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HYDROELECTRIC POWER IN CALIFORNIA

1. INTRODUCTION

Water power occupies a prominent position among the renewable and non-renewable indigenous energy resources of California. The state's proximity to the Pacific Ocean and the topographical and geologic characteristics of its mountain regions have created a significant water power potential. This fact was recognized during early power development in California for the first three-phase hydroelectric plant, Old Mill No. 1, built near Redlands in 1893,[1] was also the first modern power plant in the state.[2] Since then, hydroelectric power has been widely used in producing electricity in California. In the last few decades, however, the rate of development of the hydroelectric potential has been unable to keep pace with the rather explosive increase in electricity demands. As late as 1940, water power represented about 65 per cent of the installed generating capacity in California.[3] By 1950 its relative representation was reduced to 49 per cent; by 1960 to 21 per cent; and by 1970 to 19 per cent.[4] By 1976 it stood at approximately 21 per cent of the total generating capacity in the state.[5] Nevertheless, currently, hydroelectric power is second only to fossil fueled generation, as a source of both installed capacity and produced electricity in California.

The relative importance of developed water power in the state is also evidenced by the fact that as of January 1, 1976 California ranked second among the fifty states in both installed conventional hydroelectric capacity and corresponding electricity generation. California's hydrocapacity was 12.6 per cent of U.S. capacity and produced 12.5 per cent of hydro energy during 1975,[6] the last year before the California drought began. For comparison, hydroelectric stations supplied 16 per cent of the total United States electricity production in 1975.[7]

2. CURRENT STATUS OF HYDROELECTRIC POWER

In 1976 there were 242 power plants in California. Of these plants, 173 were hydroelectric, 60 fossil, 6 geothermal, and 3 nuclear.[5] The generating capacity of all 173 hydroelectric plants was 8500 MWe[5] with an average electricity output of 34×10^9 kWh per annum.[1,6] The hydroelectric capacity represented 24.6 per cent of the total generating capacity in California in 1976. On the other hand, the average electricity output comprises 26 per cent and 23 per cent, respectively, of the electricity produced (130×10^9 kWh/y) and consumed (150×10^9 kWh/y) annually in California.[8] It should be emphasized, however, that of the total hydroelectric capacity, 7200 MWe constitute conventional capacity, 300 MWe pumped storage capacity, while the remaining 1000 MWe reflect capacity associated with the California State Water Supply System which consumes essentially all its electricity output for its own functioning. Consequently, the state average electricity output actually reflects production by hydroelectric capacity, excluding that of the Water Supply System.[1,5,6] Finally, the total capacity given above represents maximum nameplate rating. The actual generating capability, however, is approximately 12 per cent greater than the nameplate rating.

The 173 hydroelectric plants in California vary in size from a minimum of 0.2 MWe to a maximum of 644 MWe.[5] The minimum per plant electricity production presently worth developing is $25x10^6$ kWh per year.[1] Only 16 hydroelectric plants, with a total capacity of 87 MWe, are classified as base-load plants, with the remaining 157 being considered peak-load plants. The use of hydroelectric capacity as peak-load power increased because of the characteristics of modern methods of electric generation. Earlier hydroelectric plants were designed to meet the entire demand, having a capacity factor of 50 to 60 per cent and serving as base-load plants. In the present system of joint operation of hydroelectric and high-capacity-factor fossil, nuclear, and geothermal plants, it pays to increase the installed hydro capacity serving the shorter peaking periods (6 to 8 hours per day) with load factors of 25 to 30 percent to better utilize the controlled flow of water. Since part of the installed hydroelectric capacity has to remain idle during parts of each year because of the lack of water, hydroelectric power is now generally used primarily to supply peak-load demand. To change an existing hydroelectric plant to a peak-load plant requires only the cost of installing the additional generating capacity, approximately \$100 to \$200 per kWe. If the same hydroelectric plant were maintained as a base-load plant, the additional capacity to meet the peak demands of the system would have to be provided by a fossil or nuclear fueled plant at a cost of \$500 to \$1000 per kWe installed. The latter option is not only more expensive than the former, but in addition results in displacing a free and renewable energy source (water) by a costly and non-renewable fuel (gas, oil or uranium). Hydroelectric power therefore must be used to meet peak-load demands. As a consequence of the peak-load use of hydroelectric plants, both the installed capacity and the average electricity output of each such plant have to be specified since the former does not necessarily determine the latter as it would for any other type of power plant, including base-load hydroelectric plants.[9]

3. FUTURE DEVELOPMENT OF HYDROELECTRIC POWER

The future development of hydroelectric power in California can be anticipated to be characteristic of hydroelectic development elsewhere:

i. Rerating existing facilities. - This is accomplished by rewinding existing generators and by adding new turbines and generators to the facility. Addition of new turbines is warranted, however, only if unutilized water flow exists at a given facility.

ii. Building new facilities. - This requires the construction of new dams which account for an average of between 50 and 75 per cent of the total capital investment of any hydroelectric plant.[10]

iii. Installing small hydroplants. - This includes the development of sites with energy potential less than 25×10^6 kWh/y or alternatively 5 MWe at 60 per cent load factor.* Also included are dams built for other purposes such as river navigation, flood control, irrigation, and recreation.

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*There is no special definition of a small hydroplant. In general, small plants constitute the low head category, i.e., less than 100 foot heads, less than 5 MWe capacity, and less than 10,000 acre-feet of reservoir storage capacity.[11,12]

At the present time only options i. and ii. are being used, for option iii. has received attention only during the last two or three years. As a result, ample information exists concerning the potential development of the larger sites (options i. and ii.) but only limited data are available for the smaller plants (option iii.).

Thus far no distinction has been made between conventional and pumped storage hydroelectric plants. Option i. and predominantly option ii. apply more to the development of pumped storage plants than does the development of conventional plants. Before examining the potential development of conventional and pumped storage hydroelectric capacity in the state, two general comments concerning such development in California are in order.

First, the best sites for conventional hydroelectric power production have already been developed. The term, "best sites", is applied to locations with the highest water flow for a given installed capacity of essentially conventional (natural streamflow) type. Such development is clearly the product of economics. For any given number of sites, those with the highest kWh firm output per cost of installed capacity are, other factors being equal, the most profitable and hence the ones to be developed first. These other factors include capacity investment per MWe of installed capacity, operating costs per KWh of generated electricity, and maintenance costs per kWh of generated electricity. Additional economic issues of hydroelectric power development will be considered later in this paper. At this point, however, it is sufficient to mention that any further development of water power might have ceased almost completely by this time were it not for the dramatic increases in the prices of fossil fuels in general and oil in particular that have occurred since 1970. While fuel oil costs have more than tripled between 1970 and 1976, hydroelectric costs increased by only 50 per cent.[10]

Second, future hydroelectric development is related to restrictions imposed by law on potential sites. In 1968, the Congress enacted Public Law 90-542, the Federal Wild and Scenic Rivers Act,[6] which precludes the hydroelectric development of certain sites in California.[1] In addition, the State of California passed SB 107 in 1972, creating the California Wild and Scenic Rivers Act which exludes additional sites from development.[1] Both the federal and state acts preclude either the further development of partially developed sites or any development whatsoever of undeveloped sites. It is important to note that certain of these excluded-from-development sites in California constitute a significant portion of the estimated conventional potential development of hydroelectric power in the state.[1,6]

In the following two sections the potential development of conventional and pumped storage hydroelectric power will be examined separately, since these two types of water power utilization are quite different in the way they operate and function within the general utilities system.

4. CONVENTIONAL POTENTIAL DEVELOPMENT

Conventional hydroelectric power is derived from natural streamflow alone. In most instances, available reservoir storage capacity regulates natural streamflow for better utilization of the water, either diurnally or seasonally. Such regulation of the streamflow does not alter its energy content. Instead, it provides better shifts in time usage and thus increases the capability for meeting power peak demands.

The potential development of hydroelectric power from natural streamflow has been examined by two studies concerning the future development of conventional water power in California. The first and most recent report (1976) was prepared by the Federal Power Commission (FPC).* The second study was issued by the California Department of Water Resources (DWR).

According to the FPC study 44 per cent of the conventional hydroelectric capacity of the state of California has already been developed. This capacity amounts to 7200 MWe with an average annual output of $34x10^9$ kWh. The remaining undeveloped capacity totals 9300 MWe with an average annual electricity generation of $27.6x10^9$ kWh. The undeveloped potential of 9300 MWe does not include the capacity of sites whose development is precluded by the Federal Wild and Scenic Rivers Act or any other federal act. Furthermore, this total potential is distributed over 167 sites ranging from 5 MWe to 1015 MWe, with the exception of one site which is rated at 1.6 MWe. However, the California DWR estimates that the total potential of undeveloped hydroelectric energy is $31x10^9$ kWh per annum. According to the DWR study, only $12.5x10^9$ kWh/y could be actually developed; the remaining $18.5x10^9$ kWh/y being excluded by either federal or state acts. In addition, the same study projects that $9.7x10^9$ kWh/y out of the

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*As of October 1, 1977 the Federal Power Commission ceased to exist as an independent agency and became part of the Department of Energy.

12.5×10^9 kWh/y could be developed within 15 years (1990). The report estimates the capacity, corresponding to the 9.7×10^9 kWh/y, at 5356 MWe.

The first observation to be made in comparing the corresponding numbers in the two studies is that the FPC and the California DWR give quite different estimates of the potential development of water power in the state. Part of the discrepancy is due to the exclusion in the DWR study of a number of sites whose development is precluded only by state acts and which sites are, therefore, included in the FPC study. However, the most significant factor contributing to this variance is the lower DWR estimate of the potential development capacity for almost every site. There is no apparent reason for the variation other than the possibility that the two agencies used different methodologies in making their estimates. However, several errors exist in the DWR study's presentation of the installed capacities of already developed sites. Consequently it can be assumed that the FPC study estimates, which are summarized in Appendix A, are more reliable than those of the DWR study. Adjusting the FPC estimates to account for the capacity and energy of the sites whose development is restricted by the California Wild and Scenic Rivers Act, the potential for development of hydroelectric capacity is reduced from 9300 MWe to 7900 MWe and the generated energy from 27.6×10^9 kWh/y to 23×10^9 kWh, as is shown in Appendix A. Thus, the maximum non-restricted-by-law development of conventional hydroelectric capacity stands at 7900 MWe with an electricity output of 23×10^9 kWh/y. It must be emphasized, however, that all these estimates include only development by building new dams. There exists also the possibility of rerating existing facilities.

In 1977 the U.S. Army Corps of Engineers conducted a study on the hydroelectric power potential at existing dams.[12] The study considered three ways of improving the capacity of existing dams over 5 MWe: installing new turbines and generators or rewinding existing generators at existing hydroelectric dams, enlarging existing hydropower dams with expansion potential, and fitting existing non-hydroelectric dams with turbines and generators. The study concluded that rerating existing hydroplants would yield 650 MWe with an output of 3.1×10^9 kWh/y; expanding existing hydropower dams would yield 970 MWe with an output of 3.3×10^9 kWh/y; and utilization of non-hydroelectric dams for power production would add 500 MWe with an output of 2.3×10^9 kWh/y. Rerating of existing dams with capacity greater than 5 MW can therefore contribute 2120 MWe with an electric output of 8.6×10^9 kWh/y. No significant environmental restrictions to this development are anticipated since dams already exist in all sites under consideration.

As already stated there are no studies concerning the potential development of small hydroelectric sites in California although there is a comprehensive study applying to other states.[12] The Army Corps of Engineers presently is systematically surveying possible sites of small hydroelectric plant development throughout the United States, in order to refine the results of the previous study.[13] It is therefore quite certain that within a year or two a more accurate estimate of the small hydroelectric plant potential of California will become available.

Nevertheless, at this time a rough estimate can be made of the potential of small water power plants, based on existing information. In 1976, the California Department of Water Resources (DWR) conducted a preliminary mail survey of generation potential at hydroelectric sites with an annual energy potential of less than $25x10^6$ kWh/y.[14] Only 8 of the 81 water agencies contacted responded. Approximately 210 MWe of capacity at 47 sites were identified with a generating potential of about $1x10^9$ kWh/y. About 40 per cent of the 47 sites were located at existing dams used currently for other-than-power-production purposes or completely abandoned. The rest referred to run-off-the-river power through pipelines. Therefore, regarding the above results for 10 per cent of the contacted agencies as a statistical sample, the average small hydroelectric plant potential of the state is calculated to be 2100 MWe at 470 sites with an electricity output of $10x10^9$ kWh/y. These results for the potential of small hydroelectric plants in California appear to be of the right order of magnitude. According to the 1977 Army Corps of Engineers study, there are 1007 dams in California with height less than 100 feet and storage less than 10,000 acre-feet. An average capacity of 2 MWe per dam at 60 per cent load factor could yield 1000 MWe with $5x10^9$ kWh/y output. In addition, during the last 25 years about 20,000 earth dams have been built on California farms and more are being built each year. Although their original function in most cases was water storage, today more and more of these dams are being used by the farmers for irrigation, flood control, and even recreational purposes.[15] If all 20,000 dams were also utilized for power production and if each of those sites could yield on the average 100 kWe* a total capacity of 2000 MWe could be obtained. Assuming, furthermore, an average load factor of 60 per cent, a total electricity output of 10.5×10^9 kWh per year could be generated. No one expects, naturally, that all 20,000 dams can be used for power production, but depending on its size, each dam could produce power from 100 kWe to a few MWe.

All these simplistic calculations are not intended to establish the magnitude of the small hydroelectric plant potential for the state but rather to emphasize the fact that small hydroelectric plants can generate amounts of electricity comparable to that expected for remaining-to-be developed large plants in the state. The technology for developing small hydroelectric plants is well established.[11,16] Furthermore, the generated electricity could be either fed directly into the grid, or used to meet the energy demands of local consumers. The factors which will determine the more preferable option are: (i) The magnitude of demand of energy in the vicinity of the small hydroelectric plant (low or high load factor) and (ii) the distance of the plant from the nearest grid system (transmission of electricity). Generally, lower load factors (less than 20-30%) and longer transmission distances (more than 10-20 miles at 40 kV) favor local usage of the generated electricity. Electricity generated in rural areas for local usage can accommodate household needs and also will meet various

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*The standard hydropower formula $P = QHe/11.8$ with $P = 100$kW and $e = 0.9$ yields $Q\cdot H = 1300$ (ft^3/sec x ft.), i.e., for a height of $h = 20$ ft, a streamflow $Q = 65$ ft^3/sec is required to produce 100 kW. Although 100 kW is an assumed capacity, it is reasonable on the basis of the typical numerical values required for the height and flow rate of the water.

agro-industrial demands that develop from local farming operations.[17] The only obstacle to the development of these small hydroelectric plants may come from cost-benefit considerations.

Before the oil price rise in 1974, many small hydroelectric plants with capacity generally less than 10 MWe were being retired. At the same time, larger plants continued to expand and new dams were built. While the total generating capacity increased by 50% from 1965 to 1975, the number of plants decreased by 5 per cent.[10]

An insight as to why large hydroelectric sites are being preferentially developed can be gained by an examination of the capital investment in the various hydroelectric plants in California and in the entire United States compared with their respective electricity generation costs, as cited in the most recent (1975) pertinent Federal Power Commission report.[10] Three conclusions may be drawn from an analysis of the data cited (Appendix C). (i) The capital investment for a hydroelectric plant, expressed in dollars per kW, appears to be independent of the total size (kWe) of the plant. (ii) The cost of electricity production (maintenance and operating costs only), expressed in mills per kWh, also appears not to be statistically correlated to the size of the hydroelectric plant. However, this cost drops as the size of the plant increases. For example, the average cost drops by a factor of 10 as the plant capacity increases from 10 MWe to 2000 MWe, approximately the range of capacities considered in the FPC report.[10] (iii) The capital investment cost (capital amortization) in mills per kWh varies from slightly to several times larger than the cost of production (maintenance and operating costs only). Nevertheless, the total generation cost (capital investment and production costs combined) is much less than the corresponding figure for thermal (fossil and nuclear) plants.[18]

It is well known that thermal plants operate more efficiently with lower generation costs per unit of electricity produced under a constant load factor. This characteristic of thermal plants combined with the three conclusions relating to hydroelectric plants explains why the prevailing trend is to use hydroelectric plants (conventional as well as pumped storage) for peaking purposes. Larger and larger hydroelectric plants are being built to match their thermal counterparts and also to serve primarily as capacity displacement systems, fuel displacement being secondary as long as low fuel prices prevail.

It might be concluded in view of the foregoing discussion that the development of small hydroelectric plants is rather unlikely. Nevertheless, two arguments can be made supporting the economic feasibility of small plant development. First, the skyrocketing prices of fossil and nuclear fuels since 1974 make any hydroelectric development relatively competitive. Extensive studies on a case by case basis would be necessary to establish the firm capacity and energy displacement, as well as the secondary energy displacement by small hydroelectric plants. In general, as the cost of fossil fuel generated electricity increases, the "opportunity cost" for new hydroelectric development to replace thermal generation also increases, making hydroelectric generation more and more competitive.* Consequently, fuel (oil or gas) displacement alone will eventually make small hydroelectric generation competitive, depending on the rate of price increase of fossil fuels in the future. Secondly, the capital investment for the development of small hydroelectric facilities can be minimized and equipment costs reduced substantially by mass production of the appropriate small hydroelectric plant bulb turbine-generator units[11] in the United States. Furthermore, the capital investment for such small hydroelectric plants can be diminished by at least a factor of two if these plants could be developed at already existing dams. Based on information provided in the 1975 FPC report,[10] the following distribution of general expenditures associated with the construction of a hydroelectric plant can be derived:

1.	Land and Land Rights	0.18
2.	Structures and Improvements	0.14
3.	Reservoirs, Dams and Waterways	0.52
4.	Equipment Costs	0.25
5.	Roads, Railroads and Bridges	0.01
		1.00

Therefore, construction of a small hydrolectric plant at a site where the dam exists would require an investment as little as one quarter and not more than one half of that for a completely undeveloped site. It is plausible that the relatively low capital investment for such

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*At present, California electric utilities are offering prices as low as 14 mills per kWh to pay the opportunity cost. This price is estimated to be less than half of the oil displacement value of hydrolectric energy in the early 1980's.

a small hydroplant may offset the relatively lower benefit derived from its operation.[19]

The above distribution of the capital investment also explains why it is important to rerate large hydroelectric facilities and build on larger remaining-feasible sites. However, it is also important that relatively smaller facilities be developed and that adequate financial incentives be provided for such development. Between 20×10^9 kWh/y and 40×10^9 kWh/y of conventional hydroelectric generation can be added to the current California hydroelectric production level by the end of the century, probably reaching the limit of conventional development in the state.

5. PUMPED STORAGE POTENTIAL DEVELOPMENT

Pumped storage hydroelectric power is derived during peak load periods by using water which has been pumped from a lower to an upper reservoir during off-peak periods. There are two major categories of pumped storage plants:

(a) Pure type facilities which produce power only from water that has been previously pumped to an upper reservoir.

(b) Combined type facilities which utilize both pumped water and natural streamflow for the production of power.

All of California's 300 MWe of pumped storage capacity is of the combined type. Because the use of pumped storage development is still rather limited, only 4 per cent of the net generating hydroelectric capacity of California is of that type. If the Water Supply System capacity, most of which is of pumped storage type, is also included, there is a relative contribution of 13 per cent. Nationwide, on the other hand, the respective participation of pumped storage is little better, about 15 per cent.[6] The small proportion of pumped storage to the total hydroelectric development is due to its late introduction into the electricity production system. The reasons for such late arrival were economic rather than technological in nature. As long as a relatively large amount of undeveloped conventional hydropower existed, there was no need for developing pumped storage which is costlier in terms of both capital investment and cost of production for a plant of the same installed capacity.[10] However, as the best conventional sites were developed it became more cost-benefit advantageous to develop one large pumped storage facility instead of several smaller conventional plants. Therefore, it can be anticipated that the relative significance of pumped storage will increase in the future.

The San Francisco Regional Office of the Federal Power Commission, in a 1975 study covering the state of California and the Pacific Southwest,[20] estimated a total California potential of 144,200 MWe at 56 sites. However, it only considered sites whose capacity exceeded 1000 MWe. Pumped storage facilities with capacity lower than 1000 MWe were not deemed economically feasible for development. In addition, it was felt that the number of sites had to be kept within reasonable limits. All sites were selected with a minimum head of 700 feet to reduce water storage requirements and, consequently, the area of inundated land. Also, all sites were chosen with the horizontal distance between upper and lower reservoirs less than 15 times the head. Care was taken that all sites were not within the boundaries of areas whose development is restricted by any law whatsoever. Consequently, the cited number of 144,200 MWe excluded all sites whose development is precluded by federal and state law. A capacity of 7,700 MWe, within the Eel River Basin, is precluded from development by state act until 1984 at which time the Department of Water Resources is to report the need for developing that area to the Legislature. If the Eel River Basin development is permanently restricted, the maximum pumped storage capacity will be reduced to 136,500 MWe. Finally, consideration was also given to the environmental impact of transmission to and from those sites.

Although it is not known how accurately the aforementioned capacity describes the pumped storage potential of the state, it probably represents an upper limit of such development for any real development of pumped storage would never exceed the cited numbers. This prediction is based on the fact that the study itself was the product of a detailed topographic and geologic map examination, of all possible locations within the state, but did not include any on-site inspection. Factors which may restrict the development of any of these 56 sites include:

1. Geologic characteristics of the site.
2. Distance of pumped storage facility from load center and pumping energy source.
3. Possible adverse effects on wildlife.

However, the study did not consider sites with a potential capacity less than 1000 MWe. Inclusion of these sites could conceivably outweigh possible elimination of the larger sites for any of the reasons mentioned above. It is questionable, however, that development of smaller, pure pumped storage facilities is feasible in terms of cost-benefit analyses, given that all the much larger sites are still undeveloped. Furthermore, the 56 sites were selected for having the lowest unit costs ($/kW) among all possible locations following relative cost evaluation based on reconnaissance-type information.

For each site of potential pumped storage development used in the FPC study, the usable storage, as well as the upper and lower reservoir drawdown, has been estimated. On the basis of this information the average surface area of both the upper and lower reservoirs for each site can be then calculated approximately, as shown in Appendix B. Thus, if only those sites whose upper and lower reservoirs do not exceed 1000 acres each are considered, a capacity of 125,500 MWe (119,400 MWe without the Eel River potential) is obtained. If the maximum upper or lower reservoir area is reduced to 400 acres each per site a capacity of 97,600 MWe (91,500 MWe excluding potential of the Eel River Basin) is obtained.

Although the expected electricity output is not given in the 1975 FPC report, it can be calculated from the given head and hydraulic capacity for each site (Appendix B). The output is found to be 650×10^9 kWh per year. This output is reduced to 615×10^9 kWh per year if the Eel River Basin is excluded. If the area of each of the upper reservoirs is less than 1000 acres and the area of each lower reservoir is less than 400 acres, an output of 570×10^9 kWh/y or 415×10^9 kWh/y results respectively. In the calculation, an overall conversion efficiency of 85 per cent was used and a daily 12 hour operation for each site throughout the year was assumed.

To obtain the distribution of the maximum pumped storage potential versus the site capacity and the number of sites, Table 1 has been constructed using the data of the relevant FPC report of 1975. Note that most of the 144,200 MWe is concentrated in locations with capacities between 1000 MWe and 3000 MWe (about 47%) and that the maximum individual plant capacity stands at 7800 MWe.

Having reviewed the potential development of pumped storage capacity, it would be instructive to study also the possible functions as well as the mode of operation of this capacity within the electric grid. Although peak-load utilization of pumped storage will be retained, it also will be extended to the intermediate load if relatively substantial capacity is developed and incorporated into the system. Furthermore, pumped storage may be used for the storage of renewable but intermittent energy resources. For example, if wind, whose potential in California is considered to be very large, is to contribute substantially to the power supply of the state, an appropriate storage system is necessary.[13,21] Although hydro-storage is the obvious first choice, conventional hydroelectric capacity in the state cannot exceed 15,000 MWe. Therefore, wind capacities of the order of 40,000 MWe, as some scenarios predict for the California energy supply and demand,[22] would require use of pumped storage as well. Nevertheless, not only wind but also thermal, nuclear and possibly solar generated electricity will have to compete for the same available conventional or pumped hydro-storage capacity. If nothing else, the huge pumped storage potential of the state will facilitate the development of the wind and solar energy resources of California. The relative locations

Table 1. Distribution of total potential pumped storage capacity versus site capacity and number of sites.

Site Capacity (MW)	Number of Sites	Total Potential Capacity (MW)
1000 - 1900	26	36,000
2000 - 2900	13	31,600
3000 - 3900	7	24,000
4000 - 4900	4	16,900
5000 - 5900	4	21,200
6000 - 6900	1	6,700
7000 - 7900	1	7,800
8000 -	0	0
Total	56 sites	144,200 MWe

of energy demand centers, pumped storage sites and incidence of wind, which possibly may be the first intermittent resource to be developed in terms of current technological feasibility and economic competitiveness, will determine the method of wind-pumped storage interconnections.* Thus, there could be direct storage of wind into the pumped hydro-facilities from which electricity would be drawn depending on the demand. There could also be direct integration of wind with the grid and storage of any excess electricity into the pumped hydro-system; or, most probably, a combination of both extremes. The modes of operation of pumped storage facilities will be dictated to a great extent by the characteristics of the load requirements of the grid, the generating capacity and economics of operation of the pumped storage, and the generating capacity of other types of power plants in the system. The usefulness of a pumped storage power plant to replace peak load capacity is greatly enhanced if its pumping operation can take place, not only during the regular weekday night periods, but also during the weekend. However, such an operation entails larger reservoir capacity. In the 1975 FPC study example of such mode of operation (Fig. 1), a typical weekly utility system load curve is given, along with the weekly fluctuation of the level of the upper reservoir. It is assumed that in the electrical utility

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*The first Federally sponsored wind system has been intermittently in operation at Clayton, N.M. since Jan. 1978. Rated nominally at 200 kW it constitutes 2.5% of the existing capacity although it can supply, when in operation, up to 15% of the town's total power load during off-peak periods. Its output is fed directly into the local grid with no provision for storage so that it is operated as a fuel-displacement system only (zero capacity-displacement system).[23]

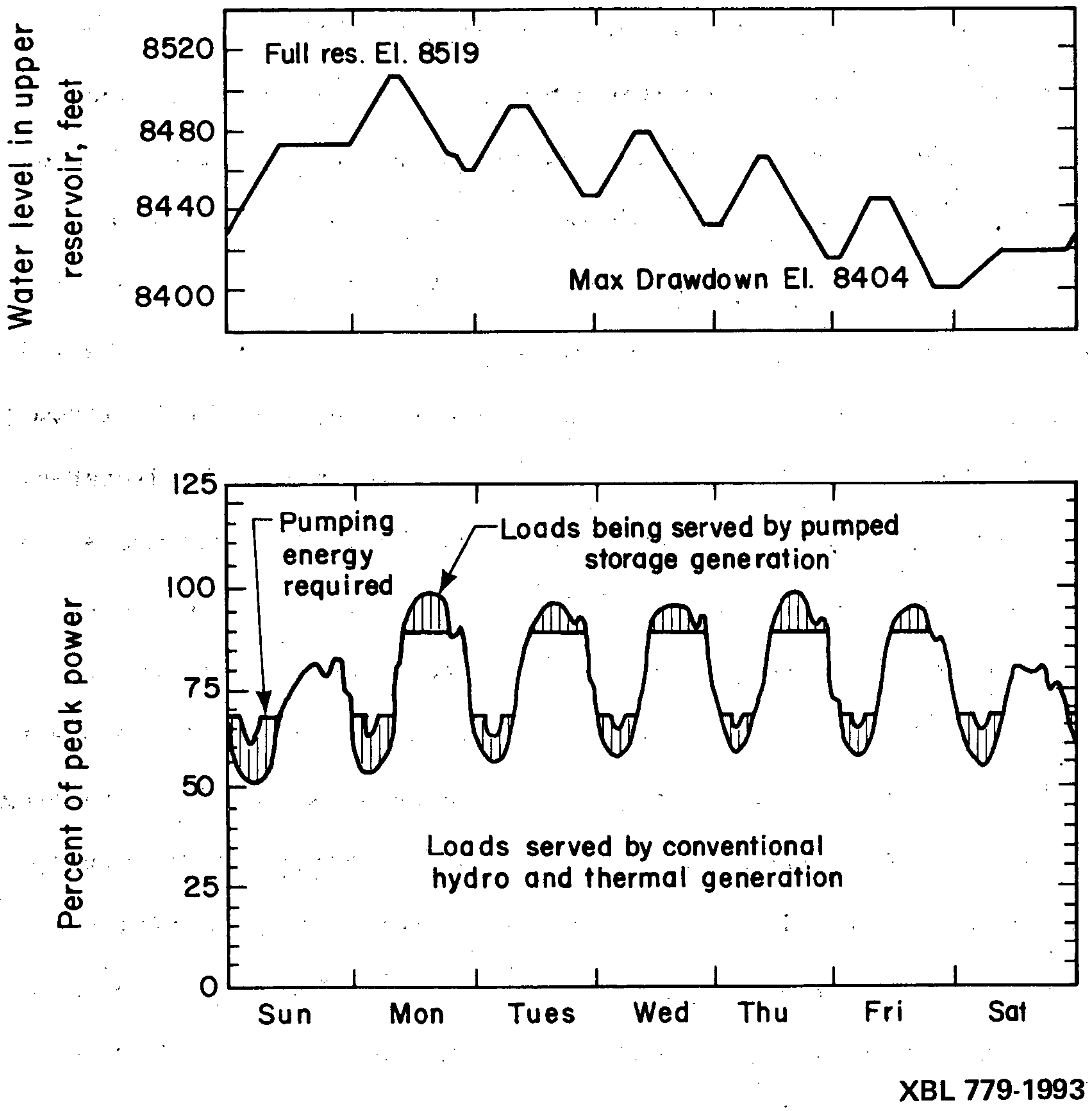

Fig. 1. Typical summer weekly system load curve for the Pacific Southwest.[20]

system under consideration pumped storage is utilized with reservoirs sufficiently large to provide full power generation 8 hours each weekday. It is also assumed that the upper reservoir is drawn down gradually over five days and refilled through limited pumping during night periods and the weekend. The choice of operating mode--daily cycle versus weekly cycle--is a tradeoff between larger reservoirs, on the one hand, and higher overall capacity installed in the system, on the other.

6. POTENTIAL PROBLEMS IN HYDRO POWER DEVELOPMENT

Two problems which either impede or restrict the potential development of hydro-power have already been discussed. One is economics; the other, various federal and state acts. A number of additional problems are also associated with the development of water power. The abundance of water or, rather, the extent of its availability for power generation is one such problem. Another involves effects of hydro-power development in the biosphere. Both problem areas have an impact on hydroelectric generation.

Water availability is the determining factor of hydroelectric development. However, it affects development of conventional and pumped storage facilities in different ways. Since conventional development depends on the existence of natural water flow only, it is relatively easy to determine where such facilities may be developed. Pumped storage development, on the other hand, may depend on the availability, through rainfall and possible subsequent runoff, of sufficient amount of water to fill one of the reservoirs. Thus, one must determine whether or not the storage water requirements of the maximum pumped storage potential of California are within the limitations imposed by the natural rainfall in the state. From the relevant data on pumped storage in the 1975 FPC study the usable water storage associated with the 144,200 MWe capacity can be estimated as approximately 1.90×10^6 ac-ft.[20] This required water storage includes also the dead storage, the fraction of water not circulating between the upper and lower reservoirs of each plant. The FPC study assumed a minimum dead storage of 2000 ac-ft. for each reservoir at any site. However, there are additional water requirements for each site. These are caused by losses due to evaporation and seepage.

Evaporation losses take place through the surface of the stored water and depend, not only on the surface area of the reservoirs, but also on the temperature, the humidity, and the intensity of wind in the area surrounding each site. Assuming a total surface area of 100×10^3 acres for the entire projected pumped storage capacity (see Appendix B) and considering an average evaporation rate of 3 feet per year,[24] a loss due to evaporation equal to 300×10^3 ac-ft per annum is obtained.

Seepage losses depend on the geological structure of the ground where a reservoir is located. It is estimated that losses due to seepage constitute about 5 per cent of the stored water. Therefore, seepage loss in this case would amount to 100×10^3 ac-ft per year.

The total water requirement for the 144,200 MWe of maximum potential is then 1.900×10^6 ac-ft, with an annual replenishment rate of 0.400×10^6 ac-ft. The average rainfall in California is 200×10^6 ac-ft per annum while the annual runoff is 70.8×10^6 ac-ft and the annual net demand is 31×10^6 ac-ft.[25] Obviously, even if the entire water storage of all pumped storage facilities had to be supplied anew every year there would be no burden on the water supply of the state.

Although the magnitude of the available water resources of the state does not pose any restrictions on the development of its hydroelectric potential, it should not be forgotten that the fluctuation of water supply annually is erratic in behavior, for the range of rainfall is 30 to 50 per cent above and below the mean in regions of medium precipitation such as California.[26] In general the drier a region is, the larger the deviation of its annual rainfall from its mean. Such wide variations in annual rainfall may have significant impacts on the operation of conventional facilities,[27] but probably much less on that of pumped storage sites.

The second major potential problem in the development of hydropower, the effects of hydroelectric development on the environment, can be both good and bad. On the positive side, in addition to power generation, one can include items such as the creation of new lakes, flood control, water quality control, increased water supply, irrigation, reservoir fisheries, navigation, and recreation. Moreover the possible expansion of vegetation--notably forests--into arid or semi-arid areas adjacent to the artificial lakes created primarily by pumped storage could yield substantial quantities of biomass for energy or materials production. On the negative side, one can have inundation of land, reduction in wildlife habitat, damage to stream fisheries, elimination of free-flowing streams, and population displacement in some areas.

Hydroelectric facilities are generally more environmentally attractive than thermal power generating plants in terms of power generation. As far as the possible negative effects on the environment are concerned, one must observe that these apply only to the development of new sites. In the case of conventional hydroelectric development, rerating of existing facilities or building of small plants would have minimal effect on the environment.

This is true because rerating existing facilities requires no additional dams, waterways, or reservoir construction. Small plant development, because of their size and--in many instances--the prior existence of dams, is not expected to produce any significant changes in the environment. Pumped storage, on the other hand, can cause substantial environmental changes since all the development will take place at sites which are presently undeveloped. Prior to any new development, of course, an environmental assessment of the proposed project must be conducted by the appropriate state or federal authorities. These studies can minimize or mitigate adverse effects on the environment. At the same time, exploitation of beneficial environmental effects can be considered. Past experience in the development of hydroelectric power indicates that whenever careful planning was employed before and during such development, the results were outstanding in improving the quality of the environment. The development of the Tennessee Valley Authority (TVA) is an example where, in addition to power generation, the devastation of residential and industrial areas by flood has on occasion been avoided, the transportation of goods has been facilitated, and the agricultural production of the land has been significantly increased.[28] On the other hand, the building of the Aswan Dam in Egypt--where, evidently, power generation was the primary planning factor--has had devastatingly negative effects on the ecology of the area by depriving the land of valuable silt and destroying fish production.[29]

It therefore becomes clear that in any development, as long as the oneness of man and natural resources is recognized, both mankind and nature will benefit. In that respect, any _a priori_ objection to hydroelectric power development is unfounded and contrary to the best interests of both nature and mankind.

7. CONCLUSIONS

In the previous sections the hydroelectric potential of California was examined and the problems related to the development of that potential reviewed. In this section, previous results will be summarized and conclusions stated concerning future significance of hydro power.

Conventional hydroelectric power development is expected to add between 0.2 and 0.4 quads* (20×10^9 to 40×10^9 kWh) per year to the current hydroelectric supply of 0.3 quads. The upper limit of 0.4 quads appears to be close to the maximum remaining-to-be-developed hydroelectric potential in the state, thus bringing the California total potential to 0.7 quads. Furthermore, it is anticipated that within the next 20 years at least half of that undeveloped conventional potential will be or can become cost-benefit favorable for development.

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*Since in this work all the numbers in kWh refer to electricity, a conversion factor of 10,000 Btu/kWh is used here to obtain the equivalent thermal energy in quads.

This projection is based on currently prevailing trends in the prices of fossil and nuclear fuels. These trends are expected to continue for the rest of this century.

The pumped storage potential of the state has an upper limit of 6.5 quads, all undeveloped. Since the pumped storage potential represents an energy storage rather than net energy producing potential, it must be coupled with other energy resources such as wind or solar energy. It is anticipated that development of the pumped storage potential of the state will follow simultaneous and parallel development of other renewable resources, notably wind. Consequently, no time table of pumped storage development can be projected. Relatively small development, less than 0.3 and even 0.15 quads, or 7,000 and 3,000 MWe respectively, of pumped storage associated with the water supply, and fossil and nuclear power generation probably will continue throughout the remainder of this century. The attendant water and land requirements for the full development of the 6.5 quads of the pumped storage potential, estimated to be less than $2x10^6$ ac-ft and $100x10^3$ acres respectively, do not pose any strain on the natural resources of the state since they constitute only 1.0 per cent of the annual rainfall and 0.1 per cent of the land of California.

Finally, hydroelectric development entails, in most cases, changes in the environment. These changes may have disastrous effects on the ecological system if taken lightly. Past experience, however, has proven that responsible study, planning, and execution of any hydroelectric project always leads to results beneficial to both nature and humanity.

Barring the possibility of a rather revolutionary breakthrough in the development of entirely new energy sources, hydroelectric power in California could supply ultimately 0.7 quads ($70\text{x}10^9$ kWh/y) of conventional generation and 6.5 quads ($650\text{x}10^9$ kWh/y) of pumped storage, the latter probably being associated with the wind energy resources of the state.

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APPENDIX A

Analysis of Conventional Capacity in California

In order to determine the maximum development of conventional hydroelectric potential in California, it is first necessary to estimate the maximum potential for each river basin in the state, using data from the 1976 FPC study,[6] which takes into account all federal law restrictions. The hydroelectric potential for sites restricted by state law[1] is then substracted from this estimate. This provides the maximum hydroelectrical potential for sites restricted by neither federal or state laws. Restrictive federal laws are detailed in the Federal Wild and Scenic Rivers Act. State restrictive laws include the California Wild and Scenic Rivers Act, as well as moratoria locally imposed by the voters (the Mad River Basin restriction, for example). All sites considered here have potential capacity of at least 5 MWe and consequently do not include any "small" hydroplants. The sites considered have totally undeveloped potential (no dam currently existing). Detailed results of this analysis are given in Table A.

Table A. Conventional hydroelectric potential of the state of California non-restricted by federal and/or state acts.

River Basin	Development non-restricted by Federal Wild and Scenic Rivers Act		Development non-restricted by Federal and Calif. State Wild and Scenic Rivers Act	
	Capacity[a] (MW)	Generation[a] (10^6 kWh)	Capacity (MW)	Generation (10^6 kWh)
North. Calif. Coastal Drainage				
Smith River	100	460	0	0
Klamath River	1,019	3,711	0	0
Mad River	45	140	27	62
Eel River	322	700	(322)[b]	(700)[b]
Russian River	16	250	16	250
Sacramento River Drainage				
Sacramento Main River	1,324	1,364	1,324	1,364
American River	1,190	3,411	1,140	3,213
Feather River	1,009	3,172	1,009	3,172
Clear Creek	450	1,184	450	1,184
Pit River	68	281	68	281
Other Minor Rivers	632	1,938	632	1,838
San Joaquin Drainage				
San Joaquin Main Stream	425	1,785	425	1,785
Mokelumne River	58	208	59	208
Stanislaus River	545	1,450	545	1,450
Tuolomne River	233.5	1,877	233.5	1,877
Merced River	190	927	190	927
Willow Creek	335	72	335	12
Big Creek	110	230	110	230
Other Minor Rivers	240	400	240	400
California Basin Drainage				
Kings River	572	1,493	572	1,493
Kern-Kaweah River	270.5	1,372	270.5	1,372
South. Calif. Coastal Drainage				
Aqueduct River	173	973	173	973
Other Minor Rivers	96	676	96	676
TOTAL	9,423	27,974	7,964	23,025

[a] Taken from Ref. 6.

[b] The California Wild and Scenic Rivers Act imposes a moratorium on Eel River development until 1984 when the Legislature will decide on the future role of that river.

APPENDIX B

Analysis of Pumped Storage Capacity in California

For each of the 56 sites of pumped storage hydroelectric capacity in California both the head (ft) and the hydraulic capacity (cfs) are given in the 1975 FPC study.[20] Consequently the generated electricity at each of these sites can be calculated from the standard formula

$$E = \varepsilon \frac{H \cdot Q \cdot t}{11.8}$$

where E is the electrical energy in kWh/y, H is the head in ft, Q is the hydraulic capacity in cfs (cubic feet per second), t is the time per year in hours during which the plant generates electricity, and ε is the efficiency coefficient for converting the kinetic energy of the falling water into electricity. Here a 12 hour daily operation has been considered with a corresponding

$$t = 12\text{h} \times 365 \text{ days/year} = 4380 \text{ h/y} \quad .$$

Furthermore an overall conversion efficiency of $\varepsilon = 0.85$ has been assumed.

The results are given in Table B. In order to minimize the length of that table the results belonging to sites within distinct river basins have been grouped together. Also, whenever appropriate, adjacently located basins have been combined. Such grouping, however, does not necessarily imply that all potential pumped storage sites are directly associated with major rivers but rather that appropriate

Table B. Maximum capacity, generation and covered land area of potential pumped storage facilities.

Basin	Number of Sites	Total Maximum Capacity (MWe)	Total Maximum Generation (10^6 kWh)	Total Maximum Surface Area (acres)
North Calif. Coast				
Klamath-Smith	2	6,500	29,793	1,184
Mad-Eel[a]	3	9,600 (3,500)	43,408 (15,689)	4,729 (2,357)
Other Tributaries[a]	3	4,800 (1,600)	21,712 (14,291)	6,400 (4,619)
Sacramento River				
Upper Sacramento	5	8,700	39,102	11,511
American-Feather	5	12,300	56,728	8,076
Lower Sacramento	2	2,700	12,401	1,507
San Joaquin				
Mokelumne-Stanislaus	5	27,200	123,171	8,638
Tolumne-Merced	7	20,600	92,898	16,137
Upper San Joaquin	6	9,800	44,349	7,658
Tulare				
Kings	3	5,300	23,591	4,609
Kern-Kaweah	3	12,200	55,380	4,572
Lahontan	5	11,500	51,621	11,074
Central and South. Calif. Coast	7	13,000	59,285	10,978
TOTAL	56	144,200	653,439	97,073

[a] Numbers in parentheses indicate the part of the project which is completely outside the Eel River and its tributaries and therefore could be developed at any time.

geological and topographical formations for such development exist within those river basins.

The total area in acres which would be covered by water by both the upper and lower reservoirs has also been estimated. For each of the 56 sites the 1975 FPC study[20] gives the usable storage (ac-ft) and the drawdown (ft) of both the upper and lower reservoirs. Using this data, the maximum surface area can be reasonably well estimated by assuming a triangular cross-section for each reservoir with a drawdown in excess of 10 feet. Ten feet is the minimum drawdown assumed in our calculation which used a rectangular cross-section. The surface area A is given then by:

$$A = 3V/D$$

where V is the volume (storage) of water and D is the maximum depth for each reservoir. The thus calculated surface area is essentially an upper limit for the real surface area since this formula for computing A normally overestimates the surface area for a fixed and known reservoir depth.

APPENDIX C

Economic Analysis of Hydroelectric Power Generation

The total cost of electricity generation in a hydroelectric plant or, for that matter, any other power plant, is the sum of two independent components: capital cost (cost of amortization of the capital investment over the life-expectancy of the plant) and production cost (annual operation and maintenance expenditures).

According to the FPC,[10] the capital investment for a hydroelectric plant can be subdivided into 5 categories as follows:

1. Land and land rights
2. Structures and improvements
3. Reservoirs, dams, and waterways
4. Equipment costs
5. Roads, railroads, and bridges

It would seem natural to expect that the dependence of the capital investment in dollars per kW ($/kW) versus the total plant capacity in kW is dictated more or less by the economies of scale. However, close examination of the capital expenditures of various projects, as given by FPC,[10] reveals that such dependence is almost nonexistent, due evidently to the uniqueness of each hydroelectric plant.

To illustrate the lack of dependence of the economies of scale on the capital investment of hydroelectric plants, a typical year is considered and the characteristics of all plants that began operation in that year are examined. This selection is made simply to minimize the impact of inflation on capital investment. Thus, 1958 is chosen as a typical year. The characteristics of all plants that started their operation in that year are given in Table C-1.[10] It can be noted from this table that 5 of the 13 plants listed are located in California--the largest number of hydroelectric plants to start operation within the same year in the history of the state. The fact that 10 plants are located in western states is of some significance in this analysis because it could minimize the impact of varying construction costs from one section of the country to another. A linear fit of the data on capital investment ($/kW) versus installed capacity in Table C-1, plotted also in Fig. C-1, gives the regression formula

$$y = 239.88 - 0.019x$$

with x in MWe, y in $/kW. The corresponding correlation coefficient is $r \simeq 0.055$. Next, the same data are fitted with a power curve since the economies of scale are generally represented by a similar curve. Thus we obtain

$$y = 281.06\ (x^{-0.0482})$$

with x in MWe, y in $/kW. The correlation coefficient is now $r = 0.126$. These results indicate that the capital investment for a hydroelectric plant has hardly any dependence on its installed capacity.

Production expenses generally consist of operating expenses and maintenance expenses. In the case of hydroelectric power generation, these expenses can be further subdivided, according to the FPC,[10] as follows:

Table C-1. Characteristics of hydroelectric plants in the U.S. with the same year of initial operation (1958).

Plant Name and Location	Capacity (MWe)	Ann. Generation (10^6 kWh)	Capital Inv. ($/kW)	Cost of Production mills/kWh	Mode of Operation A:Automatic M:Manual SM: Semi-Manual
Brownlee (Idaho)	360.4	2,361.6	191	0.12	M
Cochrane (Mont.)	48.0	381.8	217	0.31	A
Robert Moss (N.Y.)	912.0	7,307.7	245	0.18	M
Boyle, John C. (Oreg.)	80.0	513.1	150	0.42	SM
North Fork (Oreg.)	38.4	247.1	453	0.86	A
Swift No. 1 (Wash.)	204.0	811.1	271	0.37	M
Center Hill (TVA)	135.8	491.5	215	0.77	M
Cheatham (TVA)	36.0	171.4	-	1.49	M
Balch No. 2 (Calif.)	97.2	587.9	109	0.28	M
Butt Valley (Calif.)	36.0	220.4	239	0.59	A
Caribou No. 2 (Calif.)	109.8	605.1	254	0.32	A
Haas (Calif.)	135.0	613.0	190	0.37	A
Poe (Calif.)	124.2	791.2	302	0.35	A

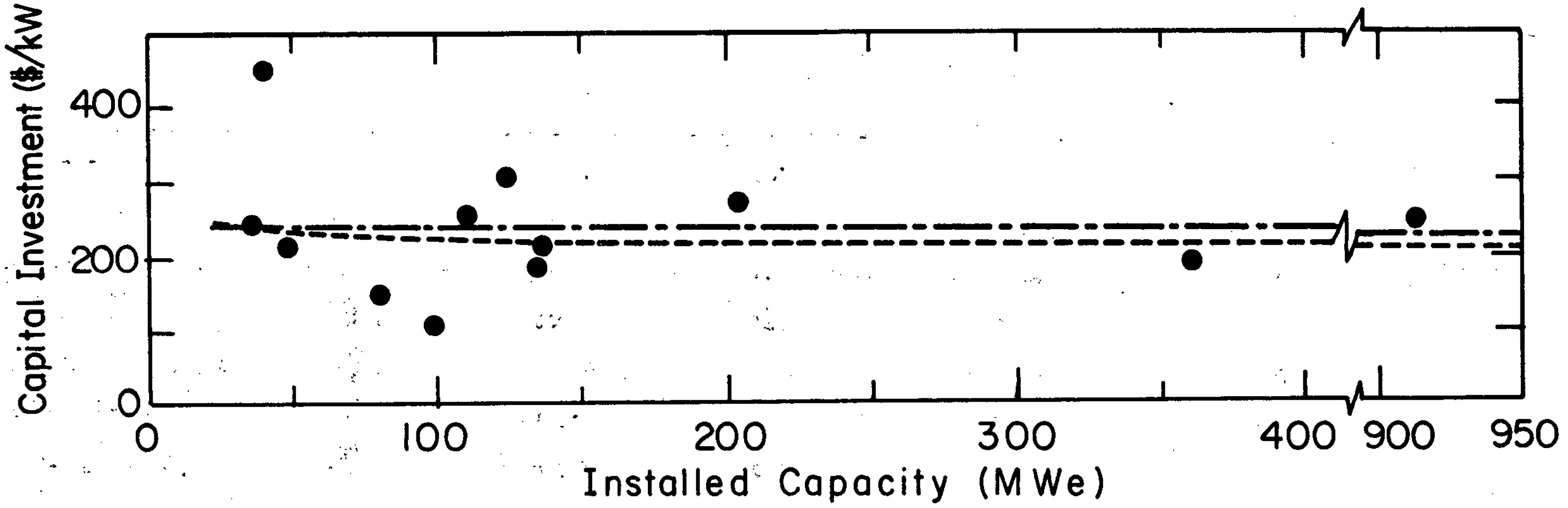

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Fig. C-1. Capital investment in $/kW versus installed capacity in MWe (as of 1975) for the hydroelectric plants in the United States which started operation in 1958.

1. Operating expenses
    a. Operation, supervision, and engineering
    b. Water for power
    c. Hydraulic expenses
    d. Electric expenses
    e. Miscellaneous hydraulic power generation expenses
    f. Rents
2. Maintenance expenses
    a. Maintenance, supervision, and engineering
    b. Maintenance of structures
    c. Maintenance of reservoirs, dams, and waterways
    d. Maintenance of electric plant
    e. Maintenance of miscellaneous hydraulic plant

These subcategories do not contribute equally to the total production costs. Examination of the production costs cited by the FPC[10] reveals that operating costs generally exceed maintenance costs. Electric expenses, hydraulic expenses, and supervision and engineering, in order of relative importance, are by far the most predominant components of operating costs. By contrast, only maintenance supervision and engineering and maintenance of electric plant are significant cost contributing subcategories of overall maintenance expenses. Considering now the dependence of generation costs in mills/kWh on the installed capacity of the plant, it can easily be established that, on the average, operation costs fall by a factor of 10 as installed capacity varies from 10 MWe to 2000 MWe.[10] The dispersion about the average, however, is very large. To demonstrate this point, let us examine once more the data of Table C-1 (and these data are plotted in Fig. C-2). A power curve fit of these data yields

$$y = 4.462\ (x^{-0.513})$$

with y in mills/kWh, x in MWe. The correlation coefficient is $r = 0.73$. This value is less than significant, even at the 1% level. Thus, if there is a correlation between production costs and installed capacity, it is not strong. Furthermore, if our examination is not restricted to those plants which began initial operation in 1958 but, instead, consider all the plants listed in the 1975 FPC study, a negligible correlation $r \simeq 10^{-2}$ to 10^{-3} is again obtained. On the basis of these results, the difference between dependence of capital costs versus plant capacity and production costs versus plant capacity can be determined. If one is using a statistically large sample in studying production costs versus plant capacity, it can be expected that, on the average, the larger plant would have lower electricity production costs. On a one-to-one basis, however, nothing can be predicted beforehand and only a case-by-case study can determine both capital costs and production costs.

Next, the contribution of the capital investment amortization on the price of generated electricity is examined. Let us consider again the data in Table C-1. An amortization time interval of 50 years, a typical lease period of hydroelectric dams by the Federal Power Commission, is assumed. It should be noted, however, that the life expectancy of dams, reservoirs, and waterways far exceeds 50 years. Furthermore, a discount rate of 6% is used, a rate which is probably

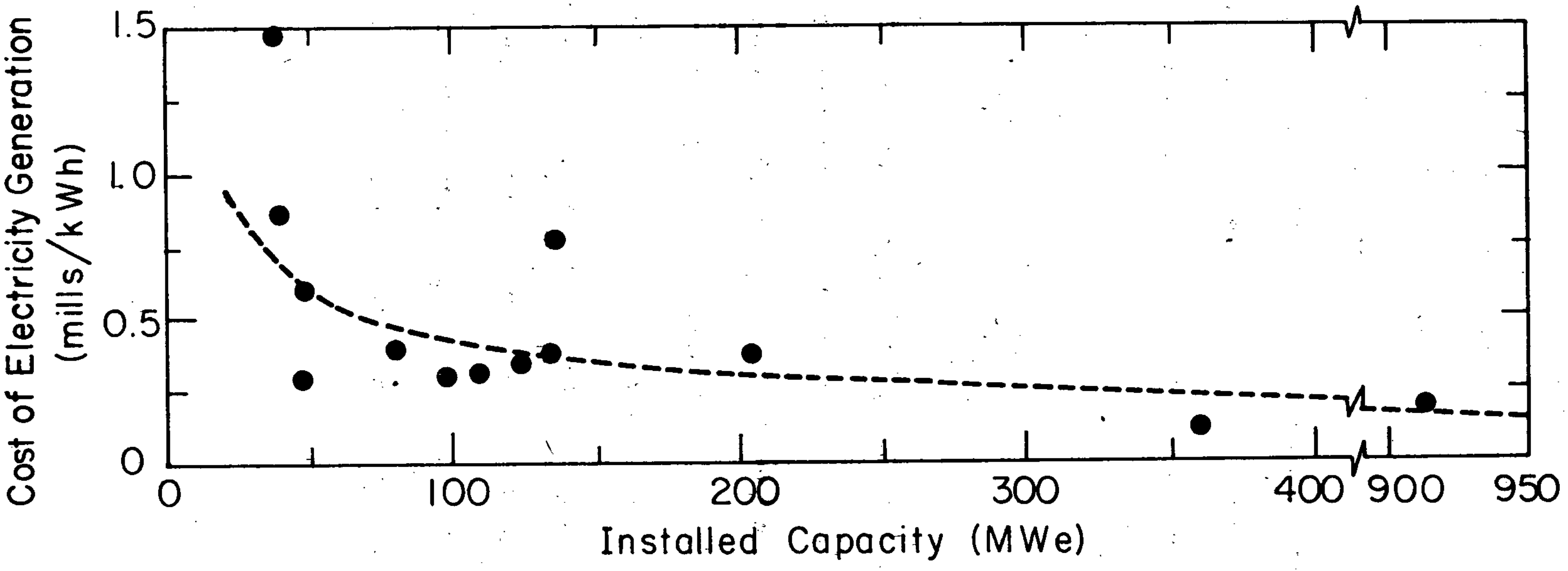

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Fig. C-2. Cost of electricity generation (maintenance and operation) in mills/kWh versus installed capacity in MWe (as of 1975) for the hydroelectric plants in the United States which started operation in 1958.

higher than that charged for federally-built projects subsequently leased to utilities.[30] Our calculations will therefore yield annual capital investment costs higher than those currently prevailing. Nevertheless, it would be instructive to know how their level compares to those of production costs, particularly now that smaller projects may be developed by private parties with no federal subsidies. The following capital recovery factor

$$\mathrm{CRF} = \frac{i(1+i)^n}{(1+i)^n-1} = \frac{0.06(1+0.06)^{50}}{(1+0.06)^{50} - 1} = 0.06344$$

has been used to calculate the annual principal and interest payments. The results are given in Table C-2, together with applicable information from Table C-1, using once again data for the year 1958. A study of the last three columns of Table C-2 clearly indicates that the cost of capital is generally several times the cost of production (maintenance and operation). On the other hand, the total cost of generation for hydroelectric power is several times lower than the similar cost for thermal power,[18] even if we take into consideration the more-than-250% increase in the implicit price deflator from 1958 to the present time.[31]

Table C-2. Total generation cost of hydroelectric plants in the U.S. with the same year of initial operation (1958).

Plant Name and Location[a]	Capacity[a] (MWe)	Ann. Generation[a] (10^6 kWh)	Capital Inv.[b] 10^6\$	Cost of Capital[c] mills/kWh	Cost of Production[a] mills/kWh	Cost of Generation[d] mills/kWh
Brownlee (Idaho)	360.4	2,361.6	68.836	1.85	0.12	1.97
Cochrane (Mont.)	48.0	381.8	10.416	1.73	0.31	2.04
Robert Moss (N.Y.)	912.0	7,307.7	223.440	1.94	0.18	2.12
Boyle, John C. (Oreg.)	80.0	513.1	12.000	1.49	0.42	1.91
North Fork (Oreg.)	38.4	247.1	17.395	44.6	0.86	5.32
Swift No. 1 (Wash.)	204.0	811.1	55.289	4.32	0.37	4.69
Center Hill (TVA)	135.8	491.5	29.197	3.77	0.77	0.54
Cheatham (TVA)	36.0	171.4	-	-	1.49	-
Balch No. 2 (Calif.)	97.2	220.4	10.594	3.05	0.29	3.33
Butt Valley (Calif.)	36.0	220.4	8.604	2.48	0.59	3.07
Caribou No. 2 (Calif.)	109.8	605.1	27.889	2.92	0.32	3.24
Haas (Calif.)	135.0	613.0	25.650	2.65	0.37	3.02
Poe (Calif.)	124.2	791.2	37.508	3.00	0.35	3.35

[a] From Table C-1.

[b] Capital Investment (\$$10^6$) = Capital Inv. (\$/kW) x Capacity (MW) x 10^3.

[c] Cost of Capital (mills/kWh) = Capital Investment (\$$10^6$)/Ann. Generation ($10^6$ kWh).

[d] Cost of Generation = Cost of Capital + Cost of Production.

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