* **	France	24	13,600	21	210	93.8	1961
ARGENTAT**	France	1	19,250	54	150	150	1953
VAUGRIS I	France	2	24,500	21	246	75	1976
VAUGRIS II	France	2	24,500	21	272	75	1976
PIERRE BENITE	France	4	28,100	28	240	83.3	1962
PALDANG*	Korea	4	28,800	39	205	120	1966
GOLFECH	France	3	31,600	47	201	125	1968
GERSTHEIM*	France	6	32,400	38	220	100	1963
GAMBSHEIM	France	4	34,000	41	220	100	1970
STRASBOURG*	France	6	39,400	47	220	100	1967
AVIGNON	France	4	40,400	30	246	93.8	1969
GERVANS	France	4	41,500	31	246	93.8	1968
CADEROUSSE I	France	2	43,600	30	246	93.8	1971
CADEROUSSE II	France	4	43,600	30	272	93.8	1971
SAUVETERRE	France	2	45,000	30	272	93.8	1969
BEAUCAIRE	France	6	47,600	50	246	93.8	1965
SABLONS	France	4	55,000	38	246	93.8	1974
CAKOVEC	Yugoslavia	2	53,700	61	213	107	1977
CHAUTAGNE	France	2	60,500	48	252	107	1977
BELLEY	France	2	60,500	48	252	107	1977
ROCK ISLAND	U.S.A.	8	71,000	40	291	85.7	1974
Total No. of units & capacity		105	3,524,870				

* manufactured partly by others

** units operate as reversible pump-turbines

More than 60 other small bulb units have also been delivered.

Table 14. Large Alsthom-Neyrpic bulb units.

Tube Turbines

by G.E. Pfafflin

Among low-head hydroelectric generating units the tube turbine has a very specific if limited niche or application. As a concept the tube turbine does not generally compete with the bulb turbine nor with the rim unit, and only very limitedly with the design of the cross-flow turbine. While there are several U.S. installations of large tube units these should not be viewed as the recommendation for such projects by the U.S. hydro-turbine industry.

Pictorially we view the range of tube turbine applications generally as illustrated in Figure 45.

Simplicity in design and project economics have favored the tube turbine in the area identified. For new low-head power stations requiring larger tubular units, Allis-Chalmers would generally recommend bulb turbines as most cost-effective, taking into account overall project economics. For heads in excess of 15 meters or 50 feet, conventional vertically-arranged fixed blade or Kaplan propeller turbines would likely best fit project requirements.

In its most commonly used form the tube turbine is horizontally arranged with a directly coupled generator downstream of the turbine, (Figure 46.) Butterfly valves, fixed wheel gates and other devices have been used for upstream shutoff.

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Norwich example

For best overall turbine efficiency, particularly when part load operation is planned, runners with adjustable blades have been adopted as in this installation in Norwich, Connecticut, (Figure 46) which has been in operation since 1967.

Synchronous generators with static exitation and induction generators have both been used depending on project requirements and system characteristics.

This city of Norwich unit driving a synchronous generator has been designed with full black start capability, a feature which while not standard, can clearly be provided for very little extra cost.

Other configurations of the tube turbine include inclined shafts with downstream or indeed upstream generators as in the case of this installation in New England where two units have been in service since 1976 and 1977 respectively. (Figure 47.) The reason for this arrangement lies in the designer's attempt to maximize the runner submergence without increasing the excavation and consequently construction costs.

Yet another configuration used in connection with tube units is represented by this vertical arrangement installed in Brazil. (Figure 48.) While these machines which were designed as dual purpose pumps and turbines required the siphon on the right, modern designs of vertically arranged tube turbines can be significantly simpler, much like low-head axial flow pumps.

There is a great deal of flexibility with regard to the arrangement of tube-type turbines, the specific

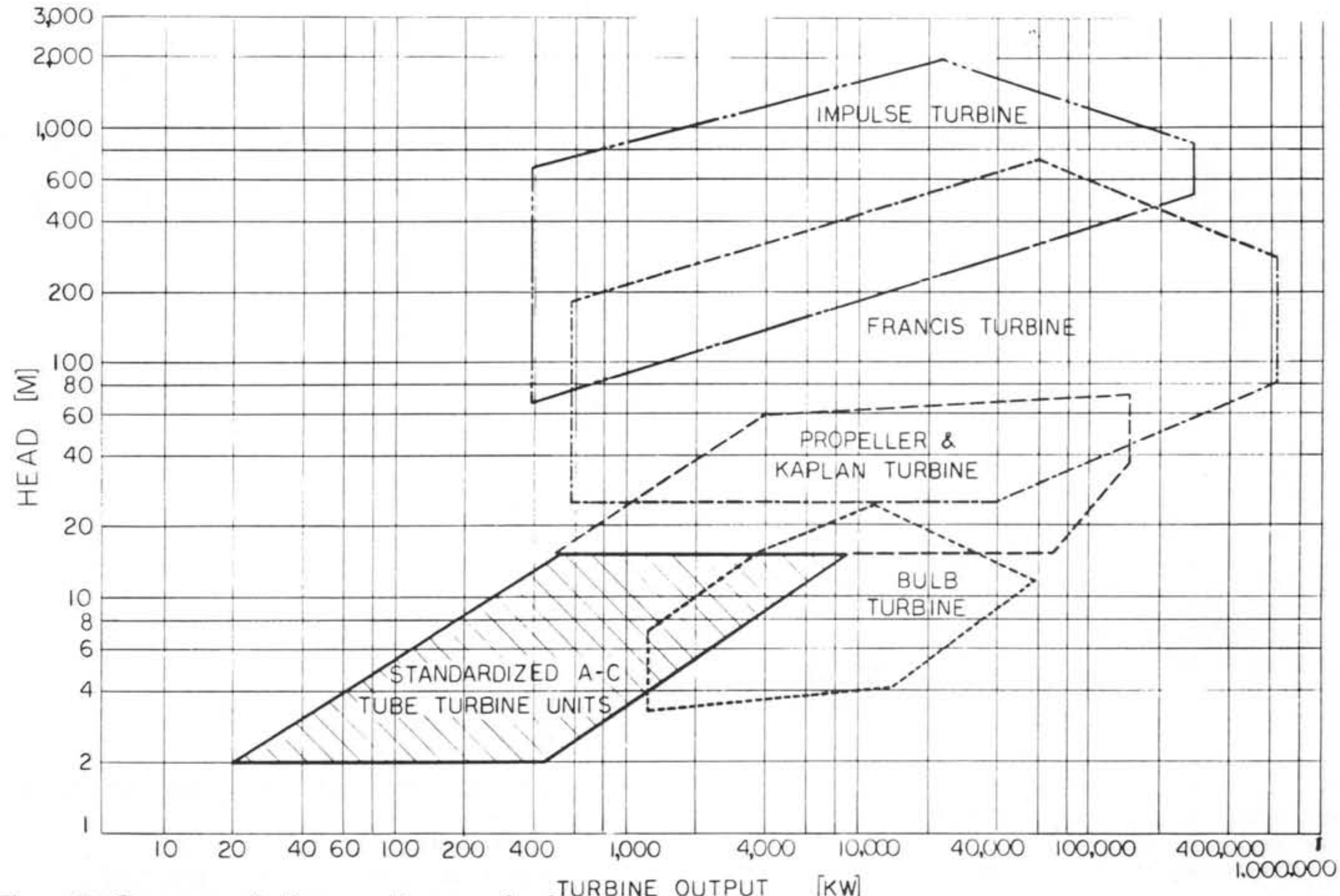

Figure 45. Common application ranges for conventional hydraulic turbines.

recommendation depending on project requirements and constraints.

Common however to each of these configurations are simplicity in design and low cost.

Two major uses

The merits of the tube turbine generating sets recommend this concept for two principal applications. (Table 15.) (1) For mini low-head hydro installations which would generally operate unattended and for which the more efficient and more elaborate bulb or rim type units are either not available or not economical. (2) For the rehabilitation of old low-head plants where in many instances the physical constraints favor the tube concept.

Examples of the former are those two units currently in manufacture, both based on a newly adopted standard design of horizontal configuration utilizing standard butterfly valves for upstream shutoff, and adjustable blade runner and a 900-rpm generator rated 1,000 kw and 1,500 kw respectively (Figure 49).

This configuration has been designed in standard form for units ranging in size from 30" runner diameter to 120" and for operating heads from 7' to 50'. This size and head range provides a capacity range from 50 kw to 5,000 kw per unit available as a fixed blade or adjustable blade machine, driving a synchronous or induction generator running at 900 rpm.

The other primary application of tube turbines, namely in the rehabilitation or upgrading of old power stations, often requires variations of the above standard theme. Figure 50 highlights two such projects in both of which the units are rated 10 Mw.

The turbines however are of very different configuration. The installation described in the upper portion of this figure, which is on the Ottawa River in Canada, involves a full Kaplan design, i.e. with coordinated adjustable wicket gates and runner blades. This 10 Mw unit driving a synchronous generator was installed in the mid 1960's in an empty bay of a power plant built in 1920 for a 5.5 Mw horizontally arranged multi-runner Francis unit.

The installation in the lower portion of this figure is of more recent vintage. Here three 10 Mw units with fixed blades and without wicket gates are installed in an old station originally built for a total capacity of 15 Mw.

In both of these projects the engineers selected tube turbines as the preferred solution for reasons of overall project economics.

In summary I would like to reiterate that tube turbines have two primary applications: (1) in standardized form for mini-hydro projects with unit capacities up to 5,000 kw and heads up to 15 m., and (2) for rehabilitation for upgrading of old low-head stations for which we would not expect to exceed unit capacities in the order of 10,000 kw. (See Table 15.)

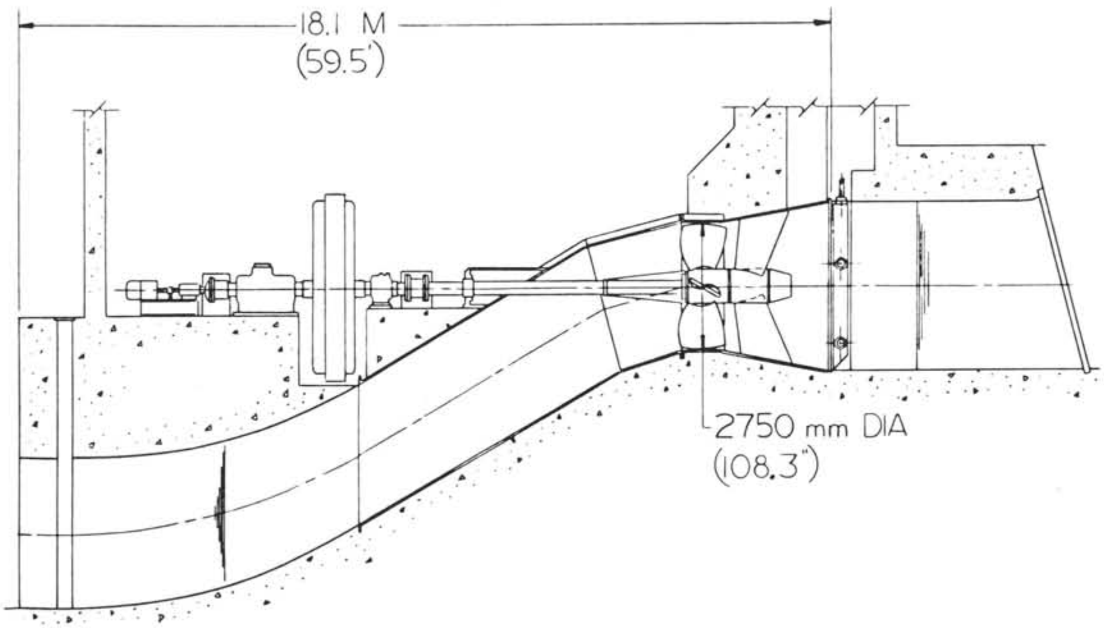

Figure 46. Tube turbine installation, Norwich, 1967. 1-1, 490 kw, 4.7m. (15.4') head.

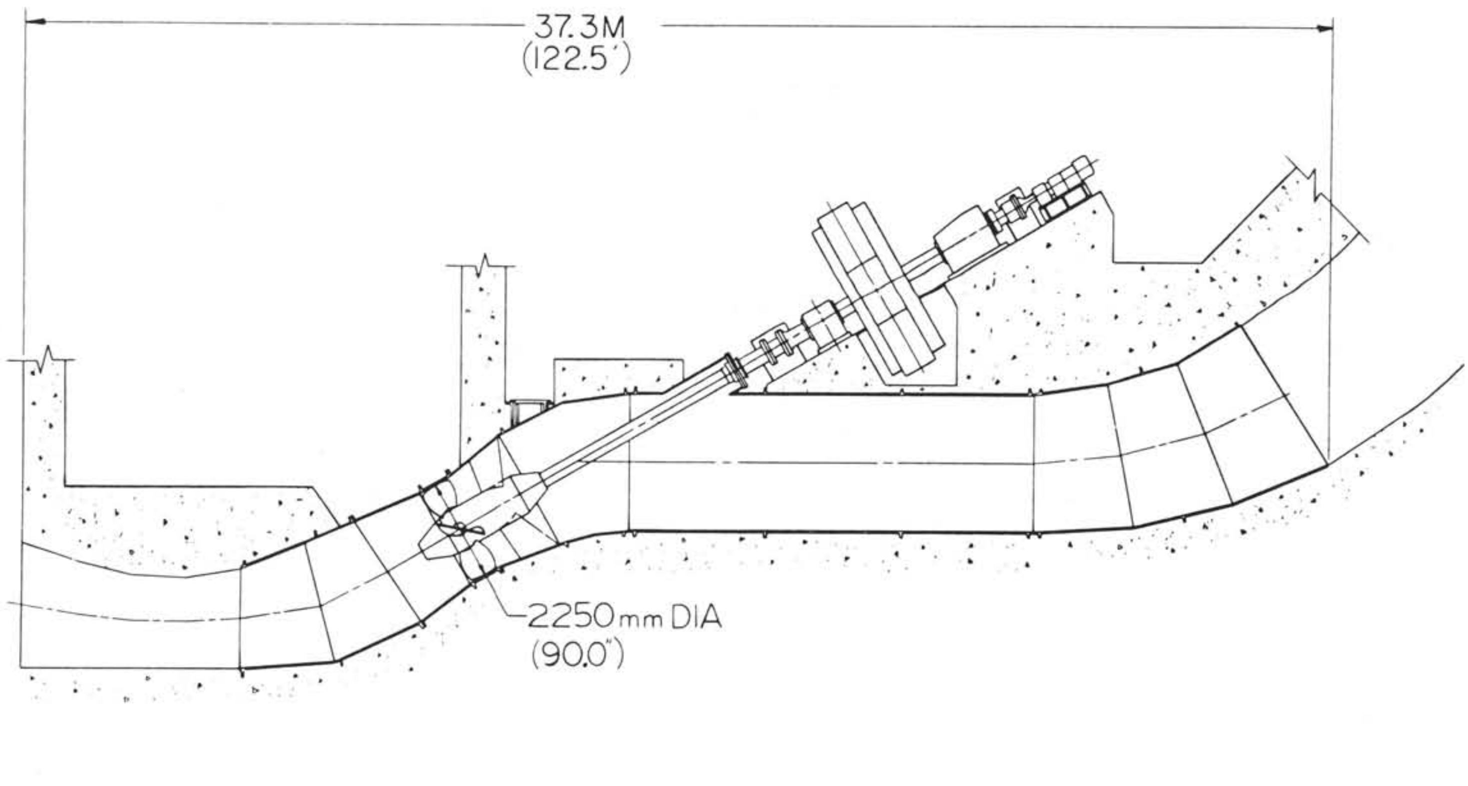

Figure 47. Tube turbine installation, Dolby Hydro Station, 1976/77. 2-4,200 kw, 14.m. (48') head.

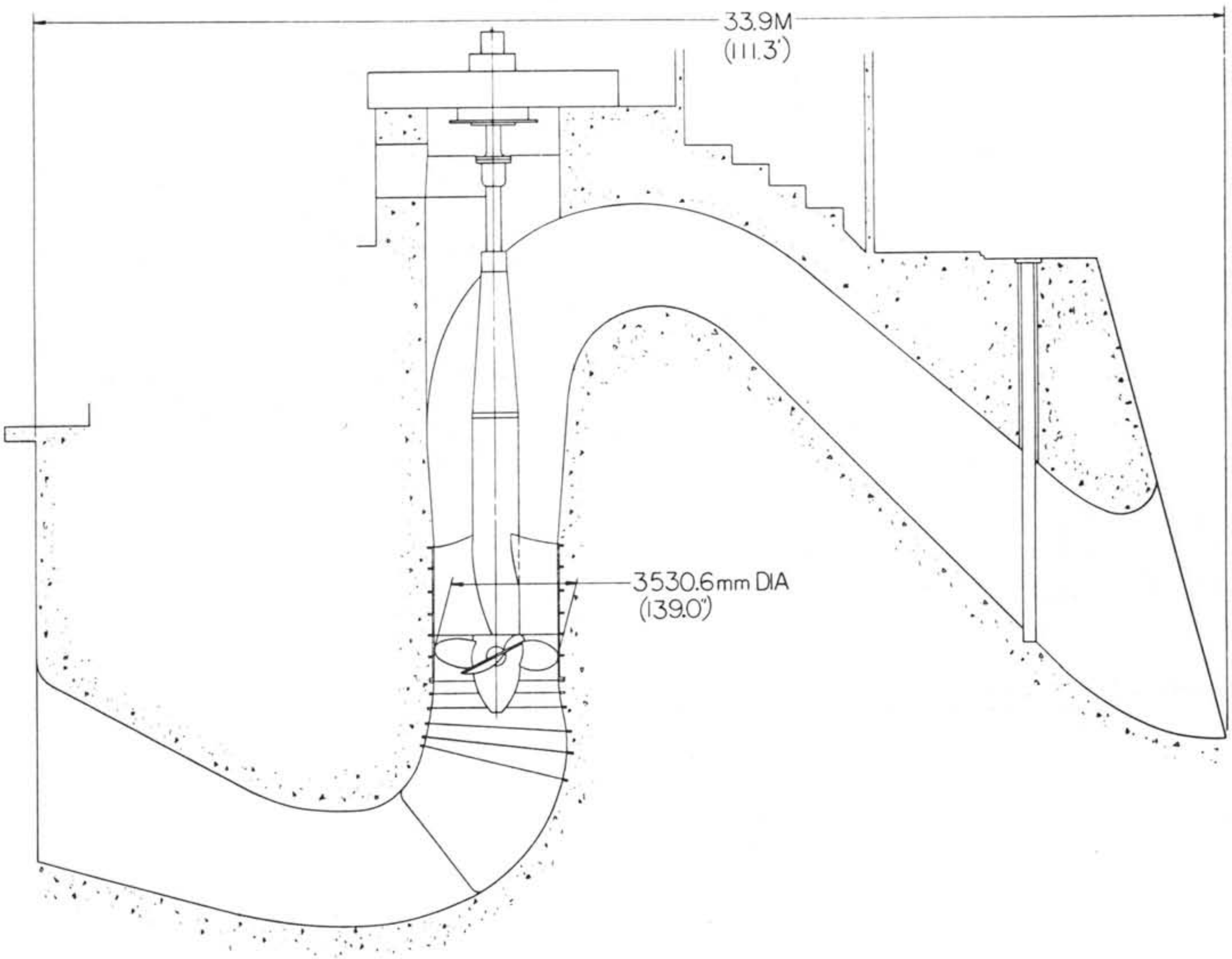

Figure 48. Tube turbine installation, Tricao Power Plant, 1938. 3-2,570 kw, 7m, (23') head.

TUBE TURBINE APPLICATIONS

1. MINI LOW HEAD (UP TO 50') HYDRO WITH UP TO 5000 KW UNIT CAPACITIES.

2. REHABILITATION AND/OR UPGRADING OLD LOW HEAD PLANTS.

Table 15.

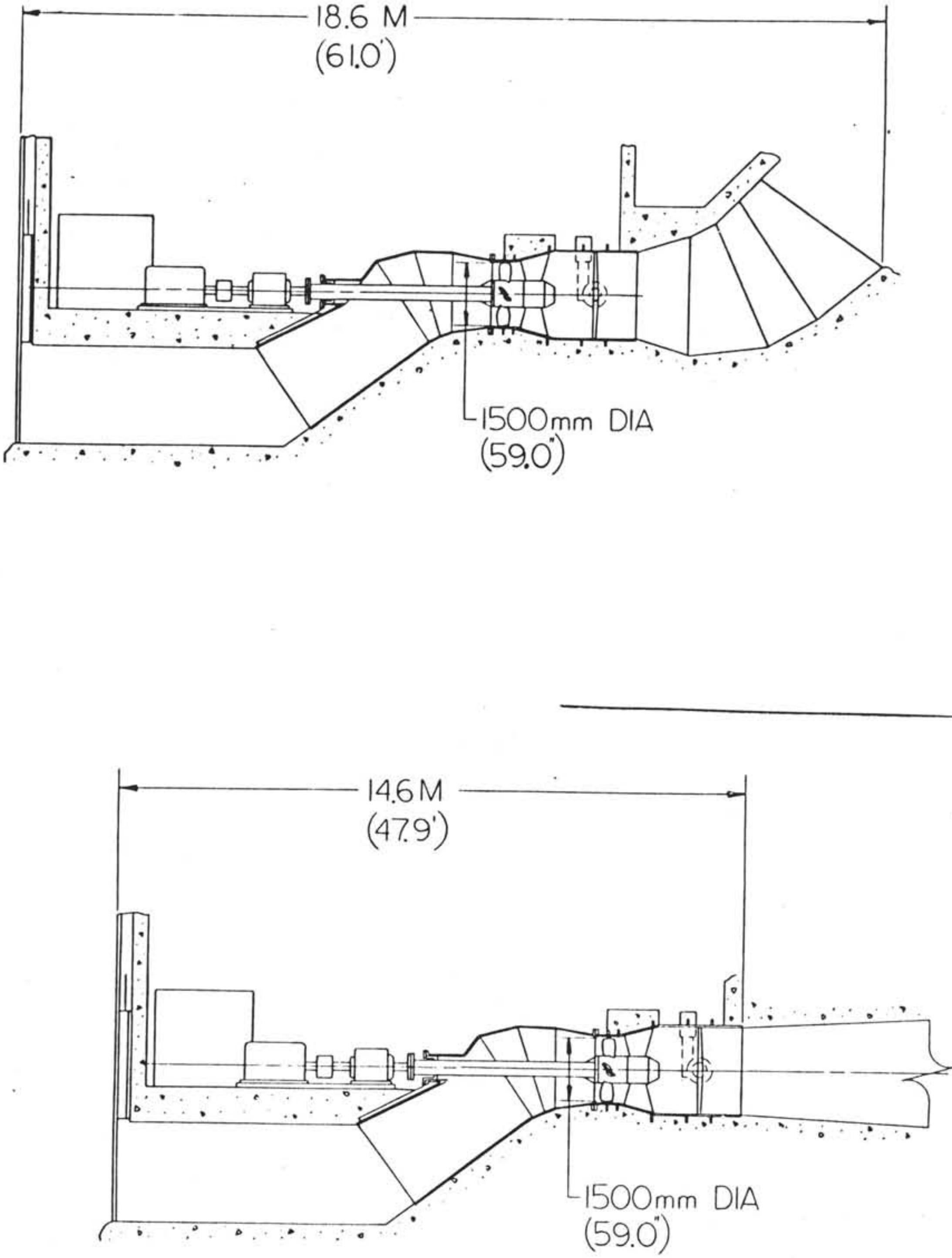

Figure 49. (Top) Tube turbine installation, North Canal Project, Mass., 1979. 1-1,000 kw 9.6.m. (31') head. (Bottom) Tube turbine installation, Barker Mill Dam, Maine, 1979. 1-1,500 kw, 14m. (45.9') head.

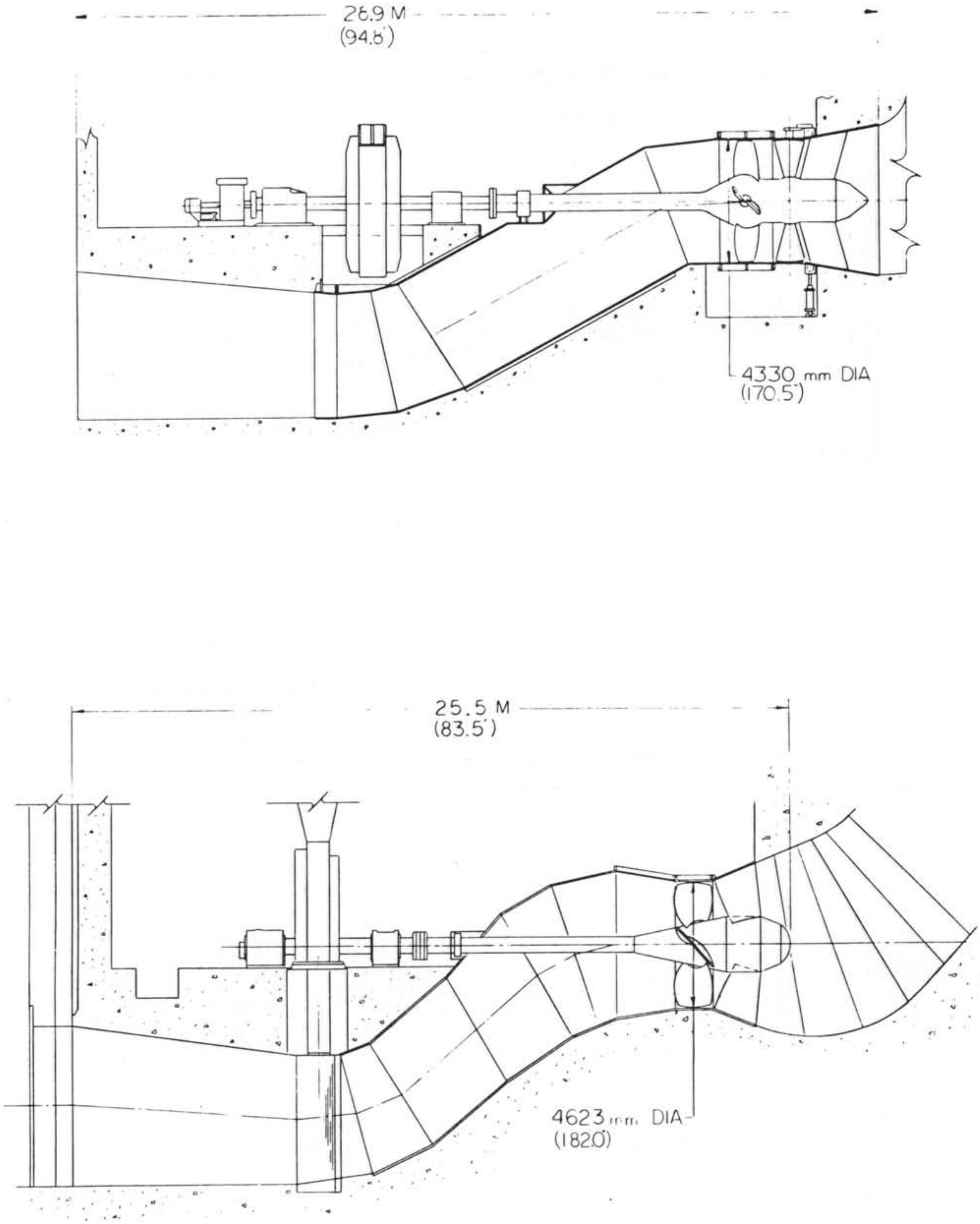

Figure 50. (Top) Tube turbine installation, Chaudiere II Project, Quebec, 1968. 1-10,000 kw, 11m. (36') head. (Bottom) Tube turbine installation, Cornell Project, Wisc., 1976. 3-10,000 kw, 11m. (36') head.

Very-Low-Head Hydroelectric Generation

by Albert G. Mercer

Head, or the drop in water level across a hydroelectric installation, is generally not an overriding factor in the economics of hydroelectric plants. Since benefits and costs both vary with head, its importance tends to be cancelled out. The situation is different, however, when the head is very low (say, less than the height of the structure needed to house the generating units). Then costs tend to become independent of head, while benefits continue to decrease, so that head becomes the overriding factor in determining the attractiveness of these plants. Such plants might be classified as very-low-head plants and defined as those having design heads less than 25 feet (7.5 m), compared to simply low-head plants which have been defined[10] as having heads less than 50 feet (15 m). One might think that there are few in the very-low-head category, but Table 16 lists over 150 units in this range throughout the world installed during the decade preceding 1970 alone.

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It is seldom economically feasible or environmentally desirable to develop very-low-head sites for the sole purpose of generating electric power, but there are many low-head water storage, flood control or river navigation developments that could be economically enhanced by power-generating facilities. There should be a minimum of environmental objection to the addition of these quiet, unobstructive, low-profile and pollution-free structures, once the commitment to develop the site has been made. In view of increasing opposition to all types of power generating facilities, these environmentally attractive sources of power should not be overlooked. This is especially true since they represent the production of energy from a nondepletable resource.

This paper looks at the state of the art of very-low-head hydro generation and considers some of the factors pertinent to its development.

Characteristics of very-low-head units.

Low-head hydroelectric generating units are divided into two main groups. The first group, representing earlier development, has a turbine arrangement that uses a spiral case with wicket gates to control the flow. This arrangement was developed for, and is essential to, medium-head Francis turbines. It was subsequently adopted in the development of low-head propellor and Kaplan turbines.

NAME	RIVER	COUNTRY	YEAR	NO. OF UNITS	HEAD METER	TURBINE OUTPUT MW	TURBINE SPEED RPM	GEN. SPEED RPM	TURBINE DIAMETER METER	REMARKS
AARBERG	AARE	SWISS	1964	1	6.4	.21	450.0	1025.0	.82	BULB
AJANRUEZ		SPAIN		1	3.1	.49	155.0	155.0	2.24	BULB
ALBAS		FRANCE		5	3.4	.42	117.0	117.0	1.80	BULB
ALTBACH	NECKAR	GERMANY	1960	2	5.1	1.01	175.0	750.0		BULB
ALCANADRE		SPAIN		1	2.5	.38	136.0		2.24	BULB
AMBIALET	TARN	FRANCE	1961	2	6.6	2.00	187.5	187.5	2.55	BULB
AMBRE	L AGOUT	FRANCE		1	3.0	.26	167.0	167.0	1.60	VERT.PROP.
ARLEN	ACH	GERMANY	1959	2	4.6	.29	265.0	750.0	1.20	BULB
ARTELSHOFEN		GERMANY	1960	1	1.6	.06				KAPLAN
AUBAS		FRANCE	1961	3	3.3	.30	218.0	218.0	1.60	BULB
AUE BADEN	LIMMAT	SWISS	1963	2	5.6	1.74	136.4	1000.0	2.70	BULB
AWE		SCOTLAND	1963	1	6.9	.44	375.0	375.0	1.25	BULB
BAR MILLS		USA	1957	2	6.0	2.20	120.0	120.0		VERT.PROP.
BERGERAC		FRANCE		2	3.6	.88	136.0	136.0	2.50	BULB
BERGHEIM	DONAU	GERMANY	1965	3	6.0	8.30	83.4	83.4	5.35	KAPLAN
BERTOLDSHEIM	DONAU	GERMANY	1965	3	4.9	6.70	71.4	71.4	5.35	KAPLAN
BIRNER		GERMANY	1956	1	1.5	.05				KAPLAN
BIRSFELDEN	RHINE	SWISS	1954	4	6.1	15.60	68.2	68.2	11.25	KAPLAN
BITTENBRUNN	DONAU	GERMANY	1965	3	5.2	7.20	83.4	83.4	5.35	KAPLAN
BRUCKMUHLWEHR		GERMANY	1952	1	2.0	.23				KAPLAN
BRUNNENMUHLE		GERMANY	1962	1	2.3	.05	350.0	1000.0		BULB
BUANAMESON		SPAIN	1962	1	4.3	.63	220.0	220.0	2.00	BULB
BUCKENHOFEN	REGNITZ	GERMANY	1960	2	5.2	1.46	166.7	166.7	2.45	BULB
BURGLEN	THUR	SWISS	1955	1	3.1	.45	113.0	1000.0	2.20	BULB
CASTET	GAVE OSSAU	FRANCE	1953	2	7.8	.82	250.0	250.0	1.65	BULB
CHATEAU D BREVIL	TOUQUES	FRANCE	1968	1	2.3	.18	242.0	750.0	1.25	BULB
CHIAMPO		INDIA	1968	1	5.8	.05	797.0	1000.0	.46	BULB
CITY OF NORWICH	SHETUCKET	USA	1967	1	4.7	1.50	128.6	128.6	2.80	TUBE
DEISISAU	NECKAR	GERMANY	1966	2	5.1	1.00	175.0	750.0	2.19	BULB PUMPS
DETZEM	MOSEL	GERMANY	1959	4	7.0	5.88	92.5	750.0	4.20	BULB PUMPS
DORLAR		GERMANY	1945	1	1.7	.15				KAPLAN
ENKIRCH	MOSEL	GERMANY	1965	4	5.1	4.25	79.0	750.0	4.60	BULB PUMPS
FAIMINGEN	DONAU	GERMANY	1962	2	6.5	5.65	100.0	100.0	4.20	KAPLAN
FANKEL	MOSEL	GERMANY	1962	4	4.1	3.57	77.0	750.0	4.72	BULB
FLUMENTHAL	AARE	SWISS	1965	3	7.6	8.02	107.1	107.1	4.20	BULB
GANDAK		INDIA	1966	3	6.1	5.52	107.1	107.1	4.10	BULB
GIRISHK		AFGHAN.	1958	2	7.5	1.60	187.5	187.5		VERT.PROP.
GOSSMANNSDORF	MAIN	GERMANY	1948	2	2.7	1.03			3.70	KAPLAN
GREVENMACHER	MOSEL	GERMANY	1962	3	5.5	2.62	120.0	750.0	3.20	BULB ASYNCH.
GRIFTE			1959	2	2.4	.25	137.0	765.0		BULB
HAUSEN		GERMANY	1962	2	5.0	.93	200.0	200.0		BULB
HERRFORS		FINLAND	1961	1	3.5	.43	165.0	600.0	1.80	BULB

Table 16. Very-low-head turbines.

NAME	RIVER	COUNTRY	YEAR	NO. OF UNITS	HEAD METER	TURBINE OUTPUT MW	TURBINE SPEED RPM	GEN. SPEED RPM	TURBINE DIAMETER METER	REMARKS
HESSENTHALER		GERMANY	1946	1	1.1	.06				KAPLAN
ILLER V	ILLER	GERMANY	1940	3	8.1	1.57	214.3	214.3	2.10	ANNULAR GEN.
ILLER V	ILLER	GERMANY	1949	1	8.1	1.39	214.3	214.3	1.95	ANNULAR GEN.
INGOLSTADT	DONAU	GERMANY	1965	3	5.7	7.90	83.4	83.4	5.35	KAPLAN
ISOLA SERAFINI	PO	ITALY	1960		6.0	11.80	53.6	53.6	7.80	KAPLAN
JARMENIL	MOSELLE	FRANCE		1	5.5	1.05	167.0	167.0	2.15	KAPLAN
JENPEG		CANADA	1974	6	7.3	29.00	62.0	62.0	7.50	2BULB
KANEV	DNJPR	RUSSIA	1967	24	8.4	18.20				BULB
KETTERSHAUSEN	GUNZ	GERMANY	1968	1	5.0	.33	300.0	760.0	1.20	BULB
KHASM EL GIRBA	ATBARA	SUDAN	1967	3	7.0	2.79	150.0	750.0	2.70	BULB
KIEV	DNIEPER	RUSSIA	1966	20	7.8	17.20	85.7	85.7	6.00	BULB
KISLOGUBSKAYA		RUSSIA	1965	1	1.3	.40	72.0	600.0	3.30	BULB TIDAL
KITZINGEN		GERMANY	1954	2	3.1	1.50				KAPLAN
KLETTHAM		GERMANY	1951	1	1.3	.37				KAPLAN
KOSI EAST	CANAL	INDIA	1966		6.1	5.60	93.8	93.8	4.50	BULB
LAGARDE		FRANCE		4	2.2	.18	182.0	182.0	1.60	BULB
LA MAIGNANNERIE		FRANCE		2	1.8	.06	224.0	224.0	1.12	BULB
LANDESBERGEN		GERMANY	1957	3	3.6	2.35				KAPLAN
LECH 9 PLANTS	LECH	GERMANY	1940	54	8.2	1.36	214.3	214.3	1.95	ANNULAR GEN.
LEHMEN	MOSEL	GERMANY	1966	4	5.3	4.62	85.0	750.0	4.60	BULB PUMPS
LEITZACH	MANGFELL	GERMANY	1963	2	4.8	.38	253.0	760.0	1.35	BULB
LES ALBAREDES	TARN	FRANCE		2	2.3	.30	136.5	136.5	2.06	VERT.PROP.
LOWER PAINT	PAINT	USA	1952	1	6.1	.10	533.0	533.0	.76	TUBE ASYNCH.
MAUZAC	DORDOGNE	FRANCE		1	6.7	4.58	94.0	94.0	4.30	KAPLAN
MCARTHUR FALLS	WINNEPEG	CANADA	1954	8	7.0	7.40	85.7	85.7	5.10	VERT.PROP.
MENUZA		SPAIN	1952	2	6.0	5.06	93.8	93.8	4.40	KAPLAN
MONSIN	MEUSE	BELGIUM	1954	3	3.0	5.25	65.2	65.2	5.60	KAPLAN
MUDEN	MOSEL	GERMANY	1962	4	4.1	3.57	77.0	750.0	4.72	BULB
MUHLACKER	ENZ	GERMANY	1963	2	4.6	.39	232.0	770.0	1.45	BULB
NEEF	MOSEL	GERMANY	1961	4	5.5	3.98	76.0	750.0	4.60	BULB
NEU-BANNWIL	AARE	SWISS	1965	3	8.1	8.42	107.1	107.1	4.20	BULB
NEUVILLE-AMPSIN	MEUSE	BELGIUM	1962	4	4.0	2.41	97.5	750.0	3.60	BULB
OBERMAUBACH	RUR	GERMANY	1968	1	6.9	.67	280.0	280.0	1.45	BULB
OSBERGHAUSEN	AGGER	GERMANY	1955	1	6.6	.38	312.0	1000.0	1.20	BULB
OZARK LOCK	ARKANSAS	USA	1971	5	7.9	20.00	60.0	514.0	8.00	TUBE
PALZEM	MOSEL	GERMANY	1965	3	3.4	1.48	78.0	750.0	3.60	BULB ASYNCH.
PETERSHAGEN		GERMANY	1952	3	2.5	1.10	68.0	500.0	3.89	KAPLAN
PIERRE BENITE	RHONE	FRANCE	1966	4	7.9	20.70	83.3	83.3	6.10	BULB
PUHOS		FINLAND	1960	1	4.5	.80	150.0	750.0	2.20	BULB
RANCE	TIDAL	FRANCE	1966	24	5.8	10.00	93.8	93.8	5.35	BULB PUMPS
RANDERSACKER	MAIN	GERMANY	1948	2	2.8	1.18			3.80	KAPLAN
RAVENSBURG	SCHUSSEN	GERMANY	1955	1	4.0	.13	280.0	1000.0	1.00	BULB
RAVENSBURG II	SCHUSSEN	GERMANY	1957	1	4.2	.14	300.0	1000.0	1.00	BULB

Table 16 (cont.). Very-low-head turbines.

NAME	RIVER	COUNTRY	YEAR	NO. OF UNITS	HEAD METER	TURBINE OUTPUT MW	TURBINE SPEED RPM	GEN. SPEED RPM	TURBINE DIAMETER METER	REMARKS
REUTTE	LECH	AUSTRIA	1956	1	6.1	1.25	165.0	1000.0	2.20	BULB
ROSTIN	PARSENTA	GERMANY	1936	2	3.7	.20	250.0	250.0	1.30	ANNULAR GEN.
RUAES		PORTUGAL	1960	2	2.5	.52				KAPLAN
RUCHLIG	AARE	SWISS	1960	4	3.3	1.62	75.0	1000.0	3.70	BULB
RUST			1961	1	2.0	.18				KAPLAN
ST. ANTHONY FALLS	MISS.	USA	1952	10	7.0	.85	225.0	225.0		VERT.PROP.
ST. JORY		FRANCE		1	2.4	.10	214.0	214.0	1.30	VERT.PROP.
SAINT MALO	TIDAL	FRANCE	1959	1	5.5	9.00	88.2	88.2	5.80	BULB
ST. MARYS FALLS	CANAL	USA		4	6.4	5.20	80.0	80.0	1.63	VERT.PROP.
SASTAGO		SPAIN		4	7.0	.77	250.0	250.0	1.65	BULB
SCHUSSELBURG		GERMANY	1954	3	2.7	1.65				KAPLAN
SCHWEINFURTWERK		GERMANY	1960	2	4.0	1.90				KAPLAN
SEYSSEL	RHONE	FRANCE	1947	3	8.0	14.85	75.0	75.0	6.30	KAPLAN
SHADIWAL		CANADA	1958	2	7.0	6.50	83.3	83.3	5.85	KAPLAN
SIIKAKOSKI		FINLAND	1966	2	3.4	1.00	105.0	1000.0	2.80	BULB
SONTHEIM		GERMANY	1967	1	2.1	.12				KAPLAN
STEVENS POINT	WISCONSIN	USA	1963	1	6.7	2.10	150.0	150.0	2.80	TUBE
STUGUN	INDAL	SWEDEN		2	7.1	17.50			7.30	KAPLAN
THIESS		GERMANY	1967	1	3.4	.18				KAPLAN
TISALOK	TISZA	HUNGARY	1946	3	3.0	4.00	75.0	75.0	6.00	KAPLAN
TISZA II		HUNGARY	1973	4	6.4	7.20	107.0	107.0	4.30	BULB
TRAICAO	TIETE	BRAZIL	1957	3	7.1	2.58	150.0	150.0	3.51	TUBE
TRIER	MOSEL	GERMANY	1958	4	5.0	4.42	78.0	750.0	4.60	BULB
TURNIP CHECK	IRR.CANAL	USA	1964	1	5.0	.42	218.0	900.0	1.53	TUBE
UNTEREGGINGEN	WUTACH	GERMANY	1960	1	3.5	.20	248.0	750.0	1.20	BULB
UNTERMAUBACH	RUR	GERMANY	1964	1	3.1	.23	220.0	760.0	1.45	BULB
URSPRING-STUFE	LECH	GERMANY	1963	3	8.2	3.39	166.7	166.7	2.85	BULB
VARGON	GOTA-ALV	SWEDEN	1946	2	4.3	12.00	46.9	46.9		KAPLAN
WADRINAU		FRANCE	1956	4	4.5	1.48	107.0	750.0	3.05	BULB
WEBBERS FALLS	ARKANSAS	USA	1973	3	6.7	23.00	60.0	514.0	8.00	TUBE
WEILHEIM	AMMER	GERMANY	1960	1	4.4	.58	186.0	600.0	1.80	BULB
WIDDERT		GERMANY	1964	1	3.1	.32				KAPLAN GEARS
WINTRICH	MOSEL	GERMANY	1963	4	5.6	4.90	83.0	750.0	4.60	BULB PUMPS
WIPFIELD		GERMANY	1948	2	3.2	1.38				KAPLAN
ZELTINGEN	MOSEL	GERMANY	1964	4	4.0	3.30	67.0	750.0	4.80	BULB

Table 16 (cont.) Very-low-head turbines.

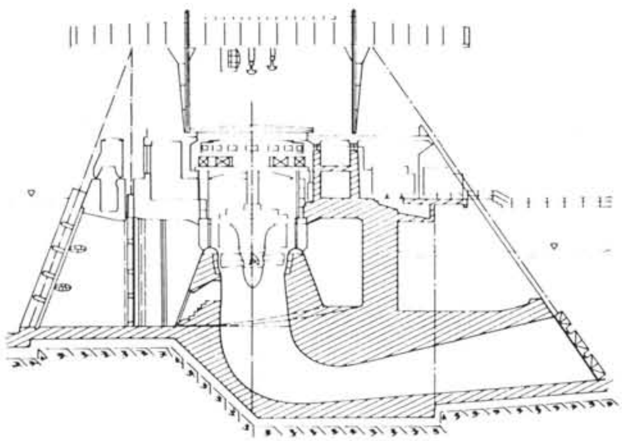

Figure 51. Sackingen Powerhouse, Swiss-German border. Turbine diameter 7.4m.

The spiral case arrangement, except in some smaller units, utilizes a vertical turbine axis with an elbow draft tube as typified by the Sackingen plant on the Rhine River shown in Figure 51. This modern plant has 25,000 hp Kaplan turbines directly connected to sychronous generators installed in a very low-profile structure. This type of design provides a compact and serviceable turbine-generator assembly but the complex flow passages require a civil structure with a relatively large plan area.

While direct drive to the generator is common, essentially all very-low-head units are within the power range where speed increasing gears can be utilized. The Petershagan installation shown in Figure 52 is an example of this type of arrangement. This 1,500 hp turbine has a rated head of 8 feet and rotates at 68 rpm while the generator with a horizontal axis is gear driven at 500 rpm. An interesting feature of this Petershagan plant is the elevated syphon setting of the turbine. The entire runner can be de-watered for servicing simply by allowing air into the spiral case. The elevated setting of the turbine also reduces the depth of excavation required for the draft tube.

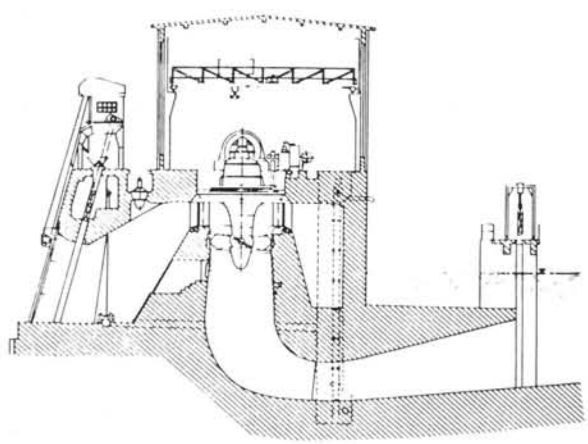

Figure 52. Petershagen Plant, Weser River, Germany. Turbine diameter 2.7m (J.M. Voith).

Tubular turbines

Tubular turbines make up the second group of low-head plants. They were developed to reduce costs by simplifying the flow passages and thereby reducing the size of the civil structure. There are several distinct arrangements for tubular turbines, but the feature they all have in common is the elimination of the spiral case.

Except for some small plants, all tubular turbines are oriented so that their axis is horizontal, or nearly so. The flow approaches the turbines axially but is first given the necessary whirling motion by guide vanes located upstream of the runner. The whirling motion is converted to shaft torque by the turbine blades so that the flow leaves the turbine axially. The draft tube geometry, which is simplified by the horizontal alignment, closely approaches an ideal shape for energy recovery.

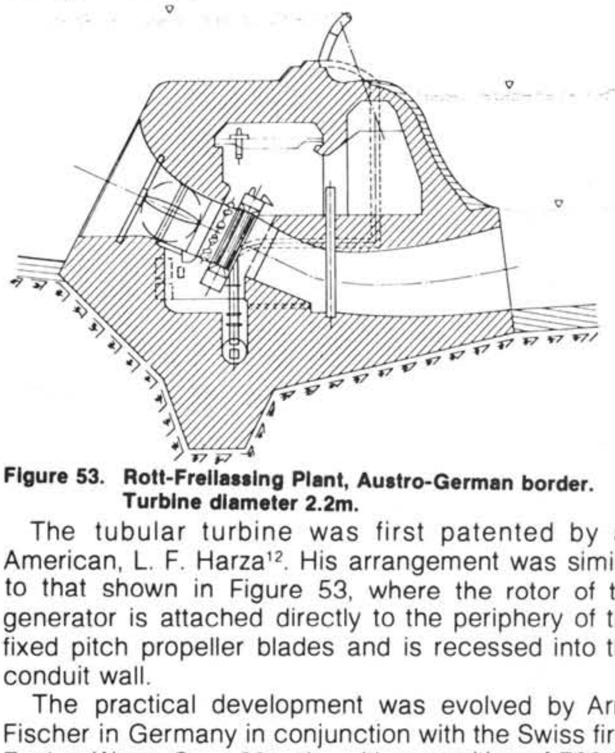

Figure 53. Rott-Freilassing Plant, Austro-German border. Turbine diameter 2.2m.

The tubular turbine was first patented by an American, L. F. Harza[12]. His arrangement was similar to that shown in Figure 53, where the rotor of the generator is attached directly to the periphery of the fixed pitch propeller blades and is recessed into the conduit wall.

The practical development was evolved by Arno Fischer in Germany in conjunction with the Swiss firm, Escher Wyss. Over 60 units with capacities of 700 hp were built during the period 1935 to 1951. Although these units are considered to operate with dependability, there has been limited interest in building new units because of newer and more competitive arrangements.

Interest in this type of unit has not lagged entirely, however. A Russian plant, Ortachalskara[5], was recently built with an 8,600 hp annular generator unit. The English Electric Company also has been studying this type of unit for tidal power developments in England.

Bulb units

The next development in tubular turbines was the

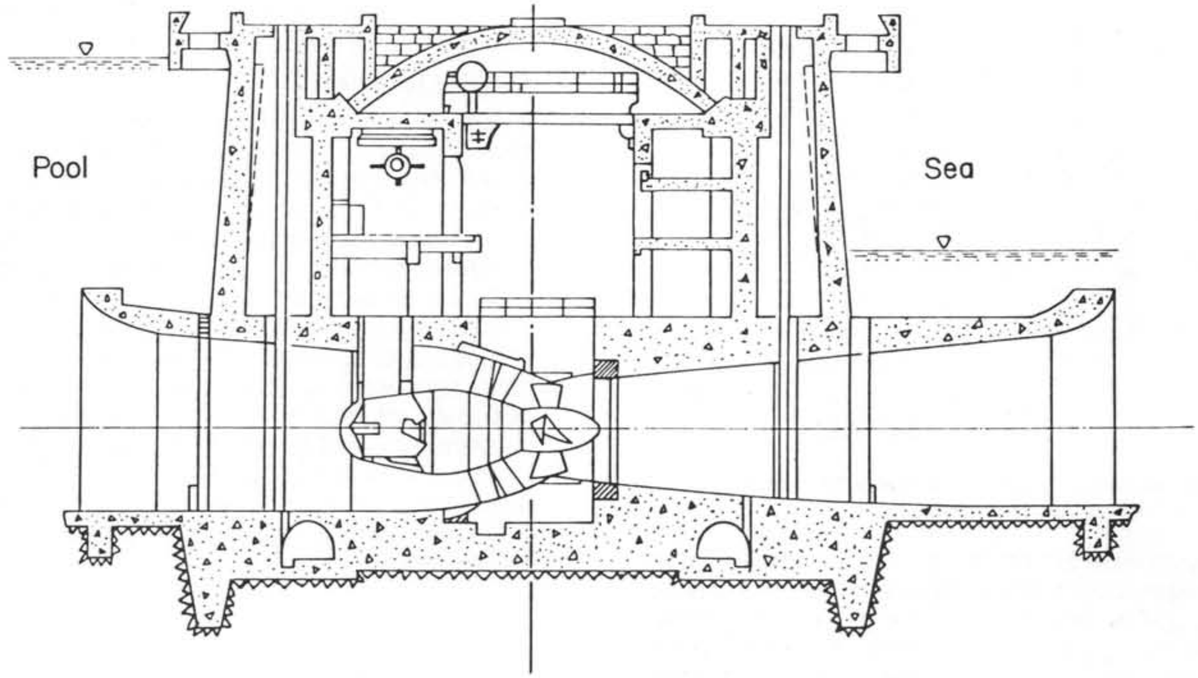

Figure 54. Rance tidal power plant, France. Turbine diameter 5.35m.

bulb unit in which the generator is encased in a bulb in the middle of the flow conduit. Bulb units have been manufactured in many sizes since the first one was constructed in Poland in 1936. The best known are probably the 14,000 hp units designed for the Rance Tidal Power Plant in France[13]. These special units, shown in Figure 54, were designed for generating or pumping, with flows in either direction.

The successful development of the bulb unit is due largely to the efforts of the French National Electricity Authority (Electricite de France) whose research led to the best type of unit for the Rance project. The largest units of this type are those provided for the Beaucaire Plant in France. They have 6.5 m diameter runners developing 47,500 hp under a head of 37 feet. The lowest head unit of this type is one provided by Neyrpic for the experimental Kislogoubskaira tidal plant in Russia which will deliver 530 hp at a rated head of 4.2 feet.

Bulb units are very compact but generally require a sophisticated design in order to fit the generator into a bulb of acceptable size. This is particularly true of the higher capacity units with direct shaft connection between the turbine and generator. Smaller capacity units have intermediary speed increasing gears, usually of the planetary type, which permit the use of smaller, high speed generators. In some large units, a man-way is provided so that the generator enclosure is accessible, but in smaller units no access is provided and the plant must be unwatered to service the generator.

Several modifications of the bulb arrangement have been built. In Germany, a number of plants have a large stairway access passage to the generator so that the bulb has the appearance of a pier in the middle of the flow conduit. In smaller plants, an open generator pit is sometimes provided so that water flows around the sides to the runner. These arrangements are most suitable when used with the small generators that are connected to the runners by speed increasing gears. Bulb type or annular generator type units are being introduced into the Western Hemisphere (Jenpeg Plant in Manitoba and Rock Island on the Columbia River).

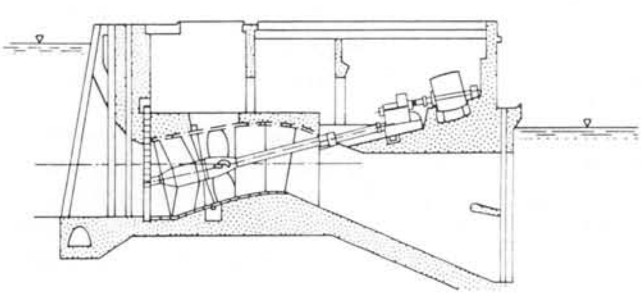

Figure 55. Ozark lock and dam, U.S.A. Turbine diameter 8m (Allis-Chalmers).

Tube arrangement

To avoid the high costs associated with the engineering and manufacturing of these rather sophisticated designs, Allis Chalmers, an American firm, has developed the tube turbine arrangement.[6] Figure 55 shows the generating units for the Ozark Lock and Dam constructed on the Arkansas River, which is typical of this arrangement. These units, which develop 27,000 hp with 8m diameter runners, are the largest tubular

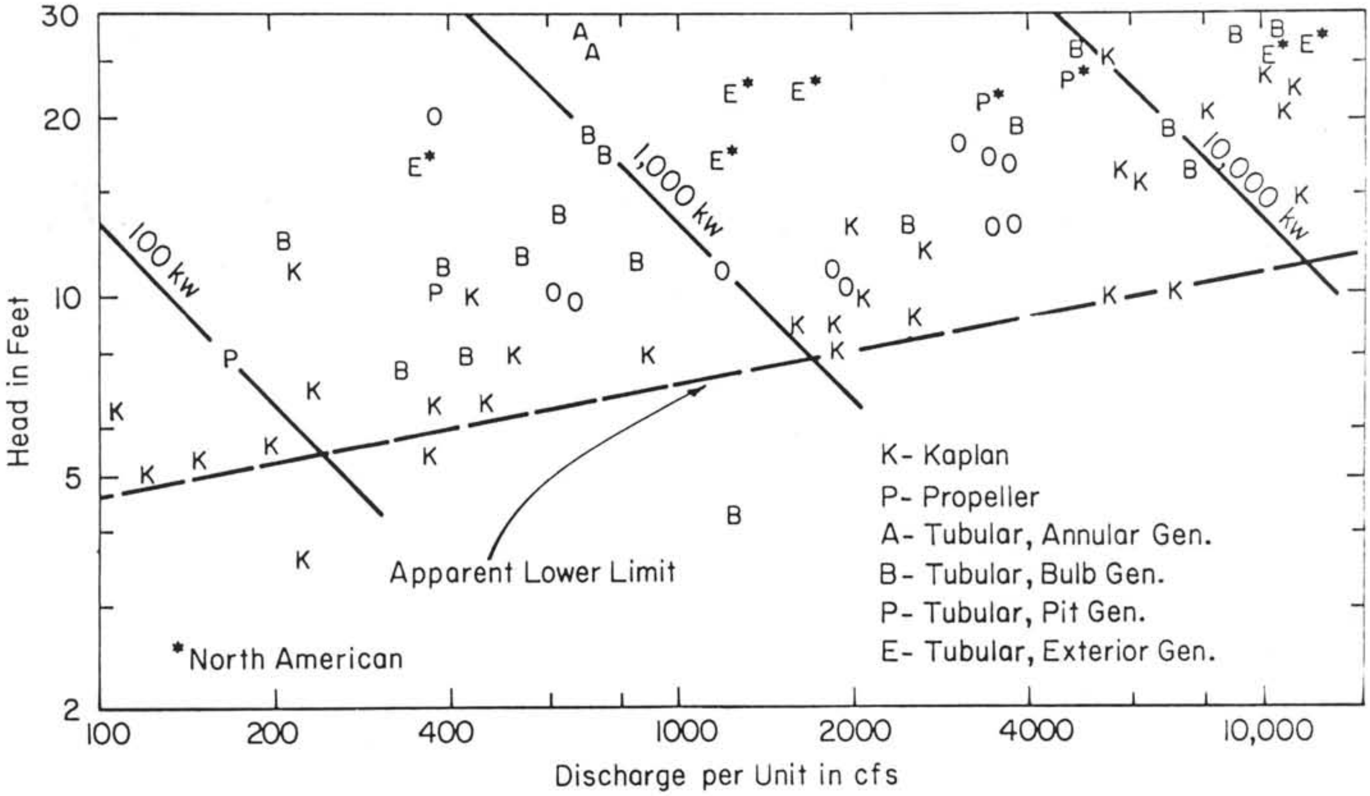

Figure 56. Existing very-low-head hydroelectric plants.

turbines ever contracted (as of 1974). This tube turbine arrangement requires a slight bend in the flow passage which, in turn, permits the generator to be located outside of the passageway. The special advantage of the tube turbine arrangement is that the speed increasing gear and the generator are highly accessible. Another advantage is that the equipment can be quite standard, requiring a minimum of special design or fabrication. Numerous variations of this arrangement are possible with the generator located either upstream or downstream of the runner according to the peculiarities of the site. The arrangement shown in Figure 55 is, however, well suited to very low-head plants.

A factor that is especially important for low-head installations is the loss of head that occurs when river flows are high. When a river is carrying a large discharge, the depth of flow is relatively great and water level upstream of the plant is usually not affected to as great an extent because this level is controlled by the spillway release gates. A number of plants have been designed to utilize the energy of the extra water released from the spillway to offset the decrease in head.

Using excess spillway flow

The arrangements for using excess spillway flows to lower draft tube pressures are called head increasers.[10] One such arrangement is shown in Figure 53. In this instance, the spillway is built over the powerhouse and the flow is discharged into the river just above the draft tube, producing an aspirator effect that reduces the pressure and increases the head on the turbine. Other arrangements have been developed that introduce the excess flow right into the draft tube using a geometry similar to a jet pump. These internal devices may be somewhat self-defeating in that the draft tube must be designed to handle both the turbine flow and the head increaser flow.

Induction generators

Induction generators[9] are used for very-low-head plants wherever it is practical because they are cheaper than synchronous generators and because they require less control and less maintenance. Their efficiency is greatest at higher speeds so they should be operated with speed increasing gears. They cannot be used to establish frequency, however, and they will not operate at all unless connected to a system with other synchronous generators because they take their excitation from system current. They also cannot be used to match the power factor of the electrical load since their power factor output is not adjustable as with the synchronous machines. They do, however, serve the basic purpose of adding to the kilowatt output of a system with high efficiency.

The advantage of induction generators is their simplicity. They require no excitor and need only a

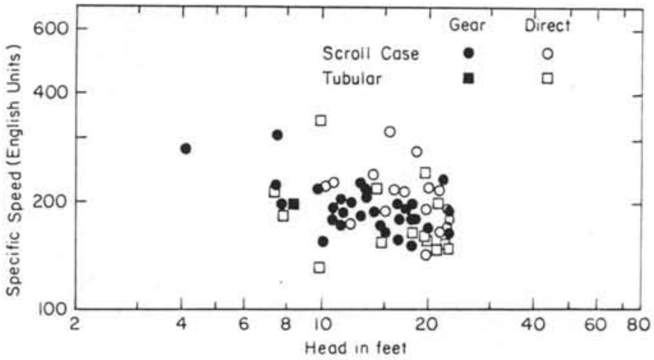

Figure 57. Specific speed of very-low-head turbines.

squirrel cage rotor which uses no wire windings or brushes. Also, as they do not run at exact synchronous speed, complex synchronizing equipment is not needed to bring them onto line.

A number of low-head hydroelectric developments are shown plotted in Figure 56 according to their rated head and discharge. The data used to prepare Figure 56 are the rated head h and rated turbine power output P of Table 16 from which the discharge q was computed using

$$P = \frac{q\gamma he}{k}$$

where γ is the specific weight of water, e is turbine efficiency and k is a conversion factor. With power in kilowatts k has a value of 737 for English units and 1000 for SI units. The efficiency used was 88 percent.

The chart is not a complete record of installations. As a result, the density of the plotted points is not too significant. There are, however, no known units which would plot below the broken line labeled "Approximate Lower Limit" except those shown. Although the tubular turbines seem best suited for very low heads, a surprising feature of the chart is that most of the lowest head plants are vertical Kaplans with spiral case arrangements, and most of these have been constructed since 1950.

Figure 56 defines a fairly sharp lower limit for the rated heads of existing plants and, significantly, this limit varies with capacity. The present actual lower limit for 10,000 kw units is about 12 feet while the limit for 100 kw units is only five feet. This chart emphasizes only that there is a limit below which electric power organizations have never cared to invest in hydrogeneration.

A common parameter used to characterize hydraulic turbines is specific speed N_S defined by

$$N_S = \frac{n(HP)^{1/2}}{h^{5/4}}$$

where n is speed and HP is horsepower. A given turbine design has a particular value of specific speed regardless of its size. One small difficulty with specific speed is that it is not dimensionless so that its value is different depending on whether English or SI units are used. The specific speeds suitable for different installations are commonly associated with the available heads. Figure 57 shows the specific speeds for the units of Table 16 plotted against head. There appears to be a general trend towards higher specific speeds at lower heads but the correlation is poor.

Somewhat better correlation exists between dimensionless parameters that might be called speed factor N, head factor H and scale factor D defined by

$$N = \frac{wq^{1/5}}{g^{3/5}} \qquad H = \frac{hg^{1/5}}{q^{2/5}} \qquad D = \frac{dg^{1/5}}{q^{2/5}}$$

where w is the turbine speed in radians per second and d is the turbine runner diameter. Being dimensionless, the values of the factors are independent of the system measurement used. Figure 58 shows N plotted against H and Figure 59 shows D plotted against H. Both plots define the general trend although there is considerable scattering of the data. The plot of Figure 58 suggests, as might be expected, that the speed factor is lower for units with speed increasing gears. The use of gears does not seem to affect the scale factor, however. There appears to be no real distinction between scroll case units and tubular units as far as either speed factor or scale factor is concerned. Regression analysis was used to see if speed factor, scale factor and head factor were mutually related but the correlation was not significantly better than for the plots of Figures 58 and 59. It must be remembered that the data are the result of designers' decisions and do not represent natural deterministic or stochastic processes.

Lower limit

The trend in the variation of turbine sizes and speeds with different design heads can easily be demonstrated with Figures 58 and 59 if units of equal discharge capacity are considered. Figure 58 shows, on this basis, that turbine speed varies approximately as the square root of the head. Lower speeds mean proportionately higher torques, heavier shafts and heavier speed increases. At the same time Figure 59 shows the trend towards larger

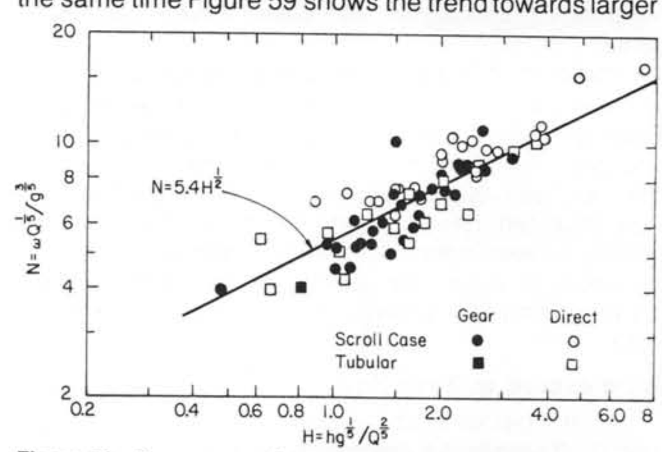

Figure 58. Runner speed as a dimensionless function of head and discharge.

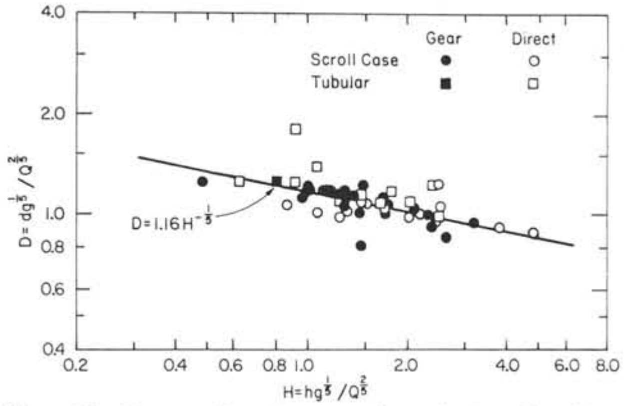

Figure 59. Runner diameter as a dimensionless function of head and discharge.

turbine diameters for smaller heads. This is due to the need to keep conduit velocities and the associated conduit head losses small relative to the available head. Larger conduits for lower heads means larger civil structures. If velocity heads in the conduit are to be proportional to the available heads, conduit dimensions for units of the same discharge capacity should vary according to the negative one-fourth power. Figure 59 shows what appears to be a compromise where the size factor varies more nearly with the negative one-fifth power of the head factor.

Lower head units would be expected to have lower efficiencies mainly because of proportionately larger conduit losses. Figure 60 shows overall peak efficiency. Variable pitch runner blades and/or guide vanes are commonly provided to keep offpeak efficiencies as high as possible. If both guide vanes and runner blades are variable, as with Kaplan turbines, efficiency can be maintained consistently high over a wide range of operating conditions. Propeller turbines, with fixed runner blades and variable pitch guide vanes have on the other hand, rather poor efficiencies at offpeak conditions. A reasonably flat efficiency curve can be achieved in a tubular turbine with variable runner blades and fixed guide vanes. Since there are usually many more guide vanes than runner blades in a unit, this represents a considerable saving in costs.

Cost comparisons

To fully appreciate the significance of head for very-low-head plants, it is necessary to make some estimate of costs. The figures presented in this section are based on data collected from several sources and interpreted by using a number of assumptions, some of which can be only partially supported. The results are intended to show only the general trend of costs and are not sufficiently reliable to be used even for preliminary cost estimates. To discourage their use in estimates, the figures are shown only as indices relative to the cost of a reference plant. This reference plant has a head of 50 feet and a capacity of 10,000 kw per generating unit.

The cost curves are shown in Figures 61 and 62. Figure 61 contains relative costs for 10,000 kw units with heads varying from 10 to 50 feet. The costs are divided into hydromechanical, electrical, and civil categories to show the effect of head on these components. According to Figure 61, a 10,000 kw unit with a head of 10 feet, costs almost six times as much as one with a head of 50 feet. Figure 62 contains costs for 1,000 kw units relative to the 10,000 kw reference unit with 50 feet of head. The costs per kw are shown to be higher for the smaller units largely due to higher electrical costs.

It is assumed that all plants consist of tube turbines since these promise to be the most economical in North America for very-low-heads. The costs are for a single powerhouse unit and no allowance has been made for an erection bay or a crane or gantry. Costs for foundation preparation, dewatering, or channel improvement are also neglected. It is assumed that the units are to be installed in a development for which all costs, other than those directly related to power production, are to be charged to some other purpose.

The hydromechanical costs include the turbine with its accessory equipment, the speed increasing gear, and an emergency closure gate. The costs for turbines are based on bid data published by the Federal Power Commission.[14] The lowest head reported is 37.5 feet for the North Highlands Project on the Chattahoochee River in Georgia. Extrapolation to lower heads is made by using turbine weight data in reference[10] assuming a constant cost-to-weight ratio. There is a great deal of scatter in the bid data, which includes both Kaplan and propeller turbines, but a definite trend is apparent. The tube turbines are assumed to cost the same as propeller turbines which, according to this data, are about 25 percent cheaper than Kaplans.

High gear costs

Speed increasing gears are a fairly well established product and the cost depends largely on the input torque. Lower head runners deliver more torque per kw because they run at lower speeds. The gear costs are

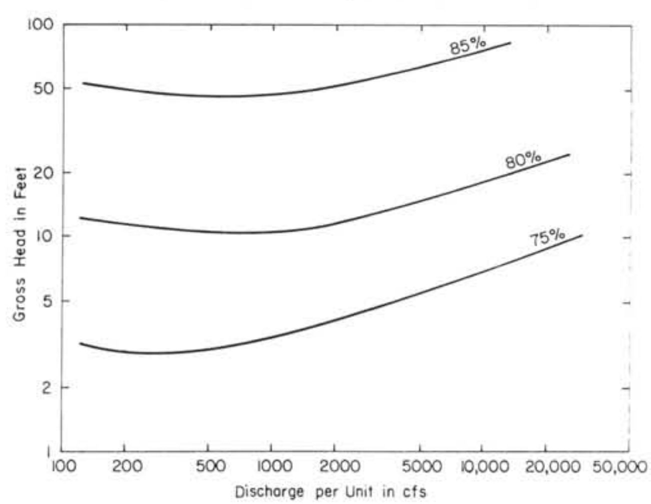

Figure 60. Estimated overall peak efficiency for units of different rated head and discharge.

therefore higher on a per-kw basis. For heads of 10 feet, the gears cost approximately as much as the entire electrical system. There is also a trend for small capacity gears to be more expensive per unit of torque than large gears. This causes gears for small plants to be more costly per kw.

There is a wide range of opinion regarding emergency closure gates for low-head plants. Conservative practice is to provide each unit with a quick operating gate. For some very-low-head plants, however, several units have been provided with a single gate to be transported by a crane from a storage area when needed. For this study, it is assumed that each unit will have an emergency gate.

The electrical costs include the generators and switching equipment, but not the high voltage transformers. The costs are based on the use of horizontal axis, sychronous generators operating through gearing at 600 rpm. It is assumed that electrical costs per kw would depend upon capacity but not on head. Electrical equipment for smaller capacities costs considerably more per kw than larger capacities, as shown in Figures 61 and 62.

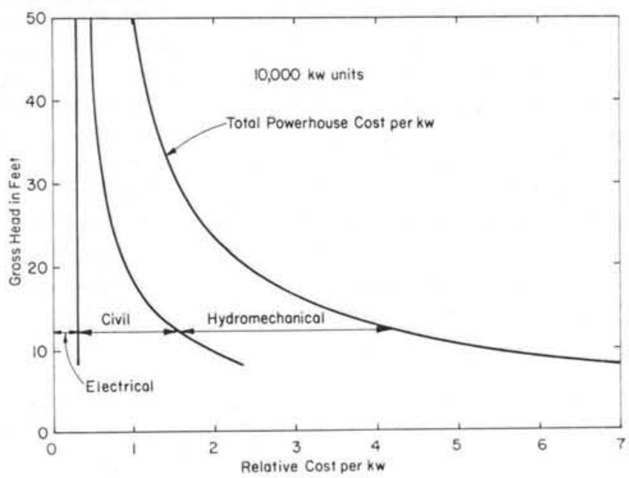

Figure 61. Relative cost of 10,000 kw units.

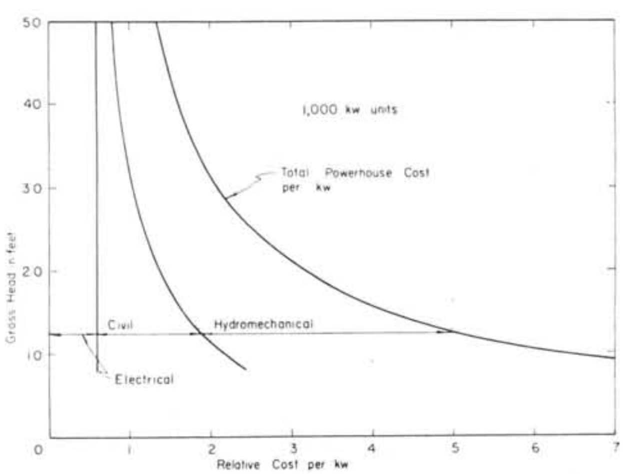

Figure 62. Relative costs of 1,000 kw units.

The civil costs comprise the powerhouse substructure and superstructure and include the trashracks. No allowance is made for foundation excavation or dewatering on the assumption that, if the powerhouse was not built, this work would have to be done on the alternative embankment structure. These costs vary considerably from site to site, in any case. The total civil costs are on quantities determined from preliminary powerhouse layouts based on the arrangement of Ozark Lock and Dam in Figure 55.

The relative costs of Figure 61 and 62 clearly show the reason for an absence of units in the very-low-head range of Figure 53. One would expect from these figures that larger capacity plants could be built at lower heads than could smaller plants, which is contrary to the data of Figure 56. The explanation must be that the smaller low-head plants are in remote areas where low-cost electricity is not available.

Comments and conclusions

One of the outstanding advantages of very-low-head hydroelectric development is its compatibility with the natural environment. Aesthetically, low-head plants can be fitted into a powerhouse with a very compact, low, unobtrusive profile. There is virtually no pollution associated with hydroelectric plants either in the form of sound, heat, or smoke. The level of activity around a hydroplant is also low. The trend is to automatic control with very few people in attendance and a minimum of maintenance personnel. As a result, low-head plants can be located in areas, such as lakeside or riverside parks, where aesthetics are important, without introducing an obvious industrial atmosphere to the area. This is in sharp contrast to steam plants with prominent industrial type buildings, high stacks, and cooling towers.

It is not easy to understand why there are so few very-low-head units in North America compared to Europe. In the beginning of this century a great many small, low-head units were installed on this continent, mostly by small utility and industrial organizations. With the development of large improved thermal and hydroelectric plants, most of these small plants were shut down as they wore out. In Europe, however, low-head hydro generation has continued to develop. Some of this development may have been due to unsettled political climates, whereby governments would look to hydropower as being insurance against a loss of fossil fuel supplies. Some is undoubtedly economic, reflecting differences in the value of resources, including manpower, on the two continents. However, the impression is that low-head development has been bypassed in North America by planners who are pressed to develop large blocks of power to meet rapidly growing load demand. This tendency is likely to continue, even as the pollution problem associated with thermal and nuclear power increases. The development of low-head power, where economically justifiable, will seem to depend on the action of persons conscious of the waste of an untapped non-depletable national resource rather than on persons looking to meet power demands.

As a result of this study it is possible to draw the following conclusions:

1. Hydraulic turbine manufacturers in the past have been actively engaged in the development of special turbines for low-head application. This effort has culminated in bulb type units common in Europe and tube turbines which are finding application in North America.

2. The countries of Europe have made extensive use of navigation control structures for the generation of electricity and have built many units with heads less than 25 feet, whereas there have been very few units built in North America with heads of 25 feet or less.

3. The available head is the most important factor affecting the feasibility of low-head hydroelectric plants. Considering well designed low-head plants of equal discharge capacity but different heads, the lower head plant will have:

a. lower kw capacity
b. larger, slower turning turbines
c. heavier, slower turning generators (alternatively more expensive speed increasing gears)
d. larger flow conduits
e. lower overall efficiency
f. higher total cost
g. higher cost per kw
h. lower benefit/cost ratio.

4. Low-head generating units can be located in low-profile structures with high aesthetic qualities and function without contributing to the pollution of the environment.

ACKNOWLEDGEMENT

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4

The Governmental Presence

Bureau of Reclamation photo

Minidoka Dam, a combined diversion, storage and power structure on the Snake River, Idaho

Small Scale Hydro Development: Institutional and Legal Problems

by Ronald A. Corso

The institutional and legal problems that face a potential developer of a small scale hydroelectric (hydro) developments or any scale development for that matter, are many, complex, and at times seeming almost insurmountable. We at the Federal Energy Regulatory Commission (FERC) share the concern that has been expressed by Congress, the public, and you most of all, the potential developers, designers, and owners of hydro developments.

In organizing this paper, I have tried to put myself in the place of a potential developer, attempting to wend his way through the myriad of requirements that will eventually lead to project construction and operation. My remarks today will be confined principally to obtaining Federal approvals. Due to the delegation of Federal authority in some areas to the States, I will necesarily need to discuss some State approvals also.

Early in the infancy of water resources development, Congress realized that it could not continue to authorize each project through special legislation. Therefore, Congress divided its authority, retaining the direct authority over Federal development, and delegating to the Commission through the Federal Water Power Act (Act) of 1920 the authority to license non-Federal hydroelectric developments.

The Act was later substantially amended to its present form in 1935. The Commission is authorized to license non-Federal developments that (1) occupy in whole, or in part, lands of the United States; (2) are located on navigable waters of the United States; (3) utilize surplus water or water power from a government dam; and (4) affect the interests of interstate commerce.

Court interpretations of the Commission's jurisdiction have defined this authority so that it covers virtually all projects. For any potential developer unsure of the jurisdictional status of a project, there is a relatively simple legal procedure that can be followed to obtain a Commission decision on a particular project. A Declaration of Intention filed pursuant to Part 24 of the Commission's Regulations is a formal request for a jurisdictional finding. The requirements of Part 24 are short and uncomplicated, and can be completed with a minimum of data, much of which is usually available from published sources. A simpler and more direct method is to request an unofficial opinion from the FERC Staff. Usually this will suffice. You have now, as a developer, passed the first hurdle toward obtaining a

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The Licensed Projects Division of FERC handles the licensing of all non-Federal public and private hydroelectric developments.

Mr. Corso has a B.S. in Electrical Engineering from the University of Pittsburgh.

license.

Different Procedures

At this point you can follow one of two different procedures. You may apply to the Commission for a preliminary permit (Permit) or a license. Although a Permit is not a necessary prerequisite to an application for license, it can be important to a potential developer. A Permit, during its term, provides sole authority to develop a site, or in other words, priority to file an application for license. A Permit thus protects the substantial investment that is made in feasibility studies and license application preparation, because it precludes development by others.

There are several institutional and legal problems associated with a Permit. First, under the Act, public entities are given preference to power sites. Section 7 (a) of the Act gives priority to public entities, provided they have filed an equal application or can revise any application it has filed to make it equal to one filed by a non-public entity. This naturally generates the traditional public/non-public controversies that have been with us for many years.

There is one point I should make at this juncture. Under the Act, Rural Electric cooperatives (co-ops) have the same status as private entities. This preference clause has resulted in some very interesting controversies. For instance, in Vermont we have on file Permit applications for sites with co-ops versus public entities, and public entities versus private utilities.

In another case in the State of Colorado, three applicants have filed for sites that, depending on the final outcome of FERC Staff's analysis, could be mutually exclusive. In that case, we have co-applicants for one project that are both public and private, a public applicant for another, and a private applicant for the third.

If competing public and private entities file for the same site and the applications are equal, the public entity automatically obtains the Permit, regardless of when the applications are filed. If the applications are not equal, the commission would then issue the Permit to the applicant that proposes the project that best fits the plan for comprehensive development of the river basin, pursuant to Section 10 (a) of the Act.

Solutions

If the competing applicants are either both private or both public entities, and the proposals are equal, then the party filing earliest would be awarded the Permit. Obviously, the number of combinations are many. With the new interest in hydro development, we are seeing an increased number of competing applications. This competition has caused long delays because extensive additional legal and technical analyses are necessary before a Permit can be issued.

What are the solutions to the competing Permit application problem? I suggest that the best resolution to competing applications is negotiation.

For instance, the City of Burlington, Vermont and Green Mountain Power Corporation filed competing applications for Preliminary Permits for the Chace Mill Project. At our urging, both parties entered into serious and honest discussions that eventually resulted in the FERC issuing a joint Permit. If the project proves feasible, each party would utilize about 50% of the project's power output.

In the west, particularly in Northern California, a different approach has been used. The utilities in that area are very receptive to being the power market. In those cases where the utility's interest is confined to purchasing power, the public bodies have come forth as the potential developers. We have had, however, competing applications by public entities in that area. Absent these kinds of solutions, the only remaining solution would be legislative. However, legislative remedies to this problem would not be easily pushed through Congress because the same competing public/non-public interests would be involved.

New delays possible

There are other significant problems that must be considered. One area that has concerned the FERC Staff recently resulted from a new position by the Department of the Interior. We see this position as possibly being adopted by the Department of Agriculture (U.S. Forest Service), also. Interior recently advised the FERC that it believes the Commission cannot issue a Permit if the project would be located in an area under study for possible inclusion as a Wild and Scenic River. Interior has, in fact, advised the FERC to request a 7(b) determination under the Wild and Scenic Rivers Act. The Commission has not rendered a decision in that case, but Interior's position has important implications. This same position could be advanced for lands under study for wilderness areas or national parks, thus causing long delays until a final decision by those agencies is rendered.

One final note regarding Permits should be mentioned. If a developer needs to make field investgations, which is likely, he would need to obtain permission to enter upon private or U.S. lands to conduct subsurface explorations, gather engineering and environmental data, and perform surveys and mapping. Permission to enter private lands does not usually cause insurmountable problems because developers are able to negotiate with private land owners. On Federal lands, you may need to obtain a permit under the Federal Land Policy and Management act to enter upon the lands. If the Federal land agency does not act promptly, or contends that studies or environmental assessments are necessary, long delays will necessarily follow.

I would now like to focus on the problems associated with obtaining a license. The license processing steps that are discussed below are also followed by the FERC in processing a Permit application.

Obtaining a license

Assuming a potential developer has obtained a

Permit, he may file an application for license during the term of the Permit with the security that there will be no competing applicant. If, however, a potential developer decides to file an application for license without a Permit, there would then be the same risks as with a Permit of a competing application for the same site. Again, the same preference rules would apply regarding the public versus Cooperative or Private applicants.

However, because the license application stage involves greater and more far reaching issues, it is most likely that, if there are competing applications, the Commission would require a hearing before making any final determination. A hearing would involve the following issues: (1) adequacy of design; (2) economic feasibility; (3) environmental impacts; (4) financial capability of applicants; (5) availability of power market; (6) dam safety; (7) projects' adaptability to comprehensive development of the river basin; (8) potential for federal development; (9) water rights; and (10) other pertinent matters.

A hearing can be an expensive and a protracted proceeding, sometimes resulting in months or years of delay. I strongly urge anyone, particularly a potential developer of a small scale project, to avoid a hearing if at all possible.

Fish facilities

If there are no competing applications, a hearing may be required if there is opposition to the project or its proposed operation. Hearings on hydro projects are usually related to environmental issues. For small scale developments, the most probable reasons would be water quality or fishery matters. For instance, in many states fish and game agencies routinely intervene on every application for license to protect interests, sometimes undefined. For small scale developments, we anticipate some problems, particularly in those areas where fish facilities may be required. It is our intention to encourage agencies to cooperate by either providing funds or technical assistance to developers. If developers are expected to fund fish facilities, it will render many small scale developments infeasible.

All this will result in delays unless agencies and developers are committed to solving these issues expeditiously. Any developer must also be able to address all of the issues noted above if there is an intervenor that disputes any of those issues, particularly environmental matters.

So that you do not get too discouraged at this point, I would like to offer some encouragement. Our experience, to date, indicates that small scale developments are unlikely to require hearings and do not usually involve issues that cause extensive delays in the licensing procedure.

The application's journey

Now that we have discussed the preliminary stages of the licensing procedure, we are ready to discuss how an application makes its way through the FERC procedures. The procedures that I am going to discuss have evolved over many years and are a result of requirements of the Federal Power Act and, more particularly, other legislation enacted by Congress. The following is a list of some of the other more important statutes affecting the licensing process:

- •National Environmental Policy Act (P.L. 91-190)
- •Fish and Wildlife Coordination Act (P.L. 85-624)
- •Endangered Species Act (P.L. 93-205)
- •Historic Preservation Act (P.L. 89-665)
- •Water Pollution Control Act (P.L. 92-500)
- •Water Quality Improvement Act (P.L. 91-241)
- •Wilderness Act (P.L. 88-577)
- •Wild and Scenic Rivers Act (P.L. 90-542)
- •Coastal Zone Management Act (P.L. 93-612)
- •Federal Land Policy and Management act of 1976 (P.L. 94-579)

Other statutes

Before briefly describing the licensing processing steps, let's review the effect of these other statutes on potential developer of a hydro project. The effect of these statutes on a developer occurs at three stages: (1) pre-license application; (2) during the licensing process; and (3) after issuance of the license. Briefly, here are some of the problems a developer encounters from these statutes.

I believe you are all familiar with the requirements of the National Environmental Policy Act (NEPA). Our greatest problem with NEPA is not compliance, but over-compliance, We find that every agency at the State and Federal level is doing NEPA assessments or statements before making decisions. This results in delays in FERC receipt of agency comments or other permits and licenses required from State and Federal agencies.

For small scale developments, there is a need for cooperative efforts to reduce this over-compliance. A lead agency must be recognized to meet NEPA requirements. although the lead agency concept is accepted at the Federal level, some agencies do not follow it. Therefore, there is considerable duplication of effort. At the State level, state agencies will sometimes recognize federal NEPA impact statements. They will not, however, recognize an assessment or negative determination. On the other hand, Federal agencies do not recognize any State environmental assessments or statements prepared pursuant to State laws. The solution is to expand the lead agency concept to both the Federal and State agencies.

Fish and Game

The Fish and Wildlife Coordination Act (FWCA) requires the FERC to consult and cooperate with Federal and State fish and game agencies. We do this in two ways. First, each application for license must include an Exhibit S, a fish and wildlife plan. FERC regulations require that an Exhibit S be developed in consultation and cooperation with the agencies. It should be emphasized that an Exhibit S is the developers plan. Agency input is not for the purpose of dictating the contents of the plan, but to provide assistance and guidance.

After the application for license is filed, fish and game agencies are requested to comment on the plan. If there is disagreement on the adequacy of the Exhibit S, as often occurs, then the FERC must resolve the differences. This is done through meetings or conferences, further correspondence, or formal hearings, all of which require time. For small scale developments, we are optimistic that the problems will be small, too. The greatest problem we anticipate is the possible requirement for construction of expensive fish facilities that could preclude economic development.

And still more

The Endangered Species Act places a responsibility on the FERC to assure that development will not interfere with or destroy any endangered species. Since the FERC is a regulatory agency and not a constructing agency, we require each applicant to determine if a proposed development affects any endangered species. The FERC also specifically requests the Department of the Interior to comment on this matter. The impact of this statute on small scale hydro development is indeterminable at this time.

The Historic Preservation Act has resulted in some special problems for small scale developments because the proposed project may itself be an historic landmark. Before the FERC can issue a license, the Advisory Council on Historic Preservation and the State Historic Preservation Officer must be consulted to assure that no historic or cultural site will be adversely affected. Exhibit V of a license application requires applicants to consult with these agencies, and the FERC also requests agency comments on the application regarding this statute.

Water quality statutes are a very important consideration for any potential developer. Pursuant to Sections 401 and 404 of the Federal Water Pollution Control Act Amendments of 1972, approvals from the Environmental Protection Agency (EPA) and the Corps of Engineers, respectively, are necessary.

EPA has delegated to most states its Section 401 responsibilities. Section 401 requires certification that a development meets state water quality criteria. This is usually done by imposing minimum flow requirements. Such minimum flow requirements are included as license requirements by the FERC. Placing fill or any material in a stream requires a Section 404 Permit from the Corps. Therefore, a permit is required for construction of a powerhouse at an existing dam.

If recreation facilities or other facilities requiring sewage treatment are included in a development, you may also be required to apply for a Section 402 permit (NPDES Permit). The obvious problem lies with minimum flow requirements. Minimum flows to assure compliance with water quality standards could render some small scale developments uneconomical.

The Wilderness Act and the Wild and Scenic Rivers Act do not need any explanation. The impact of these statutes is obvious. Any proposed development in a wilderness area or on a potential Wild and Scenic River is unlikely to succeed. The Coastal Zone Management Act does not present significant problems because few hydro developments affect coastal areas.

Federal lands

The Federal land Policy and Management Act (FLPMA) presents some special problems for projects located on Federal lands. The Departments of the Interior and Agriculture (U.S. Forest Service) are responsible for administering this statute. As of this writing, final regulations have not been issued by the agencies. Dependent on how the regulations are structured, FLPMA could be, on the one extreme, a duplication of most of the FERC licensing requirements, or on the other extreme, a supplementary requirement to assure protection of Federal land resources. The FERC has urged the agencies to implement regulations that minimize the duplication of efforts and reduce the filing requirements of applicants for projects on Federal lands. The full impact of FLPMA cannot be assessed until the agencies publish their joint regulations.

The laws multiply

Congress passes new legislation at the rate of at least one new bill each year. I see no solution unless Congress begins to realize the impact of these statutes, particularly on the small developers.

I am sure you will all agree that these statutes were passed for good reasons. However, they have resulted in overlapping and conflicting authority over hydro developments. The absolute solution to resolving overlapping or conflicting authorities requires legislative changes. In other instances, agency cooperation and constructive regulations could reduce the problems without compromising the intent of other legislative authority. These solutions do not appear to be forthcoming. Therefore, we must deal with the problems and attempt to reduce the time required to obtain a license. To accomplish this, the Commission has established policies, procedures, and regulations designed to meet the requirements of all statutes.

Marketing

I have dwelled considerably on the statutes and requirements of Federal agencies. An important factor, and maybe the most important, is the power marketing aspect. The FERC requires that a project must be economically and financially viable. Economic viability can be based on a number of different types of analyses, including life cycle analyses. However, the key to economic and financial viability is a demonstrated market for the power. For those developers that operate a power system, a market can be shown by demonstrating a growing need for power and the suitability of a hydro facility to meet that need.

For those developers that propose to sell all or part of the power output, establishing a market is more difficult. Before a license is issued, the FERC must be furnished with a power purchase contract. You need not be reminded that there has been in some areas of the country considerable resistance by utilities and others to enter into contracts for purchase of power. There are a variety of reasons why this has happened. Primarily, there are widely differing opinions as to the value of power from a small scale development. We see a changing of attitudes in this area toward the more positive. If the trend continues, this will encourage the development of small scale hydro projects.

Insurance

An extremely important problem area is insurance. Insurance companies may be the number one deterrent to development of small hydro projects. The cost of insurance premiums has sky-rocketed due to the recent dam failures. Higher insurance premiums seem to have no relationship to the hazards that may exist if there is a dam failure. For instance, there is a proposed development in New York with an installed capacity of less than 1,500 kw. The quoted annual insurance premium for one million dollars coverage before the dam failure in Georgia was $30,000 with a $250,000 deductible. The record of dam failures in this country and the fact that any dam licensed by FERC would be subject to its dam safety program should be reconsidered by insurance companies with the aim of reducing the cost of insurance.

Taxes

One final problem that should be mentioned is State and local taxes. Usually, dams with no power plant have minimal tax assessments. However, our experience indicates that when a power plant is constructed, the local and State tax authorities substantially increase assessments. Often the rationale is that the ratepayers can pay the increased taxes through power revenues. The economic feasibility of many small projects may rest with the tax assessment. Of course, taxes are not fixed, and are most likely to follow the upward trend of inflation and escalation in the cost of living.

To give some insight to the Commission's procedures, I will briefly describe the FERC licensing process, and some changes that are now being considered. The Commission Staff has under study the entire licensing process. The purpose of the study is to find ways to shorten and simplify licensing procedures. Changes to our internal procedures are being implemented. However, changes to those procedures not in direct control of the FERC are more difficult to implement. Figure 63 is a flow chart of the licensing procedure for an application for license involving new generating capacity. As you can see, it is a very involved and lengthy process. If we follow the step-by-step procedure, I believe you will understand how it has evolved.

Licensing process

When an application is filed, the first step is a Staff review to assure compliance with the FERC regulations. If there are deficiencies, a deficiency letter is sent to the applicant requesting a revised application. After the application is complete, or if not found deficient under the initial review, the applicant is requested to provide additional copies (usually 50 to 75) for circulation to Federal, State, and local agencies. It requires 60 to 160 days to reach this point, dependent on the extent of deficiencies in the application. Agency comments are usually requested within a 60- to 90-day period.

Our experience with agencies' comments has not been good. We normally encounter delays at this point because of late agency responses.

After all agency comments are received, the applicant is given an opportunity to comment on the agency responses. This usually requires 30 to 50 days. At this point, the FERC Staff will make a final determination on whether or not an environmental impact statement (EIS) is required. Staff does this by reviewing the application and agency comments, and by conducting its own analyses. If an EIS is not required, Staff would complete its technical analysis and prepare recommendations to the Commission. This usually requires three to four months.

Draft EIS

If an EIS is required, a draft EIS is prepared, usually four to five months after receipt of final agency comments. Federal Guidelines and FERC regulations require a 45 day comment perod on a draft EIS, but experience indicates that this period could be as much as 75 days. After comments on the draft EIS, Staff prepares and circulates the final EIS. This usually requires about three months.

At this point, the technical Staff is ready to prepare recommendations to the Commission. This step in the licensing process varies with the complexity of the proposed project. The legal Staff would then prepare an order for final Commission consideration. The usual time required for issuance of a license for a small scale development is about 12 to 15 months, assuming no EIS is required. If an EIS is required, it would require an additional ten months.

Let me offer an optimistic note at this point. Our experience with small scale developments has been good. However, there is a need for improvement so that these type developments can get underway at an even faster pace. There is little the FERC can do about the requirements of other statutes, except to suggest to agencies that regulations be simplified that overlap its licensing authority. The FERC could suggest legislative changes to reduce the number of approvals, but that approach is not usually successful. The FERC is taking steps to simplify and reduce the requirements of its licensing procedure. It is our hope that others will follow.

Changes

You may be interested in a few of the changes now in effect or being considered. On April 21, 1978, the FERC issued proposed changes in its rules and regulations to institute a short-form license for small projects (1,500 kw or less). This is the first of a three-phase program to simplify all its regulations. We are now in the process of preparing simplified regulations for projects 15 Mw or less, particularly at existing dams. Our target date for issuance of these regulations is September 1978. We would then begin revising regulations for projects of more than 15 Mw installed capacity.

There is also under consideration proposed revisions for processing Permit applications. Presently, it requires 12 to 24 months for issuance of a Permit. It is our intent to reduce this to as little as three months.

We are also considering other changes such as: (1) shorter agency comment periods; (2) earlier start of Staff environmental assessments and other studies; (3) elimination of application processing steps; (4) instituting memoranda of understanding with other Federal agencies; (5) issuance of guidelines to assist applicants; and (6) an increase in FERC Staff.

It is our goal to make the path to a license for a small scale hydro development more direct and simplified. With your cooperation and a total commitment, particularly other Federal and State agencies, this goal can be achieved.

The views expressed herein are those of the writer and do not necessarily reflect the views of the FERC.

Following his speech, Mr. Corso answered several questions from the audience.

Q: I wonder if Mr. Corso might comment on the FERC posture and some recent happenings in the recapture situation on expiration of licenses.

Corso: We are having the same competing application problem under relicense, as I mentioned, at the preliminary permit licensing stage, regional licensing stage. We have several applications before us for new licenses. The present license is for a utility license. The competing applications have been filed by both cooperatives and municipalities, and in one case an Indian tribe, actually. The commission had square before it, about a year and a half ago, that issue as to whether preference applies under relicense and they refused to rule on it because on that particular instance it involved a cooperative and a private utility, both of which have the same status.

The ramifications of public takeover or license projects is very far reaching; it gets into many areas, particularly rate areas. You take a company, for instance, like Pacific Gas and Electric, which is heavily hydro. If all of their hydro sites were taken over by municipalities, their rates to the rest of their customers would go up roughly 25%. That's very significant. There are those who advocate such takeover and there are those, utilities principally, who argue against it. Its really a national-policy-type problem, and one the commission is having great difficulty in ruling on. How it will come out in the final analysis I really can't tell you at this time except that our staff is urging as best as it can that some final resolution be reached on it as soon as possible because it causes us double workload for every one of those projects and, we surely don't have staff to waste on that kind of thing when we have a lot of other projects that should get staff time.

Q: I have a question for Mr. Corso with regard to land rentals of Federal Lands that are administered through the Federal Energy Regulatory Commission. Number one, is this part of the original FPC licensing or regulations or really does it originate from your group or from the Federal Land Management Act? That's one question. The other question is: who receives these funds once they are paid to the FERC? And the third question that I have is a comment and question, and this relates to the land rental fee itself. In other words, in our particular case as I recall, over a period of three or four years the land rental fee escalated from $2 an acre approximately to roughly $9 an acre over land that is virtually non-usable for civilized purposes of agriculture or otherwise. As a matter of fact, some of these acreages are vertical, like basalt cliffs, and they are still working on a market for that. So I guess our concern is the tremendous to us, the considerable increase in rental fees for land that virtually was non-usable prior to the existence of the project. Would you comment on this please?

Corso: First, the Federal Power Act specifically requires the commission to collect a fee for the use of federal lands, it's in section 10E of the Federal Power Act. The commission has the right to collect reasonable charges, that's where your second question comes in. What is reasonable? For administrative purposes, the commission decided that when it increased the charges to the three-stage level you mentioned, gradually up to an average value of land in the country of $150 dollars an acre. The old value was $60 an acre. That it would use the average value of land in the country. You may or may not agree with that but administratively its far better than the commission trying to individually assess the value of lands. It would mean we'd have to hire an entire staff which we do not have at present and have them visit every site and place an assessment on the lands. Hiring that staff puts you in the same boat because we also charge you for administration of the Federal Power Act. You have to pay those charges too, and frankly I think you're better off in the long run.

Q: I agree because I saw the bill the other day for that. The other comment that I haven't received an answer for or comment on is with regard to the distribution of these funds.

Corso: Section 17 of the Federal Power Act prescribes how land charges will be distributed and I think it's 37½% goes back to the state. The rest of it goes into the U.S. Treasury. We also collect other charges for use of government facilities, Indian lands for instance; those charges are entirely dispersed to the Indian reservation involved. Use of government dam facilities for instance; those charges go to the agency that operates the dam or other structure involved.

Q: Would you like to go out on the limb and comment on whether or not your feelings, with regards to the simplified procedures and so forth, are things getting better or are they going to get worse?

Corso: I have to agree that my remarks contained a note of pessimism. Now I would like to get to the note of optimism. Our experience with existing dam type projects I would term as excellent, in fact. We've had a very good success in the environmental area, we've had very good success in processing time. Right now we're looking somewhere in the neighborhood of a year or two to license an existing dam project. Sometimes a little longer, sometimes a little shorter. And that is the time we're shooting to reduce, it's not two years or three years. The two-year or three-year limit applies to a new project. And the three-year outside time usually is a case where it involved a hearing. Impact statements for instance: we've been able to convince other agencies that we do not need to do a full-blown impact statement where there's an existing dam. That usually is sold on the basis of the fact that the project will not alter significantly the operation of that dam and use the so-called negative declaration approach. I'd like to say that we're very optimistic that things are going the right direction and we're going to try very hard to make them continue to go in that direction.

Federal Legislative Considerations

by Warren Viessman, Jr.

The "energy crisis" has rekindled congressional interest in developing new hydroelectric facilities and improving existing ones. In particular, the idea of installing small units on minor rivers and tributaries has become popular. Many previously developed sites, now abandoned, offer attractive possibilities for augmenting the nation's electrical needs. An added incentive is that such projects are not fuel consumptive and do not create air or water pollution problems.

A 1977 study by the Corps of Engineers (CE) indicated that an increase of about 55,000 Mw of electric generating capacity could be obtained by rehabilitation, expansion, or new construction of hydroelectric generating facilities at existing dams[1]. This would approximately double the current capacity (1978). Relevant issues are the adequacy of Federal criteria and procedures for licensing hydroelectric facilities and the extent to which an expansion of hydroelectric facilities would benefit the national supply and distribution of electrical energy. Constraints on achieving the projected potential appear to be economic, environmental and institutional rather than technical.

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Background

The Arab oil embargo of 1973 signaled increasing energy costs and concern about dependence on oil as a prime energy source. As a result, interest has increased in other energy production systems to help reduce U.S. need for foreign oil and gas. These include: nuclear power and coal plus solar, wind, tidal, biomass conversion, geothermal, streamflow, and other small scale techniques.

Conventional hydroelectric developments now provide about 15 percent (57,000 Mw) of electric generating capacity in the contiguous United States. Projects under construction, planned, and possible for development in the next two decades (until 1995) could increase the developed hydroelectric capacity by about 40 percent. At that time, conventional hydroelectric projects providing about 80,000 Mw of capacity, the equivalent of 80 large nuclear or conventional power plants of 1,000 Mw each, could account for about 5 percent of the nation's electric generating capacity. This projected increase in electricity, if produced by thermal plants, would require an average of approximately 80 million barrels of oil per year.

Beyond the projected 1995 hydroelectric development, additional projects could add as much as 36,000 Mw of capacity, with an annual generation of 100 billion kilowatt-hours (kwh). The Federal Energy Regulatory Commission (FERC) estimated that such generation would represent an annual savings of 160 million barrels of oil over equivalent production by thermal plants.[2] If existing facilities were modified by increasing dam heights, reservoir storage or generating capacity, this potential could be increased even further.

According to the 1977 CE study, development of all the hydropower potential at existing dams could result in an increase of 160 billion kwh of electricity, a savings of 727,000 barrels of oil per day. This is 7½ times the savings associated with President Carter's goal of solar heating for 2.5 million homes by 1985. The CE evaluated the physical potential of existing dams and the constraints on development of this potential. They concluded that:

1. By installing more efficient turbines and more powerful generators at existing hydropower dams, 5,100 Mw of capacity could be obtained.
2. By installing additional turbines and generators at exiting hydropower dams, 15,900 Mw of capacity could be obtained.
3. A maximum of 33,600 Mw could be obtained by constructing powerhouses at all existing non-hydropower dams in the United States.
4. There are engineering, economic, financial, environmental, social, and institutional constraints to constructing powerhouses at existing non-hydropower dams. Complete information needed to evaluate these constraints is not available, but none is considered insurmountable.
5. Construction of demonstration facilities at some small-scale existing non-hydropower dams would help define the constraints and incentives which affect development of hydropower at such sites.
6. Although the total potential for hydropower development is small compared to projected U.S. electric generation needs, hydropower, in conjunction with other evolving energy production systems could significantly reduce the demand for oil imports.

Constraints on hydroelectric development

Economic, environmental, social and institutional factors may preclude the development of many potential hydroelectric sites. In addition, Federal statutes which impact on hydropower development are the Colorado River Basin Project Act (P.L. 90-357) and the Wild and Scenic Rivers Act (P.L. 90-542).[3] The former prohibits the Federal Power Commission from issuing licenses for projects on the Colorado River between the Glen Canyon and Hoover Dam projects. This preempts a power potential of about 3,500 Mw. P.L. 98-542 prohibits the Commission from licensing the construction of power facilities affecting rivers included in the national wild and scenic rivers systems. The thirty-seven river reaches proposed for inclusion in that system or to be studied for possible inclusion in the system contain sites which could provide about 9,000 Mw of hydroelectric capacity.

Resource base limitations

The maximum potential for hydroelectric power development is a function of the average annual streamflow of a basin. Thus the theoretical potential is constrained at the upper limit by the availability of water. In a practical sense, the theoretical limit is unattainable and current estimates place the practical limit at about 50 percent of the theoretical maximum due to technologic, environmental and political constraints. Furthermore, average annual streamflows are shrinking as a result of increased depletions by water uses such as irrigated agriculture. For example, estimates of water use in the Upper Missouri River Basin from 1975-2000 indicate a reduction of average annual streamflow of 20 percent or more.

Environmental constraints

An important constraining element in hydropower development is the conflict between expanding electric energy demands and concern for environmental quality. All levels of government, the electric industry, and various citizens groups are concerned with this issue. Institutional changes have been made requiring utilities and construction agencies to be more sensitive to environmental impacts and to explore a wider range of project alternatives. Unfortunately, developing such information and processing it through the review and decision-making levels of government is complex and often results in inordinate delays.

Although there are many favorable characteristics of hydroelectric facilities (recreation benefits, water supply, etc.) there are also aspects which may have adverse enviromental impacts. The degree to which hydroelectric facilities affect air, land and water quality depends on the site, design, mode of operation and other factors. Consideration must also be given to the effects during the period of construction as well as after the facilities are in place[4]. Fortunately, much of the small-scale development will be existing dams, and therefore, the comparative environmental effects should be minimal.

Technologic constraints

Technologic constraints related to site development and facilities for small-scale hydroelectric developments are generally not severe. In addition, recent advances in low-head turbine technology appear to signal the beginning of a much greater exploitation of low river flows. One perplexing technologic issue which merits attention relates to uncertainties of connecting small-scale hydropower plants to existing power grids.

Economic constraints

Development of new hydroelectric facilities usually requires large outlays of capital for long periods of time. Before 1974, low costs of fuels and fossil fuel electric plants often made hydroelectric development less attractive than other alternatives, but post-embargo increases in oil price have greatly improved the relative economics of hydroelectric generation. The economic attractiveness of hydroelectric power appears destined to improve as fossil fuel prices escalate.

Facility construction costs are variable and depend on the size, type and location of the dam. Land procurement, relocation of people, buildings, and facilities can be very costly. For example, the 1971 cost of a small Pennsylvania hydroelectric dam was $15 million but relocation and property adjustment added $100 million to the total cost. [4]

Retrofitting existing facilities is a different story, however, since much of the capital outlay will have already been expended. Clearing the reservoir site and building the dam has represented about half the cost of most typical hydroelectric projects. This makes installation of facilities at existing dams especially attractive.

Time lag in development

From the time a new hydroelectric project is conceived until it is on line, a period of 20 years or more may have passed. Many events which transpire in the process act as constraints on development. To illustrate this, the planning, authorization and construction sequence for a typical CE water resource project is outlined.[5] The process can be divided into four phases as shown in Table 17. In the implentation sequence, the Congress authorizes and appropriates funds for studies leading to project authorization. Following completion and review of these, the Congress must act again to provide project authorization.

The Bureau of Reclamation (BR) and Bonneville Power Administration (BPA) projects proceed somewhat differently.[5] BPA is authorized by its basic legislation to construct transmission lines, and is given authority for individual projects by the appropriation against specific items in the annual budget of the agency. TVA projects are planned and constructed under the special provisions of the TVA act.

Factors which limit efforts to compress time lag in development have been identified by FERC. They are:[5]

Construction schedule

Although the schedule obviously varies from project to project, for many Federal projects the optimum schedule consists of a five-day, one-shift work week, with additions of another shift when the nature of the work or other conditions make it necessary. For projects with extensive underground excavations, such as tunnels and underground power plants, the usual schedule calls for a six-day, two-or-three-shift operation.

Labor availability

Acceleration of a construction schedule may be constrained by lack of the additional skilled labor required to support multi-shift operation. This situation may be aggravated in areas having an especially short summer construction season, or in areas with other major concurrent projects.

Environmental Impact

The trend regarding many of the other steps of Table 17 is toward a duration increase, particularly in Steps 5, 8, 13 and 16, which provide for preparation, review, and approval of Environmental impact Statements (EIS). Annual appropriation of construction funds in Step 18 has also been recently delayed, at some projects, by environmental objections, even when projects are partially complete.

Phase I, Study Authorization

1. Initiation of Action by Local Interests
2. Consultation by Senator or Representative with Congressional Public Works Committees
3. Action by the Senate or House Public Works Committee

Phase II, Accomplishment of Study

4. Assignment and Funding of Study
5. Conduct of Study by Division or District Engineer
6. Issuance of Report and Draft Environmental Impact Statement and Public Notice by Division Engineer

Phase III, Study Review and Project Authorization

7. Review by the Board of Engineers for Rivers and Harbors or the Mississippi River Commission
8. Preparation and Coordination of Proposed Report of the Chief of Engineers
9. Transmittal of Report of the Secretary of the Army
10. Referral of the Report to the Office of Management and Budget
11. Transmittal of Report to Congress
12. Project Authorization by Congress

Phase IV, Advanced Planning, Design, and Construction

13. Project Scheduling and Reaffirmation of Local Cooperation
14. Request for Project Funds
15. Appropriation of Project Funds
16. Preparation of Detailed Plans
17. Award of Contract
18. Construction of Project

Table 17. Steps in development of Corps of Engineers multipurpose project with power.

Systemwide constraints

Hydroelectric installations and their transmission lines seldom comprise isolated, individual projects. As a consequence, opportunities for schedule acceleration at one installation are often constrained by conditions elsewhere in the system. For example, accelerated construction of a transmission line may accomplish nothing if its generating input and/or its load development are not correspondingly expedited. This situation is one reason why some of the projects already authorized for construction cannot realistically be accelerated. They each are a scheduled part of a larger system which is in various stages of development, and beneficial acceleration would only occur if it could relieve a critical path restraint or the entire development were expedited.

Multipurpose aspects

Prospects for accelerated scheduling of Federally funded hydroelectric installations are also affected by the multipurpose nature of nearly all projects. In such Federal installations, hydrogeneration must be developed in relation to flood control, navigation, irrigation water supply and other related resource needs, and as a consequence, construction schedules are determined by optimizing benefits from overall project plans.

Advantages of exisiting sites

Although the ability to expedite construction or modification of hydroelectric generating facilities has been found by FERC to be less than promising, revision of existing facilities has the advantage of a shorter time lag. Small-scale hydropower sites are particularly attractive since they can be developed quickly, possibly in less than five years where a dam already exists.

A key step in project planning is preparation of an EIS. All factors affecting the environment including the temporary effects associated with the planned construction schedule must be considered. Before a project can be expedited, anticipated environmental factors resulting from proposed schedule acceleration must also be carefully evaluated.

Licensing

If current projections are correct, a large number of small-scale hydroelectric sites will undergo development by the year 2000. Unfortunately, the current hydroelectric regulatory processes are tailored to large-scale sites (above 15,000 kw). These procedures impose a massive time-consuming barrier to the development of small-scale sites and constitute a serious front-end burden on this type of energy development. The importance of licensing delays is clear when one considers that, presently, 502 license applications have been on hand an average of 60 months. The 11 years it took Vanceburg, Kentucky, to get final licenses to operate hydro generators it proposed in 1965 is further testimony to the critical nature of this problem.

The need for small-scale hydropower development to be regulated as tightly as large-scale development seems questionable. Intense scrutiny of small sites is expensive and of dubious value. Under current regulations, license applications for small-scale projects require about the same amount of detail as that required for a dam the size of the Grand Coulee.

Licensing procedures for small-scale hydroelectric projects should be streamlined. This issue has been given consideration by the Congress in several current bills (H.R. 4018, H.R. 6831, H.R. 7730 and H.R. 8444). FERC is now proposing rule changes to provide simplified procedures for processing applications for small-scale hydroelectric projects meeting specific size criteria. In addition, GAO has studied the problem and recommended that the Chairman of FERC:[6]

- Establish followup procedures and standards insuring that information needed to process applications is pursued aggressively.
- Establish a realistic program for prosecuting those delaying the licensing program.
- Formalize the role of other Federal agencies in the licensing process by entering into interagency agreements
- Ask the Congress to amend the Federal Power Act to require (1) applicants for licenses to pay reasonable annual charges for administering the licensing program and (2) applicants for previously constructed projects to pay retroactive charges when applications are filed.

Government policy affecting 1976-1993 supply projections

Areas of government policy which are likely to impact on hydroelectric facilities development during the period 1976 to 1993 relate to further designation of wild and scenic rivers, the exercise of the Federal Endangered Species Act of 1973, and the tone of the national policy on water.

Since the mid-1960s, public rejections of proposals for multiple purpose water resource development have increased. This attitude has been largely a reflection of concerns for the environment and a desire to substitute non-structural or other alternatives for meeting the objectives of large water resource development projects. This attitude is exemplified by a 1976 decision on the Appalachian Power Company's 1.8 million kilowatt Blue Ridge Project, which would have placed a twin-dam, pumped storage hydroelectric facility on the New River in Grayson County, North Carolina. On September 11, 1976, President Ford signed legislation designating a 26.5-mile segment of the River as part of the National Wild and Scenic Rivers System. As a result, dam construction and other activities that would affect the designated segment are prohibited. "It is clear in this case that the people wanted the New River like it is," the President declared, "...The people's will has now been done. An ancient and majestic river has been saved."

Unless the prevailing posture relative to water resources development is relaxed, the likelihood of accelerated facilities development to exploit untapped hydroelectric potential is not great. Revision or expansion of existing facilities will be less affected by current attitudes, however, and this make small-scale development especially attractive.

Congressional activity

The Congress has been moving to accelerate development of small-scale hydroelectric energy (less than 15 Mw) at existing dams.

Both the Senate and House have agreed on a small-scale hydroelectric energy research, development and demonstration program. With a proposed authorization of $15 million, the Department of Energy (DOE) would be directed to demonstrate the feasibility of low-head hydroelectric energy and perform necessary backup studies. Additional authority may be sought as the program evolves.

Senate and House conferees have also agreed to a provision in the Public Utilities Regulatory Policy Act of 1977 (H.R. 4018) which provides $10 million per year for each of three years in direct Government cost-sharing loans (90 percent Federal share, 10 percent local share) to evaluate damsites and apply for necessary Federal, State and local permits. Loans are forgiven where the Secretary of Energy concludes on the basis of the study that the proposed project is not feasible for small-scale hydroelectric development. Conferees have also agreed to a measure which authorizes the Secretary of Energy to make Government cost-sharing loans (75 percent Federal share, 25 percent local share) to cover architectural, engineering and construction costs. One hundred million dollars per year for each of three years is authorized. Eligible projects are limited to existing dams only and to those projects which have no significant adverse environmental impacts.

These are important first steps in developing an integrated system of Federal incentives and policies to encourage the private development of environmentally sound, small-scale hydropower projects. Additional actions which not only deal with the Federal sector, but also identify and alleviate the many non-Federal legal, regulatory, and financial barriers which could retard or prevent timely development of small-scale hydroelectric potential at existing dams deserve consideration by the Congress.

According to the CE, the following factors affecting the future of small-scale hydroelectric development merit special consideration:

- There is a need to further develop and refine small-scale hydropower turbine technology.
- Many potential hydropower dams require major rehabilitation.
- There is a need to develop simplified hydrology, reservoir yield, and power plant capacity analysis techniques.
- The design of power transmission grids and switching systems becomes extremely complex when small-scale hydropower units are included in the network.
- The relative economic efficiency and financial feasibility of small-scale hydropower versus alternative electrical generation techniques are unknown.
- Diverting reservoir storage from current use to hydropower production could be inefficient and cause significant economic stress in many instances.
- The ecologic impacts of peak load production by small-scale hydropower plants are possibly significant.
- The social effects of a small-scale hydropower program are numerous, diffuse, and largely unknown.
- Institutional barriers may retard or prevent development of small-scale hydropower.

Summary

Increasing energy costs and concern about dependence on oil as a prime energy source have stimulated interest in expanding small-scale energy production systems such as hydroelectric facilities.

According to CE, an increase of 160 billion kwh of electricity could be obtained by rehabilitation, expansion or new construction of hydroelectric generating facilities at existing dams. They noted that the national potential was so significant that immediate action was warranted.

Congress has responded to this issue by drafting legislation to provide grant and loan funds to encourage expansion, rehabilitiation or new development of facilities at existing dams. The Public Utilities Regulatory Policy Act of 1977 (Title I or H.R. 4018) is the vehicle for most changes.

Still unresolved are questions of economics, ecological impact, social effects, institutional constraints, and interfacing small-scale hydropower plants with existing and planned regional electric networks. These areas merit attention if small-scale hydroelectric power development is to be encouraged.

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Overview of Existing Federal Programs in Low-Head Hydro

by Charles Gilmore

The Department of Energy program in low-head hydroelectric celebrated its first birthday just last month, [May, 1978] so it's a very new program. However, of all the programs that I've been involved in since I've been with the federal government, I believe that it has been one of the best programs and has accomplished more in one year than many of them have done in a much longer time. I believe that one reason for this accomplishment is that there has been such a vocal public support for the program. I believe that attendance at seminars like this one is very indicative of the support that this program has throughout the country.

As I said the program was first initiated in May of 1977 when funding was re-programed from the geothermal program to the hydroelectric program. This funding was used initially to scope the hydroelectric situation. One of the first studies was the Corps of Engineers 90-day study to come up with what was the gross potential for low-head hydroelectric power in the United States. Table 18.

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He earned a B.S. in Engineering Physics and M.S. in Nuclear Engineering from the University of Oklahoma.

HYDROELECTRIC POWER RESOURCES

*TOTAL NATIONAL HYDROELECTRIC POWER CAPACITY FOR SITES WITH CAPACITY GREATER THAN 5,000 KILOWATTS	170.7 MILLION kW
PRESENTLY DEVELOPED	57.0 MILLION kW
UNDER CONSTRUCTION	8.2 MILLION kW
REMAINING UNDEVELOPED	105.5 MILLION kW
†UNDEVELOPED POTENTIAL AT EXISTING DAMS CONSIDERING UNIT CAPACITY OF LESS THAN 5,000 KILOWATTS	26.6 MILLION kW
‡POTENTIAL FOR NEW DEVELOPMENT CONSIDERING UNIT CAPACITY OF LESS THAN 5,000 KILOWATTS	173.4 MILLION kW
TOTAL UNDEVELOPED CAPACITY	305.5 MILLION kW

*FEDERAL POWER COMMISSION
†CORPS OF ENGINEERS
‡APPROXIMATE

INEL-S-6740

Table 18.

This particular study has been mentioned several times throughout the seminar. This table is a summary of the results of the study. The major thing that I want to point out is the 26.6 million kw of undeveloped potential at existing dams considering unit capacity of less than 5,000 kw. These are dams that exist. This is potential that is waiting to be developed. There is also a large potential, 173.4 million kw, for new development considering unit capacity of less than 5,000 kw at sites that are currently not dammed.

However, our current program is concentrating on this 26 million kw at exisiting dams. I will mention that several times throughout my talk. Based upon the results of this study and other studies that were performed during that first half year, there were several goals that were set for the low-head hydroelectric program.

I'm referring first on Table 19 to the goals at the bottom. The near-term goal of 1,500 Mw by 1985. This is new power on line. The mid-term goal of 20,000 Mw by the year 2000. The long-term goal of 50,000 Mw by the year 2020. The program that I'm going to be addressing is devoted mainly to the first goal. To accomplish this goal we have set as our near-term objective to provide appropriate assistance to private and public sectors to accelerate the redevelopment of existing dams which are amenable to construction or retro-fit of hydroelectric facilities. I want to stress in that statement the words "appropriate assistance" and "existing dam" because this is where our program is currently concentrated.

The main elements

To accomplish these objectives we have set out six elements of our hydroelectric program. I am going to give just a brief overview of some of the tasks that are currently ongoing in each of the six elements.

The first element is resource assessment. You heard yesterday a good discussion of one of the programs that we have ongoing in resource assessment. That is the study which is being conducted through the University of Idaho to assess the hydroelectric potential in the Columbia River Basin. We are also funding the Corps of Engineers to update and expand their original 90-day study and to identify the best low-head sites at existing dams throughout the nation.

We are also cooperating with the New England River Basin Commission in a study that they have initiated themselves in analyzing the potential of expanding hydroelectric production in the New England states. There is also scheduled for next year in the Bureau of Reclamation, a study to evaluate the low-head hydroelectric potential in the 17 western states. We will be meeting with the Bureau of Reclamation in Denver the latter part of this week to discuss the coordination of their program with our program. The results of the resource assessment studies will be put into a data bank we are currently developing, and will be available to the public to assist them in their planning for hydroelectric development.

The next element of the program is the engineering development program. The objective of this program is to reduce the cost of low-head hydroelectric power facilities. This program is currently in the program planning stage. We expect this program to expand considerably next year. What we've been doing the past year is mainly educating ourselves as to the state of the art. We have had studies conducted by Stone and Webster on the state of the art of hydroelectric turbines applicable to low-head use. The results of that study will be published this summer. We have programs we are doing with the Bureau of Reclamation in Denver where they are looking at the state of the art in civil works, such as inlet and outlet structures and the possibility of modular construction. The results of their studies will feed into our engineering development program plan.

Innovative equipment

Also as a part of engineering development we will be looking at new innovative equipment designs. We currently are funding the testing of a Schneider Lift Translator prototype at the University of California at Davis to see exactly what type of efficiencies this new design will obtain. We have other innovative designs that have been submitted to us for evaluation that we will consider in our program next year. We're going to look at any innovative development that looks as though it has potential for reducing costs; that's in the turbines, in the civil works, in the electrical, mechanical, and control equipment.

The next two elements I will discuss are both really in the very preliminary planning stages at this time. We welcome any input that any of you have that might help us in drafting our plans for attacking these particular issues. We are a little bit further along in Element Number 3, institutional and legal considerations. The objective of this area is to identify and assist in the resolution of institutional, legal, and economic barriers to commercial development of low-head hydroelectric power. We have recognized that institutional and legal problems are not just Federal or national problems. Many are regional and local problems. Therefore, we are entering into a program with the National Conference of State Legislatures. They will be working with the state governments to develop a program for attacking the issues that are particular to each state and region.

We also have initiated a program with the Franklin Pierce Law Center. They are evaluating the institutional and legal issues in the eastern part of the nation. We are also negotiating for an institution in the west to do similar studies.

Environment, technology

The objectives of Element Number 4, environment and safety, are to provide both the government and private sector with assessments of the impacts that low-head hydroelectric installations may have on the environment, and to provide improved environmental design technology to those developing low-head hydroelectric installations. As I said before, this program is just beginning. We have not at this point in time, really entered into an active program. However, we do recognize areas that we know we will have to investigate. These have been mentioned in other talks, such as the fish ladder requirements, the environmental impacts of altering the current use of existing dams, and techniques for discovering concealed deterioration at sites to be renovated. We welcome suggestions that any of you can give us in drafting this program.

Going on now to Element Number 5, technology transfer and information dissemination. The objective of this element is to collect and disseminate to the public information relating to low-head hydroelectric research results, market data, and the status of institutional, legal, and economic issues. Since we are still a rather young program, this is one of the smaller parts of our program. However, we have initiated development of a computerized data bank that will contain such items as site characteristics for use by developers, engineering data and standardization results for use by A&E firms, and cost, marketing, and economic information. We are also conducting a series of seminars such as this one. Information gained in the other elements of our program will be provided to the public through publication of topical and final reports and topical workshops.

Now the last element is the demonstration program and this is really the largest part of our program in terms of funding. This year we are spending approximately $6 million in the demonstration area. This is 60% of this years budget of $10 million. The demonstration program is essentially divided into two areas. The first area is the feasibility studies, which we are just now getting into. The second area is the actual construction of demonstration projects.

Possible sites

Many of you here are familiar with the Program Research and Development Announcement, which we refer to by the acronym PRDA, which we have just recently completed. This PRDA was for proposals to perform feasibility assessment studies of installing hydroelectric at existing dams. It also had the stipulation that the power range was from 50 kw to 15 Mw and that the head for the site had to be 20 meters or less. We received approximately 200 proposals. Approximately half of the proposals were concentrated in the northeast. However, we did get a very good sampling throughout the continental United States, a couple in Alaska, and one in Puerto Rico. The only area of the country we feel we did not get a truly representative sample was the southeast.

We were able to select 56 proposals for cooperative funding for these feasibility assessments. Again, approximately half of them will be in the northeast. However, we are performing assessments in 30 states and one in Puerto Rico.

I've been asked many times during this seminar about the status of the PRDA contract negotiations. We have presently contacted all of the proposers. We plan to mail the contracts to them the third week of this month. Hopefully, those contracts will be back to us, signed, by mid-July at the latest and work will begin sometime in July on those studies. Most of the studies are six months or less, so hopefully we will have the results by the end of this calendar year. The information that we obtain from those studies will be put into our hydroelectric data bank, will be published, and we plan to have a workshop to disseminate to the public the information that is gained by these studies.

The second area of the demonstration program is the construction demonstrations themselves. The construction demonstrations can also be divided into again two sub-areas. One area is demonstrations of the economic viability of installing conventional low-head hydroelectric technology at existing dams. The other area we call utilization demonstrations.

This is a new area which we are just initiating. We currently have one small project with Mr. Larry Gleason in Maine. He's gotten quite a bit of publicity in the Northeast for his efforts to develop, on his own as an independent entrepreneur, a low-head hydroelectric facility. We have entered into an agreement with him to use his example to show what can actually be done in this area.

Another demonstration program we have is with the city of Idaho Falls. That project has also gotten quite a bit of publicity.

Teton-induced changes

It was just two years ago this Monday that the Teton Dam failed. As a result of that failure, the three power generating plants in the city of Idaho Falls were damaged. Idaho Falls proposed to the Energy Research and Development Administration that since the Federal Government was going to be involved in the restoration of these dams it looked like a unique opportunity to combine two objectives: first, to demonstrate the viability of the modern low-head technology and second, to restore the damaged plants. We have entered into a contract with the city and we are funding that project at $7.3 million, which is 50% of the cost of one of the three plants. The center part of the diversion dam that brought the water around the island and into the turbines was completely destroyed by the flood. Also there was damage to the power plant. However, if the diversion dam were still in operation the power plant

LOW-HEAD HYDROPOWER PROGRAM

ELEMENTS

- **I. RESOURCE ASSESSMENT**
- **II. ENGINEERING DEVELOPMENT**
- **III. INSTITUTIONAL AND LEGAL CONSIDERATIONS**
- **IV. ENVIRONMENT AND SAFETY**
- **V. TECHNOLOGY TRANSFER AND INFORMATION DISSEMINATION**
- **VI. DEMONSTRATIONS**

GOALS

1,500 MW BY 1985

20,000 MW BY 2000

50,000 MW BY 2020

Table 19.

could be operated at this time. However, in the project that we now have, we are removing the 50 to 60-year-old turbines and will be installing one bulb turbine of about 7 Mw, providing considerably simpler construction and approximately twice the power production from that site as existed before. The lower power plant was not seriously damaged by the flood because a diversion dam further upstream failed thus allowing the water to bypass this particular plant. This plant is operating now and will continue to operate. A new bulb turbine will be installed, right alongside the old turbines. This plant is currently producing about 3 Mw with two turbines. The new addition will be producing about 7 Mw with one turbine. Again, you can see the striking difference between civil works of the old plant and the new plant.

The money outlook

That's all I planned to say about the current program. I would like to make a few comments about our plans for next year. Our budget for next year has been submitted to Congress. Most of you know that we now deal with what we call zero-based budgets, where we submit to Congress several versions of our budget, depending upon the base level and the enhanced programs. We submitted a budget that ranged from $8 million to $15 million for next year. The current versions, as they now exist in the various committees in Congress, are looking like the $15 million is probably what we will get, but we have no guarantee at this time. Also, during President Carter's speech on Sun Day, in Colorado, he announced that there would be a $100 million initiative for the acceleration of certain alternative energy programs. In that $100 million initiative there will be $20 million for the small hydroelectric program. Therefore we are looking at, depending upon what Congress eventually does, somewhere between a $28 and a $35 million program for next year. In that $20 million dollar initiative program the major new area that we will be going into next year is a $10 million dollar loan program for more feasibility studies. This program currently calls for a 90% loan that is to be paid back to the government if the feasibility study proves to be viable and the project goes on. However, if the feasibility assessment shows that the project is not viable those loans may be forgiven. We feel that this is attacking the issue of the up-front financial risk of performing these feasibility studies, because these studies are rather expensive even for the low-head hydroelectric projects.

In closing, I'd like to state that the accomplishment of the goals that were shown in Table 19 depends as much on the initiative of industry as it does upon what we do in the government. The development of our renewable energy resources is really dependent upon the initiative of industry. And to go back to my original statement, we feel that our program should deal with the appropriate assistance to industry and not just the financing of the development of low-head hydroelectric projects. I want to urge that all of you who have sites that look feasible; go ahead with it! Don't wait for a government grant because government grants are going to be very few. There will be loans to help cover the up-front financial risk, but ultimately the development of low-head hydroelectric power will depend upon your initiative.

A Lawyer's View

by John A. Rosholt

I'm pleased to talk about some of the problems that I think are developing from what I'll entitle the Lawyer's Relief Act of 1978, low-head hydro. The economics of collecting a thousand dollar note are pretty similar to collecting a million dollar note. To put out a good effort and to do your homework costs the client just as much money, even though there's lots of difference in the number of zeroes. I think that the same principle prevails in how we analyze the low-head hydro. Let's also don't talk just about low-head hydro because we're probably talking about semantics. Many of the projects that have been discussed really don't fit the definition or the category of low-head. Anyway, the bottom line has got to be the power cost.

Probably the legal and institutional requirements (while somewhat easier on smaller projects that don't grab as much local and statewide attention) are the greatest contingency. Unfortunately, contingencies as to legal and institutional problems play a much more major role in the analysis of project costs for smaller projects.

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He received his B.A. in 1959 from the University of Idaho, and his L.L.B. in 1964.

Ron Corso and I were talking just before the panel started this morning as to what it costs the average utility to approach the Federal Energy Regulating Commission (FERC). But what does it cost the average utility to acquire a federal power license? While some of the requirements are duplicitious, and they can be used in obtaining additional permits and licenses, it may be that you're talking cost in the neighborhood of $500,000. You might be talking about a million dollars. You start throwing these kind of numbers into projects with a total cost of ten million dollars, and some of them may go from the "feasible" to the "nonfeasible."

One other problem that may arise in putting people that are traditionally in the irrigation business in the power business would come if the public utilities commission in your state could then not only set the rate that you charge for the power, but you may find yourself in the situation where they then want to assert jurisdiction to set your water rates for irrigation use.

Some other considerations that have been mentioned are your operational costs: they have to be built into that feasibility study. Ron adequately pointed out the insurance problem. Insurance on private dams is astronomical. You also have to analyze closely the transmission facilities available and where they are. If your client just wants to develop some power, perhaps to hedge against future operation and maintenance costs of an irrigation system, they are not going to do anything unless there's some monetary reward for them. So transmission lines seem to be important.

Marketing is obviously very important. What kind of power is it? What time of the year is it generated if its not firm power? What is the pattern of demand in your particular area?

The bottom line has got to be feasibility. You've got to work out the institutional arrangements that are going to satisfy the banker that you can pay him back. Whether that's done with a "take-or-pay contract" with a local utility or how it's done, that is the bottom line.

Amendments Needed

Now there are other things in my opinion that need to be done. One thing that would make many of the things that you've talked about these two days feasible would be to get an amendment to Federal Internal Revenue Code Section 103. That would enable non-profit corporations and irrigation districts to generate power to help alleviate the energy crisis and put them in a position where they qualify to sell their bonds at a tax exempt interest rate.

I commend FERC for their work on the small projects and Ron's encouragement that they're going to continue that to projects up to 15,000 kw. Their rules we've watched with interest. We watched in the last Congress in hopes that such exemptions as were proposed would be written into the law. One such exemption may give FERC the authority to waive licensing requirements for projects of some size, say 15,000 kw. But again, take a hard look at that before you seek the waiver on the basis that it may take longer under unknown rules to obtain a waiver than it takes to get a license under known rules.

So I encourage you to analyze your client's proposal. I think we need to get started right now to get those state statutes amended and put into shape. People who have good low-head hydro sites or hydro sites of any kind need to know what the rules are so they don't have to give away the house to build the garage.

I really think that in this endeavor we need more flexible state laws. A conservator of water should be able to benefit. For example, if a utility were willing to come into your irrigation system and line ten miles of canal in an area where you may seep away 100,000 acre feet a year, perhaps the company that has the canal lined can work out an arrangement where that water goes to the fellow who is willing to pay for its conservation. In Idaho, if a canal company were to line a canal to save the water, it can't use it beyond its needs for beneficial use. Consequently it goes back to the river, to the next senior appropriator. It is really folly to spend money to save or conserve water in Idaho. Some of these things have to be dealt with in local legislatures. I suspect the best way that we could possibly get the federal machinery to help us promote hydro projects would be if Oregon has a little difficulty selling their water bonds and we get Congressman-Chairman Al Ullman of the Ways and Means Committee interested.

Mr. Rosholt supplemented his talk with the following outline.

A checklist of necessary permissions (not exclusive)

A. Federal requirements and considerations.

1. You can determine whether or not F.E.R.C. has jurisdiction by filing a "declaration of intention". (Not required.) (Federal Power Act §23(b) Part 24 of F.E.R.C. Regs.) (See Sierra Pacific Power Company — the Pyramid Lake Paiute Tribe of Indians, F.E.R.C. Docket No. E-9530 discussing the jurisdictional issue in depth.)
2. You can file an application for preliminary permit with exhibits with F.E.R.C. (Not required.) (Approval would reserve a site for up to 3 years). (See 16 U.S.C.A. §798) (§5 of Federal Power Act.).
3. If F.E.R.C. has jurisdiction, you must file a formal application for F.E.R.C. license (16 U.S.C. 799, Federal Power Act §6).
   a. If proposed project is over 1500 kilowatts, 2-year maximum for issuance of license if negative environmental report and no formal hearing required.
   b. F.E.R.C. determines if formal environmental impact statement is required.
   c. Possible interventions may delay the issuance of permit while costs escalate, resulting in a non-feasible project.
   d. F.E.R.C. may require "head payments" for powerplants located at "government dams". Also may require payments to Indians for use of their property. (See 16 U.S.C. 803, Federal Power Act §10).
4. Section 401 Water Quality Certification from EPA and state agency is a requirement of licensing. (Public Law 92-500 — Federal Water Pollution Control Act, 86 Stat. 816).
5. Section 404 Dredge and Fill Permit from Corps of Engineers is probably required. (Public Law 92-500, Federal Water Pollution Control Act, 86 Stat. 816, amended in 1977, §67 of H.R. 3199 entitled "Clean Water Act of 1977".) See discussion of amended §404 at page 100 of U.S. House of Representatives Committee Report No. 95-830).
6. Section 402 NPDES Discharge Permit for point discharge may be required pursuant to Public Law 92-500, (86 Stat. 816).
7. Ramifications of a historic site if one exists (Historic Preservation Act, 89-665).
8. Ramifications of Wild and Scenic Rivers Act (Public Law 88-577. May be a problem if the potential site located in area under study for wild or scenic classification).
9. Federal Land Policy and Management Act — 1976 (Public Law 94-578).
10. Endangered Species Act — (Public Law 89-665).

B. State requirements and considerations.

1. A state water right permit application in Idaho is required. (See Idaho Code §42-202, §42-205, to §42-209.) Most states would also require consideration of application by State Water Board to determine if proposal complies with the State Water Plan.

2. Stream alteration permit (Idaho Code §42-3801, et seq.) There is a question as to whether a water permit pre-empts need for stream alteration permit in Idaho if the diversion is for other than irrigation.

3. State owns the bed of navigable streams. There is a question as to whether another state agency permission is necessary to locate encroachments or obstructions in navigable waters in stream bed.

4. State Public Utilities Commission permission necessary to an application for certificate of public convenience and necessity.

5. Must comply with fish passageway requirements (Idaho Code §36-906).

6. Ramifications of minimum stream flow requirements.

7. Fish and wildlife mitigation considerations.

8. Possible recreational area considerations in conjunction with site.

9. Possible ramifications of state, county, or local governments, land use planning and zoning requirements. (See Idaho Code §67-6501, et seq.)

C. Considerations for entities not generally in power business.

1. If entity is a 26 U.S.C. 501(c) tax exempt entity, consider ramifications of loss of federal and state income tax exemption and the effect of income from power site being designated as "unrelated business income."

2. Most states exempt water conveyancing facilities from ad valorem tax. If any portion of facilities used for profit making purposes, all facilities lose tax exemption (Idaho Code §63-1051).

3. Kilowatt hour tax must be considered in determining feasibility of project. Idaho is one-half mil per kilowatt hour. (Idaho Code §63-2701.)

4. Possibility that State Public Utilities Commission will assert jurisdiction to set water rates as well as power rates if applicant (otherwise only an exempt water entity) becomes a "public utility" within state statutory definition upon construction of hydro-power facility. (See Idaho Code §61-119, Idaho Code §61-124, Idaho Code §61-125, and Idaho Code §61-129.)

5. Applicant may have land acquisition problems if applicant-entity does not have eminent domain powers. (See Idaho Constitution, Article 1, Sec. 14, compare with 16 U.S.C. §814, §21 of Federal Power Act. May be that obtaining FPC license may be the only way to acquire power of eminent domain even though F.E.R.C. license might not otherwise be required under Part 24 of Regs. of F.E.R.C.).

6. Other general considerations.
   a. Operation and maintenance costs.
   b. Insurance availability and cost.
   c. Proximity of site to transmission lines.
   d. Marketing considerations (whether power generated would be available at time of peak demand, or is less valuable).
   e. Ramifications of financing. (1) Will financial analysis pass requirements of an entity that will purchase and distribute the power, as well as the lendor. (2) Possible consideration of state constitutional debt limits if state is involved in guaranteeing debt as a "lending of state credit." (The Idaho Constitution Article 8, §§1-4).

Things that might be done to lessen institutional and legal constrictions and enhance opportunities to develop low-head hydro.

A. Congress could amend 26 U.S.C. 103(b) [formerly subparagraph (c)] of the Internal Revenue Code to allow tax exempt financing for smaller projects. (See Ways and Means Committee pending Bills H.R. 3757 — Congressman McFall, and H.R. 10239 — Congressman Burleson.)

B. Must amend the Federal Power Act to streamline licensing procedures for projects under 20,000 kw. (F.E.R.C. regulations are presently proposed under Docket No. RM78-9 for final adoption of proposed rulemaking for projects under 1,500 kw. These projects would be dams under 25 feet in height above the stream bed, reservoirs impounding less than 10 acres, and generation of less than 1,500 kw.

C. Support an amendment to the pending federal energy bill (part 6 of the proposed 1977 legislation) to encourage the development of the remaining hydro sites.

D. Need more flexible state laws so that those who would effect conservation measures of water at their own expense can use the water for hydro-electric use, or other purposes if no injury to others.

E. Some type of consolidation of permission process at the state level would be desirable so that all permissions for a hydro site might be obtained in one proceeding.

F. Support S. 2187 — (Metcalf), which would authorize powerplants at certain existing Bureau of Reclamation facilities.

G. Support F.E.R.C.'s attempt to eliminate need for "full blown" environmental impact statement for power projects on existing dams.

H. Need a compilation of sources from which money is available for the development of low-head hydro sites. (Bureau of Reclamation programs, Housing and Urban Development programs, and others that already exist.)

The Woodruff Narrows Example

by Daniel H. Hoggan and Robert B. Porter

The feasibility of developing hydropower generating facilities in many areas of the West will depend as much or more on legal and institutional factors as on engineering-economic considerations. A complex framework of laws, organizations, traditions, and so forth have evolved to cope with problems of conflict and competition among a wide range of water uses. This is particularly the case in large arid regions of the West where water is in short supply relative to demands. Superimposing the operation of a new hydropower facility on the established pattern of operations on a river system in most cases would impact a number of uses and administrative institutions.

Institutional problems need not necessarily obstruct development, but do require careful analysis and solutions. Design and operating alternatives for a proposed hydropower facility would need to be evaluated in terms of institutional conditions and constraints, and conversely, laws and institutions ought to be analyzed to determine if improvements might be made to accomodate proposed developments.

Legal and institutional considerations

The problems associated with small scale, low-head hydroelectric power development are similar to those of large scale developments; however, some unique aspects could be anticipated. The most significant legal and institutional questions relate to the following:

- Licenses and permits
- Water rights
- Existing treaties, compacts, contracts, and other agreements
- Insurance
- Safety regulations
- Environmental regulations
- Capital financing
- Operation and marketing arrangements

The nature and magnitude of the institutional problems would depend upon the developer, what type of facility is being developed, and where. Although some problems would be common for all developers and for all locations, others would not. The problems of capital financing and operation would not be the same for a state as for a private firm. Development on a small

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Robert B. Porter is an attorney engaged in private practice in Salt Lake City. He began private practice in Utah in 1933. From 1953 to 1960 he was an Assistant State Attorney General attached to the Utah Division of Natural Resources and the Utah State Engineer. He was with the Legal Department of Utah Power and Light Co. from 1960 until retirement in 1975, specializing in water and related matters.

Since 1970 he has been Utah's representative on the Resolutions Committee of the National Water Resources Association. He has been a member of the Resolutions Committee of the Colorado River Water Users Association since 1964, and the committee's chairman since 1972.

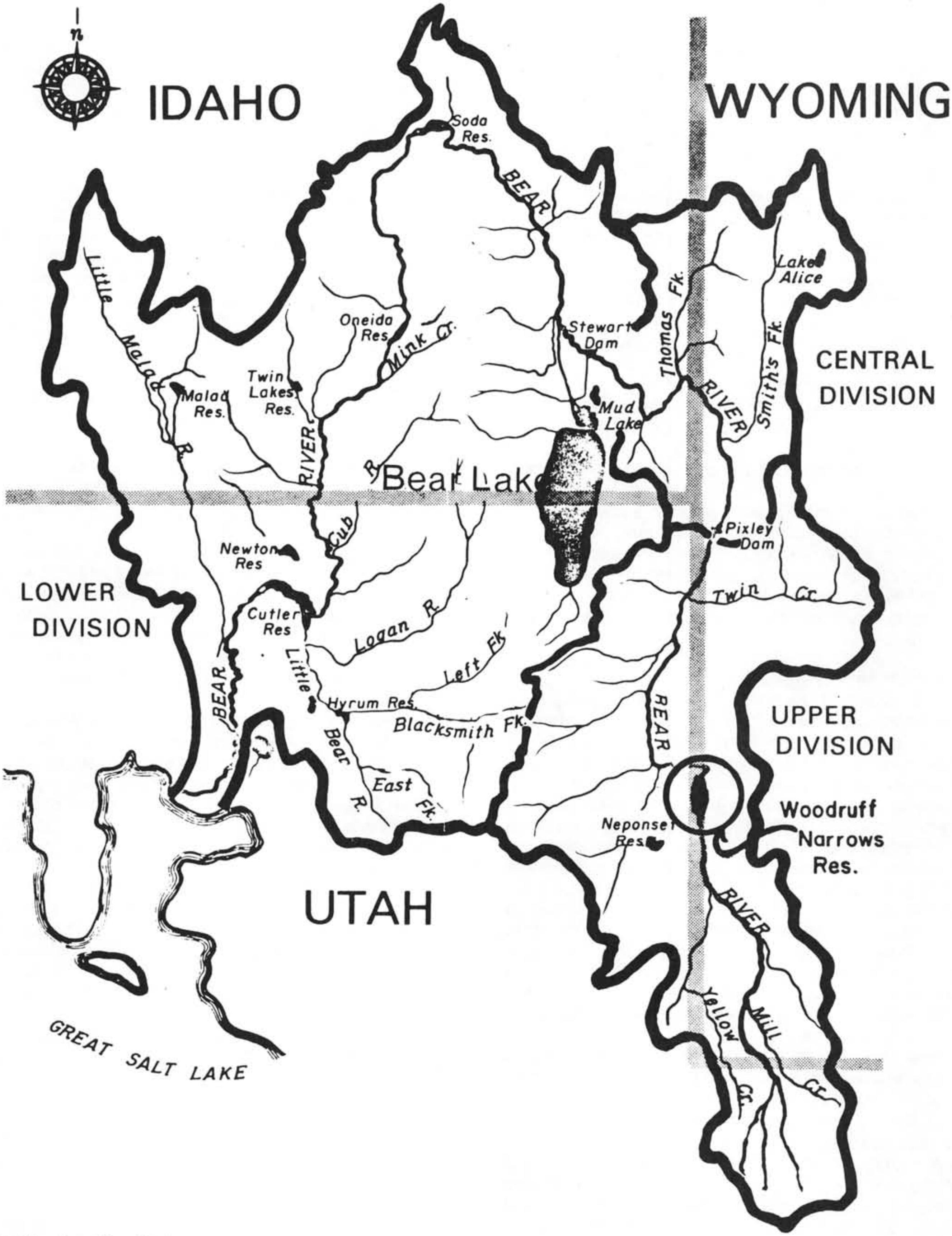

Figure 64. Bear River Basin.

Map courtesy of Bear River Commission

intrastate stream would not be affected by as many administrative agencies, agreements, and regulations as development on a large interstate water course. A run-of-the-river facility would not affect existing uses as much as a storage facility. Installing power generating capability in an existing dam would have less environmental impact than a new power dam. And a plant designed for peaking power would have different effects than one designed to provide for base load. As the Corps of Engineers (1977) noted:

> Each class of potential hydropower developer operates within a particular set of institutional constraints imposed by (1) regulatory agencies at all levels of government; (2) riparian or appropriation water laws; (3) individual, community, or corporate goals, values beliefs, mores, and customs; (4) existing treaties, state constitutions, local charters, ordinances, and municipal by-laws; (5) a unique economic and financial environment; and (6) conflicts between short-range and long-range organizational and individual objectives.

No attempt is made here to discuss all of the legal-institutional questions that could confront low-head hydro development wherever and however it might take place. As the title of this paper would suggest, a specific case will be examined with respect to a few significant legal and institutional aspects. It is hoped that such an examination will illuminate some of the types of problems that might be anticipated in the western United States. The engineering-economic aspects of the case, though important too, are beyond the scope of this discussion.

The Bear River setting

The Woodruff Narrows Dam has a particularly significant and interesting institutional setting because of its location on the Bear River, a stream which meanders through three states. The picture includes an interstate compact and compact commission; water planning and regulatory agencies of three different states; numerous local organizations—irrigation companies, municipalities, industries, and utilities; a downstream wildlife refuge; and numerous contracts and agreements concerning the allocation and storage of the water in the river. Although the problems discussed will be specific to this site, many aspects of the situation at the Woodruff Narrows Dam—the appropriative water rights system, the array of local user organizations, legal agreements, regulatory agencies, and so forth—are similar to conditions elsewhere in the Intermountain West.

Bear River has its source in the Uinta Mountains of eastern Utah. It flows north into southwestern Wyoming past the city of Evanston, then back into northeastern Utah for a short distance. It re-enters Wyoming and then turns abruptly west near the community of Cokeville and enters Idaho. It continues northwest past the cities of Montpelier and Soda Springs, then turns south and flows through Gentile Valley and Oneida Canyon and into Cache Valley in southern Idaho and northern Utah. The river continues south through Bear River Canyon, past Brigham City and empties into the Great Salt Lake near the Bear River Bird Refuge. The Bear River is the largest tributary to the Great Salt Lake and the largest river in the North American Continent that does not reach the ocean.

There are many small tributary streams along its length but the larger ones are Yellow Creek, Twin Creek, and Smiths Fork in Wyoming; Thomas Fork, Soda Creek, and Mink Creek in Idaho; and Cub River, Logan River, and Malad River in Utah. Bear Lake, straddling the Utah-Idaho state line, once had a natural outlet to the river but this was changed to make the lake a storage reservoir for spring runoff. Bear River water now is diverted to Bear Lake through the Rainbow Inlet Canal and water from the lake is returned to the river through the Outlet Canal. Releases to the river are made through Utah Power and Light Company's Lifton pumping plant at the north end of the lake.

Tri-state compact

Water uses are primarily agricultural, although Utah Power and Light Company maintains five power plants with a total generating capacity of 125.5 Mw on the river below Bear Lake. Three of the five power plants have small regulating pools for peaking purposes. There are several small storage reservoirs above Bear Lake but these are used only for local needs. The two relatively large reservoirs on the river are Woodruff Narrows, with a capacity of 28,000 acre feet, and Bear Lake with an active storage capacity in excess of one million acre feet. Uses, other than for agriculture and power, remain minimal, although demands for fish and wildlife and by home owners and recreationists on Bear Lake are increasing.

Bear River is considered to be fully appropriated above Bear Lake if the power requirements are accorded full recognition, but some additional storage could be developed with power company cooperation. Utah Power and Light company holds all of the flow rights into Bear Lake and has made numerous division and pumping contracts with irrigators and other users downstream.

A tri-state compact between Idaho, Utah, and Wyoming was negotiated during the middle 1950s and has been in operation since that time. The compact provides for apportionment of direct flows of the Bear River and its tributaries among separate sections of the states above Bear Lake, as well as establishing and limiting additional storage rights above Bear Lake. It reserves a portion of the storage capacity in Bear Lake for primary use by, and protection of, irrigation uses and rights downstream from Bear Lake, and provides that water delivery between Idaho and Utah will be based on priority of rights without regard to state boundary lines.

Negotiations have been underway for some time to alter the compact. The present compact does not divide either the direct flow or storable water between Idaho and Utah below Bear Lake, and it is considered unlikely that a major water development project could be constructed without allocating this water. Furthermore, residents above Bear Lake in all three states believe more water should be allocated for uses in their areas. Hydrologic studies show that some additional water could be allocated above Bear Lake without affecting downstream irrigation rights.

The Woodruff Narrows Dam

Woodruff Narrows Dam and Reservoir is located on the mainstem of Bear River in Wyoming a short distance east of Woodruff, Utah. The lands inundated by the reservoir are all in Wyoming. The dam, which does not now have a power plant, was constructed in 1961 by the Utah Board of Water Resources to furnish irrigation water to farmers in the vicinity of Woodruff and Randolph in Utah and to Wyoming users in the Cokeville area. The dam is constructed of homogeneous compacted earth fill and rises 58 feet above the streambed. The hydraulic head from the spillway crest to normal tail water level is 32 feet. The crest length is 600 feet and crest width is 20 feet.

The dam was constructed under a license issued by the Wyoming State engineer, and water for storage comes from an allocation to Utah and Wyoming under the Bear River Compact and from a contract with Utah Power and Light Company. The Utah Fish and Game Department provided part of the construction funds in return for an agreement providing minimum water releases from the reservoir, and the Wyoming Fish and Game Department provided funds in return for maintenance of a dead pool in the reservoir as a fishery resource. The storage capacity in the reservoir is allocated as follows:

18,240	acre-feet irrigation storage
4,250	acre-feet irrigation hold-over
4,000	acre-feet fishery storage
1,500	acre-feet dead storage
28,000	acre-feet total

The irrigation storage is divided with 15,240 acre-feet to the Utah Woodruff Narrows Reservoir Company and 3,000 acre-feet to the Wyoming Woodruff Narrows Reservoir Company.

Although the institutional structure on the Bear River is complex, the installation of a power plant in the existing Woodruff Narrows Dam could be accomplished with minimal institutional constraints if the pattern of flows to existing uses is maintained. Currently, the pattern of operation is to fill the reservoir to capacity with spring runoff and then release the irrigation storage at a relatively constant rate until it is expended, usually in mid-July. To avoid disturbing existing uses while obtaining maximum power generating efficiency (peaking), it would be necessary to utilize a regulating pool below the dam to smooth out the 6-hour peaking flow over a 24-hour period.

Several alternative dam configurations, all incorporating a downstream regulating pool, might be considered in developing the power potential:

1. No modification to the existing dam height and storage capacity.
2. Enlargement of the dam solely for the purpose of increasing power generating head.
3. Enlargement of the dam for multiple uses including power.
4. Connection of the tailwater regulating pool with the reservoir in a pumped storage arrangement.
5. Construction of a pipeline a short distance down the canyon to a generating plant, doubling or substantially increasing the power head.
6. Construction of tailwater canal to a second power plant below the dam.

Alternatives 4, 5, and 6 could be incorporated with or without the enlargement.

These alternatives would have different legal-institutional implications: Alternative 1 would require, at a minimum, licensing by the Federal Energy Regulatory Commission and a change in use permit from the Wyoming State Engineer. This, of course, is assuming that releases to current uses are maintained. Alternative 2, though consisting of an elargement of the storage capacity, would have no more institutional constraints than alternative 1, except for the requirement to secure a permit from Wyoming to make the enlargement. The Bear River Compact provides for an annual allocation to storage. If an additional amount of water were held over each year rather than being released, an enlargement would fill in a few years' time. After filling, the reservoir could be operated the same as the existing reservoir but have a higher power head.

Although enlargement of the dam and reservoir for multiple uses under alternative 3 would provide additional benefits to the users currently served by the dam, it also would increase depletions of the water supply and have greater institutional implications. The allocation of additional storage would require a change in the interstate compact or conversions of existing flow rights (irrigation, power, etc.) to storage. In either case, all three states would be affected. Utah and Wyoming would be concerned with transfers of irrigation direct flow rights to storage rights, and Idaho with what additional flow rights into Bear Lake Utah Power and Light Company might agree to transfer for storage, thus possibly affecting downstream Idaho users.

These conditions are not merely speculations. The Utah Division of Water Resources already has designed an enlargement to increase the present storage capacity of the dam and reservoir to 53,200 acre-feet, and it is evident that the problems just outlined are real. The enlargement was designed for irrigation storage, but essentially the same conditions would prevail if a power generating component were included.

The state as a developer

The fact that a state agency would be the developer and possibly the operator of the power facility, if one should be built at the Woodruff Narrows Dam, poses some interesting legal and institutional questions.

Figure 65. Bear Lake (Photograpn courtesy of the Utah Division of Water Resources)

Presumably, licensing requirements imposed by federal and state energy regulatory commissions would not present any peculiar problems to the state. It would face the same requirements as a private developer. Nor would safety regulations. Ordinarily, the state contracts with a water users organization to construct a dam. The water user organization in turn subcontracts the construction to a private firm under bond, and government safety regulations apply.

The lack of availability of dam owner/operators liability insurance confronts the state much the same as it does private companies. According to a study by the Johns Hopkins University Applied Physics Laboratory (1977), the unavailability of dam liability insurance is a significant problem to small dam site developers. Dam liability insurance deals with a special type of risk, and each dam site has unique underwriting considerations. Insurability of each site depends upon the upstream hazard in terms of flood potential, the physical condition of the dam, and the downstream damage potential of the volume of water impounded by the dam.

During the past 30 years that the Utah Board of Water Resources has been building dams, it has not carried dam liability insurance. According to a state agency official, some casual inquiries have been made, but it was found that insurance was either unavailable or at least unavailable at a reasonable rate. Since the state lost its status of sovereign immunity several years ago, it has been vulnerable to damage claims. Consequently, in the early 1960s the state on one occasion paid off on such claims. The Little Deer Creek Dam failed, causing significant damage downstream and taking the life of a young child. The state paid the claims which resulted from the incident.

If development of a dam is accomplished without federal money and does not involve federal land, the state can disregard certain environmental regulations, such as the requirement for an environmental impact statement. However, in the case of the Woodruff Narrows Dam a regulating pond may be required downstream if a power plant is added. In this case, federal land controlled by the Bureau of Land Management would probably be involved and if so an evironmental impact statement would be required.

Capital financing by the State of Utah has some interesting aspects that would apply to the prospective development. Utah, like many other states, has not used long term debt for financing water development. However, this year the state passed a bonding bill that authorizes the issuance of $25 million in general obligation bonds to be used for this purpose.

There are a number of interesting features to the financing program established by this legislation, but only one legal question that has been raised regarding the bill will be discussed here. It pertains to a constitutional limitation that prohibits the state from using its credit for projects that are not clearly for the public benefit. This question is raised with respect to projects that provide water for hydropower production, cooling water supply, and other private and industrial uses. Utah is not the only state that has this constraint. It is estimated that more than half of the states have such a limitation.

Although the final answer to this question may have to come from a court test, the key to the solution in Utah might be found under Title 73 of the Utah Code. In Chapter 1, water is held to be the property of the state and beneficial use the measure of the right granted by the state. Furthermore, Section 73-1-5 provides that "the use of water for beneficial purposes as provided in this title is hereby declared to be a public use," and the court cases cited under this section indicate that private water condemnation action, which is ordinarily limited to public entities, may be exercised by a private firm to construct a water distribution system.

The construction and operation of the power facility in a state-owned dam could be contracted to a power utility or it could be handled by the state itself. The State of Utah has not been involved in power production, but there appears to be no legal constraints to such involvement. The entry of a state into the power market would likely have greater political than legal implications. The water development bonding bill recently passed of the dam projects included. This provision resulted from political action by power company interests.

Conclusions

In spite of the relatively complex institutional setting associated with the Woodruff Narrows Dam operation, the addition of a power generating plant would appear to have minor legal and institutional implications if the pattern of releases to existing uses is maintained. This would be so whether the dam and reservoir were kept at its present size or enlarged solely to provide a higher power head.

Enlargement of the dam to provide for expanded multiple uses resulting in increased depletions of water supply would be quite a different story. This type of development on a river such as the Bear River would require interstate compact changes, water rights transfers, and federal, state, and local agency approvals.

The entry of states into hydropower development does not appear to have insurmountable legal obstacles if Utah's situation is representative. Long term borrowing restrictions may have to be overcome in some states.

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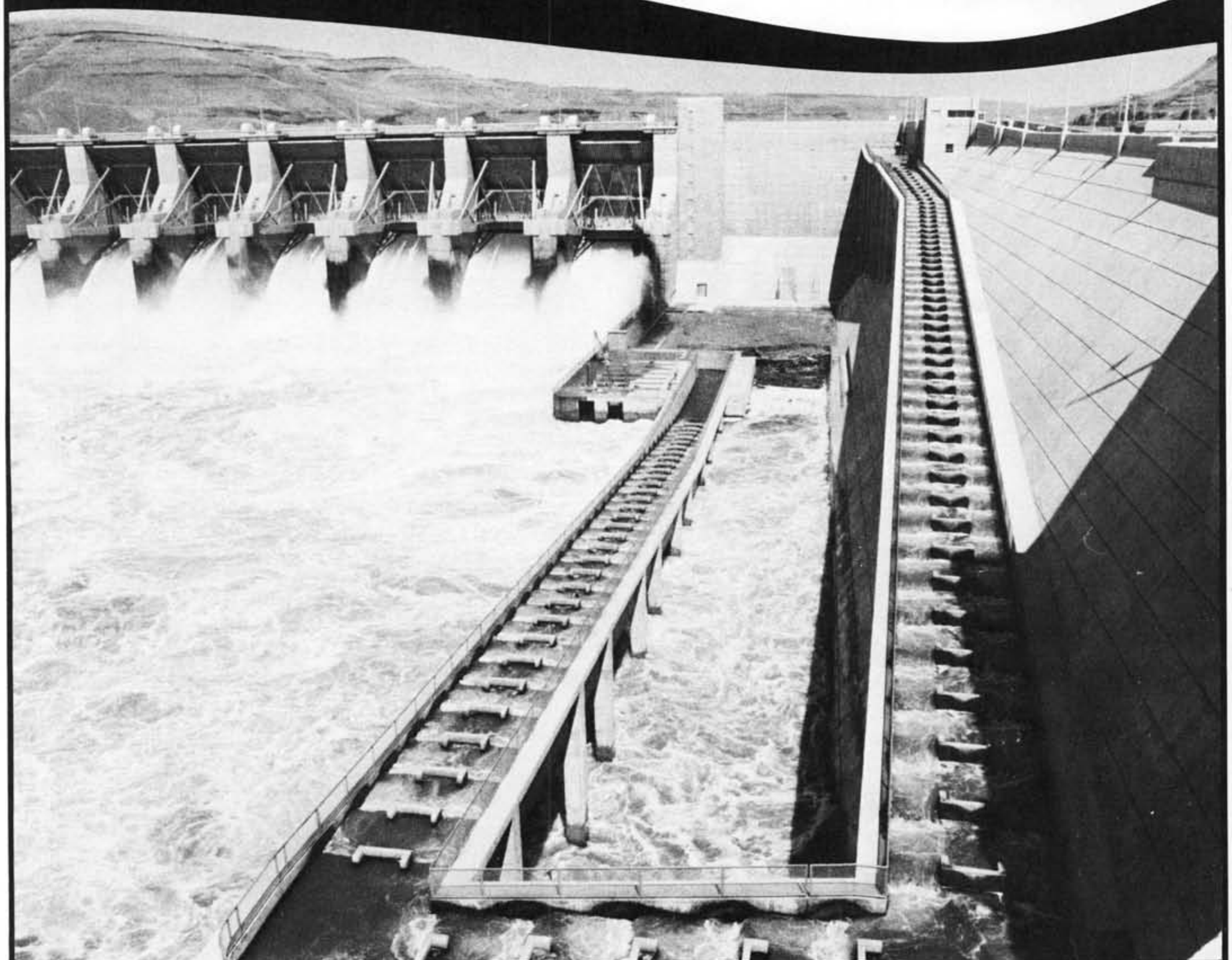
The Environment



Idaho Department of Fish and Game photo

This fish ladder is installed at Lower Monumental Dam, a large dam on the lower Snake River in Washington. Fish ladders are often practical to install at low-head dams.

Environmental and Aesthetic Aspects of Low-Head Dams

by John R. Woodworth

I haven't found too much on the environmental aspects of low-head dams and bulb turbines. From literature I have reviewed, it would seem that low-head dams and bulb or tube turbines will be a strong part of our future power production in the United States.

It would appear on the surface, at least, that the bulb turbines will be less environmentally destructive to aquatic life, general environment and aesthetic factors than our traditional high-head dams and vertical generating units. Indications are that the bulb turbines are more efficient, which would cause less fish loss. Cavitation is rather low and the fluid shear is reduced because of the straight-through flow. Smolts or young salmon or steelhead are inclined to hug the ceiling and will pass by the tip of the runner blades.

However, when low head projects are proposed, provision for fish passage facilities should be included in all installation designs. This would permit future passage of resident fish and also possible future introduction of anadromous fish. Such passage facilities should be operated only at known times of game fish migration since they could allow movements of undesirable or trash fish which may have been previously blocked from entering upstream areas by small waterfalls in the stream system.

In view of the number of low-head dams which could be developed, transmission lines may be one of the major concerns regarding the environment. Power poles carrying transmission lines should be designed to protect raptors. Designs have been developed by Morlan Nelson, world authority on raptors, working with the Idaho Power Company in Boise, Idaho. New powerlines, when possible, should be tied in with existing lines or those being planned for other transmission purposes. This point was brought out clearly in the Environmental Impact Statement on the Solomon Gulch Project near Valdez, Alaska.

No-dam power

No-dam power production is described by George S. Erskine in Environment Magazine, March 1978. He states that with sufficient year-round stream pressure and volume an entire underwater generating system can be placed directly in the river and electric cables carrying the power to the transmission system could be buried. This type of installation is technically feasible; however, it would probably be very costly. The cost and

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Mr. Woodworth received a B.S. in Fish and Game Management from Oregon State University in 1947 and an M.S. in Zoology from the University of Hawaii in 1952.

effort may be worthwhile if an attractive stream with the potential of producing the power flows through an esthetically sensitive area. The installation should be buried and sufficient water left running through the system to still have an attractive stream.

A more practical and probably less expensive possibility would be to put penstocks across S-curves or oxbows in certain stream systems (again described by Erskine). If the places are chosen properly, sufficient head could be obtained to make this feasible. Furthermore, the oxbows could be cut off by pervious dikes just below the inlet and just above the generating plant across the curve and that portion of the river could be managed for a specific fishery (Figure 66). Often, a river system is so polluted or inhabited by so many trash fish that management is impossible for desirable fishes such as bass, trout, crappie, or other so-called game fish. By isolating the oxbows with pervious dikes, and allowing enough water to go through them to maintain a substantially stable water body, a fisheries management agency could treat the water in the oxbow to eliminate trash fish and introduce desirable fish populations.

Worked well

This approach has been done very successfully on arms of major reservoirs. It also has worked very well in seep lakes that have formed on irrigation projects. The Columbia Basin Project in eastern Washington has numerous seep lakes which are connected by small waterways. Diking these with pervious material allows the water to seep to the level of the main body of water. Then the fisheries management agency can chemically treat the water to eliminate the undesirable fish and introduce the desired species for good fishing.

This activity is also effective in aiding waterfowl production by getting rid of carp, for example, which are detrimental to waterfowl production.

It would appear that powerplants in large canals, particularly those with drops, would have considerable potential. However, it should be noted that many of these canals transport highly desirable fish from one lake body to another, such as from Banks Lake at Grand Coulee Dam in northcentral Washington down to Billy Clapp Lake through the Bacon Siphon. If bulb-type turbines were put in the water conveyance system, it would be highly desirable to put in bypass provisions to move the fish around the turbines, rather than through them. The possibility of meeting irrigation energy demands within the distribution system could potentially provide a significant energy savings in irrigated agriculture areas.

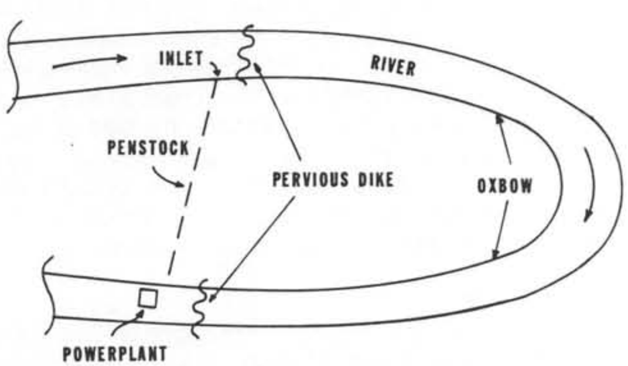

Figure 66. It may be possible to place penstocks across oxbows in certain stream systems if sufficient head could be obtained. Also, oxbows could be isolated by previous dikes below the inlet and above the powerplant to allow special treatment and management of a fishery in the oxbow area.

Refurbishing

There are other related actions that appear to be feasible and would probably have a minimum environmental effect. One would be the utilitization of existing dams where conventional hydroelectric systems were once installed and then abandoned because of low productivity and efficiency (Alaska, Idaho Falls, Barber Dam near Boise, Idaho, for example). Installing bulb turbines of a modern design in these old facilities might be feasible and since the dam and the lake are already there, new environmental degradation would be considerably reduced.

Basically, I think each proposal, no matter where it is or how high the dam, must be evaluated on its own merits. The environmental evaluation process should start at the very inception of the project. Persons or agencies promoting the projects should make an evaluation very early on in the program. This should begin with a short general description of the project and what the environmental impacts could be. Elaborate studies would not be needed at this stage.

The evaluation should then be circulated to agencies or groups that would be affected, to get an idea of how serious some of the potential impacts are. In some cases, this would be as far as it would have to go. In other cases, more detailed studies would be needed. A detailed assessment could be made that would determine whether or not a National Environmental Policy Act or some similar requirement would apply. If a full environmental process is indicated, the assessment could serve as the means or main source for the environmental impact statement.

Once again, I would like to emphasize that each project will have to be judged on its own merits. A substantially high-head dam might prove to be very beneficial and have a relatively low environmental impact. An example of such a project would be the USBR/Fish and Wildlife Service Bumping Lake proposal on the Yakima River system in Washington State. On the other hand a low-head dam or system of dams could possibly have very significant environmental impacts, particularly if used extensively as run-of-the-river plants with several low dams covering long stretches of a river system.

Only on a case-by-case basis can these environmental impacts be weighed and evaluated and a decision reached as to whether a power proposal should move forward.

Following his speech, Mr. Woodworth was asked the following questions.

Q: You suggested the 9 million salmon and steelhead, is this for the Yakima?

Woodworth: That would be the Yakima system alone. It would be an eight-year project to restore the fish and then they would be on their own and those hatcheries could be used to do the same thing in other streams.

Q: Are there currently areas above Priest Rapids that are being considered for salmon mitigation or salmon hatcheries, above Priest and Wanapum?

Woodworth: Yes, we have the Oroville-Tonasket project on the Similkameen River, which is a tributary of the Okanagon, where we will either remove or ladder an old dam and open up about, well, 60 miles in the U.S., I don't know how much in Canada, and we will introduce salmon and steelhead there. And we have been asked by the Columbia River Fisheries Council to look at four headwater sites on the entire Columbia and Snake Rivers for upstream storage for fish passage.

Q: This will be dedicated primarily to years like last year, low flow years and things of this type?

Woodworth: Right. These would be multi-purpose projects that would probably serve minimum flows, power, irrigation, and flood control, but the priority would be re-ordered, and fish would be number one on those built specifically for that purpose.

Q: Are there currently reports on these areas of investigation that are available?

Woodworth: The Columbia Fish Technical Committee is in the process of giving us a report asking us or directing us as to what to do. We have, as I mentioned, been asked to look at about 12 streams, two right here outside of Moscow. That wouldn't really help your situation, but the Palouse and the Potlatch are completely defished and they have the possibility of restoration right here.

Q: I think it would be well to explain the cost-sharing arrangement you have in the Northwest. I think you have a more realistic appraisal of the problems and ways to resolve the financing than most any of the other areas in the country, probably because of the greater economic value of the fisheries. And one of the big problems, particularly in the Northeast, in the rehabilitation is the high cost of fish bypass facilities in these low-head installations or rehabilitations. In many instances from an economic standpoint this makes them impossible to build. Would you comment on that please?

Woodworth: Yes, we here in the Northwest are blessed with these terrific river systems that have these extremely valuable fish, the anadromous fish; salmon and steelhead. These fish are caught throughout the Pacific, from Alaska down through Canada down to San Francisco, roughly, in the Pacific Ocean. And since you can't pinpoint where the economics ends up, it's costs reimbursed, or non-reimbursible costs for anadromous fish projects. So the government is picking up that cost because of the widespread values and the value of the fish is so high that you could build almost anything and get a good return on it. And they're re-doing the values all the time and they're coming up. I think when I started looking at this thing not too long ago, they were given $9 a day for fish and now some studies are indicating $75. And the reason we can do these projects here is because of the anadromous fish value.

Q: What about the sharing of funds between the federal government and the state government? Do you have any state participation?

Woodworth: On resident fish there's a bill, a law that gives cost-sharing at 3 to 1; 75% federal, 25% state, which makes resident fish projects feasible and possible. On recreation, it's 50-50, for recreation on lakes and stuff that would be for them.

Q: I would like to make a comment about dam vs. fish. There is no question in my mind a dam does hurt the fish. The higher the dam the more trouble for the anadramous fish. Now, however, this smaller dam does have less trouble because this fish has been jumping across a waterfall many centuries, who knows how many, so they are pretty good at it. And they can jump across a vertical fall 11 or 12 feet high. So, I think from fisheries point of view probably the definition of low-head should change to 3 meters. And this fishery is a major, important problem in this Northwest. Currently, I am working on a project to restore the stream gravel for fish spawning by removing the silt in the stream gravel. important problem in this Northwest.

Woodworth: I want to talk to you about that, because I know a guy that has invented a suction machine that is eight times more efficient than any one available now and it is ideal for cleaning spawning gravel.

Q: I'd like to reply to the gentleman who mentioned that the salmon jumped 10 feet over waterfalls. These are the athletes. So you will have to contact the state and federal agencies in regard to requirements for fish passage. I also wanted to mention that under the Mitchell Act our Columbia Program Office has removed a lot of low-head dams in their Stream Clearance Programs. I kind of hate to see some of these go back in. (Charles Wagner, National Marine Fisheries.)

Woodworth: Chuck is the engineer for National Marine Fisheries primarily with fish passage.

Q: My observations from the conference so far are that there are definite differences between the West and the East as far as hydro development. Back East, we're talking about very small developments and streams that are industrialized to some extent and have completely different conditions. For example, some of the environmental problems that we've run into include water quality from the standpoint of dispersion and assimilation of the wastes that are deposited into the streams. Dissolved oxygen is a problem in some of our streams, like the Hudson River. Because of industrial developments along the rivers we have a concern for migrating contaminated materials, things such as Mirex and PCB are common terms and concerns for our state environmental people and in general.

Well, these are some of the differences. We also are faced on some projects with our friends, the endangered species. So, some of these are common, but I think some are different because of the basic difference in the amount of water available, the type of stream, the development around the streams. We are basically an industrialized area, where you're more in an agricultural area here, which makes a big difference in our projects.

In regard to fish, I was interested in a clarification of the value placed on the fish because I am a promoter of the idea of some kind of sharing for the environmental benefits that may be derived, and I think that's the only way that we're going to be able to justify the development of low-head hydro because low-head hydro in itself is a very marginal cost-benefit relationship. So if we're going to need to satisfy the environmental aspects, the fisheries, and any other minimum downstream flows and those kind of things that are a detriment from a hydroelectric standpoint, we need to share the costs to keep the economics and the environment in balance.

Woodworth: Good comment, and I'm sure that conditions are different and that's why I said that you're going to have to take each one on its own. I'm sure you'll find a lot of projects back East that won't require any environmental consideration that amounts to anything.

Q: We will not develop in the Northwest this very promising new energy source area, low-head hydro, if we stick to the 3-meter-head concept as has been suggested. Maybe we will develop just if we have in the next 50 years. If we're going to have in the Northwest area, let's say, 100 low-head hydro that probably should be developed, among them the 3-meter-head ones, I would say economically, technically feasible that could be built wouldn't be more than 5%, sir. I'd like to suggest that.

Woodworth: Chances are a lot of these won't be on anadromous fish streams and migration problem won't be that great.

Let's Not Have Another Hells Canyon Impasse

By James A. Nee[1]

The previous paper by Mr. John Woodworth provided the basis from which the ideas in this paper were evolved. Mr. Woodworth's paper should be read before proceeding to this one.

For many years hydropower interests have wanted to build a series of high-head dams in the Hells Canyon portion of the Snake River Basin. Initially, there appeared to be strong public support for the proposals. However, as time passed the public sentiment indicated that the long term environmental costs of the dams would have exceeded the short term benefits. The result was Congressional establishment of the Hells Canyon Wild River and National Recreation Area.[2] It is doubtful that any dams will be built in Hells Canyon during the next few generations.

When the pros and cons of Hells Canyon high-head dams were being argued, a strong attitude of distrust developed between the preservationists[3] and conservationists on one side and the engineers on the other. The issue quickly polarized into preservation versus total development. In the end, the issue was decided on the basis of which of the two groups had the most political power in Congress.

The need for more electric power is self evident, even to many preservationists. What has yet to be decided is how much power, where and when. The development of low-head horizontal turbine hydropower in the United States will offer all of us an opportunity to reverse the Hells Canyon Syndrome and to create cooperation, trust and understanding among preservationists, conservationists and engineers. Since virtually nothing is known about the environmental effects of low-head horizontal hydropower developments, we could, theoretically, build mutual trust just by the opposing groups communicating more with one another. However, the Hells Canyon experience has put people on guard against their assumed opponents. Now it will take firm commitment and much hard work on both sides to create a middle ground. The stereotypes are just too firmly imbedded in people's minds for anything less to work.

Not "pie in the sky"

The need for mutual trust is especially vital with respect to low-head hydro development because of the narrow benefit-cost ratio of such projects. Environmental benefits could "make or break" many projects, so it may be wise for engineers to incorporate environmental features in the projects at the outset, instead of waiting for the FERC to require them.

If I had read this plea for trust five years ago, I would have dismissed it as "pie in the sky" stuff. Since then, I participated on an inter-agency team to help develop a

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He has a Bachelor's degree in Wildlife Management from Michigan State University, a Master's degree in Public Administration from Wayne State University, and a Master's degree in Zoology from the University of California, Berkeley.

water plan for the Snake River Basin in Idaho. When we started that effort a great deal of distrust existed between what we believed to be the representatives of the development agencies and the preservation agencies. After several meetings and informal gatherings we began to realize that none of us fit the stereotype of what we thought the opposition should be like. Soon developers and preservationists actually began to hear and understand what their supposed opponents were saying. After more dialog we realized that we all had far more in common than we could have previously imagined. We learned that all of us were conservationists to varying degrees. The realization of this simple truth was essential for effective comprehensive planning to occur.

Mr. Woodworth, in the previous paper, urged project sponsors to begin talking to environmental conservationists in the early stages of plan formulation. Such discussions are an esssential step to build trust between apparent adversaries. But additional measures are needed. The two groups must be brought together on neutral ground to confront issues. Our universities can play an important role by sponsoring workshops, group encounters, round-table discussions and other such dialog-type meetings for preservationists, conservationists and developers to attend.[4]

Perhaps these meetings could be jointly funded by the U.S. Department of Energy, several states agencies, environmental groups and private companies. However, a word of caution. Don't expect an immediate outpouring of the environmental constituency to these meetings. There is just too much distrust that has yet to be overcome.

As the country begins to develop its low-head horizontal turbine hydropower potential there is an opportunity to avoid a protracted conflict between historically polarized groups. But we have got to start talking and listening to each other for this to occur. Once we start, we will find that we have more in common that we suspected. This will lead to the gradual creation of mutual trust. As this trust builds, our opposing goals may remain unchanged, or we may find that we can modify our goals without significantly increasing project financial and environmental costs. In either case we will seek to achieve our individual goals in a cooperative atmosphere and at a more rapid rate than without mutual trust.

FOOTNOTES

1. The opinions expressed by Mr. Nee are his own and do not necessarily represent the views of the U. S. Fish and Wildlife Service.

2. See Ashworth, W. 1977. Hells Canyon: The deepest gorge on earth. Hawthorn Books, Inc.

3. In this paper I consider a "preservationist" to be one who will not tolerate any man-caused environmental change in the status quo. A "conservationist" will tolerate moderate man-caused environmental change, if the change will not significantly impair environmental quality.

4. A good discussion of dialogue enhancement can be found in French, W. L. and C. H. Bell, Jr. 1973. Organization Development: behavioral science interventions for organization improvement. Prentice-Hall. See especially chapters 9-14. Also useful is Blake, R. R., et al. 1964. Managing Inter-group Conflict in Industry. Gulf Publishing Co.

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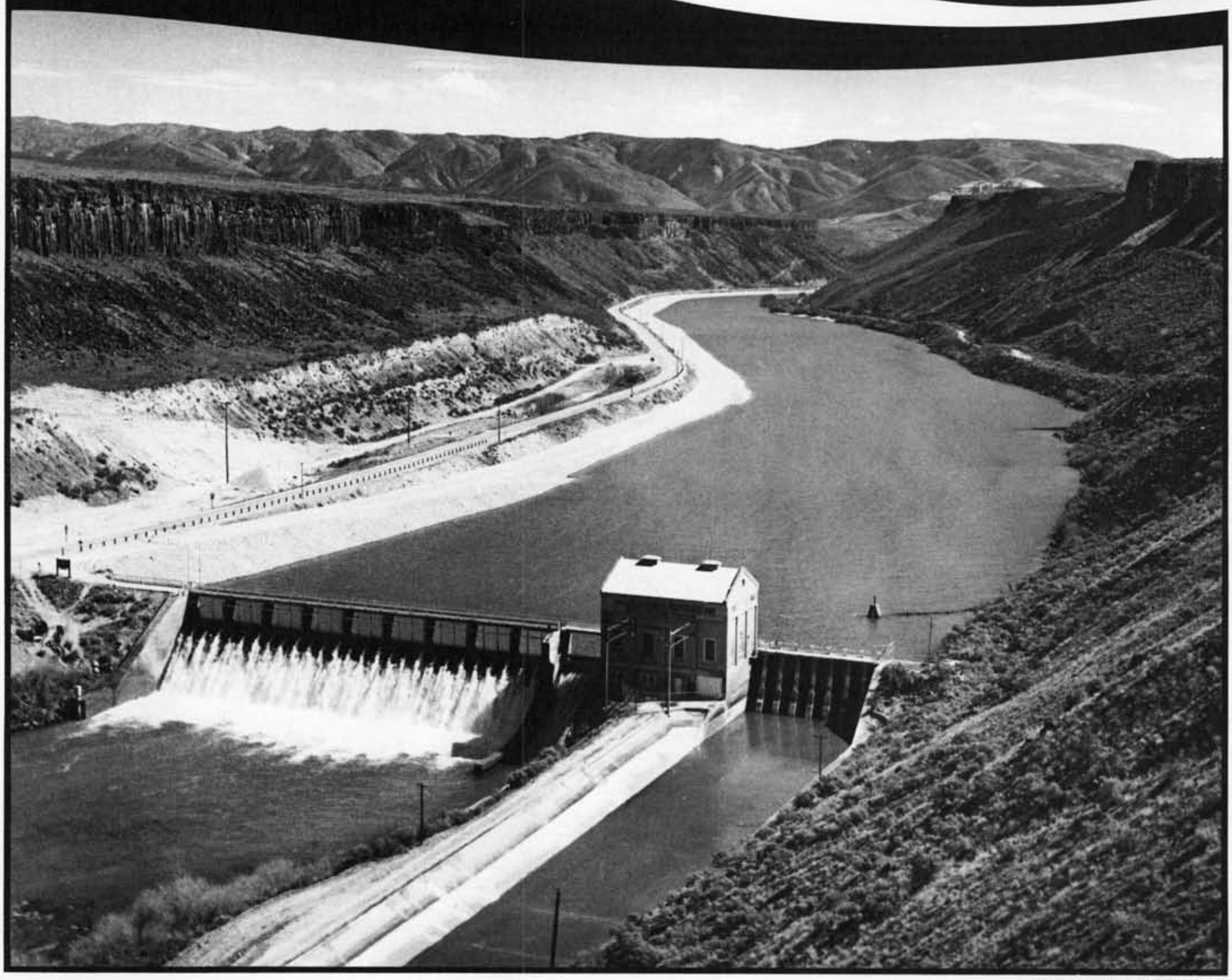
Surveys of Energy Potential



The Boise River Diversion Dam, near Boise, Idaho

Bureau of Reclamation photo

Introduction

by Peter C. Klingeman

The arrival of the industrial revolution in America encouraged the extensive development of small hydropower systems in the Eastern states. Industries flourished on streams with adequate flows and gradients. The ensuing westward movement carried small hydropower across the continent.

With the advent of large-dam technology in the 1900's, attention quickly shifted away from small-scale to large-scale hydropower generation. Extensive transmission grids carried electricity to distant and isolated users, freeing them from the necessity of locating along rivers for their power supplies.

Recent social, economic and environmental factors have led us to again consider the possibilities for small hydropower developments. For the most environmentally-oriented individuals, these might be envisioned as backyard systems capturing the energy of small creeks. For the more developmentally-oriented, small hydropower systems could even represent sizeable dams creating modest impoundments. For the majority, however, low-head run-of-river developments that could benefit small communities or industries are most likely to be envisioned.

During the present century, technological improvements in constructing dams and developing hydroelectric generating equipment have expanded the potential applications for low-head river development. This has awakened considerable interest in the possibilities for small hydropower systems to meet part of our energy needs.

This section reviews the "state of the art" regarding surveys to determine the energy potential for low-head hydropower. Three primary types of such surveys are described: (1) determination of the maximum energy potential of streams, based on hydrologic variables; (2) determination of the energy that might be developed at existing river structures, some of which may already have turbines installed; and (3) determination of the energy potential at sites that have been proposed for development but have not been built.

Peter C. Klingeman is the Director of the Water Resources Research Institute, Oregon State University.

Potential at Existing Impoundments

by David C. Willer

Today's new interest in small dam power generation is not a parochial subject stemming from a local problem here in Idaho. It is the direct result of international developments on the broadest economic scale. We are sitting here today because of problems which started in the oil fields of the Middle East and have been the subject of deepest concern in London, in Paris, in Washington, D.C., in Tokyo, and in Berlin.

The hard fact of life is - Middle East oil is costing us $15 a barrel.

When oil was $2.25 a barrel at the beginning of the 70's, low-head hydroelectric power was not the way to go. In comparison with the availability of cheap petroleum, the prospect of huge nuclear plants and the availability of major hydro generating sites, it didn't make much sense to look at the small plants. Today, petroleum is not cheap; environmental arguments have stymied many nuclear plants; and most of the good dam sites have been developed.

Today, one of the best ways the nation could help reduce the energy shortage is to build new small power plants at hundreds of existing dams. A great deal of water is flowing over existing dam spillways and through existing canals which could be put to work generating electricity. It could also solve some employment problems since nearly half the total construction cost of a small hydro project is paid out in wages.

We could never solve our total energy shortage with these small hydro projects. We need more massive projects. But many cities and public utilities could install some generating units at existing dams and produce energy at a fraction of the cost of the alternatives.

Look at the advantages. The natural resource is already there, flowing over or through an existing structure. It is a renewable resource. There is usually no environmental impact - no air pollution or water pollution. The process is clean and quiet, small scale and unobtrusive, and frequently takes place near a population center, eliminating the need for long or high voltage transmission lines.

Idaho is to be commended for re-opening this subject and bringing it to public attention, and I suspect that what some other speakers say here this week about small power plant development will be enlightening and encouraging.

Few dams used

What is our inventory of existing dams and impoundments where power facilities could conceivably be developed? A recent Corps of Engineers study has been an eye-opener. The Corps

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He graduated from the University of Iowa with a B.S. in Civil Engineering in 1952, and from the University of Southern California with an M.S. in Civil Engineering in 1958.

has found that we have 50,000 dams in this country, of which only 800 are currently being utilized to produce electric energy. Hundreds of these dams produced power at one time, but as the initial equipment wore out and alternative sources became cheaper, it was not economically feasible to refurbish them. The Corps of Engineers believes that if all of the dams which could produce power were reactivated, or if new generating capacity were installed, they could supply a total of 54,600 Mw and generate almost 160 billion kilowatt-hours.

It would take 265 million barrels of oil each year to generate that amount of power.

Idaho is not the only state which is awakening to the potential of small power plants. We recently completed a power potential study of 47 dams owned by the State of Montana, and one dam on the Missouri River alone could generate 80 million kilowatt-hours per year and serve a city of 25,000 inhabitants. Most of you will remember that New England small dams and power plants gave birth to early American industry. Correspondence we have had with New York State officials indicates they may have 1,000 small dams in that state alone.

Many possible sites

In the four states that Tudor has been retained to study projects for various clients in the last two years, we have found a potential of 155 Mw, representating 27 sites for hydro plants at existing dams all less than 15 Mw in size. The potential average annual generation of these projects is in excess of 800 million kilowatt-hours per year.

In short, there is no question but that hundreds of existing dams could be utilized to produce electric energy. We are entering a new and challenging era for water power.

One of the challenges involved is that of engineering. Tudor Engineering Company is involved in the engineering of a number of such projects, first of all determining the economic and engineering feasibility and then, if projects meet approval, going to design and manage procurement and construction of the installation.

The most fortunate aspect of hydroelectric power is that this kind of technology exists. It may take ten years or more to develop wind power, solar power, or thermal power, but the technology of generating hydroelectricity exists in highly sophisticated form. For low-head hydroelectric projects, generation can easily be achieved in 5 years' time from the date of conception.

The questions

Obviously only a portion of this nation's 50,000 existing impoundments can be developed for power generation. As engineers, some of the first questions we would ask are:

Is it economically feasible to build a power house at this particular site and to install generating capacity? Is the water supply sufficient? What payment for the power could be expected? What alternatives are available?

Could the source be developed to the point where it not only produces energy but is also dependable? Will it not only produce enough power to justify construction and equipment costs, but will it deliver it at the right time, and could it be delivered at reasonable cost to the right places?

Is it technically feasible? Could the existing plant be rebuilt or expanded under existing site conditions? Would a new plant constructed on the site be more cost effective? Is the existing dam in good enough shape to justify power plant construction? Are turbine and generating equipment available at reasonable cost and delivery schedule? What are the environmental impacts

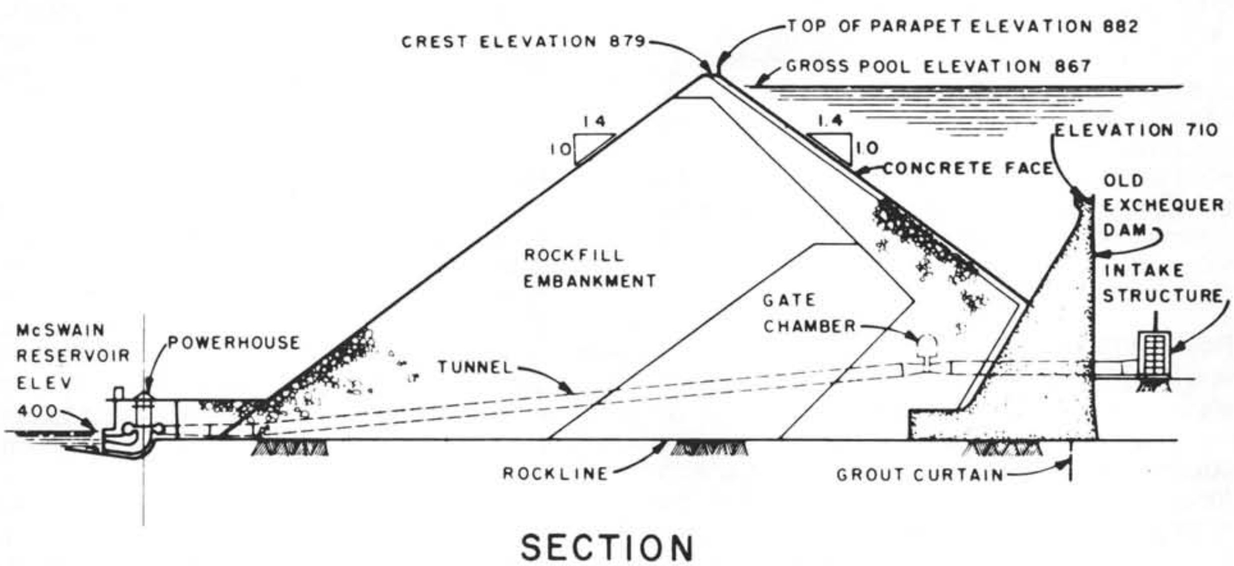


Figure 67. New Exchequer Dam - cross section.

of the proposed action?

These are hard questions that may indeed siphon the enthusiasm out of some projects. And I could think of another dozen questions you might want answers to before deciding that a particular project was both economically and technically feasible.

In spite of these hurdles, we believe hundreds of existing dams can be put to work for power production in the western states.

Examples

Let's get down to "real life". I'd like to relate some of our own company experiences in recent months, simply because these illustrate the problems encountered in small power plant engineering at existing impoundments.

Ten years ago, the Merced Irrigation District in central California reached the point of needing far more irrigation water. Tudor was given the task of investigating the length of the Merced River through that area for a potential site for a new dam or coming up with some scheme for enlarging an existing 310-foot-high concrete gravity dam. All of our studies indicated that the existing site was still the best available site on the stream.

It would have cost too much to demolish the old dam and build a completely new and larger structure. It was not structurally feasible to construct a concrete structure over the old one. We developed a design which incorporated the existing concrete gravity dam in the structure of a new rockfill dam. It certainly wouldn't have won any beauty contests, but it is now buried and out of sight under 180 feet of water (see Figure 67).

The power plant at Exchequer is producing 80 Mw of power so obviously it is not a small hydro project. But the integration of two such different dam structures into one integral structural design makes it a project of which we are particularly proud, as engineers.

We currently have over two dozen small hydroelectric projects in progress - ranging in capacity from 1 to 15 Mw - at existing dams or canal drop structures where energy is presently being wasted. We have also received funds from the Department of Energy's Low-Head Hydro Program for investigation of five other projects in Washington, Idaho and Montana.

In each small hydro case the engineering involved is different, as might be expected. Even on small jobs like these, some kind of team effort is required among the engineers, financial consultants, attorneys and environmental consultants.

The Rollins Project

One of our projects now under construction is an 11 Mw plant at Rollins Dam in Northern California for Nevada irrigation District (see Figure 68). I will describe the economics of these projects in the panel discussion, and today would just like to describe some of the engineering technology involved.

At Rollins we had a 240-foot-high earthfill dam and potential for developing a 225-foot head for a power

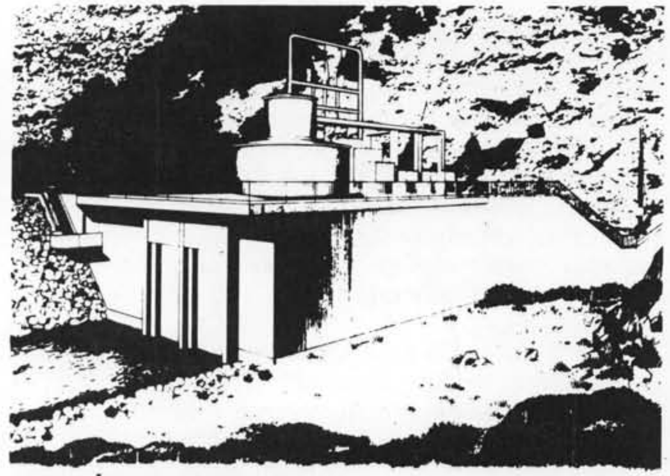


Figure 68. Rollins power plant.

plant. In the original dam construction, the contractor had driven a 21-foot-diameter diversion tunnel which was subsequently plugged with a 50-foot plug of concrete when its original purposes had been served. We determined that this tunnel could serve appropriately for an 8½-foot-diameter penstock needed to carry water to the proposed power plant, and we sited the plant accordingly (see Figure 69).

Blasting through the plug was a bit tricky, because we had to avoid damage to the dam. But it was accomplished by some tight specifications on the contractor's blasting operation, which we monitored with shock wave instrumentation to insure compliance.

Penetrating this plug into the reservoir seemed a major problem since there was no upstream control gate to shut off the flow of water into the tunnel. We drafted plans for forming an ice plug at the upstream end of the plug and excavating through the concrete plug from the dry downstream side. We also considered utilizing a steel bulkhead and low-strength concrete plug to form a barrier and after excavation for the penstock to employ divers to remove the bulkhead. Fortunately for this project, but unfortunately for many, the record California drought took the water level to the bottom of the reservoir so the the contractor was able to excavate the penstock bore completely in the dry last summer.

Re-use equipment

Another interesting aspect at Rollins was the acquisition of the turbine-generator. We located a 1927 turbine and generator at the abandoned Melones power plant in central California which Pacific Gas and Electric Company relinquished to the district for salvage value. Even though it is more than 50 years old, it is physically and mechnaically sound enough to merely refurbish the equipment and we expect it to serve at least another 50 years. We have even found a supply of unused spare parts in storage - wicket gates, seal rings, windings, bearings and an exciter. And we found we could use the two 102-inch butterfly valves from the old Melones penstock for a guard valve and for the turbine shut-off valve.

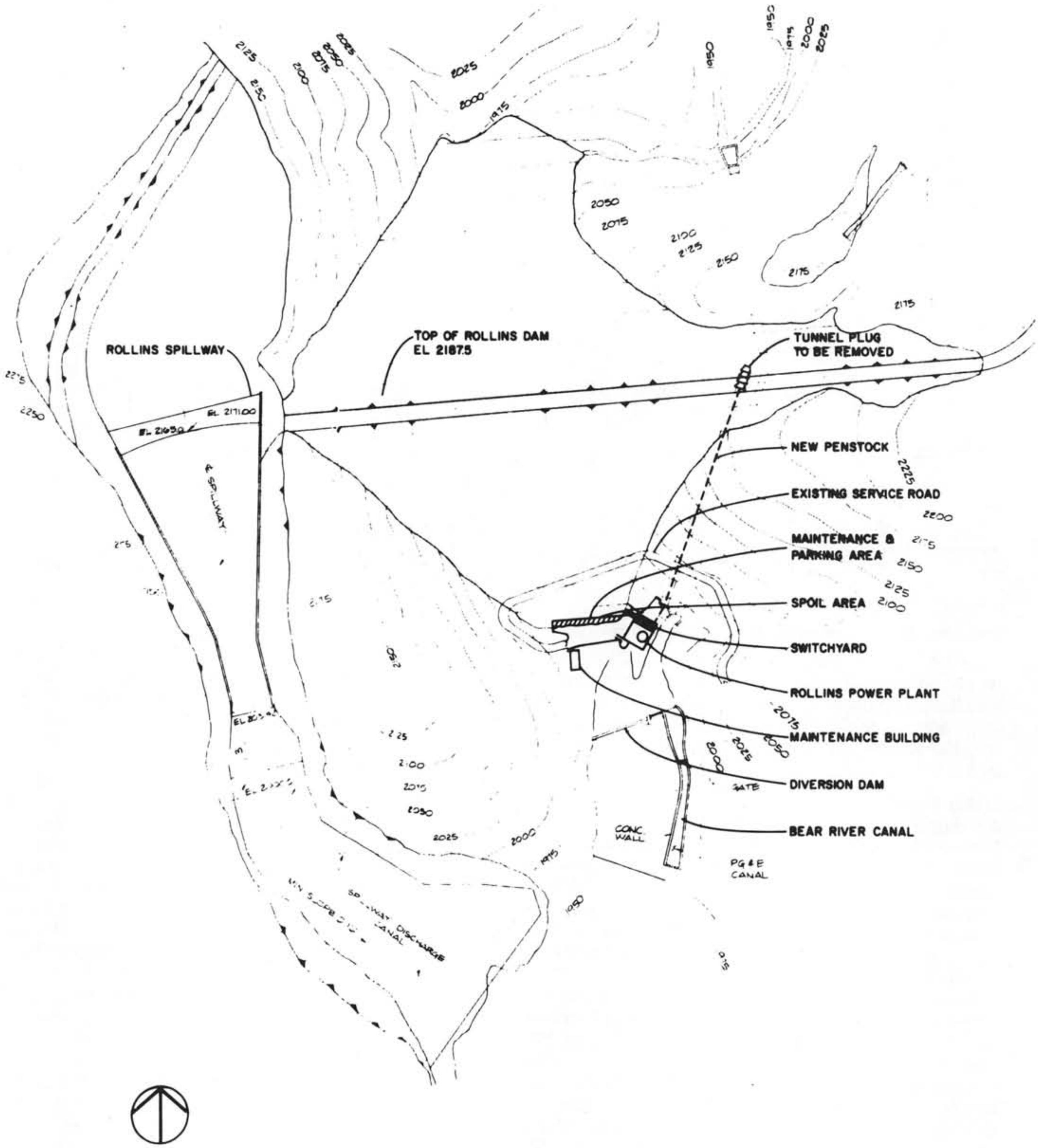


Figure 69. Rollins power project - plan view.

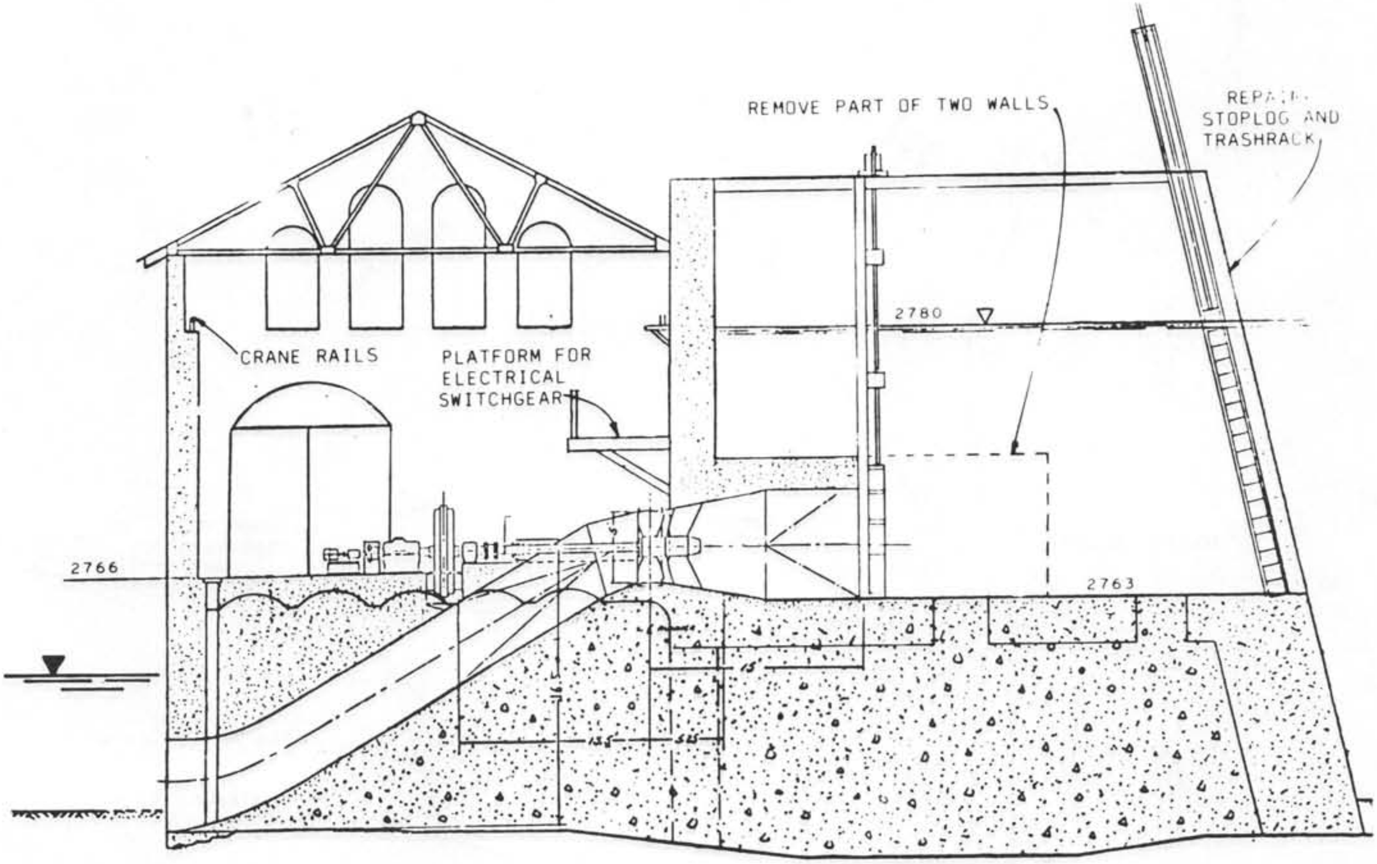


Figure 70. Barber Dam power plant - cross section.

Altogether, we calculate that the purchase and rebuilding of existing equipment was done for $1 million less than the cost of procurement of a completed new unit, and possibly more importantly, use of the refurbished equipment reduced the time of construction by six to nine months.

Other Projects

Another interesting project, here in Idaho: the Barber Dam, a timber crib structure about 25 feet in height, and power plant on the Boise River six miles upstream from Boise was abandoned some years ago and is in a delapidated condition. It was necessary to stabilize the structure this spring to prevent dam failure. It is a typically obsolete, abandoned project, built early in the 1900's.

Nevertheless, this facility can be rebuilt and put into service to utilize the energy potential of over 1 million acre-feet of water flowing past the dam each year. We are recommending installation of three 1,430 horsepower horizontal shafts, adjustable blade tube turbines and generators. These units could be fitted into the bays of the old power plant with little structural alterations (see Figure 70). The cost would be about $3 million dollars or more, but the plant would add 3,200 kw and 15 million kilowatt-hours for power use within the state.

Another California Project: Box Canyon Dam was constructed in 1967 to form a recreational lake near Mount Shasta. We have begun to design a 4,000 kw power plant for this facility which will cost about $3 million. The existing outlet pipe through the dam can be employed as the penstock and the main outlet valve, a 60-inch energy dissipation valve, can be relocated downstream.

The most interesting innovation here, we feel, is the plan to tuck the power plant under an extension of the spillway apron. It can be installed there most economically and will create the least adverse visual and environmental impact there, also (see Figure 71).

In the category of low-head hydroelectric plants, there are many opportunities to develop power in our western irrigation canals. An example of power plants on a main supply canal is Turlock Irrigation District's Drop 1 and Drop 9 power plants for which we have recently completed the civil and mechanical design. The two power plants, which are inserted into existing canal drop structures, develop 27 and 17 feet of fall and have a generating capacity of 3,000 and 1,100 kw respectively. The turbines furnished by Leffel Company are open flume type and the synchronous generators furnished by General Electric Company are the same as their synchronous motors (see Figure 72).

Challenge tradition

For power plants of this size, engineers must again look at and challenge traditional design solutions. Without the need for 100 percent reliability, some

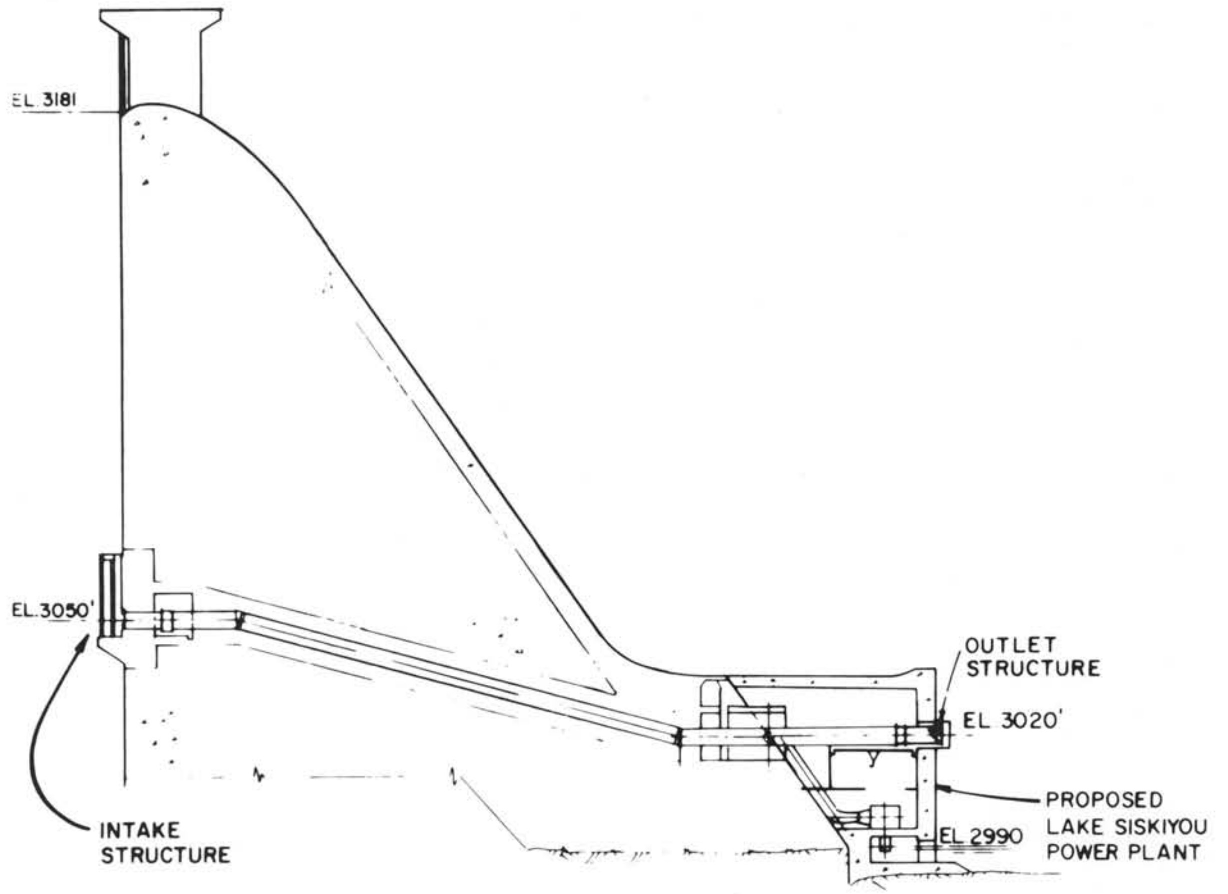


Figure 71. Lake Siskiyou power plant - cross section.

auxiliary systems and protection equipment can be eliminated. The most difficult challenge to be met when customary auxiliaries are reduced or eliminated is shutting the plant down upon load rejection. The turbine wicket gates must close, canal by-pass gates must open at the same flow rate to prevent a surge, the cooling of the generator bearings must continue, a braking force must be applied to the turbine-generator, alarms need to be sounded and transmitted, and all functions must be performed faultlessly with minimal cost, off the shelf, stored energy systems.

I hope these examples are sufficient to alert you to engineering challenges involved in small power plant design at existing impoundments and the kind of technology which engineers can apply to these problems.

I would like to close on a different note. The federal government's low-head hydro energy incentive program currently defines those projects as eligible for certain funding as those with less than 66 feet in head and less than 15,000 kw in capacity. Our experience has been that in the western states there is a great potential for small hydro projects, up to 15,000 kw, with heads as high as 500 feet. It may be wise if such projects could be made eligible for government assistance, also. The extent to which that running or falling water is not being utilized represents a waste of natural resources.

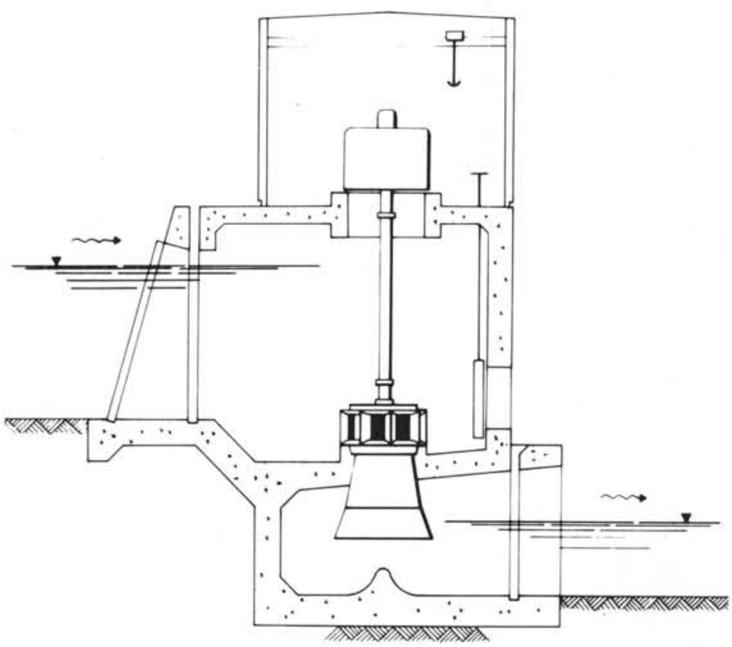


Figure 72. Power plant drop 1, Turlock Irrigation District - cross section.

Following Mr. Willer's paper he and an Idaho Water Service official answered questions.

Q: I'd like to ask David on [Barber Dam], could you give us some indication of how you prepared it, or what's been done to it to make it more safe?
Willer: The repair was conducted under the supervision I think of the Water Resources, State of Idaho, and what they did there was to remove all the timber facing, replace the rock ballast into the rock cribs, and place gunnite and reinforcement mesh on the ogee crest.

Q: What was the cost of the repairs on that?
Willer: I believe it was in the vicinity of $200,000 dollars and I think the crest is about 800 feet long, but I think there's somebody here from the State of Idaho who could help me I think on this.
Idaho Water Resources official: Yes, we supervised the construction. The actual construction costs was just slightly over $300,000 by the time the design was changed. It was originally to be reconstructed in timber and the contractor made some suggestions and the design was changed by the owner and it did come out to be slightly over $300,000. Our estimate of the life is probably about 40 years more. Gunnite, as you know, does require some additional maintenance so the maintenance might be certainly not as high as the timber, but it would probably be an annual type of maintenance. It has a nice flow characteristic over it now. While we feel there will be some cracking in the gunnite, we don't feel that this is a problem that can't be repaired. My estimate has been about once every three years we could go in and touch it up a bit.

Q: I'm curious about how you handled that water diversion. What did you do when you repaired it?
Official: Well we do have Lucky Peak Dam which is above, so we do have some control on the river and we did it during the very low flows and we had eight weeks to finish the construction before the flood waters were turned into the Boise River. So we had some control and we diverted the river flow, which was about a 100 second-feet at that time, through the old power structure.

Some Hydrologic Analysis Techniques

by Leroy F. Heitz

The purpose of this paper is to describe the hydrologic analysis techniques that were used to evaluate the maximum hydrologic potential of streams in the Pacific Northwest Region. The development of this technique was made as part of a research project funded by the U.S. Department of Energy and entitled "A Resource Survey of Low-Head Hydroelectric Potential—Pacific Northwest Region." This project is being coordinated by the Idaho Water Resources Research Institute in cooperation with the State of Washington Water Research Center, Oregon Water Resources Research Institute and Montana University Joint Water Resources Research Center. Development of the techniques used to determine the maximum stream hydro power potential was a joint effort of the four institutions listed above.

Some background information on this project will be provided in order that the reader can get an idea in what framework the analysis techniques were being applied. The study area covered all the Columbia River basin in the United States plus remaining basins in Washington, Oregon and Montana as shown in Figure 73. For the purpose of this study, the smallest-size power plant that was considered was 200 kw. The maximum height of dam that was considered was 20 meters. For the purpose of defining maximum developable power potential, these power and head criteria determined how far upstream in a tributary stream the techniques would be applied. In general, analyses were carried out in streams where discharge was greater than 36 cfs at least 50% of the time. This flow corresponds to the discharge required to produce 200 kw with 20 meters of head assuming an efficiency of 1.0.

Leroy F. Heitz is a Research Associate with the Idaho Water Resources Research Institute at the University of Idaho and is the coordinator of a project funded by the Department of Energy to determine the low-head hydroelectric potential of the Pacific Northwest.

He has been involved in studying, planning, and operating various large-scale water resource projects for the U.S. Army Corps of Engineers and the IWRRI. In 1976-77 he was chief of the Water Resources Section of Tudor Engineering where he served as project engineer for several large flood insurance studies and supervised the design of several small urban flood control projects.

He received a B.S. in Civil Engineering in 1970 and an M.S. in Civil Engineering in 1975, both from the University of Idaho.

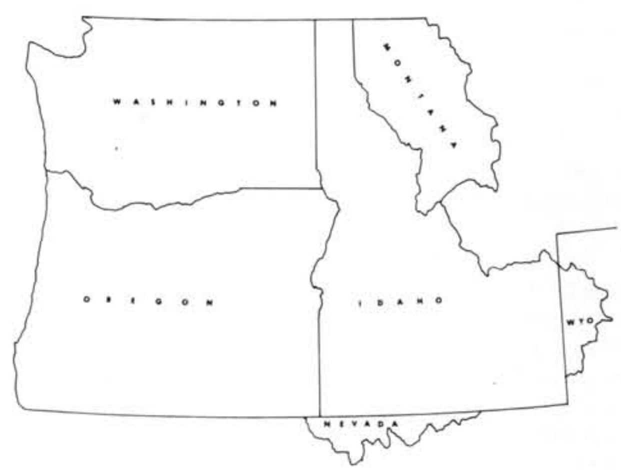


Figure 73. Study area map.

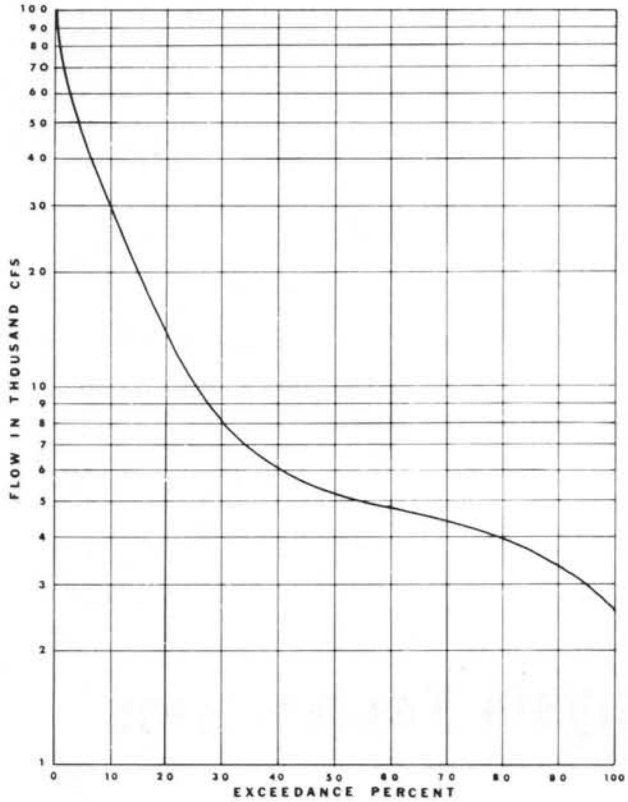


Figure 74. Typical duration curve.

Analysis technique

The basic analysis technique used in determining the maximum developable low-head potential was to divide all the streams in the region into segments called reaches and then to determine the total head and average discharges available in each of the reaches. The flows and available heads were processed through the normal power and energy computations to determine the maximum developable hydroelectric potential of the reaches. Summations of the reach values were made to determine basin, state and regional total potentials.

Reaches were assigned in such a manner so that each reach contained a fairly homogeneous segment of a stream. The reach end points were chosen so that major tributaries to the stream would enter at either the upstream or downstream end points of the reach.

In order to define the regime of flows available in a reach over time, a duration curve approach was used. A typical duration curve is shown in Figure 74. The abscissa is exceedance percentage and the ordinate scale is flow.

It has been assumed that any new low-head hydro projects would operate essentially as run of river power plants. Any storage that would be made available at new sites would make more power available than is computed using the run-of-river assumption. Therefore, power estimates in this study are conservative as far as the effect of on-site storage is concerned.

The duration curve technique was chosen over say just using the flow available 50 percent of the time as had been used in previous reports because it was felt that a complete duration curve is much more informative than just a single flow value. Because of this, the duration curves technique provides a more detailed estimate of resource potential. These duration curves will also be very useful to those doing preliminary feasability studies of hydro sites on any of the streams in the study area, since the availability of these curves will eliminate some of the preliminary hydrology work that would normally be required.

Duration curve development

Since duration curves are normally developed from data at gage locations, methods had to be developed to construct synthetic duration curves for reaches of the stream where no stream gages were available. The approach that was developed was to develop generalized duration curves at known gage locations that could be applied to ungaged locations.

The first step in this procedure was to develop duration curves of daily flows for all gage locations within the basins of interest. For the states of Washington, Oregon and Montana, daily flow duration curves were provided by the U.S. Geological Survey using their computerized streamflow data access system. The duration curves for Idaho gage locations were developed using the University of Idaho's

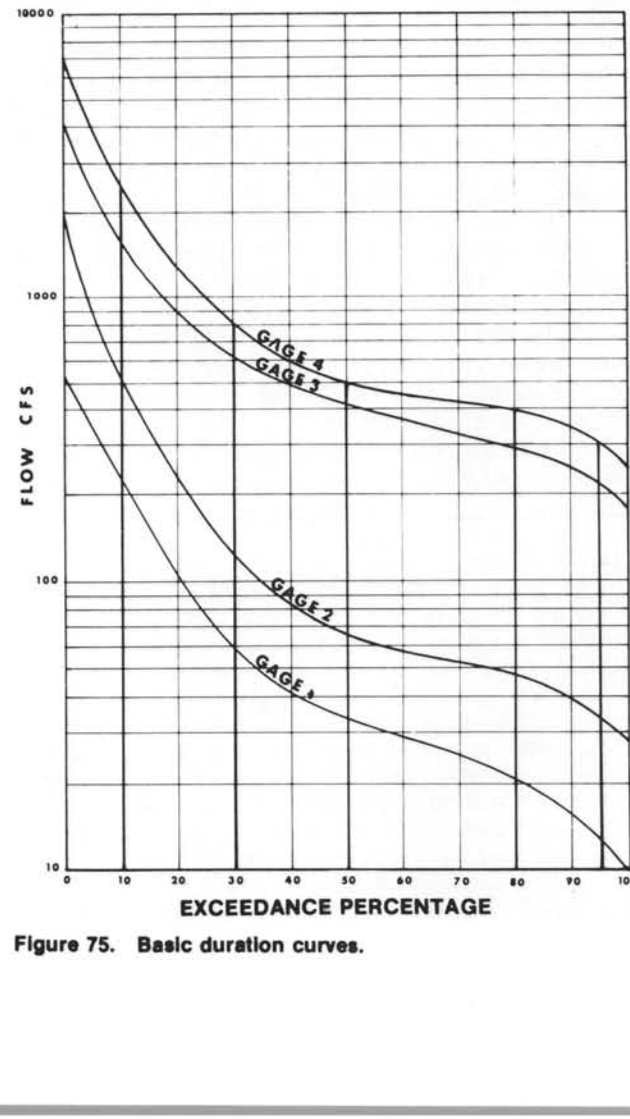


Figure 75. Basic duration curves.

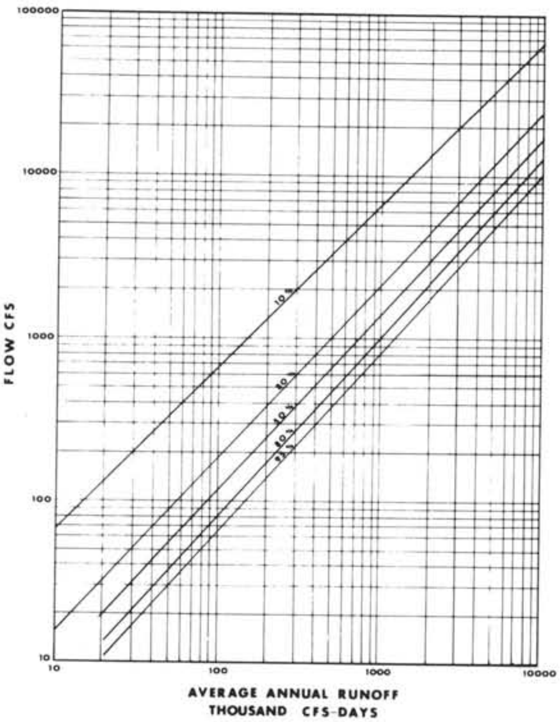


Figure 76. Parametric duration curves.

Hydrologic Information Storage and Retrieval System (HISARS) which contains U.S.G.S. streamflow data. In either case, the duration values were determined using the same method.

First, each daily flow for the period of record was categorized into one of a series of preselected flow intervals. The number of daily flows in each interval was then determined. The exceedance percentage for each interval was computed by first determining the number of flow values contained in intervals with flow magnitudes higher than the interval of interest. This number was divided by the total number of flows in all intervals to obtain the exceedance percentage. The duration curve was developed by plotting the upper flow value for each interval versus the exceedance percent for the interval.

Idaho team's method

The next step in getting the generalized duration curves was approached using several different methods. The Idaho study team used a method which involved developing a family of parametric duration curves.

The first step in this method involved plotting the duration curves for the known gage locations. Flow values for several exceedance values were picked from each of these curves as shown in Figure 75. All the flow values for each exceedance percentage were plotted

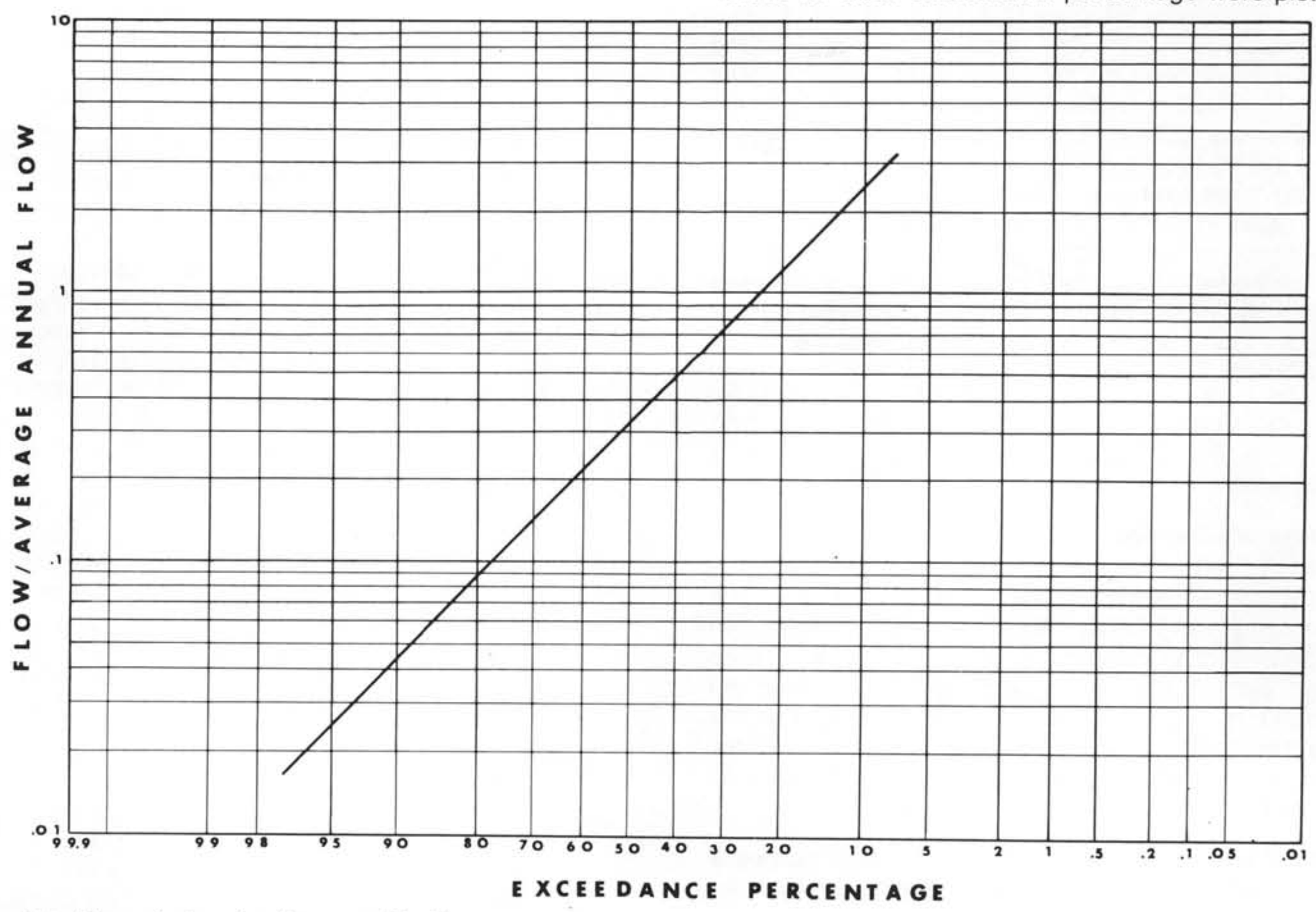


Figure 77. Dimensionless duration curve, Washington method.

against average annual runoff (QAA) at the gage. A separate curve was developed for each of the exceedance values. A correlation analysis was performed for each set of curve points to obtain a best fit curve to the data. An example of the final curves developed from this family of curves approach is shown in Figure 76.

In order to use these curves, all that is required is QAA at the point of interest. The procedure for getting average annual runoff at unagaged points will be discussed later in this report. To construct the required duration curves at the unknown point, all that is required is to make a vertical line from the known average annual runoff and pick off the flow values at the intersections with the particular percent exceedance curve. The flow values can then be plotted against the particular percent exceedance value to get the new synthetic duration curve.

Washington's technique

A second technique used to generate the required generalized duration curves was developed by the Washington study team.

Flow duration data provided by the U.S.G.S. were plotted on log probability paper with the "Exceedance Q"/QAV as the ordinate and the "Percent of Time Greater Than" as the abscissa. The QAV value used in this case was average annual flow in cfs. An example of this plot is shown in Figure 77. An examination of these plots showed that the data banded rather well with the 25% exceedance point being essentially common for all data. However, on individual station comparisons within a basin the 80% to 90% exceedance data scattered from ± 40% to ± 200% about a mean curve.

The conclusion was drawn that no single curve would fit all data in a basin and that the time required for a regression analysis and judgement of how many curves to use and where to use them required more time and money than was available. The procedure selected was to use the U.S.G.S. data at the exceedance points needed and assign each station its logical area of influence within the basin. A table of exceedance % vs. Q%/QAV was prepared for every station. The QAV value for the period of record was used for this calculation.

Montana's technique

A third slightly different technique was developed by the Montana study team. The first step in this technique involved plotting the flow duration curves for the known gage locations. Once the individual flow duration curves were plotted, they were subjected to a smoothing procedure to develop average curve profiles representative of conditions in specific sub-reaches. The specific steps involved in this procedure were as follows:

1. Flow values obtained from the U.S.G.S. data were first non-dimensionalized by expressing them as ratios of Q/Q_{10}.

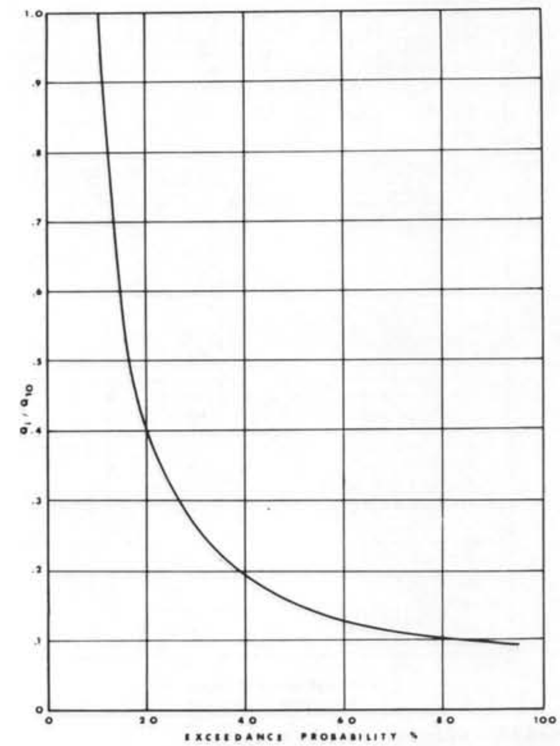


Figure 78. Dimensionless duration curve, Montana method.

2. Flow duration curves for all gaged sites were next plotted in dimensionless form using probability of exceedance values of 95, 90, 80, 75, 50, 25, and 10 percent. Plotting was accomplished by way of a special plotting subroutine on the XDS Sigma 7 computer together with a Cal Comp plotter. A sample of these dimensionless curves is shown in Figure 78.
3. Where possible, several dimensionless flow duration curves were smoothed or averaged by visual inspection and the resulting smoothed profile assumed to be representative of conditions in hydrologically similar subreaches of a given river basin. At least two factors were found to have a significant effect upon the shaping of the dimensionless flow duration curves. These factors were: (1) the magnitude of the mean annual stream flow at a given site and (2) the degree of regulation or other human influence occurring in the reaches above the specific site. The smoothing process undertaken here allowed river reaches possessing similar flow duration curve characteristics to be represented by a single average flow duration curve.
4. The averaged dimensionless flow duration curve was next used to synthesize flow duration curve profiles for ungaged sites. This was accomplished by first estimating the mean annual flow, QAV, for the reach using techniques that will be described later. The Q_{10} value was then estimated by a Q_{10} vs QAV regression

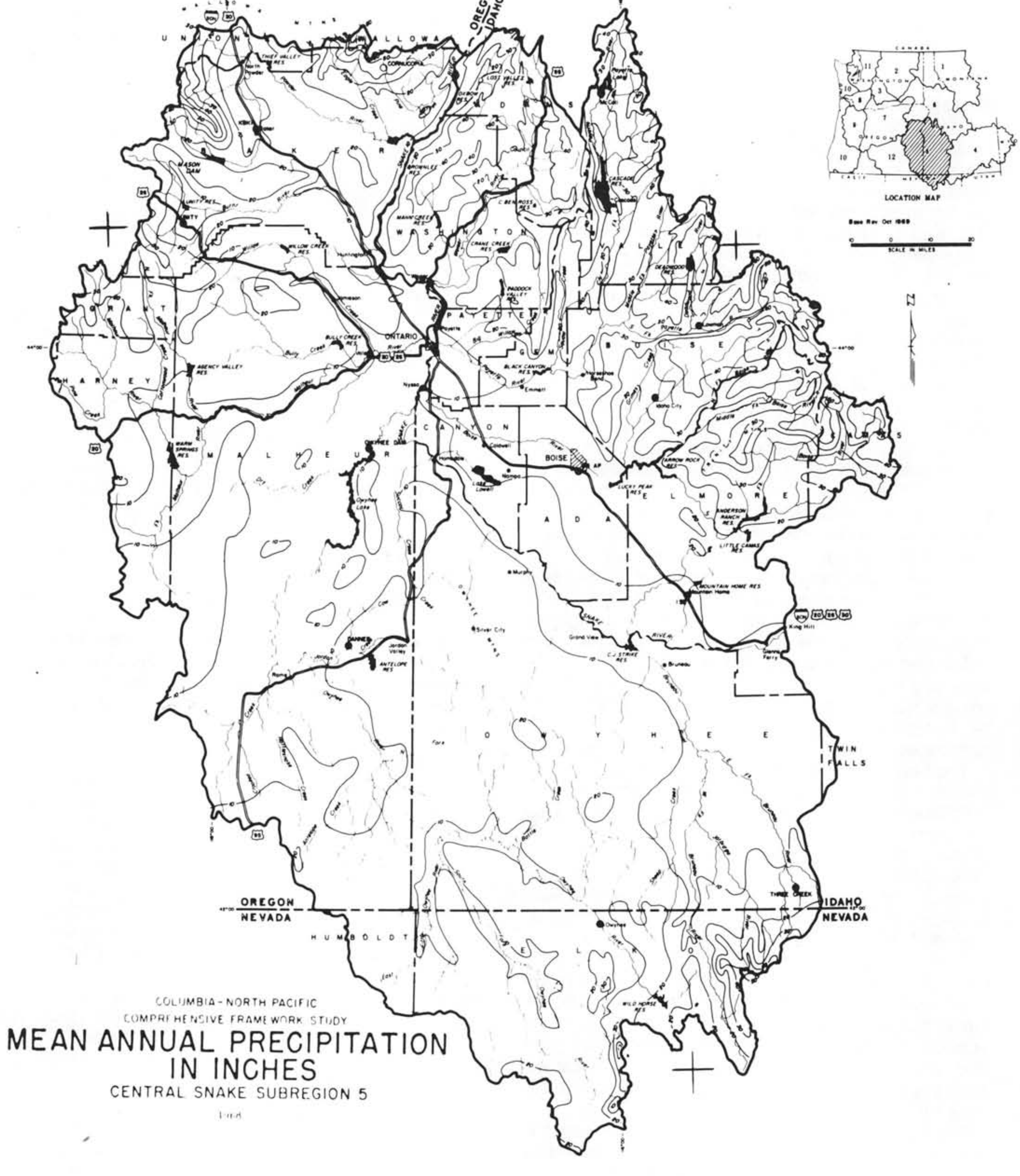


Figure 79. Normal annual precipitation map.

equation that was developed for the Columbia Basin in Montana. The form of this equation is:

$$Q_{10} = 2.98 \text{ QAV}$$

Next, the Q_{10} values were multiplied by the ordinate of the dimensionless flow duration curve to obtain the synthetic flow duration curve for the given reach.

Average annual runoff

The technique for obtaining average annual runoff for the ungaged portions of the river basin was essentially the same in all the study areas. The key step in this process involved the integration of areas between normal annual precipitation isohyetal lines. The first step was to obtain the best possible normal annual precipitation maps for the particular study areas. An example of one of these maps is shown in Figure 79. This map was obtained from the Pacific Northwest River Basins Commission from a study entitled "Columbia-North Pacific Region Comprehensive Framework Study."

The scale of maps used varied with hydrologic productivity of the area of interest. In these high runoff areas, maps of 1-62,500 scale were used in order to identify all the streams that could produce the minimum power output of 200 kw at the maximum head of 20 meters. These high runoff areas were primarily the coastal basins of Washington and Oregon. In the less productive sections of the study regions, map scales of 1-250,000 proved to be quite adequate.

U.S.G.S. topographic maps were used to develop basin description maps. Each sub-basin outline with reach delineations was traced off the topographic maps. Following this, the drainage divides were delineated for each reach. In some cases, part of this work had been done previously by the U.S.G.S. and by using projection techniques the basin boundaries could be transferred from the U.S.G.S. basin maps to a suitable scale map with only minor corrections required.

The next step involved getting the NAP map's scale to match the scale of the maps which were used to delineate the various reaches. This problem was solved by using optical projection techniques. Two slightly different techniques were used. The first involved making 35mm slides of portions of the original NAP maps. By projecting the slides through a normal slide projector, scales of sub-basin and NAP maps could be matched very easily.

The second technique involved using large (8½ x 11) transparencies that were projected onto the sub-basin maps using a standard overhead projector. Either of these methods resulted in good scale and placement accuracy when care was taken in adjusting the location and magnification of the projection. A simplified example of a complete planemetry map is shown in Figure 80.

The next step was to measure the areas between the isohyetal lines. Several techniques were explored to measure the area between isohyetal line. Use of an electronic planimeter or electronic digitizer-computer combination has proven to be very accurate and by far the quickest method for obtaining these values. Each of the areas was assigned an average precipitation amount based on the values of the surrounding isohyetal lines. The areas were then multiplied by the weighted precipitation and by appropriate scaling and conversion factors to obtain the total annual

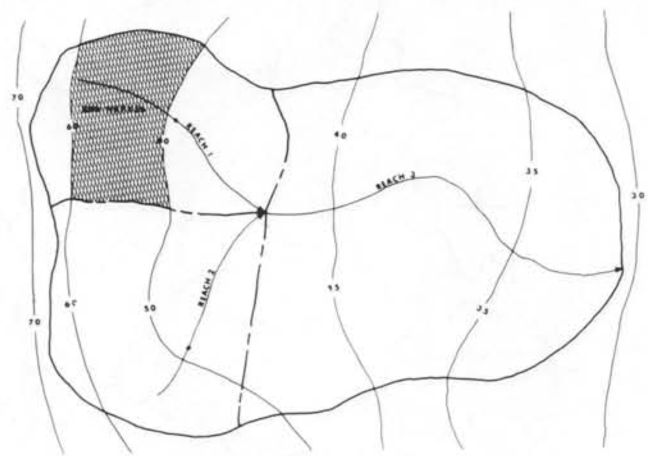


Figure 80. Reach planetary map.

precipitation input to each individual reach area. These inputs were summed in a downstream direction to get the total precipitation input for the basin upstream of the mouth of each reach.

Next, the ratio of annual precipitation input to annual runoff, "K factor," was determined. Since the U.S.G.S. stream gaging station records have different time bases and the NAP maps are based on a particular time period, it was desirable to settle on one common time base. The time base selected was the same as the time period used in developing the NAP maps that were used in a particular area. This permits use of the isohyetal map without modification.

Justification

Justification for adjusting stream flows to the common time base was confirmed by situations where upstream average flows were greater than the downstream averages. Adjustments were applied to gages in the Palouse and Puyallup Basins in Washington with corrections ranging up to 25% for the Palouse and up to 10% for the Puyallup. Because of wet and dry trends, all stream gaging records without complete records for the same period as the NAP map period require adjusting even with records for long periods of runoff. Stream record adjustment and a common base will also facilitate further runoff value adjustments should different precipitation rates or trends be anticipated in future dam site analysis and development.

When gaging stations had records for the NAP map period, QAA values were calculated for that span of years. However, if any part of the NAP period map record was missing the following procedure was used:

A reference station with a long period of record spanning the 1930-74 years and earlier years, if possible, was selected. The choice was limited to stations typical for the drainage area, free of significant flow regulation, and free of abnormal conditions. In some cases the reference station had to be selected from those in an adjacent basin. The calculated NAP map period QAA values for the adjusted stations were obtained from the following equation:

$$QAA_{\text{NAP period Adj. Sta.}}{}' = QAA_{\text{NAP Period Ref. Sta.}} \left[\frac{QAA_{\text{Comparison yrs. Adj. Sta.}}}{QAA_{\text{Comparison yrs. Ref. Sta.}}} \right]$$

Next, the ratios of average annual precipitation input to adjusted average annual runoff (K value) was computed for each gage station. Adjusting these K values to be applicable to the ungaged areas of the basin was approached in a slightly different manner by the different study teams.

The Washington study team used the following approach: K values for areas above the farthest upstream gage were taken to be the same as at that gage.

For drainage areas between two U.S.G.S. stations, K was calculated by:

$$K = \frac{QAA_{\text{downstream sta.}} - QAA_{\text{upstream sta.}}}{\text{PA contributing the difference}}$$

For basins where no U.S.G.S gaging stations were established, a K value was selected from the surrounding basins on the basis of similarity of conditions affecting the precipitation and runoff.

The Idaho study team used a slightly different technique. K values for reaches between gage locations were found by direct linear interpolation of the known gage K values. K values for reaches upstream of gages were found by extrapolation of K value data from adjacent areas with similar hydrologic conditions and from visual interpretation of factors that would effect the rainfall runoff relationship. A certain amount of sound engineering judgment is required in applying this technique especially when extrapolations are being made from the known gage data. A good knowledge of the general hydrology of the area is important in this process.

The Montana study team used a slightly different technique to predict the average annual streamflow at ungaged points. Their technique consisted basically of correlating observed mean annual flow values for gaged drainage basins with an index variable indicative of average annual precipitation conditions over the basins. This analysis resulted in the development of the following prediction equation for the Columbia Basin within Montana.

$$QAV = C(\Sigma A_i P_i)^n$$

where: C, n are constants

A_i = drainage basin area between adjacent precipitation isohyets.

P_i = the average annual precipitation for that part of the drainage basin represented by A_i.

The procedure developed for delineating A and P consisted of superposition of mean annual precipitation contours onto U.S.G.S. 1-250,000 scale topographic maps. Individual values of A were then found by planimetering areas within the drainage basins between adjacent isohyets. P was then taken to be the average of the adjacent precipitation isohyetal values. Once the index variable was found for a given drainage basin mean annual flow for the site could be estimated from the above equation.

Power computations

After generating a duration curve for a particular reach or irrigation canal site, the next step was to compute the power potential for that particular reach. The plant capacity was computed for five different flow rates corresponding to the 10, 30, 50, 80 and 95 percent exceedance levels. The basic power equation used was:

$$P = \frac{QH}{11800}e$$

where:

P = power in megawatts
Q = flow CFS
H = head available in reach
e = efficiency
11800 = conversion factor

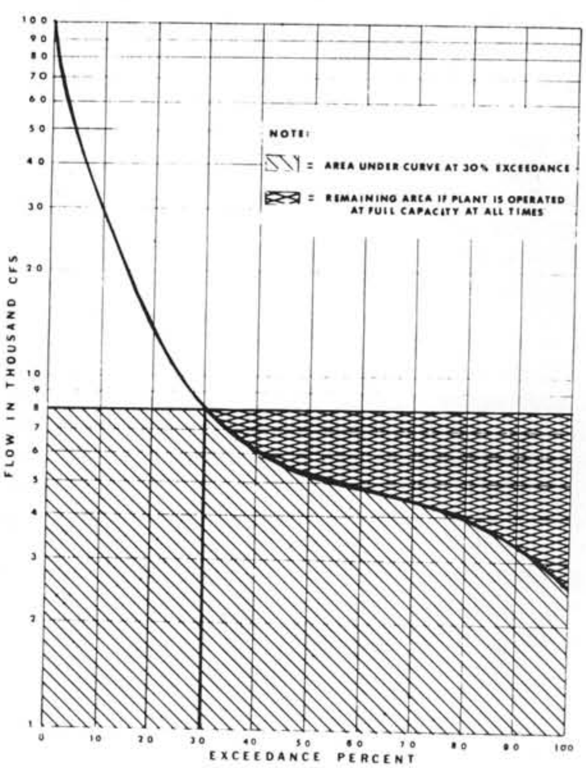


Figure 81. Energy and load factor relationship.

The Q value used is that which would be available at the midpoint of the reach. The head used is that total usable head in the reach which is computed by subtracting the elevation of the downstream point on the reach from the elevation of the upstream point of the reach. The efficiency used for all power computations was 1.0.

It is recognized that no hydropower generating system could operate at this efficiency. Since it would be impossible to predict the actual efficiencies that would be used, it was felt that using a common efficiency of 1.0 would be better than trying to second guess what the actual power generation system efficiency would be. The user can then apply his own particular efficiencies directly to the values represented in the tables and figures to find his own estimate of the actual power generated.

The energy available from the power plants sized at the specific exceedance values of Q was computed by integrating the area under the curve of plant size versus exceedance and multiplying this by the proper conversion factors to get the average energy output per year. Figure 100 shows the area under the curve at the 30% exceedance value.

Another value that is computed is the ratio of the energy that would be generated if the plant was operated at the full capacity for a given exceedance value 100% of the time to the actual energy generated computed by using the area under the curve. Figure 81 shows the relationship between the actual power generated and the power with 100% generation.

After completing the hydrologic and power potential analysis for a reach a sheet of reach characteristics is prepared. An example of this sheet is shown in Figure 82. This sheet has a section on reach location, hydrologic and hydraulic characteristics and a typical annual hydrograph for the reach. There is also a fairly detailed map of the reach plus a state locator map. This sheet is the final end product of the reach analysis. The power and energy potentials for each reach are summed by basin, state and region to get the total potential for the respective areas.

After he had delivered his paper, several members of the audience questioned Mr. Heitz.

Q: Because of the higher stream flows there will be considerable head variation. How have you taken the head variation into effect?

Heitz: For the type of large scale survey that we're doing we assumed no head variations in plant operations. We're looking at a maximum stream potential and as far as the reach-type analysis that we're doing, we just assumed that the head would be the total head available in the segment, without making any adjustments for variability in head as far as in different flow readings.

Q: I'd like to ask Mr. Heitz if he has ever attempted to apply this analysis to mean monthly flows so that we have some way of evaluating energy costs or value of energy for particular months?

Heitz: No, we haven't tried to evaluate on a monthly basis. In some of our streams, of course, we're tied in with regulation by upstream reservoirs, and in these cases we are using monthly mean flows, regulated flows in developing the duration curves. But we have not tried to develop a duration curve for say, August and one for September.

Klingeman: I would say that the monthly flow value is very important in a variety of different management decisions where you don't need the detail data. With WATSTORE it has been possible for us to get that added refinement in trying to pin down the Q-95, the 95% exceedence value, the daily flows really are essential at that part of the curve.

Q: Could you comment further on the criteria for selection of reaches in this study?

Heitz: Okay, it's kind of tough to describe how it's done; you just kind of get a feel for it as you're doing the work. Basically, what we first do is look at the stream system and try to determine where the major stream inflows and how the system fits together. Plus we mark all the gauges on there because we want to be sure to have a reach point at every gauge for the analysis part. After that it just becomes kind of a judgment factor as to where to put the reaches. Here again, it also depends on the productivity of the watershed. For instance, in both Washington-Oregon coastal areas where there are very high productive streams, we've had to make the reaches much smaller, use 7½ - 15 minute quads to do the work.So it depends on the production. You know the water productivity of the area also. And then you've got criteria such as what your final output product is going to be and how big a reach can you put on your map sheets and that kind of thing, so it's kind of a weighting thing.

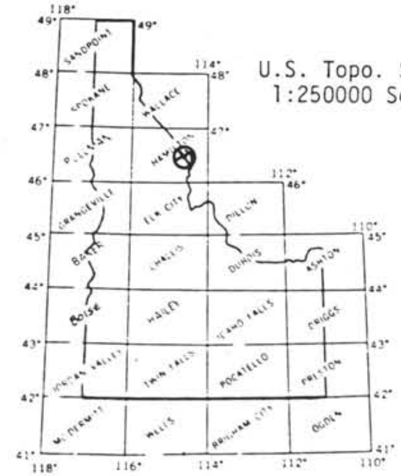
Klingeman: We're also faced a little bit with the problem of the detail on the GS topo maps where in many parts of Oregon the contour interval is 80 feet, and this creates a difficulty you can appreciate.

REACH HYDRO-POTENTIAL CHARACTERISTICS

REACH NUMBER 035002400400200R0065

I LOCATION

A.	STATE	IDAHO
B.	COUNTY	IDAHO
C.	TOWNSHIP, RANGE	T36N R15E
D.	LATITUDE, LONGITUDE	46 29 114 35
E.	STREAM NAME	WHITE SAND CREEK
F.	MAJOR BASIN NAME	CLEARWATER RIVER
G.	RIVER MILE	0.0 TO 13.0



U.S. Topo. Series
1:250000 Scale

Location Map

II HYDROLOGIC AND HYDRAULIC CHARACTERISTICS

A.	UPSTREAM ELEVATION OF REACH	4440 FT. MSL
B.	DOWNSTREAM ELEVATION OF REACH	3430 FT. MSL
C.	TOTAL AVAILABLE HEAD IN REACH	1010 FT.
D.	AVERAGE SLOPE IN REACH	77.7 FT./MI.
E.	DRAINAGE AREA ABOVE REACH MOUTH	240 SQ.MI.
F.	INFLOW CLASSIFICATION	NATURAL
G.	AVERAGE FLOW DURATION AND POWER VALUES FOR THE REACH	

EXCEEDANCE PERCENTAGE	DISCHARGE CFS	PLANT SIZE MW	ANNUAL POWER OUTPUT GWH	LOAD FACTOR
95	63	5.40	47.13	1.00
80	101	8.69	72.33	0.95
50	193	16.49	116.74	0.81
30	397	34.00	178.12	0.60
10	1630	139.52	362.98	0.30

H. TYPICAL ANNUAL HYDROGRAPH

```
                6I       AVERAGE ANNUAL FLOW =    506 CFS
      A T        I
      V O        I
      G         5I
        A        I
      M V        I
    R O G       4I
    A N          I                                        ****
    T T A        I
    I H N       3I
    O L N        I                                              ****
      Y U        I
    O   A       2I
    F F L        I                                    ****
      L          I
      O F       1I
      W L        I                                                    ****
        O        I    ********************
        W       0I****---------------------------------------------------********
                  OCT NOV DEC JAN FEB MAR APR MAY JUN JUL AUG SEP
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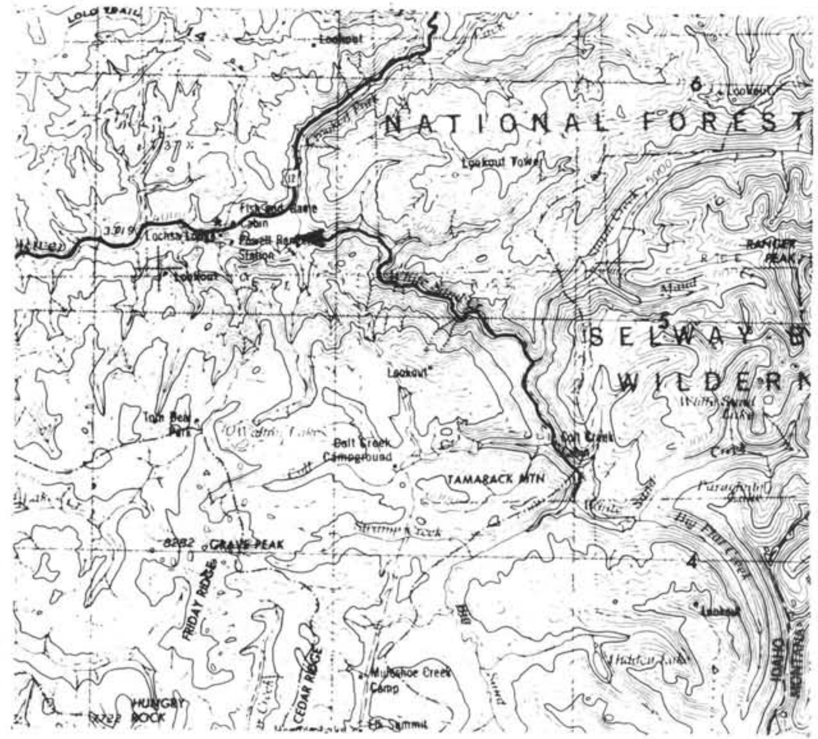

Figure 82. Typical hydro-potential characteristics for a river reach.

Potential for Hydroelectric Development in Existing Irrigation Systems

by C.C. Warnick

In the construction of several irrigation projects throughout the western United States there are places where relatively large flows drop several feet in the conveyance systems at drops, diversions, control structures, and wasteways structures. Normally the recovery or development of the energy lost in these drops was not an economically feasible possibility in earlier times. As the value of power increases, the feasibility of utilizing this lost energy in producing hydroelectric energy becomes worth pursuing in engineering planning efforts.

As a part of the Pacific Northwest Low-Head Hydro Survey sponsored by the U.S. Department of Energy a survey is being made of the extent of the possibilities that exist in various irrigation canal systems.

Methodology

The limiting size for possible consideration was set purposely at a very low figure of 200 kw. The first effort in Idaho was a mail survey checking with all canal companies and irrigation districts in the state. Requested information was an indication as to whether flows of greater than 50 cfs were flowing in canals and whether drops in elevation in a very short distance of greater than 20 feet were available in the irrigation system. Some canal companies, consultants, and government agency personnel also made inquiries after and during the mail survey. The survey is still in progress and unique combinations of changes in routing of water through canals is being systematically studied. Flow data from canal companies were obtained and an analysis made of energy potential at specific sites.

Conventional site analysis

This first effort is termed the study of conventional analyses wherein no modification in the operation of the canal flows would be attempted. To illustrate this approach the Boise Project Canal system has been chosen to illustrate the approach. Ten sites were investigated and seven sites found to have hydro potential. Figure 83 shows a schematic sketch and data sheet of the type of hydro development of various sites and Figure 84 is a photograph of one of the potential power sites and a map, Figure 85, shows the location of the various sites in the Boise Project area. The analysis of energy potential was done using a duration curve approach similar to other studies being done in natural streams and reported earlier in this seminar by Heitz. This gives an estimation of the ultimate in power potential and of various power capacity sizes. No attempt at this stage has been made to determine economic, political, and environmental feasibility. Results of the conventional type study in the Boise Project are shown in Table 20.

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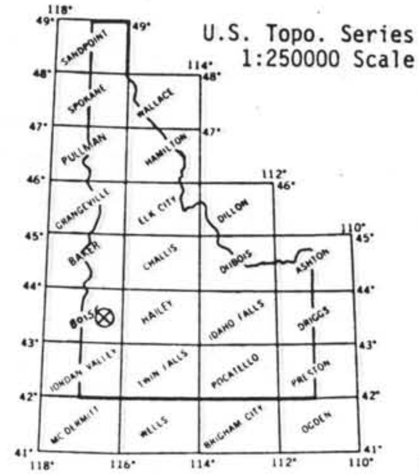
CANAL SYSTEM Boise Project

SITE # 2 - Electric Drop

I. LOCATION
- a. State — Idaho
- b. County — Ada
- c. Section, Range, Township — 33, R1W, T24S
- d. Longitude, Latitude — 116°23'W, 43°28'N
- e. District Name — Boise-Kuna Irrigation Dist.
- f. Canal Name/s — Mora, Waldvolgel

II. WATER RIGHTS
- a. Type — Flow & Storage
- b. Ownership — Irrigation District

III. HYDROLOGIC AND HYDRAULIC CHARACTERISTICS
- a. Elevation of Forebay — 2730 Ft. MSL
- b. Available Head — 36 Ft.

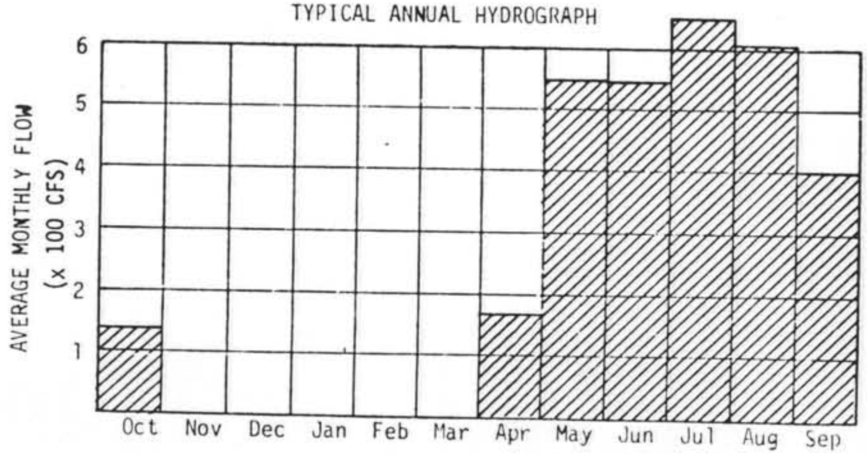


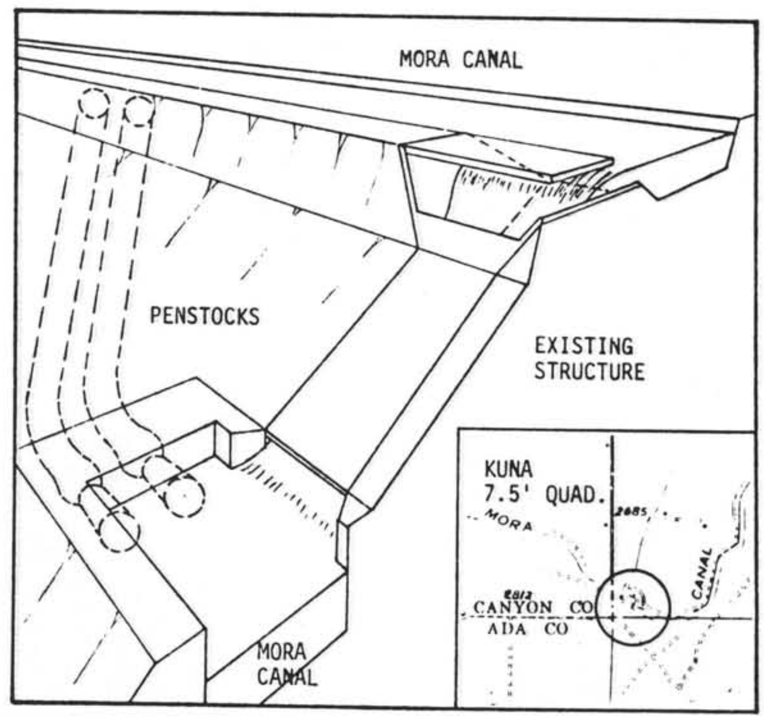
Location Map

FLOW DURATION AND POWER VALUES (7 MONTHS)

Exceedance Percentage	Discharge CFS	Plant Size MW	Annual Power Output GWh	Load Factor
95	72	0.22	1.09	0.97
80	240	0.73	3.39	0.90
50	481	1.47	5.83	0.78
30	575	1.75	6.41	0.72
10	645	1.97	6.63	0.66

TYPICAL ANNUAL HYDROGRAPH





PICTORIAL DIAGRAM

Figure 83. Schematic sketch and typical data of hydro development in an irrigation canal.

Figure 84. Electric Drop site on the Boise Project.

Unconventional site analysis

Another approach has been to make what is here termed a study of unconventional type installations involving a change in operation of the canal system. At three locations of unconventional type installations preliminary analyses have been made.

(a) Egin Bench Site.

The first is in an area known as the Egin Bench, in eastern Idaho, wherein the idea is to change the subirrigation method of irrigation to sprinkler irrigation and replace a multitude of canals and ditches with a single canal and use water saved to dump back in the river to produce power. The idea of this is shown in the map of the Egin Bench area in Figure 86. In this case there have historically been diversions in the canals averaging over 15 acre-feet per acre throughout the irrigation season.

With sprinkler irrigation, the required diversion with properly designed canals could be reduced to not more than 4 acre-feet per acre. Thus there could be a net savings in water and supply of water of 11 acre-feet per acre that could be used in power production. Preliminary analysis indicates the capacity of a power plant could be 2,300 kw. The scheme has many problems to implement it as a practical solution. Chief among these would be the social resistance to change in farming practices.

(b) Twin Falls Canal Modification.

This scheme involves using the Twin Falls Canal Company main canal as a power diversion canal and dropping the water back into the Snake River at a point where the present main canal of the Twin Falls Canal Company comes close to the Snake River Canyon. This is not a low-head power installation in that there is about 440 feet of head available at the location and a canal capacity of 4,000 cfs. The operation could be carried on any time there is excess canal capacity above irrigation needs and when there is flow passing Milner Dam.

An analysis by Woodhouse indicated the power plant could have a capacity of 52,200 kw. Figure 87 shows a map of the project for the irrigation canal-river bypass system near Twin Falls, Idaho, area. The river below Milner Dam is essentially dry during much of the recreational use season. A key component in this unconventional scheme is the Milner Dam and its operation of irrigation diversions including the equalizing reservoir, Murtaugh Lake.

(c) New York Canal Site.

This scheme would entail using the upper reaches of the New York Canal from Diversion Dam to the tailrace of Barber Dam as a power supply canal. Whenever the capacity above irrigation requirements in the New York Canal would permit and flows in the Boise River would be high enough, the flow and head combination could be

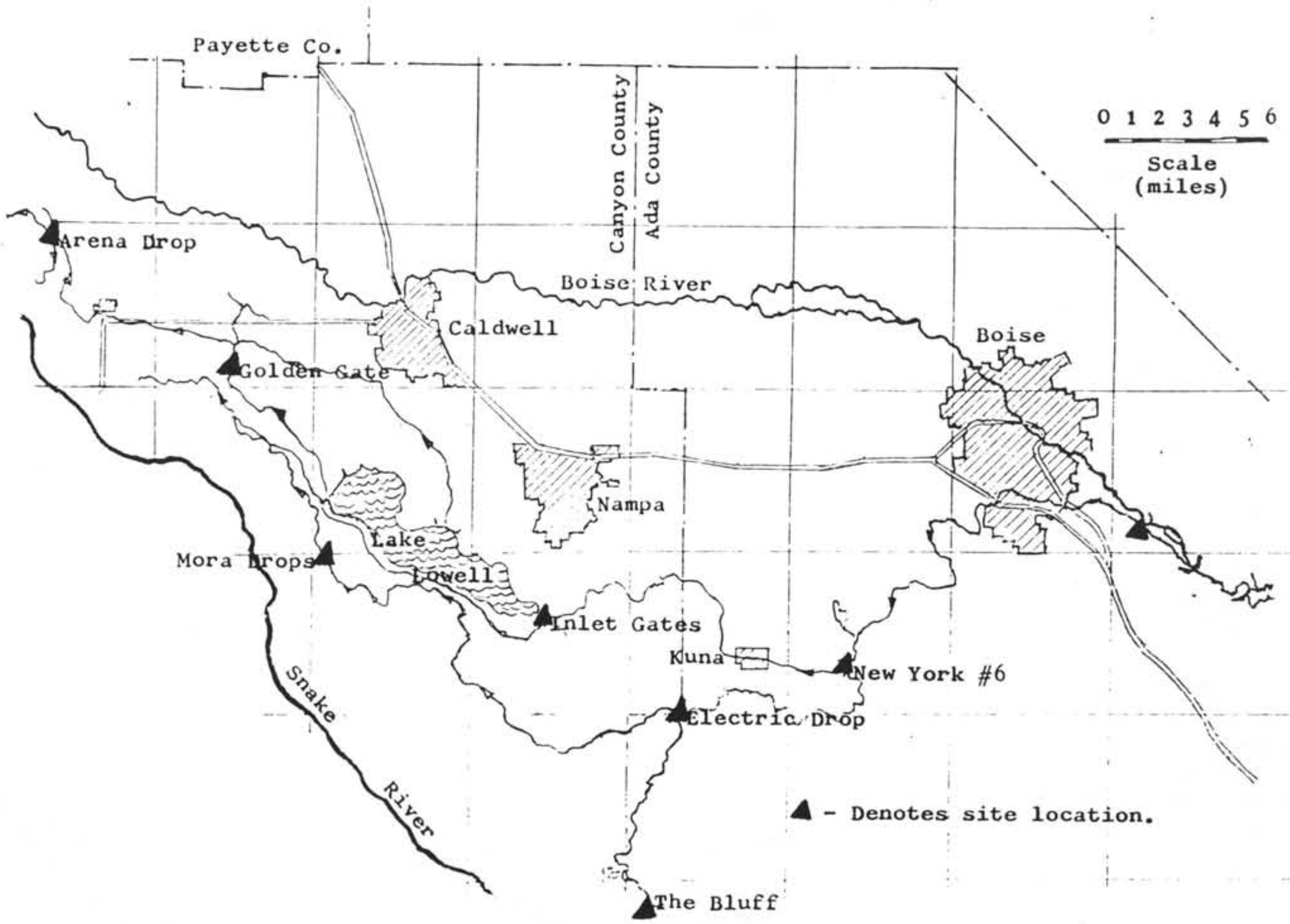


Figure 85. Potential hydroelectric power sites on the Boise Project.

used as a hydro production site. Any improvement in efficiency of irrigation use could also accrue as a supply that could be used to produce power at or below Diversion Dam in the Boise Project irrigation system. The site for these is just upstream from the city of Boise shown in the map of Figure 85.

The New York Canal-Barber Dam site has a gross head development potential of 44 feet and a channel capacity of 3,100 cfs. Woodhouse, in his studies of the flow possibilities at the site, shows an energy potential of 20,34 Gwh of electricity per year and a capacity of about 10,390 kw.

Additional sites now being investigated that would require modification of flow operation of the canal are located on the Black Canyon Irrigation District main canal near the pumping plant and on the Richfield Canal of the Big Wood River Canal Company below Magic Reservoir.

Advantages of canal development

The advantages to both conventional and unconventional type developments in canals are as follows:

1. The energy loss is really recoverable energy that does not draw on the depletable energy supplies like coal, oil, or gas. It is a recoverable resource.
2. The water rights are generally already identified and can be sustained.
3. The need coincides with the production in the canal.
4. The scheduled use is apt to encourage more efficiency in irrigation operations and thereby make for greater net benefits in irrigation project developments.
5. The water control is already provided for and expensive spillways and civil works components of construction are cheaper than high-head hydro.
6. There appears to be a very minimal impact on environmental quality because the canals are already constructed and rarely have fish in them.
7. The owning and operating entities of canals such as irrigation districts and companies already have water rights that should be able to be modified with a minimum of difficulty.

Difficulties envisioned

As with all developments involving construction and modification in water flow there are tradeoffs that must be considered. Thus in the case of water power developments in irrigation systems there are expected difficulties. The main disadvantages are as follows:

1. Scattered locations of sites and small sizes may make them difficult and expensive to maintain and operate.
2. The fact that the flows in the canals are seasonal means the energy will not be available at all times and will make it more difficult to develop such energy sources with economic net benefits.
3. The tendency for irrigation entities to fear some loss in control and weakening water rights will prevail even if the development does not modify irrigation flows.
4. There may not be organizational or institutional arrangements to permit implementation of such hydro developments. This might include license provisions that would be difficult to meet.

Conclusions

The possibility of utilizing the drop in head existing in canal systems to develop small capacity hydroelectric energy sources appears to have potential in the larger canals in Idaho. One approach would be to not alter flow regulations in the canals at all while another possibility is to modify flows and reroute water to take advantage of head and flow conditions that would permit a favorable power arrangement. Although the capacity of such plants will be relatively small, the fact that production would match needed load in a seasonal fashion would be favorable. The real advantage is that the energy is using a renewable resource.

The real question in this possibility is can the plants be built and operated economically? The U.S. Department of Energy has just awarded a grant to the Boise Board of Control of the Boise Project to make a feasibility study of the Mora Drop location, one of the conventional site locations shown in Figure 85. The other recommendations and need is to have favorable institutional arrangements which will provide incentives and encouragement to those involved in the application for licenses, the obtaining of water rights and the making of financing arrangements.

Site	Available head (ft)	Discharge (cfs)	Plant size (Mw)	Annual power (Gwh)
New York #6	26.5	700	1.41	5.38
Electric Drop	36.0	620	1.70	6.48
The Bluff	72.5	64	0.35	1.07
Inlet Gates (Lake Lowell)	14.7	600	0.67	2.33
Mora Drops	20.0	210	0.32	1.40
Golden Gate	34.0	305	0.79	2.77
Arena Drop	67.0	108	0.55	1.95
			TOTAL	21.38 Gwh

Table 20. Potential power at conventional installations of the Boise Project, Idaho.

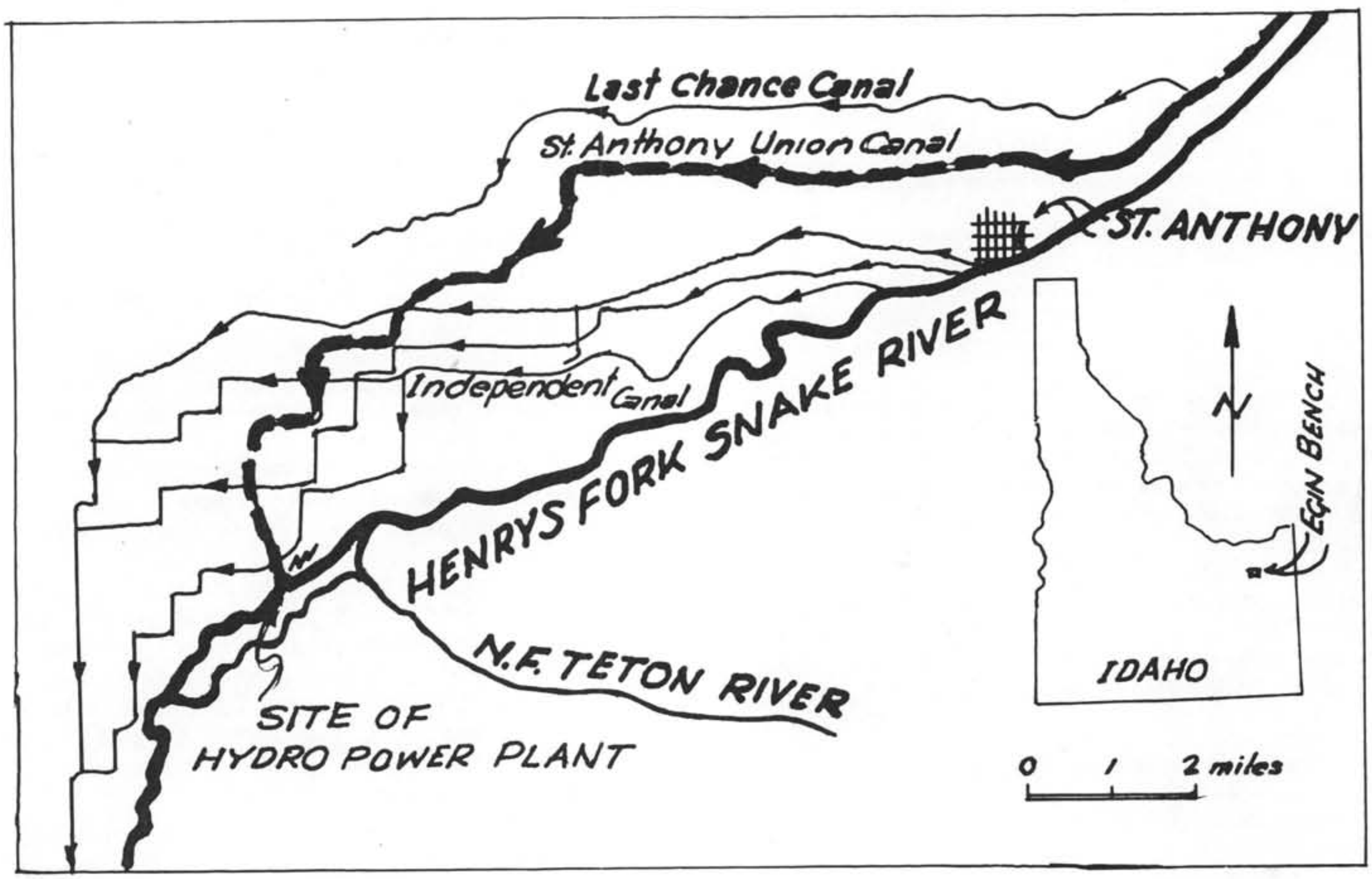


Figure 86. Map of scheme for developing hydro energy on Egin Bench Irrigation System.

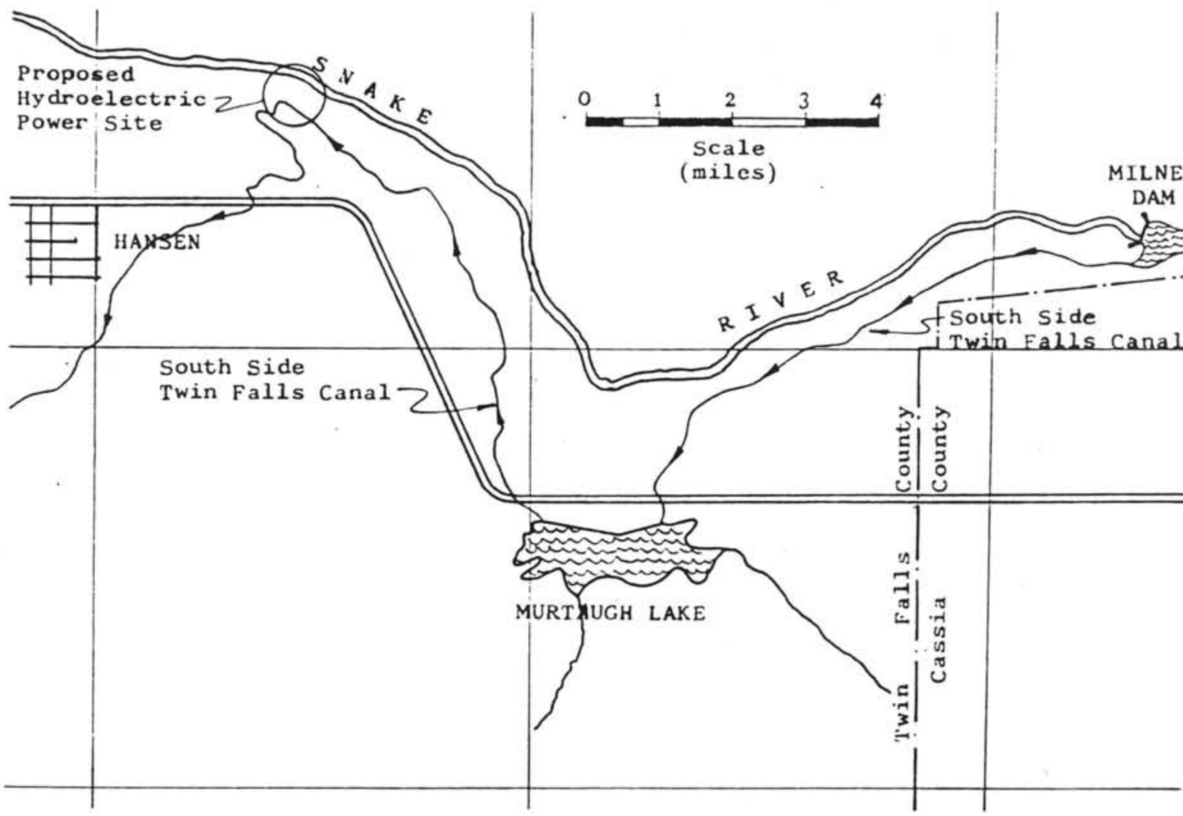


Figure 87. Irrigation canal-river bypass system near Twin Falls, Idaho.

A recommendation that should be seriously considered is that not just a single low-capacity installation be made but that a group of potential sites be studied together for simultaneous development, to utilize standard size units, remote control operation, and standard components of civil works items such as penstocks, draft tubes, and gate control units.

FOOTNOTE

1. Heitz, L.F., 1978, Maximum Stream Potential for Hydroelectric Power Production, Proceedings, Seminar on Low-Head Hydroelectric Technology, University of Idaho, Moscow, Idaho

2. Woodhouse, R., 1978, Methodology for Analyses of Hydroelectric Potential in Irrigation Canals in Idaho, M.S. Thesis, Civil Engineering Department, University of Idaho, Moscow, Idaho

Studying the Northwest's Low-Head Hydro Potential

by Claud C. Lomax and Michael J. Robinette

Work on the Resource Study of the Low-Head Hydroelectric Potential in the Pacific Northwest commenced in October, 1977. This study is funded by the Department of Energy through a basic contract with the Idaho Water Resources Research Institute. Idaho has subcontracts with the sister research organizations at Montana, Oregon, and Washington. The study area includes all basins within the states of Idaho, Oregon, and Washington, plus all of the remaining Columbia River Basin, mainly in Montana.

The first phase of the study is directed toward determination of stream gradients and flowrates. The flowrates include average annual flowrate at all reaches of the stream plus flow duration data to be used in load factor calculations. The low-head limitations were established as 200 kw or greater, at heads between 3 and 20 meters. This results in a limit on the average annual flowrate of about 35 cfs minimum.

Initially it was planned to give specific site data but the great number of possible sites plus time and funding limitations made it necessary to drop this concept and use reaches where one or more dams could be built at many locations. Any specific site identification will require more surveys unless the USGS River Survey Sheets are available for the reach under study. The best contour data are on the 7½ minute maps at 20-foot intervals but some of the areas are on1:250,000 maps with contour intervals of 200 feet. To summarize, the first phase of the study will provide data on the potential energy available in the flowing stream.

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Exclusions

In the first phase of the study it was necessary to exclude reaches of streams where dams and reservoirs existed. Not all of the dams were used for power generation so part of the low-head potential was being omitted. However in the second phase of the study this potential for power generation at these existing dams will be evaluated.

Dams have been proposed by individuals and organizations for many locations. For some, detailed survey work has been done and it is desirable to integrate these data into the low-head potential study. The second phase of the project will do this by identifying the proposed sites, by providing site-specific data for some sites, and by identifying ownership which might restrict construction of any other dam(s) in these reaches of the streams. From this basic background the remainder of this paper deals with proposed dam sites within the State of Washington. Similar studies will be done in idaho, Montana, and Oregon.

Sources of information

Only those proposed impoundments which have been documented by some published reference will be included in the study. To date, sources of information have included: USGS River Survey Sheets, Federal Power Commission listings, U.S. Corps of Engineers files, U.S. Bureau of Reclamation files, and a list from the Washington State Department of Ecology (compiled by Fred Hahn, Assistant Director) along with a few picked up from verbal communications with various people and agencies throughout the state.

During the planning stages for the Northwest Low-Head Hydroelectric Project, a number of potential low-head generating facilities were identified and discussed. These included existing dams without generating facilities, previously proposed dams, potentials at man-made structures (irrigation drop chutes and delivery systems), additional facilities at existing dams, and a seemingly unlimited supply of low-head dam sites unproposed because of earlier high-head need and constraints. It is certain that many sites have been suggested and that upon examination some have been rejected while others were proposed for dam construction based on criteria of that day. In each case new and possibly extensive evaluation of geological, engineering, economic, and ecological factors must be made before any serious future development can be started.

It is possible to build a low-head dam on a proposed site and it may also be possible to build other low-head dams upstream of a low-head dam built on a proposed high-head site. This study will identify the proposed site, identify a potential low-head dam at the site utilizing existing data, and give some assessment of the effect of the proposed site on further low-head development along the same reach of the river. The contribution of data on sites which have been examined will be solicited.

Examination of the source information

Sources of information provide the stream name and usually the location along the stream where the dam site is proposed. Kilowatt ratings are given for about one half of the sites. Only rarely is the flowrate and/or head given.

An attempt will be made to ascertain the head range for each proposed site, either from published reports on design or from surrounding limiting factors (cultural and environmental). The flowrates at all sites will be available from phase one of the low-head hydroelectric study. Examination of each proposed site will be made to determine if a dam has already been built at the site, to determine if construction of another dam has flooded the site, and to verify that the site name has not been changed.

Several proposed sites have been examined and information generated to provide the following examples of how the proposed sites will be evaluated in the extended low head study. All of these sites were chosen from USGS River Survey Sheets. Contours of the river flood plain and river bed profiles are given and in some cases the cross-section at the dam site is provided.

Site no. 118

Barstow Dam site on the Kettle River is a typical low-head site. The maximum potential head is greater than the 20-meter ((66 feet) limit established for the Low-Head Study but practical considerations limit the head to about 20 meters. Any greater head would raise the water surface above elevation 1,400 and flood the adjoining Great Northern tracks, Highway 395, and the town of Orient. Any increase above elevation 1,420 for the top of the dam will double the top length for each 10 feet of increase up to elevation 1,440. With a water surface elevation above elevation 1,445, encroachment on Canadian soil will occur. At 20 meters of head and an average annual flowrate of 3,000 cfs this dam would have a potential for 15 Mw of installed capacity. Other sources identify an Orient dam site which appears to be the same. Hopefully our further investigation will identify and clear up such redundancies.

Site No. 117

Curlew Dam site on the Kettle River has a number of serious constraints which lower the feasibility of construction and increase the cost of development. The dam site elevation is 1,760 and the Great Northern tracks, Highway 4-A, and the town of Curlew are all below elevation 1,800. Any water surface elevation above 1,780 will require considerable relocation work. At elevation 1,865, encroachment into Canada will occur. With a limited development of 7-meters of head (22 feet) and an average annual flowrate of 1,870 cfs, the potential capacity is 3 Mw. If the head were increased to 20 meters, the potential capacity would be 9 Mw.

Site No. 347

An unnamed site at river mile 3.5 on the Hamma Hamma River could be developed as a low-head site. Developed at 20-meters of head and an average annual flowrate of 516 cfs the potential installed capacity is 2.6 Mw. The maximum potential head development is about 105 feet but this would require a long dam.

Site No. 22

An unnamed site at river mile 9.3 on the Carbon River would have a potential installed capacity of 2.2 Mw for an average annual flowrate of 437 cfs at a head of 20 meters.

Site No. 23

The Fairfax Bridge dam site on the Carbon river would probably be best used for heads in excess of 20 meters. However, if developed at 20-meters of head with an average annual flowrate of 437 cfs, the potential installed capacity would be 2.2 Mw. If fully developed for a head of 215 feet, the potential capacity would be 7.7 Mw.

There are three proposed low-head sites on the Queets River drainage. Hunt Creek, Site No. 320, and Elkhorn Creek, Site No. 321, on the Clearwater River are essentially alternate sites and either could be developed to 20 meters of head with an average annual flowrate of 1,176 cfs to give a potential installed capacity of 5.9 Mw. If Hunts Creek was developed for only 10 meters of head and Elkhorn Creek for 20 meters of head, their respective potential capacities would be 3 and 5.9 Mw or an increase of 50 percent.

Site No. 307

Fisher Rapids at 20 meters of head backs water to the tailrace of the Hunts Creek Site. With an average annual flowrate of 4,200 cfs in the Queets River this site has a potential installed capacity of 21 Mw. An interesting aspect of this situation is: should the Fisher Rapids site be developed for a maximum head and flood the Hunts Creek site? Since the flowrate is more than three times as great, this appears to be a very favorable alternative. This illustrates the inter-relationship of sites and the importance of considering the drainage basin as a whole rather than as isolated dam sites. The above three sites are all in the Quinault Indian Reservation and the Fisher Rapids site will back water nearly to the Olympic National Park.

Summary

Phase Two of the Northwest Low-Head Hydroelectric Project will provide authorization to examine proposed dam sites and existing dam facilities to assess the potential of low-head development within the State of Washington. To date, about 300 proposed sites have been identified from various listings and about 600 existing dams have been listed by the Washington Department of Ecology. Discrepancies and duplications will be eliminated and a composite listing will be prepared and published.

Several examples presented within outline a few of the many constraints, economic, political, and ecological, that will be looked at and noted. Many of the proposed sites were chosen for high-head dams. One or more low-head facilities could be considered for the river reach. Only extensive and detailed studies will determine the value, feasibility and priority for development of these potential dam sites as low-head hydroelectric facilities.

Status of Small Hydropower Studies in New York State

by: Ruben S. Brown
Richard Napoli
Alvin S. Goodman
Llewellyn Thatcher

Introduction

New York State as well as the entire Northeast was once the center of American industry based on the availability of a plentiful supply of inexpensive hydro power. The hundreds of mill towns found in this area attest to their once booming economies. As the machines of the industrial revolution increased in speed and reliability, the need for a concentrated and completely reliable source of energy was required. The discoveries of coal, iron ore and eventually oil in the Mid-West and South sounded the death knell of the Northern water-power-based factories.

Not all factories in the Northeast became obsolete. Many whose water sites proved adequate were able to convert to hydroelectricity. Other hydro sites were developed by newly formed electric companies to provide power to the mills as well as the surrounding communities. The boom that built the original mills reached its peak in about 1880 and by 1910 it was over. Those that could convert to electric generation did so and the others either moved west or closed down.

Some of the mill towns were quite inventive and ambitious in their use of mechanical hydro power. Troy, New York, with a head of 135 feet, had a penstock bored through solid rock to take water around the falls where it is diverted into a number of different factories. Cohoes was an example of an early industrial park. Water diverted from the Mohawk River flowed in many directions through the town to power dozens of factories.

Interestingly, not all mill towns had success stories in the same way. Lawrence, Mass., which is now undergoing a redevelopment of its existing water power, started as a land development scheme. Typical of the period, a land development company was formed which built a dam and power canal. Land between the canal and river bed was sold along with certain "mill rights". Those companies buying the land were entitled to water to run their machinery for which they paid a fee each year. The site was a successful mill development. When the move to the west started, Lawrence, Mass., started its decline.

At the same time Lawrence was under development a similar scheme was hatched for the small town of Falls Village, Conn. A 15-foot dam was built across a 75-foot falls along with a power canal. Attempts were made to then sell the land between the canal and the river bed. The plan was a total failure. No factories were ever built. The dam and canal went unused from 1840 until 1914. At that time a small utility was formed, a hydroelectric plant was built (9 Mw) and it has been producing about 50,000,000 kwh a year for the past 68 years. The plant typical of well run and maintained operations looks as if it was built yesterday.

New York State is but one part of the Northeast but its hydropower history and its future redevelopment will undoubtedly be a model for other states. Our findings in New York are comparable to findings elsewhere. The assessments, inventories, and redevelopment work now going on in New York State is now proceeding on schedule. The Center for Regional Technology at the Polytechnic Institute of New York is playing a key role in this redevelopment activity.

Center programs

At the request of the Allis-Chalmers Hydro Turbine Division in February of 1977, the Center for Regional Technology engaged in an assessment of the regional marketing potential of low-head hydropower redevelopment in the northeastern states. Our findings indicated that a definite market exists for low-head hydroelectric technology in this area. We reviewed 5,300 dams using whatever useful information could be obtained by previous studies, governmental records, and maps. From this we were able to select approximately 1,600 existing low-head dams which were estimated to be able to produce hydroelectric power in the range of 50 to 5,000 kw. Heads of 15 to 45 feet were examined. A sampling of 25 representative dam sites were examined in more detail, yielding 12 with average heads of 22 feet and power estimates of 1,150 kw. These were deemed to have good prospects for redevelopment. If this percentage would hold true then approximately 750 low-head dams would be candidates for redevelopment.

Prospects for developing this resource into a market for low-head hydroelectricity appear to relate three variables: (1) how to respond to individual site characteristics in standardized ways; (2) how to keep economic costs as low as possible; (3) how to relax institutional barriers, such as cumbersome licensing procedures.

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Llewellyn Thatcher is an associate research professor at the Department of Civil and Environmental Engineering at the Polytechnic. He earned a B.S.E. in mechanical engineering from Princeton in 1955, a B.S. in civil engineering from Columbia in 1959, an M.A. in civil engineering from MIT in 1960, and an Sc. D. in ocean and coastal engineering from MIT in 1972.

There is widespread feeling that while this resource will be competitive in the long term, a variety of up-front governmental measures are needed now to get things moving. These range from faster one-stop licensing procedures to financial and technical assistance. There is legislation aimed at spurring small scale hydropower development now contained in the yet-to-be-passed National Energy Act. It is comprised primarily of low-interest loans ($100 million/year for the next three years) plus an additional $10 million a year in grants for feasibility studies. It is too early to assess whether good legislative and administrative intentions will turn into stimulating measures although the signs are promising.

In June of 1977, New York State Energy Research and Development Authority (NYSERDA) contracted with the Center to perform two major works in small hydropower: (1) to produce an inventory of all existing dams whose potential was at least 50 kw and (2) to select up to 20 representative sites and examine them in greater detail to uncover the institutional, financial environmental and legal problems associated with each type of site. This work is well under progress and an inventory listing 1,500 sites has been published. New York State has on record over 6,300 dams. In addition we have received either by phone or mail the names and location of several hundred others that do not appear on any list.

Phase II of this project consists of the selection of up to 20 representative sites and investigations of them in greater depth. The work to screen down our randomly selected sites is now under way. The Center's field team consists of experts in the fields of hydroelectric generation, dam construction, site geology, environment, sociology, plus support staff. The studies of our selected sites will be complete by August 31 [1978].

In addition, NYSERDA had also retained the Center to help prepare applications for feasibility studies as sponsored by DOE out of Idaho Falls. Eight such proposals were prepared and submitted. The Center was given the responsibility of meeting with all parties to each proposal (NYSERDA, the site owner, the Center, and the engineers), ironing out differences and certifying to NYSERDA that all proposals were properly completed. In addition, NYSERDA has further retained the Center to oversee the feasibility study work on the four proposals that have been funded by DOE as well as following the progress of one successful proposal submitted by Niagara Mohawk independent of the State.

Interested agencies

It is clear that the New York State Legislature is taking the redevelopment of small scale hydropower seriously. An allotment of $500,000 has been made by the Legislature to the Institute for the work to be done principally in the small hydropower field. This is in addition to any other money NYSERDA wishes to spend.

NYSERDA is not the only entity within New York State that has developed a lively interest in small scale water power. The Army Corps is conducting an assessment as is the New York State Electric and Gas Company. This private utility which at one time operated numerous hydroelectric sites is once again looking to redevelop both its previously retired sites and open new ones. Their first steps at this time are cautious. However the Power Authority of the State of New York is not so timid. This authority has been likened to the state's TVA. It produces power to be sold wholesale to the private utilities to governmental units. The Power Authority has up to now operated only two hydro sites: Niagara Falls and the Moses Dam on the St. Lawrence Seaway. Using the inventory developed at the Center, they are seeking suitable sites particularly those located on municipal water supply systems. It has presently contracted work to Tibbits-Abbett-McCarthy-Stratton to do the feasibility studies on installing hydroelectric generation on two New York City aqueducts.

Niagara-Mohawk is the largest private utility in New York in terms of the size of its service area. It perhaps is one of the leaders in the redevelopment of small hydropower. One year ago they announced a $200,000,000 program over 15 years to bring back on line 200 Mw of power at 15 sites.

DOE feasibility awards

As mentioned before, NYSERDA has received four awards from DOE to perform feasibility studies. These sites are:

1. Lake Placid: this site of the next winter Olympics has 2 sites as part of a cascading system. Together they have a potential of 500 kw.
2. Watervliet: a small city north of Albany is now using water power to drive pumps that operate its municipal water supply system. A 1,200′ penstock delivers 90% of the water to drive the pumps and 10% is used for human consumption.
3. Croton Falls: this is an old mill now declared a local historical landmark. It once produced hydroelectric power and now has recently been converted to produce cellulose insulation. The site is located on an outlet to the New York City water supply system and is guaranteed 47 cfs. Often the flow exceeds this minimum.
4. High Falls: an old utility site owned by Central Hudson which now is looking to study its potential for redevelopment. It once was rated at 1.1 Mw and the civil works are entirely intact with the exception of a plugged penstock.

In addition, Niagara Mohawk has been awarded one proposal to study the redevelopment possibilities at Little Falls, N.Y. This site once belonged to them and produced power. Many years ago it was abandoned and turned over to the town. This site lies on the Mohawk River which parallels the Erie Barge Canal.

Current inventory studies

The objective of these studies is to accumulate, in the form of a readily accessible database, information pertaining to dams and dam sites with some potential for hydroelectric development in the State of New York. A limitation has been established below which the dam or site will not be included in the inventory. This limitation is a head of 6 feet or, if capacity can be estimated, a capacity of 50 kw.

Sources of Information

In creating the data base we sought out different sources of information available in published form. The first source of information with which we have dealt is that coming from the U.S. Army Corps of Engineers Inventory of Dams. The second basic source of information is from the Federal Power Commission (FPC), now Federal Energy Regulatory Commission (FERC). The different sources which have been used are listed in Table 21.

A. National Program of Inspection of Dams
U.S. Army Corps of Engineers, Washington, D.C.
Volume III, May 1975.

B. Hydroelectric Power Resources of the United States Federal Power Commission Report, Washington, D.C. January 1976.

C. Planning Status Reports
Water Resource Appraisals for Hydroelectric Licensing
1. Genesee River Basin
2. Lake Champlain Drainage Basin
3. Hudson River Basin
4. Black River Basin
5. Oswego River Basin
6. St. Lawrence River Basin
7. Eastern Great Lakes Tributaries
8. Alleghany River Basin
9. Delaware River Basin
Federal Power Commission, Bureau of Power, 1964, 1965, 1966.

D. 1939 List of Plants
Federal Power Commission.

E. "308" Report
Corps of Engineers. 1931.

F. Multipurpose Water Resources Study
1. Eastern Susquehanna River Basin
2. Chemung River Basin
Prepared by T A M S for NYS Water Resources Commission, Conservation Dept. Division of Water Resources, April 1969.

G. Reconnaissance of Water Resources Potentials
1. Hudson, Mohawk, Long Island Areas
Prepared by TAMS, CDM, & LBG.
2. Western New York Area
Prepared by Harza.
3. Central New York Area
Prepared by Metcalf & Eddy.
4. St. Lawrence Basin & Black River Basin
Prepared by Uhl Hall & Rich.
for NYS Water Resources Commission, Conservation Dept. Division of Water Resources, 1966.

H. Alternatives for Water Resources Development & Management, Alleghany River Basin
Alleghany River Basin Water Resources Planning Board, March 1971.

I. Existing & Potential Power Sites
NENYIAC Report, Vol. 1, Part Three, Section VIII, Table 1, 1955.

Table 21. Information sources.

General approach to inventory

In this project a particular sequence of data accumulation was followed. We do not recommend this in any way as the optimum sequence. It resulted from decisions taken at the beginning of the project, at a time when the makeup of the different sources of information was essentially unkown. It is only by getting into the sources of data that one is able to discriminate and identify those which furnish the largest amount of basic data from those which do not. It had been our original hope that the Corps of Engineer's inventory would include dams from all other sources, especially those contained in the FPC reports. Such did not turn out to be the case; as a result, we were forced to wait until we had accumulated data from several additional sources before utilizing our data base for further studies.

Data from old lists is old data. There have been many changes in the physical characteristics in dams over the years and these changes are in some cases very difficult to document. Outstanding among these difficulties is the ownership of the site. The ownership of the site can change many times and if the site is dropped from a list, recent ownership can only be determined by going to the local Tax Assessor. As there is no way of knowing that the information one has is outdated, one can only adopt procedures which are designed to accumulate additional data. In this regard it should be mentioned that a telephone survey was initiated for a selected list of 75 dam sites. The telephone survey resulted in new information on many of the sites. The question then becomes; should this new word of mouth information replace that which had the authenticity of being in print? Decisions must be taken in such a study as to what data are considered valid and what data not valid.

An alternative to taking such decisions would be the construction of a database which, for each item of data, keeps track of the source of that item including previous information and its source. Such a database is many times more expensive than one in which only current information is stored. Although such a multi-level, or historical data base could be useful, its expense may not always be justified. In this study, we have adopted a current inventory or single-level approach with the resultant problem of having to make decisions as to what is considered the most recent, valid information. In back-up sheets, however, we have identification of all sources of information.

Current database statistics

On May 5, 1978, our database had a total of 1,615 sites, 1,046 of which were sites with dams, the remaining 569 being sites without dams. Statistics on the density of different data items is given in Tables 22, 23, and 24. This information is of great interest in as much as it indicates the quantity of information available for the sites. In some cases it indicates that our original categories were not appropriate. An example of this is the category "Flow". Flow is given in a few data sources; however, it is very hard to know whether the flow given is

Total records read: 1,045

Category	# of Items	% Filled
State no.	757	72
Name	1020	98
Owner	912	87
County	1016	97
Town	849	81
Basin	1003	96
Stream	1000	96
Gage	737	71
Quad no.	332	32
Quad nm.	220	21
Purpose	847	81
Type	867	83
Lat.	809	77
Long.	809	77
Const. date	699	67
Height	767	73
Length ft.	407	39
Capacity	742	71
Drainage area	919	88
Flow	4	0
Head	255	24
Cap. exist.	173	17
Cap. pot.	851	81
Gen. exist.	163	16
Gen. pot.	86	8

Table 22. Database statistics for sites with dams.

Total records read: 570

Category	# of Items	% Filled
State no.	1	0
Name	351	62
Owner	6	1
County	564	99
Town	304	53
Basin	568	99
Stream	566	99
Gage	1	0
Quad no.	0	0
Quad nm.	127	22
Purpose	99	17
Type	30	5
Lat.	232	41
Long.	232	41
Const. date	2	4
Height	240	42
Length ft.	2	0.4
Capacity	180	32
Drainage area	553	97
Flow	136	24
Head	59	10
Cap. exist.	1	2
Cap. pot.	292	51
Gen. exist.	2	0.4
Gen. pot.	36	6

Table 23. Database statistics for sites without dams.

Total records read: 1,615

Category	# of Items	% Filled
State no.	758	47
Name	1371	85
Owner	918	57
County	1580	98
Town	1153	71
Basin	1571	97
Stream	1566	97
Gage	738	46
Quad no.	332	21
Quad nm.	347	22
Purpose	946	59
Type	897	56
Lat.	1041	65
Long.	1041	65
Const. date	701	43
Height	1007	62
Length ft.	409	25
Capacity	992	57
Drainage area	1472	91
Flow	140	9
Head	314	19
Cap. exist.	174	11
Cap. pot.	1143	71
Gen. exist.	165	10
Gen. pot.	122	8

Figure 24. Database statistics for all sites.

mean flow, 25% duration flow, or some other definition of flow.

The database will have many categories unfilled if the inventory includes many data sources. For example the FPC 1939 list gives only the site name, approximately location and horsepower. In such a case we have included this dam in our inventory. Often we have found additional information about the site if it has appeared in a separate list, but if such a separate list is not available this very abbreviated information is none the less kept on record in hopes that perhaps it will be augmented at a later date, possibly through a site visit.

Computerized database

The database for New York State hydroelectric sites has been created utilizing a variety of programs. Some are specific one-time application programs which were needed during the development process, others are more general and therefore require documentation. These general programs can be broken down into three basic categories:

I. Record creation
II. Record updating
III. Record retrieval and display

The following sections will describe these three general programming areas in terms of the actual programs developed.

Record creation

The basic input to the database system was information coded on a long (42 inch) sheet with 30 vertical columns. In many cases many of the columns were not filled, for example the Public Utility Service Area (P.U.S.A.) could only be determined after the basic information was coded. Consequently, the evaluation of a database loading program included a provision for both a full line of data (almost all columns) and a very sparse line of data such as that necessary to identify a site with no dam.

The basic data record is described in Table 25 and is stored according to a Polytechnic identification number, hereafter referred to as "POLYNO".

Record updating

Information in the database is subject to modification. Often new data sources provide additional or more up-to-date information, and to enable the database to be modified an Update program has been developed to enable the user to specify the new items to be included.

The program will list the correction categories and the old or previous value of the item. Then, after all grouped corrections for a single site have been processed, a new list of the entire site record is produced.

Item No.	Item	Coding
1	Polyno	Numeric
2	State no.	Char. (10)
3	Pusa	Char. (18)
4	Name	Char. (50)
5	Owner	Char. (60)
6	County	Char. (16)
7	Town	Char. (20)
8	Latitude	Numeric
9	Longitude	Numeric
10	Basin	Char. (20)
11	Stream	Char. (52)
12	Gage	Char. (10)
13	Quad no.	Char. (4)
14	Quad name	Char. (16)
15	Const. date	Numeric
16	Pot. date	Numeric
17	Purpose	Char. (16)
18	Type	Char. (12)
19	Height	Numeric
20	Length	Numeric
21	Capacity	Numeric
22	Drainage area	Numeric
23	Flow	Numeric
24	Head	Numeric
25	Capacity, existing	Numeric
26	Capacity, potential	Numeric
27	Generation, existing	Numeric
28	Generation, potential	Numeric
29	Selection code	Numeric
30	Remark code	Char. (2)
31	Data source	Char. (4)

Table 25. Database record.

Record retrieval and display

(1) Basic retrieval by POLYNO: The retrieval of site information has been the objective of several programs of different degrees of generality. The basic retrieval program is one which lists out the complete site record identified by its POLYNO.

(2) Sorted site description by county: This output consists of seven lines of information for each site sorted by county, then by stream name and then by town. This listing has been made available to the public.

(3) Sorted lists of selected data: Programs are available that permit the user to produce sorted lists of selected data from a specified group of records. One such list prints one line of information for each site and the sorting can be on as many fields as required. For example, this program has been used to prepare a list sorted by basin, then stream name within basin. These sorted listings have been found useful in identifying sites and also in highlighting areas of contradiction, error or gaps in the database. They can also be useful for identifying and ranking sites in accordance with the magnitude of different physical parameters and power capacities.

(4) Special purpose programs: Several special programs have been useful to the project. For example one is essentially a "sorted list" as described above, but the sort is done on a parameter called "available capacity." This parameter is calculated from values of potential capacity and existing capacity stored in the database. In the event that potential capacity was not given from one of the data sources, it was estimated in terms of the drainage area and head.

Estimates of potential capacity and energy

Some of the data sources used have supplied this information and when supplied it has been utilized. The majority of sites in our data base did not have this information and it was necessary to find a means of estimating the potential capacity based on whatever information was available for the site.

The principal assumptions made in order to obtain such estimates were as follows; the turbines would be installed to take advantage of the 25% flow duration value. Previous studies have shown that for the New England region one can approximate the 25% flow by 2 cfs per square mile drainage area. Thus the design flow, Q25 in cfs, is assumed equal to twice the drainage area of the site in square miles. Assuming the 88% turbine efficiency and 95% generation efficiency, one can now estimate the potential capacity in kilowatts by the formula

$$\mathrm{kw} = \frac{H \times DA}{7}$$

where H is the head in feet and DA is the drainage area in square miles.

The application of this relationship requires the knowledge of the drainage area and also of the head available for power generation. This latter quantity is rarely available for those sites which have not been considered previously for hydroelectric purposes. This is especially true for those sites whose information was obtained from the Corps of Engineers inventory as their concern was for dam safety not hydropower. Consequently, if the head was not available the structural height of the dam was used for this estimate.

In some cases more detailed studies were made and for these studies actual flow duration data were utilized for the purpose of calculating the potential capacity. In these cases the 25% flow duration was obtained and utilized in conjunction with relationships prepared by Tippetts-Abbett-McCarthy-Stratton in conjunction with Polytechnic (Table 21). The drainage area is not always available. It can be obtained from USGS Quandrangle sheets, a procedure implemented by Polytechnic for a selected group of sites. We have prepared estimates (Table 22) of the difference between potential and existing capacity from our current database. We expect these totals to be reduced as we eliminate duplications. We do not mean to imply that this capacity is implementable. Additional work must be completed before such an estimate is made.

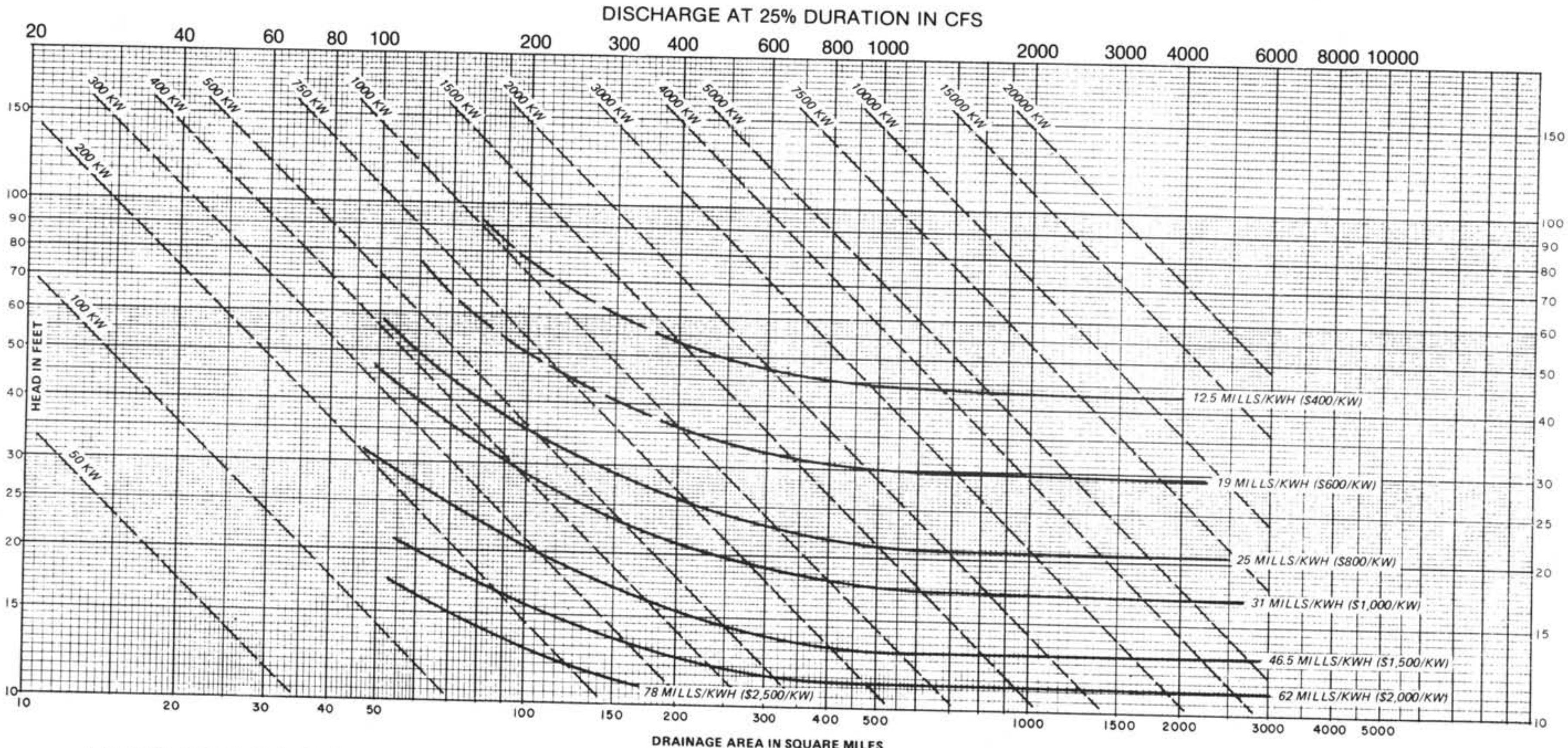
Estimates of cost of capacity and energy

Three typical power house layouts were prepared at Polytechnic, and quantity take-offs were made. TAMS applied unit prices to these quantities, included machinery costs provided by Allis-Chalmers, and added other costs pertaining to project investment and annual costs. Typical curves were prepared for installed capacities and energy costs relationships (Figure 88). These relationships could be used with head and drainage area as the basic input or, in the case of more data being available, head, 25% duration flow, and area under the flow-duration curve. (Figure 88).

There were many assumptions made in the generation of this cost data and it is important to recognize that it is, in fact, only a very approximate estimating tool. Field examinations must be made in order to better define the requirements for civil works and such requirements compared to the assumptions used for these curves.

Initial field reconnaissance

The approaches taken to the selection of representative sites was with the aim of having the selection substantially a random one, although it is recognized that randomness in a strict statistical sense is not possible. A specialized listing of the sites with dams was made, grouping the sites into five distinct categories of potential capacity. Within each category the sites were sorted by head (or by dam height if head was not available). Then, in each category of capacity, an attempt was made to select three sites with distinct variations in head. Once this selection was made, some adjustment of sites was necessary in order to make the procedure of site visits more feasible logistically. It was also necessary to replace some sites which were located in state parks, particularly the Adirondack Mountain preserve which has a "forever wild" policy.



From: "Evaluation of Hydroelectric Potential in the North-east" by Eugene O'Brien, Tippetts-Abbett-McCarthy-Stratton, 345 Park Ave., N.Y., N.Y.

1. Rated installed capacity for 2 cfs/square mile.
2. Annual energy equivalent to rated capacity for 4000 hours.

Figure 88. Typical installed capacity and minimum energy cost for small hydro plants at existing dams, northeastern United States. (Revised April, 1978.)

Makeup of the team

A field reconnaissance team was selected consisting of representatives the Polytechnic staff with experience in civil-hydraulic engineering, sociology and environmental evaluation, and two specialized consultants, one a hydroelectric engineer and the other a geologist. The general results of the initial field reconnaissance showed the difficulties in approaching hydroelectric development in this manner.

The selection of sites based on a somewhat random rather than an ideal selection criteria goes contrary to what specialists in the field have been doing. Instead of studying only the best sites, these specialists found themselves looking at mediocre sites, sites whose development was not based on hydropower considerations. It was difficult to be enthusiastic about many of the sites for this reason. Although complete sets of Quadrangle sheets were available, there was no question that more work should have been done in making sure that the site to be visited still had a dam. Some of the sites in the database came from old listings, and in two instances the field team was confronted with the remains of a previous site rather than a dam with a specified height.

In general the sites were restricted in terms of possible locations for civil work. This can be attributed to the rapid urban and rural growth which has taken place over the past 50 years making reclamation of property and environmental consideration a primary consideration for the development for future sites. A site located far from human activity is often found in a state park, which in itself presents other difficulties to hydroelectric development.

Program through summer of 1978

The database is continually being revised, cross checked and expanded. In particular, we are attempting to go through the database utilizing maps and whatever stream profiles we can obtain as a means of identifying sites and duplications of sites - an inevitability of working from many different data sources. We are continuing our contacts with government agencies and power utilities who also have information on hydroelectric sites in an effort to ensure that their information has been accurately included in our database. Additional field reconnaissance will be undertaken in June with the benefit of our experience in the initial field trips.

At some point our database will have to be considered complete, although it is our experience that such a "defined" completion is relative as the accumulation of additional information seems to be a continuous process. A final report will result from our study and included in that report will be guides for site evaluation resulting from our field reconnaissance and other analyses.

Institutional considerations

An important factor in the redevelopment of small scale hydroelectric installations will be the institutional barriers. Since the time these sites were first made operational, a number of new uses and regulations have come to bear on their continued use or redevelopment.

UTILITIES: Sites once owned and operated by utilities represent both the best and least chance for redevelopment. The operating expertise of the utilities favors them as the prime redevelopers of small sites. However small sites are not economically attractive when compared to the opportunity of constructing large fossil or nuclear power plants. Only now that there has been some publicity have the utilities within New York State begun to move towards at least studying abandoned sites. Older sites that have been fully depreciated are no longer used in determining the rate base of a utility. Now that the cost of fuel is climbing some of the old sites can act as a fuel saver. It does seem that there will need to be a change in the regulations of the state Public Service Commission that will encourage utilities to rehabilitate old sites.

PARK PRESERVES: Clearly the largest number of excellent sites lie within and on the edge of the Adirondack Park Preserve. This tract of land, larger in area than Vermont, has been legislated to be "forever wild". No development of any kind can be made without express permission of the governing board. The cutting of a single tree is regarded as an invasion of this precept. As a result no water usage may be made that had not already been in effect before 1910 except where there is a clear safety problem.

DEPARTMENT OF ENVIRONMENTAL CONSERVATION: The new sensitivity to environmental considerations, particularly in the area of water quality, fish migration, and water releases, has added another component to hydroelectric generation that did not exist when the sites were first constructed. Where old dams have been abandoned, new uses and new patterns of water use are developed. There are environmental concerns regarding the new release of colder bottom waters of large impoundments in places where only the warmer surface waters have been flowing over a spillway. New sewage treatment plants downstream of an abandoned site could be adversely affected if insufficient water is released over a 24-hour period.

LACK OF INFORMATION: Data on dams is either incomplete or out of date. Over 1/3 of dams listed have no owners of record and in a number of others the listed owner is incorrect. A significant number of listed dams no longer exist and our studies have located several hundred others that do not appear on any recent records. Information on dam height, length, stream flow, drainage area, etc. is all too frequently missing.

INSURANCE COMPANIES: At this point few companies are willing to write liability insurance in a business that sees a small return. In addition small, older dams are usually poorly maintained, and are poorly secured from trespassers. Insurance premiums when available are usually quite high.

FEDERAL FLOOD INSURANCE PROGRAM: Most communities where dams are located are not participants (or will be) in the program conducted by the

SITES WITH DAMS

Capacity Range	No. of Sites	Potential Capacity * kw	Existing Capacity kw	Undeveloped Capacity kw
>15 Mw	24	692,396	96,902	595,493
5-15 Mw	55	491,347	148,351	342,996
1- 5 Mw	105	261,113	67,005	194,108
.5-1 Mw	32	22,356	3,650	18,706
.25-.5 Mw	55	19,546	560	18,986
Total	271	1,486,757	316,468	1,170,289

SITES WITHOUT DAMS

Capacity Range	No. of Sites	Potential Capacity * kw	Existing Capacity kw	Undeveloped Capacity kw
>15 Mw	26	863,012	0	863,012
5-15 Mw	40	360,304	0	360,304
1- 5 Mw	75	168,482	0	168,482
.5-1 Mw	38	25,961	0	25,961
.25-.5 Mw	39	14,081	0	14,081
Total	218	1,431,840	0	1,431,840

* These figures are only rough estimates and in no way infer that the development of the capacity is either economically feasible or physically possible.

Table 26. Current capacity estimates.

Federal Flood Insurance Administration of HUD. Any new structure near a stream must meet the requirements of this program. Developers will have to locate all power installations so as not to encroach on established floodways.

FEDERAL ENERGY REGULATORY COMMISSION: The time and cost to license a site with FERC can simply be prohibitive. New regulations for small sites have been suggested in order to speed the process. This new system will be helpful only for sites with heads lower than 25 feet, less than 2,000 hp, and having an impoundment surface area 10 acres or less.

OWNERS OF RECORD: Even if listed correctly, many owners are hard to locate. Small unused dams represent a liability and many owners cannot give them away.

Conclusion

In spite of a number of barriers - institutional and economic - there is a growing interest in redeveloping small sites in the Northeast. A number of private developers as well as individual site owners are moving to take advantage of the D.O.E. programs and congressional initiatives. The heightened interest of both government and private individuals is mutually reenforcing. As grassroots interest rises, local and federal governments move to respond. As government shows more interest, a corresponding interest is aroused on a local level.

Small scale hydropower redevelopment may have only a small impact on a state's overall energy production. However, its impact on the locality in which it is sited can be significant. This is especially true if a redeveloped site is used to attract an industry that might not otherwise locate there, or to provide power for a municipality's own requirements, thus lowering governmental costs to local taxpayers. In a sense the impact of a number of small sites is greater than the impact of the whole.

Material contained herein was produced under contract to:
- NYSERDA
- Allis-Chalmers Hydro Power Division
- Power Authority of the State of New York

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Appendix

Bureau of Reclamation photo

Easton Diversion Dam, a concrete gravity weir structure on the Yakima River, Washington.

Appendix

On Sept. 6-9, 1977, a workshop was sponsored by the U.S. Department of Energy in Durham, New Hampshire, on the subject of low-head/small hydroelectric energy development. A number of panels considered various aspects of the subject. The authors of the present publication, "Low-Head Hydro", felt that the recommendations presented in the completion report of that workshop are of sufficient importance to bear repetition here.*

This Report was developed from the Low-Head/Small Hydroelectric Workshop held in September, 1977, at the New England Center in Durham, New Hampshire.

Sponsored by the Energy and Research Development Administration's Division of Geothermal Energy, the Workshop was organized to provide ERDA with guidance for their low-head hydro program planning. The Workshop lasted 3½ days and included 121 participants representing governmental agencies, energy offices, manufacturers, conservation agencies, universities, and legal agencies. Manufacturers from France, Japan, Canada and Austria were also present.

The participants focused on the issues of resource assessment, engineering development, institutional and legal barriers, environmental and safety issues, economics and marketability, and demonstrations. This Report contains extensive coverage of the participants' deliberations on these issues as well as complete coverage of all the Workshop activities. Over ninety specific, as well as generalized, recommendations, responding to the focused issues are documented from conception to final form.

***"Low-Head/Small Hydroelectric Workshop," by L.H. Klotz and F.K. Manasse, New England Center for Continuing Education, University of New Hampshire, Durham, N.H., Sept. 6-9, 1977.**

Panel I —
Resource Assessment — Final Recommendations

The panel sees a need to assess the role of lowhead/small hydroelectric generating plants and their integration into the national energy plan. It is imperative that an assessment of the resources be undertaken to further the development of "small" hydroelectric systems.

It is clear to the panel that a resource assessment document can be a powerful instrument in the formation of public policy at all levels of government. An awareness of the magnitude and potentialities of small hydro-power on the part of the American public can be of significant importance in "furthering" its development.

Program Scope

To assess the potential of the expansion, redevelopment, and development of hydroelectric sites with special emphasis on sites with potential capacities less than 15 Mw and/or heads less than 20 meters.

The panel recommends that the following priorities be followed by US/ERDA in allocating budget and manpower resources.

Priorities:

1. 50 kw - 15,000 kw on existing dams.
2. 50 kw - 15,000 kw on new sites.
3. Over 15,000 kw on old and new sites.
4. Less than 50 kw on old and new sites.

This prioritized list represents the panel's concern that small-hydro development be advanced as quickly as possible. Existing sites represent the possibilities with the least environmental and capital cost restraints.

Assessment Program

The panel recommends the assessment be conducted in two stages. Stage 1 should be conducted on a national level to provide overall perspectives on national and regional potentials. Stage 2 should be conducted on a region by region basis to provide specific site information. It is expected that the national assessment will be of primary use to federal agencies in the formulation of public policy and allocation of budgetary funds. This assessment will also point out to the regions the magnitude of the resource that might be available to them. This document should act as a catalyst to various national regions and states to refine the national assessment in terms of their own needs.

Recommendations

I. National Assessment US/ERDA FY77-78
   A. Be completed using FY77-78 funds.
   B. Conduct a compilation of existing "small" hydroelectric potential.
   C. Establish and document criteria for screening procedures.
   D. Screen information to eliminate pre-empted or obviously impractical sites.
   E. Publish findings of national assessment of "small" hydroelectric potential.

II. Regional Assessment
   A. This assessment is needed to provide more site-specific information to potential hydroelectric developers and users.
      1. For Potential Developers:
         a. Municipalities (Utilities)
         b. Utilities (Investor Owned)
         c. Private interests
      2. For private developers
      3. For others such as state, county and municipal agencies interested in regulatory work, public policy, tax rates, etc.
   B. ERDA should fund this assessment working in close cooperation with associations and the states. The panel suggests that regions be defined in the same manner used by the Federal Power Commission and the Army Corps of Engineers. This work should be completed as soon as possible with the expectation that such assessments will take no longer than two years.
   C. Inventory of sites by region or river basin should be made which will include the following.
      1. Site Characteristics
         a. Head
         b. Drainage area
         c. Flow duration curves
         d. Potential generating capacity
         e. Potential storage capacity
         f. Overall river capabilities
      2. Legal Factors
         a. Ownership
         b. Deed restrictions
      3. Civil Works
         a. General description
         b. Age
         c. Type of construction
         d. Present or estimated hydroelectric capabilities
   D. Review the costs and benefits of a number of representative sites suitable for development. This assessment should cover both new and existing sites, sites of varying heads and capacities, and sites with various kinds of civil works, i.e., old mill sties, existing old powerhouses etc. The purpose of this review is to give potential developers an initial concept of the magnitude of the potential investments needed as well as the possible benefits.
   E. Investigate institutional and legal factors peculiar to the region.
   F. Investigate environmental factors specific to the region.
   G. Assess the impact of installations in terms of other benefits to the region such as:

1. Employment opportunities
2. Benefit to the region or state by lessening their dependence on outside sources of energy.
3. Multiple water uses

Panel II —
Engineering Development —
Final Recommendations

After a review of basic hydraulic turbine technology and an introductory discussion on the state of the art, the consensus is as follows:

Technology

A basic differentiation concerning the technology low-head hydro should be made between small and large low-head hydroelectric power projects. Modern technology is available in the United States as well as abroad to provide economical low-head turbines of any capacity needed. Tube, Bulb, and Cross Flow turbines have been installed in USA. However, the Rim Generator technology has been applied to small units only in Europe. The demand for such equipment has been very limited in the United States due to past economic conditions. With the changed market conditions, manufacturers are able to immediately meet the demand.

Standardization

There does not appear to be a substantial need for large R & D funds for the purpose of improving low-head turbine designs. It appears that the problem basically is economic versus uneconomic low-head hydro. A key factor in improving economy can be standardization. Standardization could be developed for the three basic conditions, retrofitting of existing hydro plants, installation of power generation equipment at existing dams, and construction of new dams for power production. It is estimated that the overall cost of low-head hydro site development both with and without existing dams could be reduced by 10% to 15% if equipment and civil construction were standardized. The saving would come from standardized design criteria and predeveloped dimensions simplifying construction items. Among structures that should be studied for standization are the following: 1) powerhouse; 2) concrete embedment of equipment; 3) intake shape, gates, hoist, motor, and controls; 4) draft tube shape and closure bulkhead; and 5) spillway crest, gates, piers, hoists, and control. Other items undoubtedly can be added to the list during initial planning of the standardization studies.

Since many of the sites would involve existing dams, standardized structural and hydraulic evaluation criteria and inspection procedures should be developed.

The basis for standardization begins with the hydraulic turbine because it influences intake, generator, tailrace and other component configurations. ERDA funding to expedite turbine standardization can provide a potentially increasing benefit in the associated equipment and civil structures.

The immediate need and indicated demand are for units suitable for heads up to approximately 18 M (58'). Such units must be made in reasonable physical size and design head increments to provide a suitable range of capacities.

Having standardized the turbine, then the generator, auxiliaries, electrical systems and accompanying containment structures can also be made in modular increments. The standardization of the civil structures would apply above the basic foundation substructure. The foregoing in effect will provide packaged plants.

Automatic control and monitoring systems are available and must be utilized. The complexity and cost of the controls (no governor, induction generators etc.) can be reduced if the plant is part of a large system. In smaller systems more elaborate measures are necessary for voltage and frequency control. As with turbine standardization, ERDA funding should be made available to accelerate standardization of other plant components.

New Technology

Although we feel that current technology provides an adequate immediate technological base for low-head hydro development, innovative technology should be encouraged and researched.

Demonstration Program

Demonstration installations are needed to help develop the most favorable and compatible regional interfaces (developer, purchase, municipal, state, federal regulatory agencies, distribution), so that the benefits may be most widely distributed and specific area characteristics identified and accommodated.

When fish ladders and other fish or recreational facilities are desired in connection with low-head hydro, these facilities must be funded separately from the hydro demonstration and development program since these small installations may not be able to support these specialized interests. Solar/hydro/wind/hydro and low-head hydro/pumped storage systems have their own unique technical and institutional problems. They therefore should be included in ERDA funding for programs other than low-head hydro.

Site Selection

Low-head hydro economics are affected by the extent to which reservoir water level and turbine discharges can be varied. If pond levels can be fluctuated, there is potential for increasing the conomic value at present price levels by $500 to $1,000 per kw through re-timing the production of capacity and energy. The overall economic effects require detailed investigation and presentation to the public. ERDA funding would help accomplish this purpose. Sitespecific engineering/economic studies and demonstration installations at existing and, eventually, new dam sites should be funded by ERDA. Criteria for selection should include the following:

- Regional representation.
- Production of an adequate amount of energy (500 to 5,000 kw plant capacity for example.)
- Cost effectiveness.
- Use of best available technology including standardized designs.

Site Inventory

An inventory of sites should be developed concurrently with the standardization and early demonstration projects. The inventory will indicate sites desirable for successive later developments or demonstrations. The inventory would be prepared in standard format by river basins and would include the following for each site listed.

1. Headwater and tailwater elevations.
2. Dam height and length.
3. Water conduit length and diameter if appropriate.
4. Flow duration characteristics and indicated annual energy availability.
5. Minimum power output and minimum low flow if available.
6. Parametric cost estimates of land, power plant, building, dam, spillways, generating equipment, site access auxiliary equipment and transmission connections.
7. Percentage for engineering, overhead, etc.

Incentive Price Support

At many low-head hydro sites, the cost of energy exceeds that obtainable currently from alternative thermal sources. The annual costs of a hydroelectric plant, once it is built, are not affected significantly by inflation, whereas the fuel situation is such that inflation can be expected, so that the price situation will be reversed. ERDA can encourage low-head hydro development by providing the initial short term difference in energy cost with the aid of enabling legislation.

Summary of Priorities

1. Site inventory, specific site selection for demonstration projects, and development of standardization should be carried on concurrently and receive the highest priority.
2. Initiation of enabling short term incentive price support legislation.
3. Support R & D of innovative technology where resource assessment indicates potential for substantial gain in production of cost-effective energy.

Recommendation 1

Problem

Design standardization of plant components and civil works to reduce engineering effort and speed up development.

Recommendations

Development of design criteria and design standards involving specifications for the following: stream flow analysis; dams, spillings and foundations; intake structures, gates; pinstocks; power plant structure; tailways.

Who Can Do The Job?
An A/E firm or the ASCE.

Concluding Remarks
The only possible barrier to using this standardization approach would be unique local conditions at the site.

Parameters

		Research	Development	Demonstration
Time Frame	Start	now	now	
	Finish		6 mos.-1 yr.	
Cost			250,000-500,000	
Federal Role			100%	

Recommendation 2

Problem
Lack of organized and reliable site data.

Recommendations
A resource assessment with site-specific data.

Who Can Do The Job?
A/E's by drainage area and coordinated by ERDA or A/E managers.

Concluding Remarks
This program should receive high priority.

Parameters

		Research	Development	Demonstration
Time Frame	Start	now		
	Finish		1 year	
Cost			$9,000	
Federal Role			50%	

Recommendation 3

Problem
High cost of custom-designed turbines.

Recommendations
Standardization of turbine component design.

Who Could Do The Job?
Manufacturers.

Concluding Remarks
The only possible barriers to implementation of standardized parts could come from unique site conditions. This program should receive high priority.

Parameters

		Research	Development	Demonstration
Time Frame	Start	now	now	
	Finish		6 mos.-1 yr.	
Cost			$1,000	
Federal Role			50%	

Recommendation 4

Problem
Identify and resolve regional impediments.

Demonstration installations with front-end cost and risk reduction.

Who Could Do The Job?
Municipal and investor-owned utilities, as well as private developers.

Concluding Remarks
Interface delays may impede demonstrations.

Parameters

		Research	Development	Demonstration
	Start			
Time Frame	Finish			1 - 2 yrs.
Cost				$3,000
Federal Role				25%

Recommendation 5

Problem
The high cost of an extremely low-head hydro facility.

Recommendations
The encouragement of innovations.

Who Can Do The Job?
Individuals, industry, and A/E's.

Concluding Remarks
This is a low-priority suggestion under the current needs for low-head hydro facilities in general.

Parameters

		Research	Development	Demonstration
	Start			
Time Frame	Finish	5 years		
Cost		$2,000		
Federal Role		25%		

Panel III — Institutional and Legal

Report by Chairperson

We have identified seven major institutional and legal problems associated with achieving the goal of bringing small hydro projects on line and increasing their role in the national energy picture. We have evolved seven attendant recommendations on how to overcome these problems.

The seven problems we've identified begin with the high cost of licensing, which is also a lengthy and cumbersome process. Secondly, there are myriad laws and a great deal of overlap in federal governmental authorities with regard to water quality, water supply, environmental protection, etc. Third, the overlapping authority is certainly the major problem, as potential small hydro developers may be dissuaded by the complexity of the requirements necessary to obtain a license. There is no place you can go to find out what these requirements are. Fourth, there is often difficulty in finding customers for the electric power, from the hydroprojects, who will pay an economically attractive price per kilowatt hour. Our fifth problem that we identified was the considerable variation in states and localities in terms of laws and regulations impacting small hydro development, and as part of that, the lack of state commitment to developing the resource. Our sixth major problem was identified as recreational facilities. Fish accommodation, for example, can add significant cost to small hydro development. The seventh major problem that we uncovered was with the uncertainties surrounding insuring and financing the small hydro.
We developed three priority criteria to weigh and measure each problem with the attendant recommendation. These three priority criteria were: 1) risk and uncertainty reduction; 2) bureaucratic simplification; and 3) market impact.

The greatest weight in the area of reducing risk and uncertainty was given to recommendation number one, which was to streamline the permitting process. In the area of simplifying bureaucratic procedures, weight was assigned to the area of eliminating overlapping authorities by the establishment of an inter-agency coordinating council on the federal level. In the market impact area, the greatest weight was given to the cost sharing with states for small hydro strategy planning.

Q: In regard to overlapping jurisdiction, would you confine that to federal agencies, or did you include in the overlap state and local government as well?

A: We identified both areas as major problems. The lack of knowledge of state laws is going to be a big hurdle, bigger than the federal in some cases. We were fortunate to have Mr. Gordon Marker with us, who is involved in a small hydro project. Through his case example we were able to learn of these obstacles and it turned out that the state regulatory issues were in this case a greater barrier than the federal.

Draft Recommendations

1. Develop streamlined licensing process.
   - Categorize by size, probably environmental impact, physical conditions.
   - Existing dam sites should be particularly facilitated.
   - Less than 15 Mw. less than 10 meters and 2,000 acre feet of storage as a possible cut-off (for consistency with existing cut-off criteria, especially in the safety area) for streamlined procedures.
2. Fund study of overlapping and possibly conflicting authorities. Executive order or legislation to assure interagency cooperation; consolidation or unification of authorities. Formation of an interagency group on the Assistant Secretary level, perhaps an Interagency Coordinating Council.
3. Preparation of regulatory guidebook, a step-by-step "cookbook" approach to encourage private development of the resource. This will be one method to lower investor uncertainty and local community concerns. Prepare case studies of a range of hydro projects, in order to ascertain institutional issues and barriers that will arise in various situations (e.g., an existing dam with private financing versus a publicly sponsored new site, etc.). This will be a component of the "cookbook".
4. Fund study of problems associated with potential markets for the power. Create incentive mechanisms to facilitate the sale of power to utilities and other entities through marginal cost pricing rather than average cost pricing.
5. Study impact of state and local laws and regulations on development of the hydro resource objective to reduce state and local conflicts and overlap. Variation from state to state is considerable in this area. Cost sharing with states for resource assessment, small hydro development strategy planning.
6. Examine requirements for ancillary facilities such as fish ladders and recreational facilities, and determine who should pay for these facilities (rate payers, federal government, etc.).
7. Study liability insurance and financing problems and opportunities associated with developing the hydro resource. Develop proposal for financial assistance program including tax shelters, low interest loans, loan guarantees. Look at agencies with existing mechanisms that could serve as a model (c.f. Maritime Administration, Commercial Fisheries, Research and Development, Price Anderson Act for insurance example).
8. Redistribute ERDA small hydro funding from mechanical and engineering areas where problems are not easily resolved.

Summary & General

The institutional and legal problems associated with development of small/scale hydroelectric facilities are sufficiently serious that failure to resolve them will significantly delay or preclude most developments. This situation is based on:

- The direct and indirect impacts on project costs.
- The impacts on project risks.
- The complexity and time required to "organize and license a project.

In light of the above, ERDA/DOE should place greater emphasis on resolving institutional impediments to small/scale hydroelectric developments through, for example, reallocating funds within the program.

Problem areas were evaluated against three major criteria:

- Reduction of risk and uncertainty.
- Bureaucratic simplification.
- Market impact.

The following table outlines the major recommendations in relation to these criteria.

Recommendation	Reduction of Risk & Uncertainty	Bureaucratic Simplification	Market Impact
1. Licensing	critical	critical	moderate
2. Overlap (Federal)	low	critical	
3. Education & Promotion	low	critical	low
4. Market Access	low	low	very high
5. Variation in State & Local Regulations	low	very high	low
6. State Commitment to Development	low	very high	critical
7. Competing Uses	very high	low	very high
8. Access to Insurance, Financing Arrangements	very high	low	very high

Recommendation 1: Licensing

Problem

The high costs of licensing are relatively fixed for hydroelectric plants. For the developer, a shorter licensing time can materially reduce front-end and out-of-pocket costs.

Recommendations

Streamline and test the Federal Power Commission licensing process by developing a short-form license application for existing dam applications that meet the following requirements: a head of 10 meters or less, a capacity of 15 Mw or less, and an impoundment of 2,000 acre-feet or less.

The short form will utilize assessment parameters and will be tested with a view toward the standardization of size categories and the range of environmental impact.

Who Could Do The Job?

An interagency task force with the FERC as the lead agency. Other federal agencies would participate under executive order. Technical assistance would be required from the private sector.

Concluding Remarks

Executive order is imperative because of the high doubt that federal agencies will forego their territorial imperative and work together.

Parameters

		Research	Development	Demonstration
Time Frame	Start	now	now	now
	Finish	2 years	3 years	6 years
Costs				total: $80,000
Federal Role		100%	100%	100%

Recommendation 2a: Overlap (Federal)

Problem

The spector of complex and overlapping requirements to obtain a small/scale hydro license or permit acts as a deterrent to project initiation.

Recommendations

1. Provide a "punch list" of steps needed to obtain a license.
2. Provide a federal "Regulatory Guidebook" showing step-by-step what forms and declarations are necessary at the federal agency level.
3. Provide a state and local guide to requirements either as an addendum to the federal guidebook or as a separate guide.

Who Could Do The Job?

1) Department of Energy; 2) Inter-agency group chaired by the FPC; 3) State energy offices.

Parameters

		Research	Development	Demonstration
Time Frame	Start			
	Finish	6 mos.-1 yr.		
Cost		$5,000 @ state		
Federal Role				

Recommendation 2b: Overlap (Federal)

Statement of Problem or Need

Single purpose rational policies and corresponding implementation authorities concerning uses of water resources are often in conflict with hydropower development. These include water quality, water supply, environmental protection and public safety. The myriad laws and confrontation of resulting authorities has encumbered the reviewing process to such an extent as to create a severe lack of incentive to potential small hydro projects.

Recommendations

A national policy needs to be set forth which will reflect in the review process the importance of lowhead hydro development through its role in improving the national energy picture. This policy should direct governmental agencies with conflicting authorities to identify means and to take necessary steps toward overcoming jurisdictional conflicts.

Who Could Do The Job?

The President can establish an Interagency Coordination Council. The Department of Energy should immediately prepare background material for the President to issue an executive order and establish this Council at the Assistant Secretary level, and the Council should immediately set about resolving conflicts. Where conflicts cannot be resolved, legislation should be prepared.

Concluding Remarks

Federal agencies are likely to underplay specificity. Unless strong leadership is provided, placing emphasis on fostering the role of hydropower, the Interagency Coordination Council will be ineffective. The Department of Energy should be designated as lead agency.

Parameters

		Research	Development	Demonstration
Time Frame	Start		now	6 months
	Finish		6 months	
Costs				
Federal Role		100%	100%	100%

Recommendation 3: Education & Promotion

Problem

Entrepreneurial uncertainty regarding feasibility and applicability of his project.

Recommendations

Prepare and support case studies of a range of small hydro projects selected to maximize variation and possible solutions. Include these studies in a regulatory guidebook.

Who Can Do The Job?

An experienced developer can select samples in consultation with licensing agencies. Each state should be examined separately.

Parameters

		Research	Development	Demonstration
Time Frame	Start			
	Finish	6 mos. @ state	3 months	
Cost		$1,000 @ state	publication/ distribution	
Federal Role		100%	0% (state responsibility)	

Recommendation 4: Market Access

Problem

The independent developer of a small hydro facility often has difficulty in obtaining a buyer for electric power who will pay a price per kilowatt, making hydro development feasible. The only customer may be a utility controlling transmission and distribution facilities.

Recommendations

A formula establishing a minimum wholesale price for firm power, based on local prevailing rates. This formula could initially be based on the marginal price of power that can be displaced by that of a small hydro site. Once established at an economically attractive level, the price could follow fuel escalation or remain stable, thus making small hydro even more attractive to large utilities and other power buyers.

Who Can Do The Job?

The Department of Energy and the Federal Energy Regulatory Commission.

Concluding Remarks

A state public utilities commission might not be attracted by the above plan.

Parameters

		Research	Development	Demonstration
Time Frame	Start			
	Finish	6 months	3 months	2 years
Cost		$70,000	$37,000	$50,000
Federal Role		100%	100%	50-75%

Recommendation 5: Variation in State & Local Regulations

Problem

Wide variations and conflicts in state and local regulations are barriers to development. Examples of this problem are conservation commissions, historical and wetlands agencies, water and mill rights.

Recommendations

Intiate a cooperative cost-sharing program with states for planning and implementing a low-head/small scale hydro program. The program should include: 1) a plan for development; 2) reducing overlap and conflict; 3) accelerate licensing; 4) develop a guidebook for state licensing and an education program; 5) clarify state laws, such as mill and water rights.

Who Can Do The Job?

A joint effort between RDA and the individual states.

Parameters

		Research	Development	Demonstration
	Start		now	
Time Frame	Finish		2 years	
Cost			$25,000,000	
Federal Role			50%	

Recommendation 6: State Commitment to Development

Problem

The lack of financial incentives to speed up the implementation of small hydro plants.

Solutions

1. Senator Durkin's Bill S 2047 approaches a portion of the need in a constructive manner.
2. The implementation of tax incentives on the federal, state, and local levels would further aid the development of small hydro plants.
3. Interagency cooperation, such as the Department of Energy, would be able to provide costs for fish ladders or other high-priced environmental requirements.
4. Assure that utilities pay a fair price for small hydro power.
5. Case studies should be used to demonstrate profitability.

Who Could Do The Job?

The Department of Energy should have the responsibility for these recommendations, as there should only be a sole source for approval.

Concluding Remarks

The major dilemma in implementing a program of this sort is that all parties concerned are waiting for the government to fund it.

Parameters

		Research	Development	Demonstration
	Start	now	now	now
Time Frame	Finish	3-6 months	6-9 months	1 year
Costs		$25,000	$25,000	100,000,000
Federal Role		10%	10%	50%

Recommendation 7: Competing Uses

Problem

Hydropower projects are rarely single-purpose and are either developed to provide non-power benefits, or are actually required to provide these benefits. Recreational facilities, fish passage, and other requirements can add significant costs to hydropower development.

Recommendations

1. Develop clear statements of requirements (by river basin, size of project, type of development) demanded by the FPC, the BOR, the EPA, the COE and the DOI. A sampling of state requirements should also be made.
2. Develop estimates of costs involved in meeting requirements stipulated by the above agencies from both existing case studies and agency expertise.
3. Assess the congressional intent as to who should bear the costs. This assessment should specify the two areas of capital and operation/maintenance costs. Preparation of pro/con arguments should also be done, focusing on the following groups: rate payers, federal taxpayers, local/state taxpayers, and beneficiaries.
4. An evaluation of alternative financial mechanisms on the following criteria: equity, regional development, effectiveness in terms.
5. Comparison of analysis in Section 4 above and identify points of conflict and to draft suggested legislative or administrative changes.

Who Could Do The Job?

The Department of Energy, or a consultant with a broad experience in analyzing complex water resource hydropower issues. The consultant(s) should have contracts, or the ability to make contracts, in requisite federal and state agencies, as well as an ability to make specific policy recommendations with assumptions clearly delineated.

Concluding Remarks

Interagency conflicts are a possible barrier to the clarity and effectiveness of the above statements. Where possible, these conflicts should be resolved so as not to impede the progress of small hydro development.

Parameters

		Research	Development	Demonstration
Time Frame	Start	now		
	Finish	13 months		
Cost		$10,000		
Federal Role				

Recommendation 8: Access to Insurance, Financing Arrangements

Statement of Problem or Need

Insurance for liability, structural failure, et cetera, is frequently not available to developers and therefore poses a deterrent to such projects.

Suggested Recommendations and Approaches

A pool of monies from all groups involved (i.e., federal government, manufacturers, power company owners, utilities, construction companies) should be funneled into a central fund to insure against such problems.

Who Could Do The Job?

The Department of Energy could formulate a cooperative approach with all concerned.

Concluding Remarks

The chance for implementing this insurance fund is good on the levels of industry, utilities, and local communities.

Parameters

		Research	Development	Demonstration
Time Frame	Start	now	now	now
	Finish	3-6 months	6-9 months	1 year
Cost				
Federal Role				

Panel IV — Environment and Safety Final Panel Report

I. Environmental Concerns

The development of a new dam site does pose more environmental problems that the retrofitting of an existing structure. Land use modifications, water impoundments, water quality, alterations in stream morphology, and toxic materials are more prominent in new dam development than in retrofitting.

It should be understood that the operation of lowhead facilities would probably be run-of-the-river for base-line production. If these dams were designed for peak power production, the resulting environmental impacts could be more significant.

Because of its small physical size and relatively nonpolluting operation, small hydro should not be a significant threat to plants or mammals near the site. Nor should low-head hydro cause any major problems with surrounding ecological communities. However, passage facilities for anadromous fish are one area of major concern for both new and retro-fitted sites.

Although the retro-fitting of old sites appears to be generally of less environmental consequence, silt buildup behind the dam over a period of inactive years could be a major construction and operational concern. If so, the environmental effects of coping with the silt must be considered, especially if undesirable or toxic substances appear to have accumulated. Methods to deal with the removal of silt should be based on a specific site appraisal. If a great amount exists, it should not be sluiced through the sluice gates.

Given multiple regional watershed management objectives and the emergence of integrated arrangements to achieve them, it is deemed that generic environmental evaluation of potential sites on a regional basis would be useful. This would provide consistent base-line data on factors, such as general physical and biological parameters, conservation and recreation priorities, archaeological and historic values, and community co-existence. Such assessments could be particularly useful in providing background information regarding retro-fitting situations.

Adequate base-line environmental information on a region would facilitate environmental determinations associated with specific hydroelectric license applications. Site-specific assessment is still felt to be the most accurate method of environmental appraisal, even when preliminary indications are that a negative declaration of significant environmental impact will result.

Base-line data, whether generic or site-specific obtained prior to reconstruction or new construction, should be augmented by monitoring environmental parameters once operations are underway, perhaps in the way periodic dam safety inspections occur but on a suitably periodic basis. With early demonstration projects or other pending small hydro projects that are being closely observed for other purposes, environmental monitoring might be encouraged in order to obtain data relevant to other nearby sites which might be candidates for future development.

The environmental problems involved with expanding transmission facilities associated with a small hydro site should not be ignored in planning. For example, new cuts through woods might disrupt wildlife habitats and migration patterns or might introduce new access routes to remote areas for off-the-road vehicles.

The fundamental environmental consideration, and perhaps for safety too, affecting low-head/small hydroelectric development is the relationship of the costs of environmental and conservation controls and standards to overall project costs. On large hydroelectric projects these costs might be relatively low in proportion to total project costs, but still high in absolute dollar terms.

As project costs get smaller, the proportion devoted to environmental and conservation standards may rise dramatically and could kill the project. For example, estimates per vertical foot for fish passage facilities range from $3,500 to $95,000. Assuming a 2,000 kw project with 30 feet of head, the total project costs might be about $2,000,000 and environmental costs might be as high as 25% of that. This circumstance is especially significant because existing dams being retro-fitted for hydroelectric expansion may also be required under state and other conservation programs to retro-fit fish ladders consistent with recent measures to reintroduce fish migration into specific watersheds. This relationship needs more detailed examination that was possible in the context of this workshop.

Front-end costs for environmental and safety planning and assessment can be a particular impediment for developers (especially smaller ones) during pre-license project development activities.

The question of who should bear environmental and safety costs was debated with strong feeling in the panel sessions. The panel concluded that developers of small sites, specially private developers, need all possible forms of suitable governmental financial assistance during the next several years. Measures include subsidy, tax breaks (including depreciation allowances for such things as fish ladders), tax free financing, grants, especially for front-end environmental and safety planning purposes. If this assitance can be concentrated into a one-step federal program within ERDA that would be deemed positive, it should not divert funding from other aspects of small hydroelectric development. The panel tended to look to other federal agencies for this financing assistance, perhaps to Interior for hatchery assistance substituting for fish passages, or Commerce for fishery projects, or to Congress for new suitable companion funding to parallel small hydroelectric development funding.

II. Dam Safety

With a new site, the quality and safety of a structure are insured by modern design and construction methods, and the use of up-to-date codes which dictate the minimum requirements. Sites designed for retrofitting, on the other hand, were often designed and built at a time when modern codes and methodology were not available. Assessing the structural stability, safety and concealed deterioration of these sites can be a difficult and expensive, but necessary, process.

In the case of existing structures, it will be necessary to determine if the structures are adequate to safely pass a design flood, which should be established using the latest existing data. Since these structures are small, it may not be economically feasible to provide flood discharge facilities capable of passing a probable maximum flood. In this case it may be necessary for analysis to assume the dam is breached and then evaluate downstream damages. Some thought should be given to establishing the criteria to be used for determining the magnitude of these floods on a basin wide basis to avoid duplication of effort.

The analysis of structural integrity of the structures is a site-specific problem, and will usually be dictated by state regulations. As a minimum, the structures should be investigated for foundation stability, slope stability of embankments, and quality of the material making up the structure, such as earth, rock, wood or concrete. When necessary, a rehabilitation program should be established as part of the retro-fitting operation.

Also, an operation program with the viewpoint of safety should be developed for all small hydro projects. This would include maximum as well as minimum downstream releases, and emergency operation procedures.

III. Recommendations

We recommend and assume that a federal interagency coordinating mechanism will be set up for low-head/small hydroelectric development aided by advisory/liaison committees including state/regional/private participants. We assume also that a lead agency will be designated and other agencies will be assigned collaborative responsibilities. These recommendations would be implemented primarily by the lead agency aided by others.

1. The applicability of anadromous fish arrangements, including passages, hatcheries, etc., to small hydro projects should be investigated to:
   a. Determine what are the minimum requirements acceptable by federal and state agencies concerned with fish in respect to the need for and the efficiency of these arrangements, especially passages, and means for attracting fish to upstream and downstream passages.
   b. Determine a more realistic range of costs for fish passages or alternative measure, such as restocking, at low-head/small hydroelectric sites.
   c. Determine what is the present policy of the various levels of government and different agencies regarding financing of these facilities.
   d. Having made the above determinations, prepared a collected statement of relevant policies and make available as guidelines for developers of small hydro projects.
   e. Initiate action for federal financial and technical assistance for those projects where the cost of arrangements for fish are a heavy burden, especially for small developers.

2. The streamlining of licensing procedures by including simplified procedures for smaller projects, particularly retro-fitted projects, within a distinct category, should permit a simplification of environmental and safety guidelines. However, proper coverage of environmental and safety concerns peculiar to small hydro, especially retro-fitting, should be insured. Consideration for a category of exemptions might be considered.

3. Technical information packages should be prepared which offer environmental and safety assessment assistance pertaining to low-head/small hydro projects. These packages and related technical assistance would provide developers and reviewers of development plans inside and outside government with guidance for dealing with environmental and safety factors in site assessment, licensing, and operating requirements. These could be tested with any demonstration projects set up in FY 1978. If a general multi-purpose manual is prepared, the environmental and safety elements should be concise, yet comprehensive.

4. Studies and standard reference files:
   a. Regional assessments of base-line environmental and safety factors associated with small hydroelectric development should be conducted with an initial project in FY 1978 and extended subsequently. These should be conducted in conjunction with local, state and regional governmental and non-governmental entities.
   b. Development of standard reference files for dam records at state levels should be supported to facilitate developers and reviewers of development proposals in assessing and coping with environmental and safety factors, as well in improving design and construction.

5. Returning to the financing theme, additional federal funds should be made available for aid in dealing with environmental factors associated with retro-fitting small hydro dams, such as coping with silt problems, and for retro-fitting in general. These may be provided in part through the Durkin Bill (S.2047) or other congressional measures. This assistance should be particularly made available for "front-end" environmental and safety assessment costs prior to licensing.

6. Additional areas involving environmental and safety factors and meriting R, D & D attention would include the following:
   a. Silt during reconstruction and operations.
   b. Reconstructing civil works.
   c. Archaeological and historical values.

Panel V — Economics and Marketability

Final Panel Report

This report summarizes the proceedings of the panel reviewing economics and marketability with respect to small hydroelectric facilities. A list of the panel members is attached.

Discussion

Summarized below are the principal conclusions and resulting recommendations reached by the panel.

1. The panel's consensus was that considerable information exists with respect to the types of machinery and equipment which can be installed and the related costs of both construction and operation, and with respect to most other engineering, legal, environmental, economic and permitting considerations. Such information needs to be made publicly available in a form which would promote the development of feasible small hydroelectric projects. Accordingly, a manual which would set forth in check-list form those factors to be analyzed in determining project feasibility should be prepared in order to provide guidance to potential developers of small hydroelectric projects at existing and new sites.

The manual would, in addition to identifying the pertinent considerations and factors affecting development, specify a simple analytical methodology with respect to:

1. site parameters;
2. engineering and design;
3. project construction cost data;
4. forecast of cash flow requirements for the project during both the construction and operating periods;
5. marketing of generated output;
6. environmental factors; and
7. licensing and permitting requirements

Furthermore, ERDA should develop a simplified analytical model utilizing the information developed by a project sponsor in accordance with the manual to produce a preliminary assessment of project feasibility.

Both the manual and the analytical model would provide appropriate federal and state agencies, utilities and industrial entries and individual sponsors with the means to make a preliminary assessment, before making a major commitment of funds, as to a potential project's feasibility. This would permit ERDA to maximize the benefits which can be realized by the "seed money" program mentioned in Section #2 below.

2. The panel reviewed the desirability of ERDA's committing funds to construct one or more small hydroelectric plants in order to demonstrate technical and economic feasibility and concluded that such an expenditure of funds would not be the most productive use of the limited funds available to ERDA.

The panel felt, however, that the orderly development of small hydroelectric would be enhanced by monitoring the cost and performance of new installations. The panel recommends, therefore, that a program be instituted to monitor new projects which are currently under development. Such a program would provide information which would verify and supplement the information presented in the manual and the analytical model referred to in Section #1 above.

The panel also considered the desirability of instituting a grant and/or loan program to fund costs incurred up through the issuance of the license. A serious deterrent to the development of small hydroelectric facilities is the necessity to commit at the outset substantial funds to the project to determine its feasibility and to finance the project through the award of the necessary licenses. Any funds so expended by a developer represent a "high-risk" investment with little assurance of obtaining any return of or on investment. It was the panel's view that, once the licensing hurdle has been cleared, suitable financing arrangements could be made to fund the project if the project has favorable economics. By providing funds to a potential developer of a project which has been determined, in accordance with the manual and analytical model referred to in Section #1 above, to be feasible, ERDA could reduce the "up-front" exposure of potential developers and thus encourage and accelerate investment in small hydroelectric projects.

The panel also recognized that, by reason of national security considerations or otherwise, the federal government may desire to employ subsidies (which may include new tax incentives, guarantee loan programs, etc.) to alter existing economics to permit power generated at small hydroelectric facilities to be priced at levels comparable to alternative sources. The panel recommends that careful study be given such a program.

3. It was the consensus of the panel that the FPC and Corps of Engineers studies published to date do not accurately describe the true potential for the feasible development of small hydroelectric sites. Generally, these studies overstate the extent to which small scale hydroelectric power can be commercially developed. The panel concluded that it was necessary to develop a more complete and accurate data base in order to: a) enable ERDA to intelligently develop and administer a program to foster the commercial development of small scale hydroelectric power projects; b) provide information to utilities, industrial companies and private developers, thereby encouraging them to assess the desirability of developing the specified sites within their respective spheres of operation; and c) provide information to public utility commissions and other state and regional agencies to permit them to develop and implement policies at the state and regional levels to promote small scale hydroelectric development. The panel therefore recommends that ERDA proceed to do the following.

1. All investor-owned public utilities and public power entities should be canvassed to obtain information with respect to those projects which are currently proposed or underway.
2. All investor-owned public utilities and public

power entities should be asked to provide information as to those potential hydroelectric sites which have been considered, and either rejected or not acted upon, within the last 24 months.

3. The basic potential for redevelopment of existing dams for construction of new facilities should be evaluated by those having professional expertise, reviewing in detail the prospective sites on a river basin basis.

This work should lead to an inventory of sites having the potential of being developed, taking into account economic and other constraints.

4. The panel recommends that a series of feasibility studies, using specific sites having representative characteristics, be undertaken. These studies would test the methodology outlined in the manual referred to in Section #1 above. The studies should also include the development of a sensitivity analysis as to the cost components of small hydroelectric projects. This information would assist ERDA in determining the impact which research and development work might have on the economics of potential projects.

5. Development of a small hydroelectric site depends on the establishment of a market for the output and, in many cases, arrangements for backup power supply. The relationship between the small hydro developer and the franchised utility in his area is therefore an important factor in the development of small hydroelectric power projects. ERDA should initiate a study of this relationship as it now exists with particular emphasis on local interconnection, power back-up needs and equitable pricing to both the developer and the utility.

Recommendation 1

Problem

Inadequacy of existing studies on the potential of feasible small hydroelectric development.

Recommendations

It is recommended that a more complete and accurate data base on the availability of small hydroelectric power sites be developed. To achieve the goal the following tasks are recommended: 1) canvass utilities on projects re-evaluated or rejected in the last 24 months; 2) canvass utilities on projects currently underway; 3) perform professional evaluations and develop inventory of sites having development potential, considering existing and new sites.

Who Can Do The Job?

ERDA should complete tasks #1 and #2. Task #3 should be done by those having the prerequisite professional expertise. The overall effort should be coordinated by ERDA.

Parameters

		Research	Development	Demonstration
Time Frame	Start			
	Finish	FY 1978		
Cost		$1,000,000		
Federal Role		100%		

Recommendation 2

Problem

There is a need to understand pricing arrangements between small hydro developers and utilities to expedite development.

Recommendations

An ERDA supported study of existing arrangements and possible improvements in pricing systems would aid the promotion of equitable arrangements between individuals and utilities.

Who Can Do The Job?

The FPC and the PUC.

Parameters

		Research	Development	Demonstration
Time Frame	Start			
	Finish	6 months		
Cost		$300,000		
Federal Role		100%		

Recommendation 3

Problem

The studies and data to date do not properly reflect the true economic and engineering feasibility of potential sites. There is a need for policy decision and utility impact purposes in marketing, stability, etc.

Recommendations

Perform 20 to 30 feasibility site-studies in reasonable depth to categorize and determine cost sensitivity of project components, i.e., civil and foundations, electrical mechanisms, environmental concerns, water rights, etc.

Who Can Do The Job?

ERDA could fund these projects, which would be conducted by ERDA selected professionals.

Parameters

		Research	Development	Demonstration
Time Frame	Start			
	Finish	6 mos.-1 yr.		
Cost		\$500,000 - \$750,000		
Federal		80%		

Recommendation 4

Problem

The high up-front cost of determining the economics and legal feasibility of a particular site and procuring the necessary data to support the license application.

Recommendations

After an initial study reveals the feasibility of a site, ERDA funds are to be made available to assist the developer through the licensing stage.

Who Can Do The Job?

ERDA.

Parameters

		Research	Development	Demonstration
Time Frame	Start			
	Finish	6 months		
Cost				
Federal Role		100%		

Panel VI — Demonstrations

Final Panel Report

This report reviews the proceedings of the panel having to do with the demonstration of small hydroelectric facilities. The major question addressed by this panel was:

"Should ERDA initiate a low-head hydroelectric power demonstration program?"

The panel's recommendation is emphatically "yes". ERDA should immediately proceed with such a demonstration program.

Criteria

The panel's recommended criteria for proceeding with Demonstrations is as follows:

1. Needs immediate attention.
2. Utilize best technology available.
3. Construct as many plants necessary to demonstrate capacities in the range of 50 kw up to 5,000 kw.
4. Geographical distribution of sites.
5. Assist with front end funding.
6. Show most effective use of power.
7. Some should produce power for on site use.
8. Some should incorporate remote operation.
9. Show multipurpose use of water.
10. Some sites should show use of potentially mass produced equipment.
11. Should provide effective public information, technical assistance program and visitors at site capability.
12. Should be compatible with environment including recreation and fish passing facilities.
13. Utilize sound engineering and safety principles.

Discussion

An overwhelming majority of the members of Panel VI reached the conclusion that time is of the essence in instituting demonstration projects at geographically dispersed sites. In the opinion of the panel, it is in the national interest to cost-share in the building of demonstration plants in a variety of sizes from 50 kw to 5,000 kw. The economic barriers associated with constructing a small hydro site can be lowered through front-end funding of site-specific planning and licensing. The preliminary design should consider transfer of technology in determining the best technology for the project. Demonstration sites should be typical sites within geographic regions, so that potentially a large number of sites could be developed using the same equipment. This offers the potential of mass producing this equipment.

These projects should demonstrate that small hydro is compatible with the environment and recreation, as well as with other multi-purpose uses of water. An important part of the environmental consideration is that fish passage be shown at these small hydro projects. All dams must be safe and must have sound engineering. The panel was particularly concerned about assuring the safety and structural integrity of existing dams.

Some sites will demonstrate on-site use of energy; others will show eletrical power generation fed into the utility grid. In the latter case, it is important to integrate the dam's generated power into the utilities' other forms of power supply. Factors such as system stability, remote operation and the change in reserve requirements must be considered in determining the value of the dam's output. An effective information program on these projects would include a public information program, a central information source, visitor capability on site, and a technical assistance program.

Demonstration Plan

The demonstration plan would simultaneously include the following types of projects.

1. Demonstrate the use of improved equipment on existing power dams.
2. Demonstrate the use of new equipment or technology on existing dams which are not now producing power.
3. Demonstrate the use of new generating equipment at new sites. The panel expects the demonstrations to be completed in the order in which they are listed.

Problem

There is a need to demonstrate, as quickly as possible, a viable and economically attractive demonstration program.

Recommendations

1. Use the best technology for the program.
2. Help with front-end funding for planning and licensing.
3. Build as many demonstration plants as possible with cost-share demonstration monies and a variety of plants covering ranges from 50 kw up to 5 Mw.
4. Include system integration to demonstrate most effective use of power.
5. Some demos should produce power for on-site use and employ other non-grid applications.
6. Create a central information source and a technical assistance program.
7. Demonstrations should show multi-purpose use of water.
8. There should be an effective public information effort, such as a visitor facility on site.
9. Select representative sites which show the use of potentially mass produced equipment.
10. The demonstration should be compatible with the environment and recreational needs. Fish passage facilities, for example, should be compatible with the project.
11. A geographic distribution of sites.

12. Some site should incorporate remote operation.

Who Can Do The Job?

Individuals, corporations, and municipalities in cooperation with ERDA.

Concluding Remarks

The chances of implementation in industry are good, in utilities only fair, while in communities the chances are very good. Possible barriers to implementation are contained within existing licensing procedures, economic problems, and environmental regulations. This demonstration program should be given top priority.

Parameters

		Research	Development	Demonstration
Time Frame	Start	now	now	1 year
	Finish	3 months	1 year	3-5 years
Cost		$15,000	$20,000	½ to 1 mil./site
Federal Role		10%	25%	65%