TABLE 5-3
COMPARISON OF ELECTROMECHANICAL COSTS FOR ALTERNATIVES 1 and 3

FERC Account Number	Description	ALTERNATIVE 1 Manual Procedures	ALTERNATIVE 1 Feasibility Study	ALTERNATIVE 3 Manual Procedures	ALTERNATIVE 3 Feasibility Study
333	Water Wheels, Turbines and Generators Installed Cost (Figures 3-12 to 3-16 of the Manual)	$1,793,100	$1,433,500	$2,840,000	$2,120,900
334	Station Electrical Equipment: Transformer, Lightning Arrestor, Air Breaker Swt. Gen. Breaker and Line OCB (Figure 6-3 of the Manual)	$ 105,000	Cost included in transmission line cost.	$ 120,000	Cost included in transmission line cost.
	Battery Sys., Sta. Swt. Gear, Sta. Ser. Trans., Bus, Cable Conduit, Grd., Control Bd., Lighting Sys., Freight and Installation (Figure 5-4 of the Manual)	$ 180,000	$ 213,000	$ 195,000	$ 213,200
335	Misc. Power Plant Equipment: Ventilation, Fire Protection, Cooling Water, Communication Sys., Freight and Installation (Figure 6-5 of the Manual)	$ 55,000	$ 115,500	$ 60,000	$ 123,700
350	Transmission Line (Figure 6-4 of the Manual)	$ 6,000	$ 305,000[1/]	$ 46,000	$ 316,000[1/]
Control System		Not covered in Manual	$ 260,000	Not covered in Manual	$ 260,000
Elevator Rehabilitation, Stilling Well, Crane Rebuilding and Misc.		--	$ 62,000	--	$ 62,000
	Subtotal	$2,179,100	$2,389,200	$3,261,000	$3,095,800
	Contingency (25%)	544,775	277,936[2/]	815,250	251,970[2/]
	Subtotal	$2,723,875	$2,667,136	$4,076,250	$3,347,770
	Engineering, Constr. Mg. & Other Costs (20%)	544,775	266,714[3/]	815,250	334,777[3/]
	TOTAL INSTALLED COST	$3,268,650	$2,933,850[4/]	$4,891,500	$3,682,547[4/]

1/ Cost estimate furnished by local utility (PSE&G).
2/ Contingencies not included for vendor furnished costs.
3/ Feasibility study used 10% for Engineering Costs.
4/ Total installed costs do not include contingencies for vendor supplied equipment.

SECTION 6
POWER MARKETING ANALYSIS

General

The value of the output from the Great Falls plant depends on the project's electric production characteristics and the economics of the power purchaser. The production characteristics determine the type of power the project can displace, and the potential users, and the purchaser's economics determine the value of this class of power. This section closely follows the guidelines contained in Volume II of the manual.

Production Characteristics

Previous studies have shown that no firm generation capacity can be provided by the Great Falls project. Periods of flow below levels required for the hydrogeneration equipment studied occur between June and November annually and flow fluctuates substantially throughout the year. Since plant storage is limited to a small amount of daily pondage, the project is a run-of-the-river project with no firm capacity. In the case of a utility purchaser, the project value will be the energy cost of electricity displaced. For other users, the project value is based on reducing purchased electricity.

Previous investigation explored the possibility of raising the dam to achieve increased energy production. It was shown that the dam could safely be raised 5.7 feet, thereby increasing annual energy output by approximately six percent, but no firm capacity is gained. However, the increased dam height with accompanying gates for flow control would increase the pondage available and could affect the power value estimate.

Power Value

Sale of the Great Falls electrical output to the local utility (Public Service Electric and Gas (PSE&G)) and to an end user were considered.

Sale to Public Service Electric & Gas (PSE&G). PSE&G is New Jersey's biggest utility and the one serving the project area. PSE&G is a member of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, a power pool with centralized dispatch and free flowing power exchange. PSE&G has tentatively agreed to purchase the project energy at a price related to the cost of energy purchased through the PJM Interconnection. In 1976, this value was put at between 20 and 25 mills/kWh.

Since this offer prices the project output based on the marginal value of energy in the interconnected system, it fairly represents the economic value of the Great Falls project. However, because of the long-term nature of hydroelectric facilities, the future value of energy displacement in the PSE&G system was investigated.

PSE&G's current sources of energy and how they are used to meet demand are shown in Figure 6-1. As this figure shows, PSE&G is burning oil as a baseload fuel. The energy cost of oil firing in the system (based on the weighted average oil-fired heat rate of 11,000 Btu/kWh and oil cost at $2.35/MMBtu) is 2.54¢/kWh. This value will escalate at least as fast as inflation.

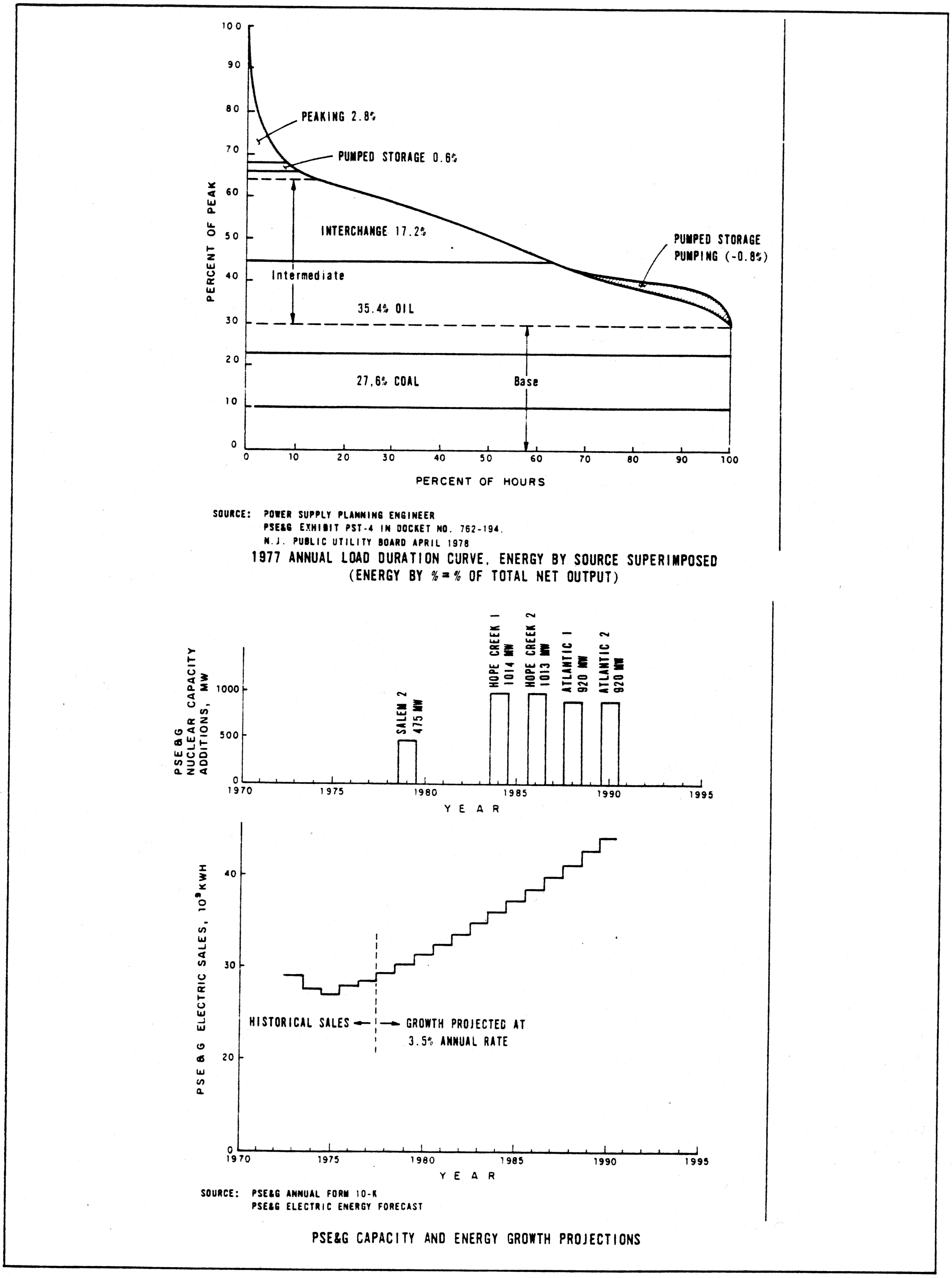
It is possible that PSE&G's aggressive nuclear expansion program could result in oil no longer being a baseload fuel. Figure 6-1 also shows the expected growth in energy sales and the timing and capacity of future nuclear addition. Future baseload production was investigated by projecting a series of load duration curves into the 1980's and superimposing energy production by source. Energy was assumed to be produced based on 45 percent annual capacity factors for nuclear and coal generation. (1977 capacity factors were 40.4 percent for nuclear and 44.5 percent for coal.) This analysis showed that oil will still be a baseload fuel through 1989.

It can therefore be concluded that through 1989, the minimum value of energy produced by the Great Falls plant will be based on the energy cost of oil-fired generation in the PSE&G system. In 1977, this value was 25.4 mills per kWh and over this period the minimum *escalation* rate should be the general inflation rate. Most observers predict the real cost of oil will rise, hence leading to a faster escalation than the general inflation rate.

Sale to End User. Power sales to an end user were evaluated and it was concluded that this is an infeasible method of selling the project output. This is so because transporting the energy to the user's site could prove very difficult and expensive. The two options are to construct a separate transmission line or to wheel the power over PSE&G lines. Construction of a separate line in this urbanized area would pose serious right-of-way problems.

The Director of the Office of Technical Assistance, New Jersey State Energy Department, was contacted in regard to wheeling. To his knowledge there are no current wheeling arrangements that would allow an industrial or other non-resale purchaser to wheel power over utility lines. He thought such an arrangement would be very difficult to obtain because the project is nonfirm and significant standby charges would be levied; the energy value of the power displaced would be related to the average energy cost of PSE&G, which is considerably less than the marginal cost; also only small pondage is available, causing energy to be lost during low usage hours. This is in contrast to a situation where the utility takes all project output.

The combination of these four factors makes it unlikely a nonutility would find the purchase of Great Falls power to be beneficial.



1977 ANNUAL LOAD DURATION CURVE, ENERGY BY SOURCE SUPERIMPOSED
(ENERGY BY % = % OF TOTAL NET OUTPUT)

PSE&G CAPACITY AND ENERGY GROWTH PROJECTIONS

Figure 6-1. PSE&G Energy Source and Growth Projection Curves

SECTION 7
ECONOMIC AND FINANCIAL ANALYSIS

Introduction

The cost and power value information developed in previous sections allows the economic and financial feasibility of the Great Falls project to be evaluated. For this analysis, two major criteria were used:

1. The project was analyzed as a stand alone venture receiving the full economic value of the energy produced. This perspective results in the true economic merits of the project being established.
2. The project has been assumed to be both owned and financed with tax exempt revenue bonds by the City of Paterson. With municipal ownership, no local or income taxes are levied against the project. For financial feasibility, 40 year, seven percent bonds were assumed.

In addition, in this section a sinking fund has been calculated which will provide sufficient funds, in future dollars, to perform major repairs and replacements. These expenditures will be necessary to maintain the facility in functional order through the financing period.

The steps followed in analyzing the plant are discussed below. The actual computations were performed by several computer programs developed for this purpose and described in the manual. By design, the cost of service (financial feasibility) and the internal rate of return (economic feasibility) were calculated in one program and consequently separate calculations are not presented here.

Economic and Financial Analysis

Economic feasibility is the evaluation of project costs and benefits with the project deemed feasible when benefits exceed costs. Financial feasibility is the evaluation of the ability of the project to provide debt service from the capital required to construct and operate the project.

The financial calculations of receipts and disbursements determine the expected "cash flow" for the project. For Great Falls, cash flow represented all quantified costs and benefits so that the financial analysis provided the costs (disbursements) and benefits (receipts) for the economic analysis. The economic criteria used was the internal rate of return (IRR).

The following analysis of the economic evaluation procedure presented in Table 4-3 of Volume II utilizes the Economic and Financial Analysis Manual. Financial calculations are made, then become the quantitative inputs for the economic analysis.

Escalation. It was first determined that inflation would be explicitly included in the analysis. A general escalation rate of six percent was used as representative of expectations of the long-run inflation rate. This rate was used for all costs and revenues.

Economic Life. The project economic life was established at 40 years, the same as the financing period. Since major repairs and replacements are periodically required for the project to remain operational, the period when these repairs are not made determines the project life. In this case, provisions were made for a 40-year operation.

Unescalated Costs. Construction and annual costs in 1978 dollars for the alternatives have been established in previous sections. These are reproduced in summary form in Table 7-1 for use in the economic and financial analysis.

The construction period was estimated to last three years. Capital expenditures were estimated to be 20 percent in the first year and 40 percent in each of the following two years.

The electrical/mechanical investigation determined that repair and replacement of major equipment components are periodically necessary for continued operation of the plant. The costs were estimated as percentages of the original cost of several major asset classes. The procedure described here was used to convert these percentages into a constant annual cost that will provide sufficient funds, in future dollars, to make the required expenditures. In this analysis, provisions were made for a 40-year project.

The first step was to use the replacement schedules and the 1978 value of the asset classes to determine the total replacement (in 1978 dollars) required in the 20th and 30th years of operation. These values were then escalated to the year of occurrence accounting for the construction period. Next, using the city's cost of borrowing (seven percent) as the discount rate, the present value of these future replacements was calculated in 1981, the first year of project operations. This amount and the equivalent 30-year, seven percent sinking fund are shown in Table 7-1. Note that this annual cost (about 40 percent of other annual operating costs) is significant and must be incorporated in the financing plan to assure project operations through the financing period.

Unescalated Benefits. The only project benefit considered in this analysis is power production since no other monetary benefits could be identified. The power marketing analysis established the value of the output at a minimum of 25 mills per kWh in 1977. For this analysis, the valve of power was set at 25 mills per kWh in 1978. This value was also escalated.

Discount Rate. The City of Paterson's cost of bond financing is the appropriate discount rate to use in the analysis. The tax status of revenue bonds used for this purpose has a major impact on their cost. Since the total

TABLE 7-1
COST SUMMARY (1978 DOLLARS)

	Alternative 1 Rehabilitation (Allis-Chalmers)	Alternative 2 New Horiz. Runners (Leffel)	Alternative 3 Cross Flow (Ossberger)	Alternative 4 Tube Turbines (Tampella)
Construction Cost				
Dam 1/	1,056,700	1,056,700	1,056,700	1,056,700
Civil Features	1,210,000	1,210,000	1,157,750	878,900
Elec/Mech	2,933,850	3,112,000	3,682,547	5,074,100
Total	5,200,550	5,378,000	5,896,997	7,009,000
Annual Cost				
O&M	73,000	90,000	83,000	89,000
Admin (20% of O&M)	14,600	18,000	16,600	17,800
Insurance (.2% of Const.)	10,400	11,505	11,794	14,019
License Fee	2,000	2,000	2,000	2,000
Major Repairs and Replacement 2/				
Present Value in 1981 of R&R through 30 years	577,580	569,230	605,860	833,770
Constant Annual Sinking Fund Payments (30 years @ 7%)	46,540	45,870	48,820	67,190

1/ Restoration of existing structure
2/ Described in the text

bonding required for all the options is less than $10 million, the established limit for tax exemption of small issues which are not otherwise exempt, the issue was assumed to be tax exempt. See Section 6 of the Economic and Financial Analysis Manual for more detail in this regard. Since the cost of financing can have a major impact on the financial feasibility, an opinion from a bond counsel should be obtained on the tax status prior to further major commitments of funds.

After reviewing *Moody's Bond Record*, a seven percent cost of bonding was used.

Results

Summary results for the four alternatives are contained in Table 7-2. The internal rate of return (IRR) was the economic evaluation criteria used to evaluate this project. IRR is defined and its method of calculation explained in Section 4 of the Economic and Financial Analysis Manual.

The project's IRR was calculated for a range of initial energy values to investigate the project's sensitivity to this major parameter. Over the range of 20 to 30 mills per kWh of initial value, the project's IRR for Alternative 2 was at least twice the client's discount rate, indicating an economically feasible project given the assumptions concerning escalation. The other three alternatives were also shown to be economically feasible.

A number of important financial quantities were determined for each alternative. These were cost escalation and interest during construction and cash receipts and disbursements. Cost escalation and interest during construction increase the Leffel alternative's completed cost by approximately $700,000 over the lump sum estimate of $5.4 million. The constant annual debt service on the bonds required to finance the project will be approximately $460,000 per year. This may vary depending on the exact structure of the bond issue.

Impact of Low Flow. If the output from this project is sold on a per kWh basis, the revenue impact of low flow must be determined. The first year of operation will be examined since this is the most critical period.

Table 7-3 shows the first year financial results of low flow. As shown, all the options have cash flow deficits under these conditions. Provisions for this possibility must be provided in the marketing agreement for each option or a reserve fund must be established for contingencies.

TABLE 7-2
SUMMARY OF TECHNICAL, ECONOMIC AND FINANCIAL DATA

	Alternative 1 Rehabilitation (Allis-Chalmers)	Alternative 2 New Horiz. Runners (Leffel)	Alternative 3 Cross Flow (Ossberger)	Alternative 4 Tube Turbines (Tampella)
Installed Capacity (kW)	5,100	7,500	6,800	7,875
Average Annual Energy Production in millions of kWh[1/]	24.4	30.8	27.9	32.3
Value of Energy Produced:				
1978 Value in ¢/kWh	2.50	2.50	2.50	2.50
1981 Value in ¢/kWh (First year of operation)[2/]	2.98	2.98	2.98	2.98
Capital Costs:				
Civil[3/]	2,266,700	2,266,700	2,214,450	1,935,600
Electrical/Mechanical	2,933,850	3,112,000	3,682,547	5,074,100
TOTAL (1978 Dollars)	5,200,550	5,378,000	5,846,997	7,009,700
$/kW	1,020	717	867	890
Completed Project Cost[4/]				
TOTAL (1981 Dollars)	5,887,500	6,089,200	6,676,000	7,935,700
Annual Project Costs (First year of service - 1981):				
Debt Repayment (Dollars)[5/]	441,600	456,700	500,800	595,200
Repairs and Replacement Sinking Fund (Dollars)[6/]	46,500	46,800	48,800	67,200
Operating Costs (Dollars)[7/]	119,100	143,900	135,100	146,300
Cost of Service (First Year of Operation - 1981) (¢/kWh)	2.49	2.10	2.45	2.50
Internal Rate of Return (%)[8/]	15.4	17.5	15.5	15.4

1/ Based on Water Years 1950/51 through 1959/60 (Representative Decade)
2/ Energy Value escalated at 6.0% per year
3/ Includes restoration of the dam. Dam cost is for most expensive of various dam alternatives studied.
4/ Capital costs are escalated to the Year of Occurrence at 6%, then Construction Interest charged at 7.0% per year
5/ Fully amortized for 40-year life at 7%
6/ Provides sufficient funds for replacements, in Future $'s, to allow 40 years of operation
7/ Includes O&M, Administrative Overhead, Insurance, and License Fees
8/ Assumes 6% General Price Escalation over the Project Life of 40 years

TABLE 7-3
FIRST YEAR RECEIPTS AND DISBURSEMENTS
LOW FLOW CONDITIONS
PER kWh SALE
(In Thousands of Dollars)

	Alternative 1 Rehabilitation (Allis-Chalmers)	Alternative 2 New Horiz. Runners (Leffel)	Alternative 3 Cross Flow (Ossberger)	Alternative 4 Tube Turbines (Tampella)
Percent of Normal year Energy Production	70%	65%	67%	65%
Low Flow Revenue (Per kWh Sale)	$508.6	$596.1	$556.6	$625.1
Less:				
Operations	119.1	143.8	135.1	146.3
Bond Amortization	441.6	456.7	500.8	595.2
Replacement Sinking Fund	46.5	46.8	48.8	67.2
Net Funds	-98.6	-51.2	-128.1	-183.6

REFERENCES

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EXHIBIT II
ROLLINS POWER PROJECT
CASE STUDY
SMALL HYDROPOWER ADDITIONS

Contents

FIGURES

TABLES

SECTION I
INTRODUCTION

Scope

This case study document describes the application of the guidance and technical data presented in the draft guide manual. Cost and design information for the Rollins Power Project, Bear River, California, is presented as an illustrative example of use of the manual materials. Also, the validity of the data and guidance provided therein is evaluated. This information is presented "after the fact", since the construction of the Rollins Power Project (Project) began in the fall of 1978. It is anticipated that the Project will begin generation in the spring of 1980. The Project was formulated and executed by the Nevada Irrigation District (District) with Tudor Engineering Company as consultants.

Existing Project

The Rollins Power Project is located at Rollins Dam on the Bear River, about 16 miles north of Auburn in the Sierra Nevada mountains of Central California. The dam was completed in 1966 as part of the Yuba-Bear River Development Project, constructed by the District. The Yuba-Bear Project stores and diverts water from the upper Yuba River watershed into the Bear River watershed for irrigation and domestic use in Nevada and Placer Counties. Above Rollins Dam, in addition to other Yuba-Bear Project facilities, the District owns and operates two hydroelectric plants, Dutch Flat No. 2 and Chicago Park. The energy from the power plants, both located on the Bear River, is sold to Pacific Gas and Electric Company (PG&E).

Rollins Dam is a 220-foot high rockfill dam with an impervious core. The concrete ogee spillway in the right abutment was designed for a maximum flow of approximately 60,000 cubic feet per second. The diversion and outlet works for the reservoir were constructed together. A single 18-foot diameter horseshoe shaped conduit was excavated through the left abutment from the reservoir for about 300 feet. At that point, a bifurcation leads into two smaller tunnels. One is a 16-foot flat invert, partially-lined tunnel which was used as the diversion during construction. The other is a 12-foot horseshoe-shaped, concrete-lined tunnel with a 60-inch Howell- Bunger valve which is currently used for water deliveries to downstream users. After construction, the diversion tunnel was plugged with 50 feet of mass concrete. This plug was pierced for the Project penstock.

The intake tower is located within the reservoir near the upstream toe of the dam. It is an ungated structure, equipped with a large trash-rack cage. Within the outlet works, there are no control gates upstream of the bifurcation. Downstream of the dam is a small afterbay and a diversion dam with head-works for the PG&E Bear River Canal. Discharges from the outlet works also flow down the Bear River to Combie Dam and are diverted at that point for use in Placer and Nevada Counties by the District.

Power Plant Addition

The Rollins Power Plant will include the following:

1. A semi-outdoor powerhouse with an installed capacity of 12,700 kilowatts will be constructed near the toe of the dam and the existing outlet portal. A switchyard, enclosed by fencing, will be built adjacent to the powerhouse.
2. A steel penstock approximately 550-feet long, will rest on concrete piers placed in the existing 16-foot diversion tunnel with an emergency control butterfly valve at the upstream end near the existing tunnel plug. The tunnel plug was pierced during a previous work phase and a steel liner was inserted to convey water to the penstock. Control equipment will be provided to allow for synchronous passage of water either from the existing outlet valve in the adjacent outlet tunnel or hydraulic turbine.
3. A tailrace channel downstream of the proposed powerhouse will be excavated in the rock between the tunnel outlet and the existing diversion dam.
4. Supplemental site development features will be built, including an apron adjacent to the power house for parking and the staging of maintenance activities. A storage and office building will be constructed for the accomodation of operation and maintenance personnel and the storage of spare parts and maintenance materials which cannot be stored within the powerhouse. An access road will be developed, by upgrading the existing service road, to accomodate the vehicular traffic to the powerhouse.
5. A transmission line will be constructed by PG&E from the power plant switchyard in a westerly direction to an existing PG&E transmission line. This feature is not considered as part of the Rollins Power Project.

The existing project features and new power facilities are shown on Figure 1-1.

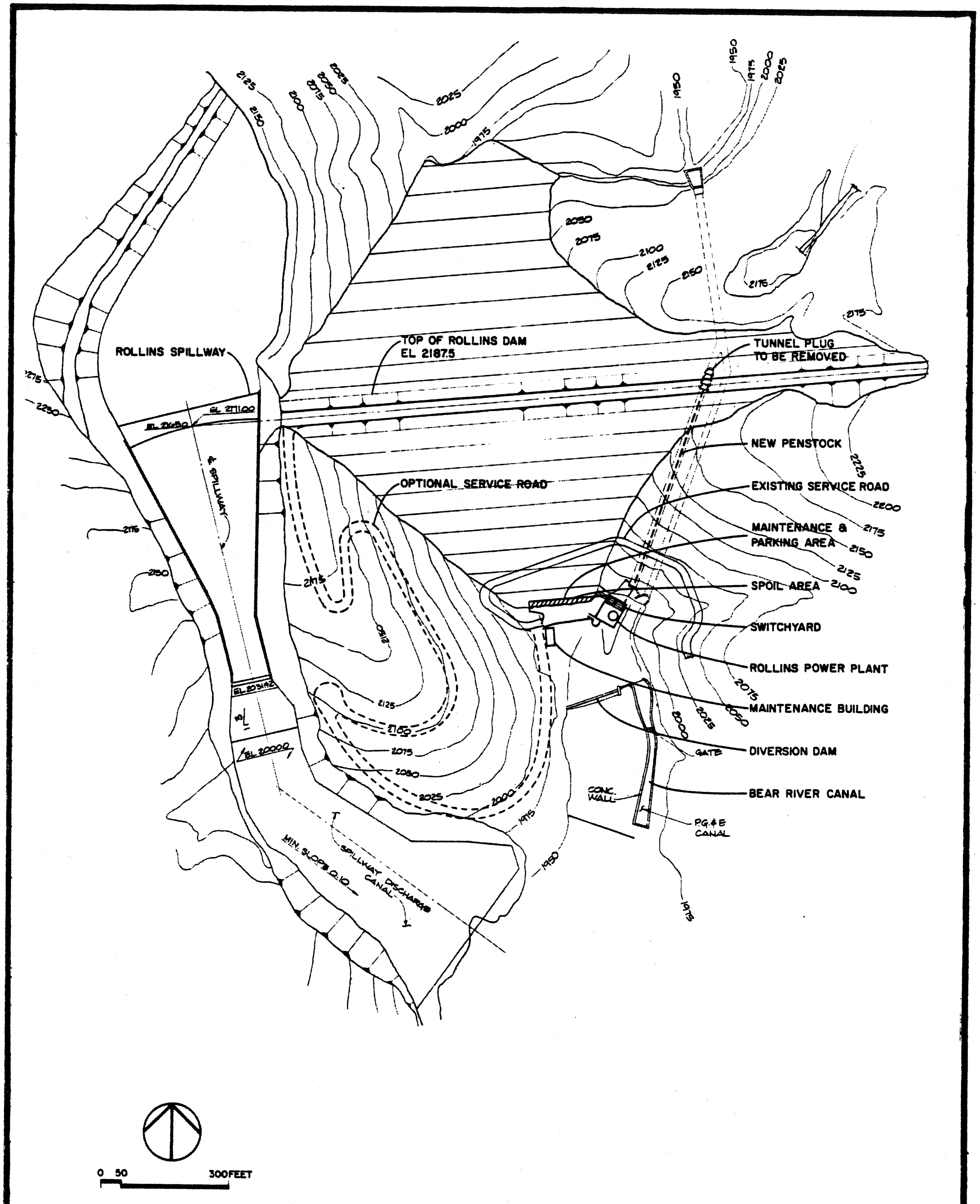


Figure 1-1. Principal Features - Rollins Power Project

SECTION 2
PROJECT FORMULATION

Formulation and initiation of the Project was accomplished by the preparation of a feasibility study, the marketing of the power to be generated, and the preparation of the necessary applications and permits. Other activities which then followed and are described in the next section on implementation of the Project, included the final design, bidding and award of construction contract. Construction of the Project is now proceeding.

Feasibility Studies

Work on the feasibility study was authorized by the District Directors in the spring of 1974 and was completed in August 1974. The main study items consisted of the review of existing studies, the formulation of four alternative project developments, the preparation of operation studies for the alternatives and cost and benefit studies of the alternatives. Conclusions and recommendations were made, along with a proposed time schedule for further action.

Four Project alternatives were formulated as follows:

1. Add power plant to existing dam with no change in present operating agreement with PG&E.
2. Add power plant to existing dam, raise maximum water surface from elevation 2171 to 2185, continue present operating agreement.
3. Add power plant to existing dam, change present operating agreement to maximize water and power output.
4. Add power plant to existing dam, raise maximum water surface from elevation 2171 to 2185, change present operating agreement to maximize water and power output.

The study period for the reservoir operation studies was taken to be 1928 through 1937. This is the same period previously used by the District water supply studies and it was considered important to be able to compare results. This study period included an extreme drought period and the average annual energy from this period was lower than would be realized if a longer-term more representative record was used. An example of the systematic routing operation studies used for this Project is shown in Figure 2-1.

Due to the uncertainty at that time in future cost of fuel oil (circa Spring 1974) on which a traditional benefit and cost analysis should be based, the report included the calculation of the cost of energy from the four project alternatives in mills per kWh. That cost was then converted to a cost for an equivalent barrel of fuel oil. It was assumed that fuel oil would be the source of replacement energy if the project was not constructed. The lower the equivalent fuel oil cost, the greater the benefit of the project. Table 2-1 shows these equivalent fuel oil costs for the four alternatives ranked in order of benefit. It can be seen that the costs range from $5.04 to $8.55 per barrel. At approximately the time of the report, it was reported by PG&E that the cost of imported low sulfur fuel oil rose from $7.75 to $13.00 per barrel. From this information, it was concluded that all of the alternatives considered would be economically feasible.

After evaluating the economic and institutional aspects of each alternative, alternative 1 was selected. A 12,700 kW turbine/generator unit would be installed, with no increase in the height of the dam or addition of spillway gates. The plant would be operated as a run-of-the-river plant with no change in the release pattern. The raising of the water surface entailed by alternatives 2 and 4 was not selected because of the impact on the environment, disruption to the existing recreational facilities next to the reservoir and the added cost of the relocation of old Highway 40 where it crossed an arm of the reservoir. Alternative 3 was not selected since it was decided by the district not to attempt a renegotition of the operating agreement with PG&E.

Since the present operation requires the reservoir to be occasionally lowered to an elevation below the minimum head for power generation, no dependable capacity was credited to the installation. A peaking operation was not considered as an alternative because of the lack of a suitable afterbay site.

Several constraints on the Project were found during the feasibility study. Financially, the District had 7.8 million dollars in authorized but unissued revenue bonds remaining from the construction of the Yuba-Bear Project. These could be used for the Rollins Project, but if that amount was exceeded, other forms of financing the overrun, including possible additional authorization by the electorate to sell more bonds, would be necessary. Also, if the power was sold to an investor-owned utility, the bonds would take the form of Industrial Development Bonds (IDBs) and would lose their tax exempt status. (Revenue bond financing and IDBs are discussed further on page 6-8 of Volume II.) The District's financial consultant indicated that the IDBs would carry an interest rate greater than the maximum allowed by California Irrigation District's law, i.e., eight percent. Therefore, it was proposed, and later accomplished, that the District's law be amended to permit a higher interest rate, not to exceed 10 percent.

The most difficult physical constraint discovered was necessity to pierce the plug in the original diversion tunnel for the penstock. There was no valve or control gate with which to close off the upstream side of the plug so that the work could be performed without draining the reservoir. Several unique and challenging

RESERVOIR OPERATION STUDY

CASE III - MODIFIED OPERATION ONLY

CASE III
Sheet 1 of 4

Water Year (month)	Total Inflow (1000 a-ft)	Releases (1000 a-ft) Demand 1/	Evap.	Total	Inflow Minus Release (1000 a-ft)	Storage @ End of Month (1000 a-ft)	Reservoir Stage @ End of Month	Spill (1000 a-ft)	Deficiency (1000 a-ft)	Avg. Head on Turbine (feet)	Energy 2/ M-KWH	Average Power 3/ MW
1928												
Oct.	16.9	33.3	.2	33.5	-16.6	49.3	2150			194	6.40	8.6
Nov.	44.2	29.0	.1	28.1	16.1	65.3	2170			214	5.83	8.1
Dec.	30.1	25.8	.1	25.9	4.2	65.9	2171	3.6		215	6.13	8.2
Jan.	33.7	25.8	.1	25.9	7.8	65.9	2171	7.8		215	7.01	9.7
Feb.	35.3	23.4	.1	23.5	11.8	65.9	2171	11.8		215	7.34	10.9
Mar.	124.8	14.3	.2	14.5	110.3	65.9	2171	110.3		215	4.25	12.7
Apr.	65.2	30.3	.3	30.6	34.6	65.9	2171	34.7		215	9.11	12.7
May	33.9	37.9	.3	38.2	-4.3	61.6	2165			209	7.58	10.2
June	23.0	33.2	.6	33.8	-10.8	50.8	2152			196	6.26	8.7
July	34.1	37.9	.8	38.7	-4.6	46.2	2145			189	6.89	9.3
Aug.	36.3	37.8	.6	38.4	-2.1	44.1	2141			185	6.75	9.1
Sep.	19.9	37.0	.4	37.4	-17.5	26.5	2117			161	5.44	7.6
											78.99	
1929												
Oct.	12.8	23.0	.2	23.2	-10.4	16.2	2079			123	2.42	3.3
Nov.	13.2	12.6	.1	12.7	.5	16.7	2080			124	1.33	1.8
Dec.	15.8	11.6	.1	11.7	4.1	20.8	2092			136	1.36	1.8
Jan.	14.5	10.5	.1	10.6	3.9	24.7	2103			147	1.44	2.0
Feb.	17.5	14.1	.1	14.2	3.3	28.0	2110			154	2.01	3.0
Mar.	23.7	19.1	.1	19.2	4.5	32.5	2119			163	2.94	8.8
Apr.	29.6	18.8	.2	19.0	10.6	43.1	2139			183	3.42	4.8
May	24.7	37.3	.3	37.6	-12.9	30.2	2114			158	5.33	7.2
June	27.0	36.9	.4	37.3	-10.3	20.0	2090			134	4.34	6.0
July	34.7	37.9	.4	38.3	-3.6	16.5	2079			123	4.12	5.5
Aug.	36.6	37.8	.3	38.1	-1.5	15.0	2074			118	3.78	5.1
Sep.	19.7	34.6	.3	34.9	-15.2	4.6	2025		4.7	---	--	2.2
											32.49	
1930												
Oct.	12.4	22.0	.1	22.1	-9.7	4.6	2025		9.7	---	--	---
Nov.	12.2	11.9	.1	12.0	.2	4.8	2026				--	---
Dec.	56.0	25.8	.1	25.9	30.1	34.9	2123				3.97	5.3
Jan.	40.1	25.8	.1	25.9	14.2	49.1	2150				4.87	6.8
Feb.	48.3	23.4	.1	23.5	24.8	65.9	2171	8.0			8.54	12.7
Mar.	49.5	14.3	.2	14.5	35.0	65.9	2171	35.0			4.25	12.7
Apr.	47.2	30.3	.2	30.5	16.7	65.9	2171	16.7			9.10	12.7
May	37.1	37.9	.3	38.2	-1.1	64.8	2170				7.90	10.6
June	24.0	34.2	.6	34.8	-10.8	54.0	2157				6.84	9.5
July	34.0	37.9	.7	38.6	-4.6	49.4	2151				7.29	9.8
Aug.	36.2	27.8	.6	38.4	-2.2	47.2	2147				6.87	9.2
Sep.	19.9	37.0	.5	37.5	-17.6	29.7	2115				5.29	7.3
											64.92	

1/ Assume No Demand for 15 days each March.
2/ Includes use of spills when available up to maximum turbine capacity.
3/ No power is generated when head is less than 100 feet.

Figure 2-1. Example - Systematic Routing Study

TABLE 2-1
SUMMARY OF STUDIES

Alternative	Average Generation (Year 1927-1937) kWh × 10^6	Energy Cost Mills/kWh	Equivalent Fuel Oil Cost $/barrel
1	53.0	7.96	5.04
2	55.0	11.45	8.55
3	56.8	7.43	5.55
4	60.4	10.42	7.78

proposals were made for accomplishing the work under those adverse conditions. However, during the unprecedented drought in the summer of 1977, the reservoir water surface was lowered below the level of intake structure and the proposed work schedule was accelerated to take advantage of the unexpected opportunity to pierce the plug in the dry. This work was approved and performed under the supervision of the Division of Safety of Dams, Department of Water Resources, State of California.

Spillway Flood Studies

Two of the alternative project formulations investigated included the maintenance of the existing maximum reservoir water level (Alternatives 1 and 3) and two others entailed the increase of the spillway crest elevation from 2171 to 2185 in order to increase the power and water conservation yield (Alternatives 2 and 4). The raising of the spillway crest would have required a similar raise in the dam crest to facilitate the passage of the spillway design flood. This dam would be classified as a large dam (over 50,000 acre-feet) in a "significant" hazard area (see Table 4-3 Volume III); therefore, the spillway would be required to pass the total probable maximum flood (PMF).

In order to investigate the adequacy of the spillway, the PMF hydrograph and the criteria used to establish the maximum probable preciptiation were obtained from the Division of Safety of Dams in Sacramento, California. The source of the probable maximum precipitation data was found to be Hydromet Report 36 and was judged by the Consultant and Safety of Dams to be adequate. The PMF hydrograph was routed by computer model over the existing spillway crest and the resulting maximum water surface was contained by the dam with about two feet of free board. The spillway was judged to be adequate. The inflow hydrograph and the routed outflow hydrograph are shown on Figure 2-2.

Integrity Investigation

The investigation of the integrity of the existing dam was minimal. The dam has been reviewed for safety each year by the engineering staff of the Division of Safety of Dams and once each five years by staff of the Federal Energy Regulatory Commission. The FERC requires as a part of their five-year review that the owner furnish to FERC a report prepared by a Consultant on the safety of the dam. During these investigations, no conditions have been observed that required remedial measures.

The State of California Water Code, Section 6225, requires that any additions or alterations to a dam receive the approval of the Division of Saftey of Dams prior to construction. An application was made to cover the removal of the tunnel plug. The design and construction criteria, plans and specifications were provided to Safety of Dams and approval was granted. Since blasting of the concrete plug would take place under the dam within 20 to 30 feet of the existing outlet, the consultant proposed and the State agreed that the wave velocity of the explosion be limited to less than three inches per second. During construction, the wave velocity was monitored by instruments and did not prove to be an unreasonable constraint on the blasting operation.

Representatives from Safety of Dams have continued to review and to monitor the construction and will provide final approval upon completion.

Selection of Turbine/Generator

The two turbine options considered for the Rollins Project were Francis and Crossflow. These are the appropriate options for head conditions of between 150 and 200 feet (from Figure 2-2, Volume V). The Crossflow turbine was not considered in detail because of limited available unit capabilities, as described in the manual.

The design turbine flow of 610 cfs was determined by the contractual commitments to PG&E for release and by the District's requirements for irrigation and domestic releases and low flow augmentation. Controlled flows are not released in excess of this demand condition. Uncontrolled flows spill over the spillway, and could be routed through the turbine up to the maximum hydraulic capacity.

The average weighted gross head on the turbine was calculated by multiplying the measured outflow from the reservoir in cfs-days times the daily gross head and dividing by the summation of measured outflow. This computation was accomplished as a part of the computer program used for the systematic routing. The results of

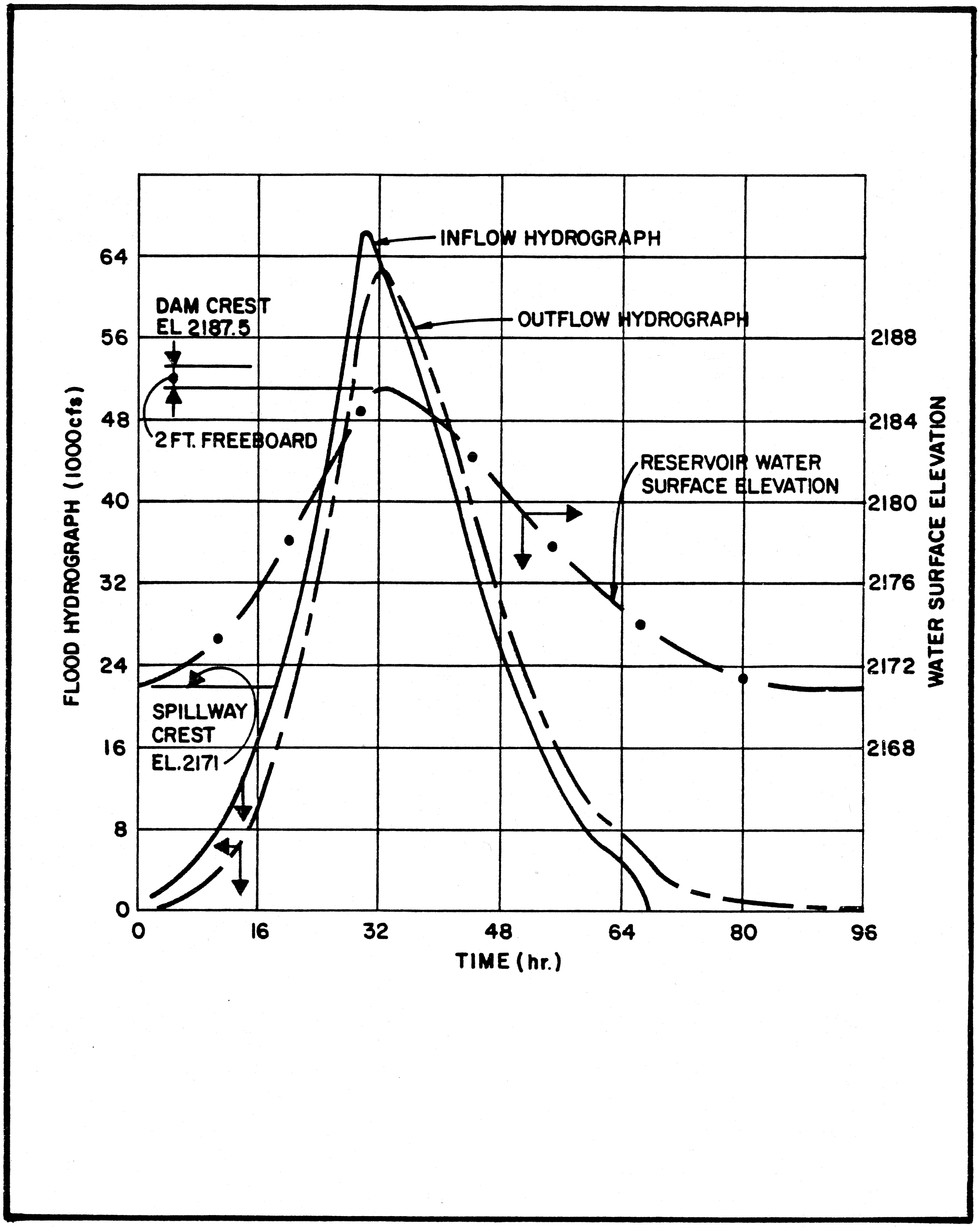


Figure 2-2. PMF Flood - Inflow and Outflow Hydrographs and Water Surface Elevation

this study indicated that the average weighted head was 175 feet.

From the maximum flow of 610 cfs, and with a head of 175 feet and an efficiency of 87 percent, the output of the generator would be about 7800 kW. The generator and related electrical equipment must be designed, however, to receive the maximum hydraulic output of the turbine at the maximum reservoir water surface elevation. This corresponds to a gross head of 204 feet, a flow of 845 cfs, and a plant capacity of about 12,700 kW.

Power Operation Studies

Systematic routing operation studies were performed by computer to estimate the amount of energy to be generated by the power plant. The studies were based on the assumption that Rollins Reservoir will continue to be operated under rules set forth in the Yuba-Bear Water Operation Contract dated July 12, 1963. All discharges will be dictated by the downstream requirements of the Bear River Canal, as operated by PG&E, diversion at Combie Reservoir, as operated by the District and minimum fish flow requirements, as set forth in Article 33 of Federal Energy Regulatory Commission License 2266. Discharges solely for the purpose of generating energy will not be made.

The studies were based on the assumption that excess flows above the capacity of the turbine would be spilled and that flows too small to drive the turbine or flows released when the turbine head is below the safe operating head would be passed through the existing outlet works. The latter case occurs when the water elevation falls below approximately elevation 2040 corresponding to a head of 82 feet on the unit. Below this stage turbine cavitation and rough operation would make power generation undesirable. Operation limitations for a Francis turbine are shown in Volume V.

The tailwater elevation will be controlled by the diversion dam downstream at the Bear River Canal headworks. The normal tailwater elevation was assumed to be at elevation 1958. Spills from Rollins Reservoir will cause no increase in tailwater because of the diversion dam.

For the purposes of estimating energy, inflows for two cases were evaluated: the hypothetical conditions and the actual flows since the dam was completed. The hypothetical study was based on an assumed operation scheme from October 1928 to September 1947 and was derived from the 1960 Ebasco "Yuba-Bear River Project Report". For the purposes of estimating a probable average of the energy to be generated, the years 1939-1947 appear to be most representative. These years have average runoff characteristics, similar to the 65 year average of all years for which flow records have been kept. From this study it is estimated that the average annual energy generated would be 71.1×10^6 kWh and that the average annual capacity factor would be 74 percent. The minimum and maximum generation for this period was 58.5 and 88.5×10^6 kWh. Figure 2-3 illustrates the reservoir elevations, flow duration and plant capability for this study. Note that about 10 percent of the flows discharged from Rollins Reservoir would be at flow rates in excess of the maximum possible turbine outflow. Also note that the capacity of the power plant fluctuates with head. During approximately five percent of the time, no energy could be produced.

The second study, with historical data, was based on the records of inflow and outflow of Rollins Reservoir since operation began. The period of study is from October 1964 to September 1976. During this period, the average annual energy would be 85.4×10^6 kWh and the average annual capacity factor would be 89 percent. Figure 2-4 shows the reservoir elevations and flow duration for this study.

Power Marketing

The procedure followed to market the power consisted of distribution of the project report to interested power purchasers, discussions with the prospective power purchasers, review and ranking of offers received and the negotiation of a memorandum of understanding with the selected power purchaser. This marketing procedure is generally described on page 3-38, Volume II as "Cost Plus a Royalty Subject to Escalation". Offers to purchase the power were received from PG&E, the California Department of Water Resources and the Northern California Power Agency. The Sacramento Municipal Utility District and the U.S. Bureau of Reclamation did not submit an offer. After study and review, the District's Directors voted to negotiate first with PG&E, an investor-owned utility

The main points of the offer as made by PG&E were as follows:

1. District will own and operate the power plant.
2. District will finance the Project through sale of revenue bonds, the total debt service to be guaranteed by the power purchase agreement from PG&E.
3. PG&E will receive all of the power from the Project.
4 PG&E will pay for debt service on bonds, and annual operation and maintenance costs; PG&E will advance "development costs", to be paid back from the sale of revenue bonds.
5. PG&E will pay to the District an added incentive payment or royalty equal to at least 4 mills per kWh.
6. PG&E will escalate the added incentive payment based upon the change in cost of wholesale price of energy in Northern California.

The offer by PG&E was judged to be reasonable. At the time of the offer, December 1975, the cost of the fuel oil being used to generate power in California resulted in a cost of electrical power of about 20 mills per kWh. This cost was considered the highest replacement value of energy in the PG&E system. The cost to develop power at Rollins was estimated to result in a cost of about 12 mills per kWh. Therefore, payment of 4

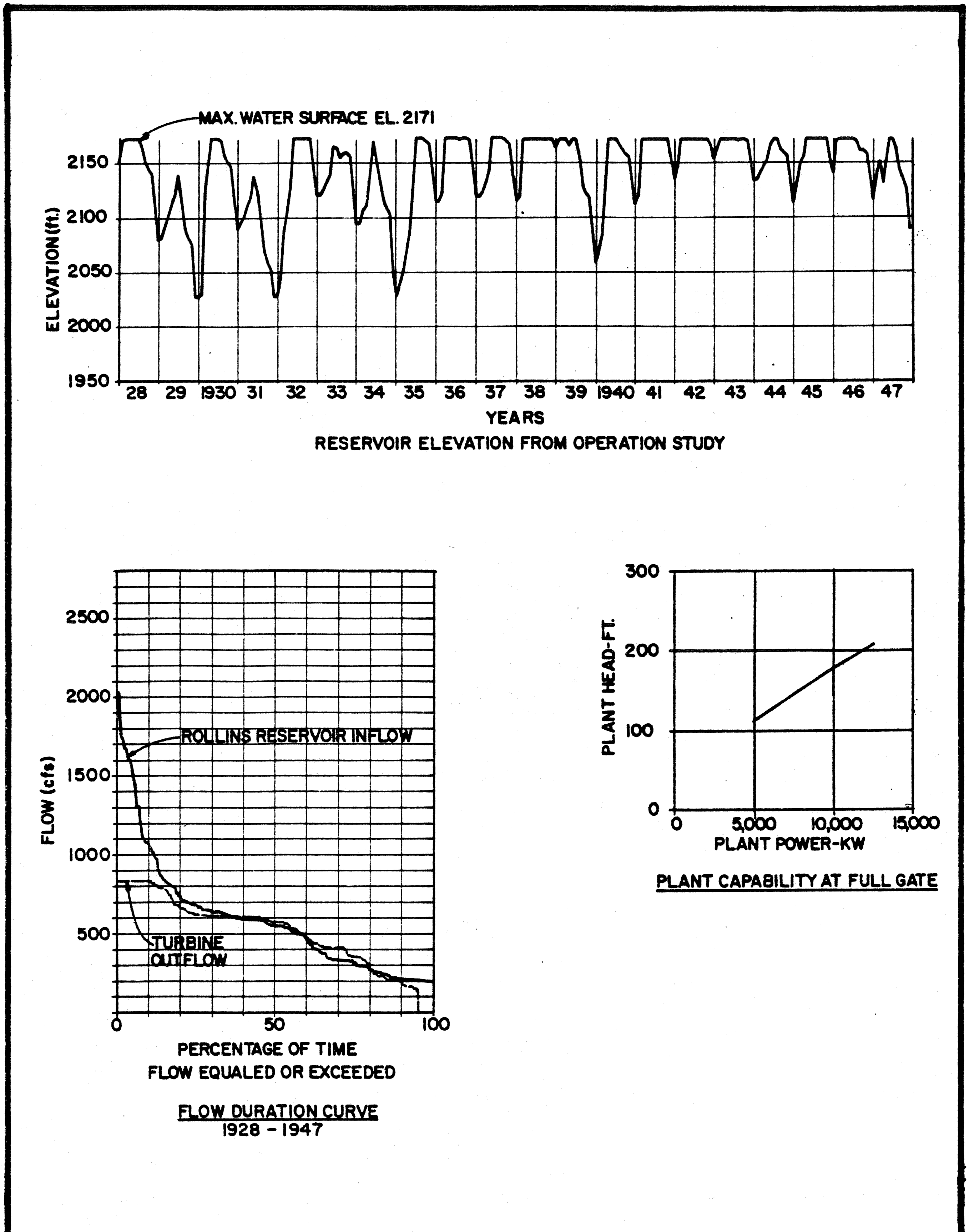
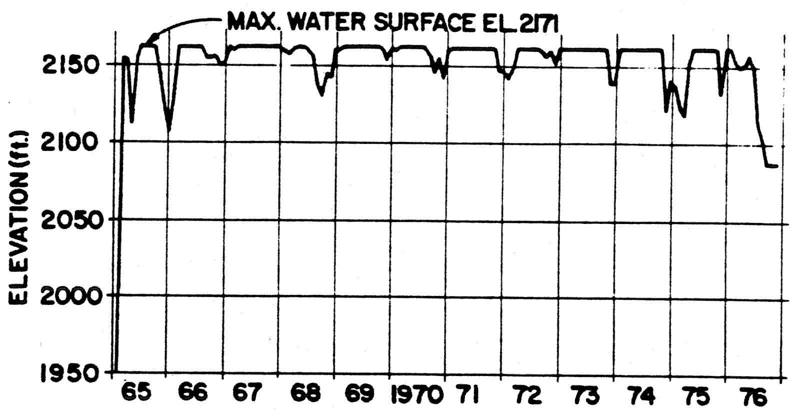
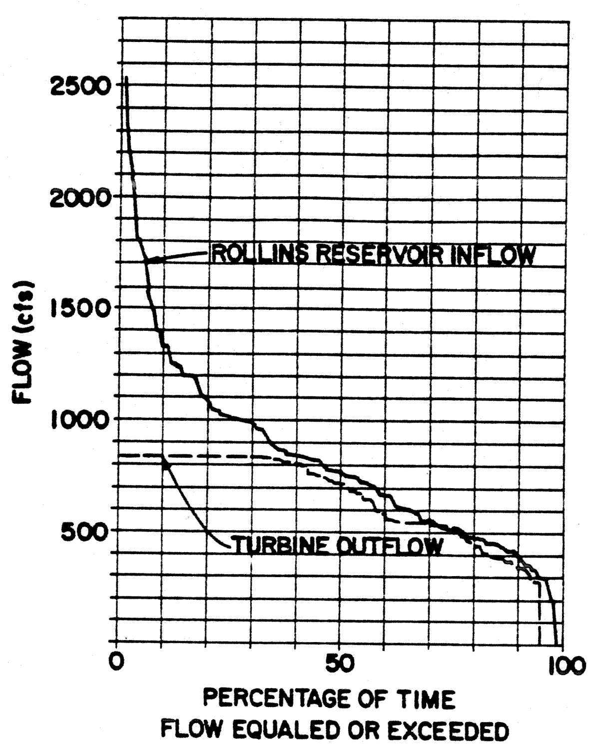


Figure 2-3. EBASCO Operation Study



RESERVOIR ELEVATION FROM OPERATION STUDY



FLOW DURATION CURVE
1965 - 1976

Figure 2-4. Historical Operation Study mills per kWh, one-half of the difference between the replacement value of energy and the cost to produce the energy, was approved as a fair royalty to the District.

The last step in concluding the marketing arrangement was the preparation of a memorandum of understanding. The memorandum encompassed all the major points of the offer. In addition, since only 7.8 million dollars were available for the project, provision was made to permit short-term warrants to be used for any cost overrun. These warrants could be authorized by a majority vote of the Board of Directors under the Irrigation District law.

The revenue bonds which were issued by the District for construction of the Project were sold with an interest rate of 9 7/8 percent (taxable IDBs). The term of the bonds, 32 years, coincided with the years remaining on the District's FERC license for the Yuba-Bear Project. The total annual cost to PG&E including debt service on bonds, estimated operation and maintenance cost, and added incentive payment amounts to the sum of \$810,000, \$75,000 and \$284,400, respectively for a total of \$1,169,400. With an annual energy production of 71.1×10^6 kWh, the cost of energy, delivered at the bus bar, is 16.5 mills per kWh.

Application and Permits

The applications and permits which were prepared and received are as shown on Table 2-2. The table indicates several significant points. The actual experience shows that, with the exception of the time required to obtain water rights from the State of California, the schedule for project implementation provided in the manual can be achieved. The time required for water rights was due in part to slow processing by the State and to the intervention of a downstream irrigation district. This intervener was eventually satisfied by the execution of a supplemental agreement between the two parties which primarily reiterated each party's intent not to cause harm to the other.

Another significant aspect of the application process was the determination by the District that no significant adverse environmental impact would be caused by the construction. A negative declaration was therefore submitted by the District's Directors. This determination was considered by the Federal Energy Regulatory Commission and, after further review and consultation, indicated to the Council on Environmental Quality that no adverse impact would occur and a negative declaration should be issued.

The question of adverse impact on the local fisheries was not an issue. The release requirements from the dam were jointly developed 10 years previously with representatives of State and Federal governments to enhance the fisheries below Rollins Dam. (No fish passage facilities exist at Rollins because there are no migratory runs within the river.)

TABLE 2-2
SCHEDULE OF APPLICATION AND PERMITS

Permits or Applications	Responsible Agency	Date Filed	Approval Granted	Months Before Approval
1. Water Right Application to Develop Power at the Site	State Water Resources Control Board	1/29/76	9/27/77	20
2. Environmental Impact Negative Declaration in accordance with California Environmental Quality Act	Nevada Irrigation District	9/27/76	7/11/77	9
3. Amendment to License to Develop Power at the Site	Federal Energy Regulatory Commission (F.E.R.C.)	10/1/76	10/14/77	12
4. Water Quality Certificate (Sec 401 F.W.P.C.A 1/)	Regional Water Quality Control Board	2/20/77	5/11/77	3
5. Request to Lower Rollins Reservoir below Minimum Level	State Dept. of Fish and Game and F.E.R.C.	4/15/77	4/21/77	0
6. Application to Alter Permit Application No. 6333 (Sec. 404 F.W.P.C.A. 1/Permit)	Corps of Engineers Sacramento District	6/8/77	6/29/77 2/	1
7. Application to Make Alterations to a Dam	California Divison of Safety of Dams	6/10/77	7/11/77	1
8. Permission to Sell Phase I Bonds 3/	California Districts Security Commission	6/22/77	7/29/77	1
Phase II		1/11/78	9/20/78	8
9. Permission to Work in tunnel	California Division of Industrial Safety 4/		4/28/78	n/a

1/ Federal Water Pollution Control Act
2/ Not required
3/ For permission to sell revenue bonds
4/ Article 8422 D, Title 8, California Administration Code.
Classification of tunnel work required. Work was classified as non-gassy.

SECTION 3
DESIGN

General

The standards and criteria used for the design of the Rollins Power Plant were organized during the preliminary design stage. The contract between the District and PG&E stated "the power plant shall be equal to completeness of features and quality of design and materials in all respects to recent installations as in Pacific (PG&E) Feather River, McCloud River and Pit River projects." Therefore, the Rollins Project was designed as a major hydroelectric plant installation. As such, the costs of the Rollins Power Project are greater than the costs provided in the guide manual since the manual suggests the reduction of the requirements for control and protection on various items from those that would be necessary for major installations. A general description of the major electromechanical and civil features follows. Thereafter, a section is included which points out the specific discrepancies between the manual and the Project as designed.

Electromechanical Equipment

The appropriate turbine parameters were determined by a series of systematic routing operation studies in which the size of the unit and the design head (the head of maximum efficiency) were optimized. The turbine efficiency curve used was similar to the curve shown on Figure 3-8, Volume V. The curve is given in a different form in Figure 3-1 of this Appendix. For Rollins, a 12,700 kW unit with a maximum gross head of 204 feet was determined to be the most cost-effective installation. During the course of the investigation, it was learned that PG&E was decommissioning a power plant with two 13,000 kW Francis turbines and generators installed in 1927 with similar head and flow characteristics. An investigation was made of the desirability of using one of those turbine/generator combinations for the Rollins Project. After a thorough study, it was decided it was feasible to refurbish one of the units for the Project. Not all of the old parts could be reused, however. Manufacture of a new draft tube, spiral case and stay ring was required. The total cost of refurbishing the 13,000 kW unit was found not to be significantly different than the purchase cost of a new 12,700 kW unit. However, the time for procurement was reduced by 9 months by the reuse of the old equipment, providing a significant savings in cost and a one year reduction in the construction schedule. Furthermore, the old unit, being substantially heavier than a new unit, provided increased rotational inertia for better speed regulation and more durability.

Civil/Structural Design

The standards and criteria used in the civil/structural design were generally in accordance with common utility practice. Several features were particularly worth noting. A semi-outdoor design was used for the power plant. This design was selected primarily for economy. The power plant structure was designed to accommodate a portable gantry crane. The crane, however, was not included in the Project since its use would be infrequent and it could be rented when needed. An office building with storage area for spare parts and maintenance equipment was furnished as a separate building. This building, although built with power plant funds, was needed for other Yuba-Bear River Project purposes and would not have been necessary for the power plant alone.

Comparison of Guide Manual and Actual Costs

Construction Costs. A comparison of the power plant cost derived by use of the manual with the actual construction costs bid by the contractor for the Rollins Power Project is provided in Table 3-1. The cost level for manual costs is July 1978. The project was bid and awarded in about the same time-frame. Upon comparison, it can be seen that the actual costs are higher than those estimated by use of the manual. This difference can be attributed to the fact that the actual Rollins construction cost contains several items in addition to the basic power plant cost addressed by the manual. A listing, by account number, of the differences between the manual estimate and actual costs follows.

Account No. 331

1. The Rollins turbine was designed for bottom removal of the runner, a feature which adds to powerhouse depth. Bottom removal is not normally required and was therefore not considered in the manual.
2. At Rollins, the turbine is a refurbished older unit. This unit is considerably larger in physical size than a new unit of the same capacity. Because of the larger turbine, the powerhouse structure is larger than would have been required to house the turbine. Also, the PG&E required that certain equipment be installed in the powerhouse which normally would not be required and was therefore not considered in the manual. The larger turbine and additional equipment resulted in the Rollins powerhouse area being nearly 20 percent greater than the area that would have been calculated by use of the manual.

Account No. 332

1. The owner furnished the upstream shut off valve for the Rollins project. Consequently, the costs determined by use of the manual were higher than the actual Rollins costs.

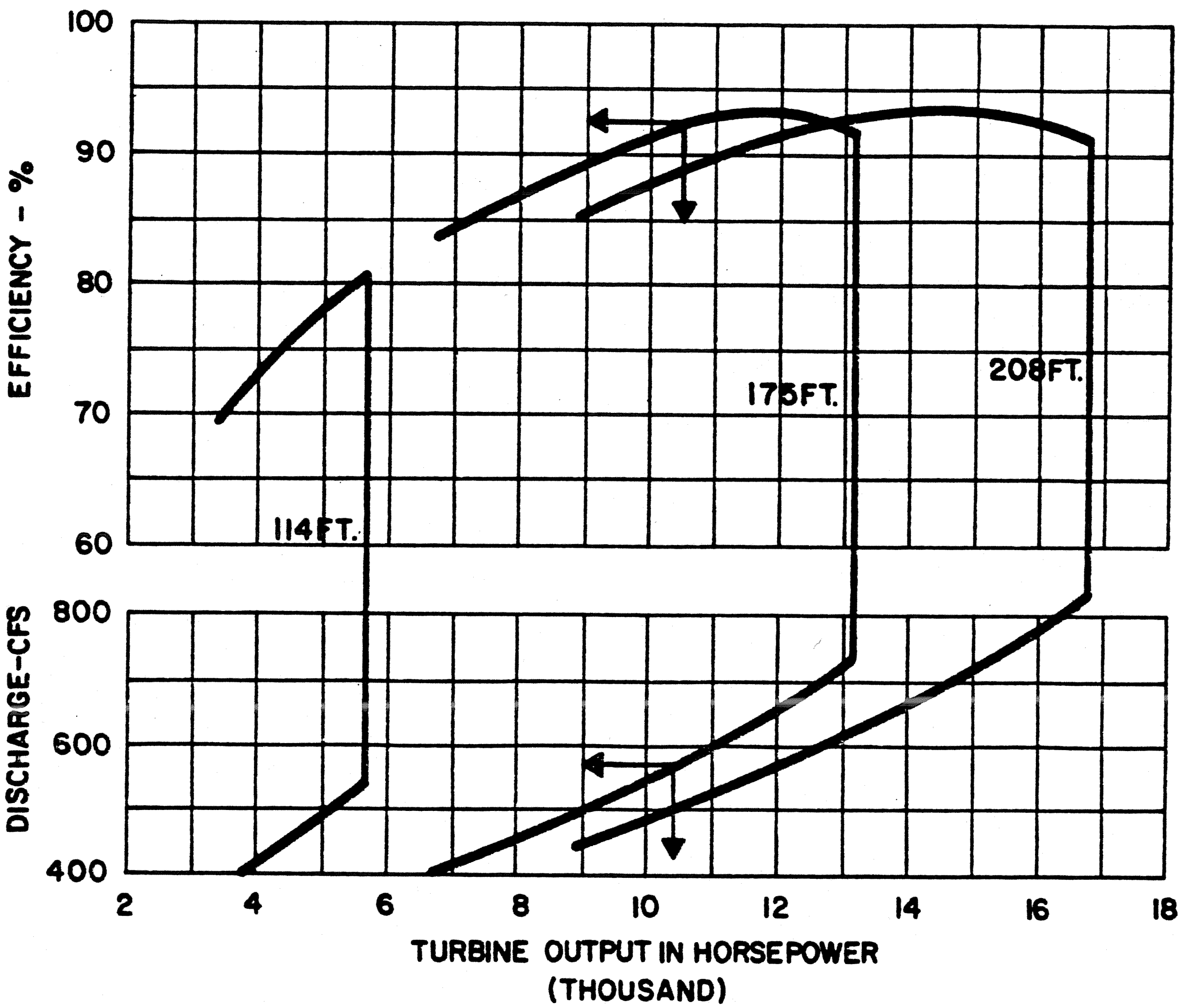


Figure 3-1. Francis Turbine Efficiency Curve

TABLE 3-1
COMPARISON OF CONSTRUCTION COSTS VS. MANUAL COSTS

Account No.		Guide Manual	Actual
331	Structures and Improvements	$ 642,000	$ 876,000 1/
332	Waterways	765,000	531,000
333	Turbine & Generator	2,300,000	2,479,000 2/
334	Electrical	785,000	897,000
335	Mechanical	125,000	292,000
		Total: $4,617,000	Subtotal: $5,075,000
Additional Work Items:			
Road and traffic control			$ 110,000
Toe drainage for dam			37,000
Office and warehouse building 3/			38,000
Channel diversion and afterbay excavation			90,000
Remote control (including equipment in Chicago Park Powerhouse)			150,000
	Total Phase II Contstruction Contract		$5,500,000
	Other Costs:		
	Tunnel plug contract		352,000
	Turbine/Generator purchase		112,000
	Contingencies		223,000
	TOTAL CONSTRUCTION COST		$6,187,000

1/ Concrete for waterways included in structures

2/ Includes governor $206,000
Includes governor housing $80,000

3/ Electro-mechanical included in accont 334 and 335

Account No. 333

1. The Rollins turbine has an automatic grease lubricating system which is not normally required and was not included in the manual.

2. To enable the unit to be motored and operated as a synchronous condensor, provisions were included at Rollins for water lubrication of the wearing ring at an increased cost not considered in the manual.

3. A special requirement of the power purchase agreement at Rollins was that the unit be capable of operating in an isolated system. This requirement mandated the installation of an Electric-hydraulic Speed Regulating Cabinet Type governor. Normally, a gate shaft governor would be adequate.

Account No. 334

1. Due to additional mechanical equipment in the powerhouse which was requested by the power purchaser, it was necessary to install an additional motor starter center and a low voltage distribution system.

Account No. 335

1. A heating system, not normally required and not considered in the manual, was included in the Rollins powerhouse.

2. At the Rollins project, the generator is water-cooled. The manual addresses air cooling only.

3. Rollins has an automatic fire protection system as opposed to the manually operated fire stations addressed by the manual.

4. A station air compressor with outlets at work areas is included in the Rollins project but not considered by the manual.

5. Rollins has hoists and jib cranes which are not normally required for a small hydroelectric project and were not addressed by the manual.

As a general commentary, the design of the Rollins power plant was greatly influenced by the requirements of the power purchaser. The plant operating criteria were based upon recently constructed major hydroelectric projects in the power purchaser's system. There are several major features which could be eliminated or modified, with an attendant reduction in cost, if the design has been consistent with normal small hydroelectric plant design practices.

Total Project Costs. In comparing the total project costs, Table 3-2 is presented. As can be seen, the percentages assigned in the manual to estimate indirect costs are relatively close to the actual percentages experienced at Rollins.

TABLE 3-2
ESTIMATED TOTAL COST OF PROJECT

Costs:			
Construction Contract			5,500,000
Design and Development			640,000
Construction Supervision			395,000
Surveys and Testing			30,000
Tunnel Plug (Construction already completed)			352,000
Equipment Purchases from Pacific			112,000
District Counsel			125,000
Costs of Issuance			110,000
State Treasurer's Review and Certification			28,000
Contingencies			223,000
	Gross Project Costs		$7,515,000
Less:	Investment Income (Estimated at 6.5%) 1/		390,000
	Net Costs		$7,125,000
Add:	Funded Interest (Two years at estimated 9-1/2% 2/)	$1,482,000	
	Less: Accrued Interest (Estimated 1-1/2 months)	93,000 3/	1,389,000
	Total Costs		$8,514,000

	Recap of Total Project Cost by Categories Cost	Actual Percentage of Construction Cost	Guide Manual Percentage of Construction Costs
Construction Costs	$6,187,000		
Indirect Costs	1,065,000	17.2	20
Financing Fees	138,000	2.2	1.7 - 3.3
Interest During Construction	999,000	16.2	15.8
Legal Fees	125,000	2.0	Not estimated
Total Cost	$8,514,000		

1/ Includes investment income from Interest Fund for approximately 16 months and assumes Construction Fund balances available for approximately 9 months.

2/ From July 1, 1978 to and including the July 1, 1980 payment.

3/ Received as part of the proceeds from the sale of the Bonds.