9.0 ECONOMIC EVALUATION

9.1 General

During the initial project studies carried out in 1981, an evaluation was made of the economic tunnel diameter and economic tunnel length for the four basic alternative schemes developed at that time, Alternatives A, B, C & D (described in Section 3). This economic study was made using tunnel costs calculated for tunnel excavation by conventional drill and shoot methods. Subsequent studies performed in 1982 indicated that cost savings will be achieved if the tunnel would be driven by tunnel-boring machine. Alternative E is based on tunnel boring machine excavation. These studies are discussed in Section 8. No re-examination of the economic tunnel diameter or length has been made using these modified tunnel costs, but any change in economic diameter or length of tunnel is considered to be small.

Determination of the economic tunnel diameter involves comparing the construction costs of tunnels of varying diameters, with the present worth of the difference in power produced over the life of the project as a result of the changes in hydraulic loss in the tunnel as the diameter is varied. The economic tunnel length is determined from an economic balance between the cost of increasing the tunnel length to develop additional head on the powerhouse, and the present worth of the additional power produced by the higher head over the life of the project.

It should be noted that these economic evaluation studies were based on economic parameters prevailing in 1981. These parameters which include capital costs of thermal generating plants and fuel costs for both coal and natural gas have, of course, now been superseded. In future studies, the influence of updated economic parameters on the economic tunnel diameter and length should be made.

9.2 Parameters for Economic Evaluation

Alaska Power Authority has developed the following parameters for economic analyses of hydroelectric projects.

Inflation Rate	0%
Real Discount Rate	3%
Economic Life of Hydroelectric Projects	50 years
Economic life of thermal plants (conventional coal fired or combined cycle)	30 years

In sizing the various project elements, i.e., tunnel diameter and length, the value of power generated by the hydroelectric project has been considered equal to the cost of the equivalent power generated thermally by coal fired plant or by natural gas fired combined cycle plant.

As agreed with APA, in order to arrive at a project cost which can be readily compared with that for the Susitna Project a 50% plant factor has been used for determining the installed capacity of the power plants discussed in this report. Future studies should concentrate on refining the preferred plant factor for the project.

9.3 Cost of Power from Alternative Sources

9.3.1 General

To ensure uniformity of data between the various feasibility studies of hydroelectric projects which are currently in progress, including the Susitna Hydroelectric Project, APA requested that the following sources be used for the development of cost of power from alternative thermal generation:

(1) Acres American Incorporated report "Susitna Hydroelectric Project" Task 6 Development Selection Report, Appendices A through I, July 1981 for construction cost of coal fired and combined cycle thermal plants.

(2) Battelle Pacific Northwest Laboratories, for the cost of operation and maintenance and fuel for coal fired and combined cycle thermal plants. Data on these items were obtained during a visit to Battelle's office on September 1, 1981.

9.3.2 Construction Cost

(a) Coal fired thermal plant:

The Acres American report referred to above develops the construction cost of a 250-MW coal fired thermal plant at Beluga in 1980 dollars to be $439,200,000 direct construction cost and $627,650,000 total cost including 16% contingency, 10% for construction facilities and utilities and 12% for Engineering and Administration, but not including interest during construction. This total cost corresponds to $2510/kW. Including interest during construction at 3 percent per year for a 6 year construction period, the total cost amounts to $2706/kW. (This differs but little from the $2744/kW value given in Table B.13 of the Acres Report apparently because of some rounding of numbers in the Acres calculation and apparently slight difference in cash flow during the construction period.)

(b) Combined Cycle Plant

The Acres American report also develops the construction cost of a 250-MW combined cycle plant in 1980 dollars to be $121,830,000 direct construction cost and $174,130,000 total cost including 16% contingency 10% for construction facilities and utilities and 12% for Engineering and Administration, but not including interest during construction. This corresponds to $697/kW. When interest during construction is added at 3 percent per year, the total cost is $707.5/kW.

9.3.3 Operation & Maintenance Cost

Data obtained from Battelle is summarized below for 1980 price levels.

(a) Coal-fired Thermal Plant

Fixed Operation and Maintenance $16.71/kW/year
Variable Operation and Maintenance 0.6 mills/kWh.
Escalation above general inflation rate 1.9% until year 2012 with no escalation after 2012.

(b) Combined Cycle Plant

Fixed Operation and Maintenance $35.00/kW/year
Variable Operation and Maintenance 0 mills/kWh.
Escalation above general inflation rate 1.9% until year 2012 with no escalation after 2012.

9.3.4 Fuel Cost

Data obtained from Battelle is summarized below for 1980 price levels

(a) Coal from Beluga

Fuel cost $1.09/mill. BTU
Escalation above general inflation rate 1.5% until year 2012 with no escalation after 2012.
Heat Rate 10,000 BTU/kWh.

(b) Natural Gas - Combined Cycle Plant

The natural gas prices as estimated by Battelle for the future years are given in Table 9-1.

Heat rate 7500 BTU/kWh.

TABLE 9-1

NEW CONTRACT GAS PRICE (AML&P)-ANCHORAGE

Year	Gas Price $/Mill BTU
1980	1.08
1981	1.08
1982	1.09
1983	1.09
1984	1.09
1985	1.09
1986	1.35
1987	1.56
1988	1.65
1989	1.89
1990	2.11
1991	3.62

1992	3.74
1993	3.86
1994	3.98
1995	4.11

Forecast escalation after 1995 = 3% per year until the year 2012, and no escalation thereafter.

9.4 Value of Hydro Generation

The value of the hydro generation is established by determining the cost of generating power from alternative sources. For the purpose of this study an analysis has been made of the cost of alternative coal-fired and combined cycle generation, using the basic cost data presented previously in Section 9.3.

The annual cost of interest, depreciation and insurance for the alternative thermal plants were calculated on the following basis:

Interest	3.0%
Depreciation (30 year life)	2.1%
Insurance	0.25%
Annual Charge on Capital Cost	5.35%

Based on an arbitrary selection of 1990 as the in-service date for the Chakachamna Project and examining a fifty year period, equal to the economic life of the hydro plant, and using the unit costs for thermal generation discussed above, comparative costs were prepared for each year of the 50 year period of the cost of generating power at 50% load factor by each of the two alternatives, conventional thermal using Beluga coal and combined cycle using gas. These annual costs over the 50 year period were then used to determine their present worths at the first year of generation taken as 1990. The calculations were performed on a cost per kWh basis and are presented in Tables 9-2 & 9-3 for the conventional coal fired and combined cycle cases respectively.

The levelized annual cost of generation by a coal fired plant using Beluga coal is calculated to be 55.60 mills per kWh compared with 75.21 mills per kWh for the combined cycle plant, based on 50% load factor generation. The higher cost for the combined cycle plant is due primarily to a higher initial fuel cost, a much higher escalation on the cost of fuel, and somewhat higher operation and maintenance cost. Taken collectively these more than offset the much lower annual charge on the capital cost of constructing the combined cycle plant. The cost of power produced by the coal fired plant was therefore adopted as the alternative for establishing the value of hydro generation.

The capital cost of a hydro plant which gives a levelized annual cost over the 50 year life equal to the levelized annual cost of the coal fired thermal plant of 55.60 mills per kWh, based on 50% plant factor, and including a credit of 5% less installed capacity required in a hydro plant because of the reduced system reserve requirements with hydro generation, is calculated to be $6,117 per kW. This total cost includes contingency, construction camp facilities, engineering, and construction management and interest during construction.

TABLE 9-2 (Sheet 1 of 2)

COAL FIRED PLANT

COST OF GENERATING POWER AT 50% LOAD FACTOR

Year	Amortization & Insurance	O&M	Fuel	Total	Present Worth
1	33.02	5.32	12.65	50.99	49.50
2	33.02	5.42	12.84	51.28	48.34
3	33.02	5.52	13.03	51.57	47.19
4	33.02	5.63	13.23	51.88	46.09
5	33.02	5.74	13.43	52.19	45.02
6	33.02	5.84	13.63	52.49	43.96
7	33.02	5.96	13.83	52.81	42.94
8	33.02	6.07	14.04	53.13	41.94
9	33.02	6.18	14.25	53.45	40.96
10	33.02	6.30	14.46	53.78	40.02
11	33.02	6.42	14.68	54.12	39.10
12	33.02	6.54	14.90	54.46	38.20
13	33.02	6.67	15.12	54.81	37.32
14	33.02	6.79	15.35	55.16	36.47
15	33.02	6.92	15.58	55.52	35.64
16	33.02	7.06	15.82	55.90	34.84
17	33.02	7.19	16.05	56.26	34.04
18	33.02	7.33	16.29	56.64	33.27
19	33.02	7.47	16.54	57.03	32.52
20	33.02	7.61	16.79	57.42	31.79
21	33.02	7.75	17.04	57.81	31.08
22	33.02	7.90	17.29	58.21	30.38
23	33.02	7.90	17.29	58.21	29.49
24	33.02	7.90	17.29	58.21	28.64
25	33.02	7.90	17.29	58.21	27.80
					946.54

NOTE: Escalation rates above the general escalation rate are as follows.

Amortization & Insurance - Nil.

Operation & Maintenance - 1.9% for first 22 years only.

Fuel - 1.5% for first 22 years only.

TABLE 9-2 (Sheet 2 of 2)

COAL FIRED PLANT

COST OF GENERATING POWER AT 50% LOAD FACTOR

Year	Amortization & Insurance	O&M	Fuel	Total	Present Worth
					Fwd. 946.54
26	33.02	7.90	17.29	58.21	26.99
27	33.02	7.90	17.29	58.21	26.21
28	33.02	7.90	17.29	58.21	25.44
29	33.02	7.90	17.29	58.21	24.70
30	33.02	7.90	17.29	58.21	23.98
31	33.02	7.90	17.29	58.21	23.28
32	33.02	7.90	17.29	58.21	22.61
33	33.02	7.90	17.29	58.21	21.95
34	33.02	7.90	17.29	58.21	21.31
35	33.02	7.90	17.29	58.21	20.69
36	33.02	7.90	17.29	58.21	20.08
37	33.02	7.90	17.29	58.21	19.50
38	33.02	7.90	17.29	58.21	18.93
39	33.02	7.90	17.29	58.21	18.38
40	33.02	7.90	17.29	58.21	17.84
41	33.02	7.90	17.29	58.21	17.32
42	33.02	7.90	17.29	58.21	16.82
43	33.02	7.90	17.29	58.21	16.33
44	33.02	7.90	17.29	58.21	15.85
45	33.02	7.90	17.29	58.21	15.39
46	33.02	7.90	17.29	58.21	14.94
47	33.02	7.90	17.29	58.21	14.51
48	33.02	7.90	17.29	58.21	14.09
49	33.02	7.90	17.29	58.21	13.68
50	33.02	7.90	17.29	58.21	13.28
					1430.64

Equivalent Levelized Annual Cost = 55.60 mills/kWh.

TABLE 9-3 (Sheet 1 of 2)

COMBINED CYCLE PLANT

COST OF GENERATING POWER AT 50% LOAD FACTOR

Year	Amortization & Insurance	O&M	Fuel	Total	Present Worth
1	8.64	9.64	21.1	39.38	38.23
2	8.64	9.82	36.2	54.66	51.52
3	8.64	10.01	37.4	56.05	51.29
4	8.64	10.20	38.6	57.44	51.03
5	8.64	10.39	39.8	58.83	50.75
6	8.64	10.59	41.1	60.33	50.53
7	8.64	10.79	42.33	61.76	50.22
8	8.64	11.00	43.60	63.24	49.92
9	8.64	11.21	44.91	64.76	49.63
10	8.64	11.42	46.26	66.32	49.35
11	8.64	11.64	47.65	67.93	49.07
12	8.64	11.86	49.08	69.58	48.80
13	8.64	12.08	50.55	71.27	48.53
14	8.64	12.31	52.06	73.01	48.27
15	8.64	12.55	53.63	74.82	48.02
16	8.64	12.78	55.23	76.65	47.77
17	8.64	13.03	56.89	78.56	47.53
18	8.64	13.28	58.60	80.52	47.30
19	8.64	13.53	60.36	82.53	47.07
20	8.64	13.78	62.17	84.59	46.84
21	8.64	14.05	64.03	86.72	46.62
22	8.64	14.31	65.95	88.90	46.40
23	8.64	14.31	65.95	88.90	45.04
24	8.64	14.31	65.95	88.90	43.73
25	8.64	14.31	65.95	88.90	42.46
					1195.92

NOTE: Escacalation rates above the general escalation rate are as follows.

Amortization & Insurance - Nil.

Operation & Maintenance - 1.9% for first 22 years only.

Fuel - 1.5% for first 22 years only.

TABLE 9-3 (Sheet 2 of 2)

COMBINED CYCLE PLANT

COST OF GENERATING POWER AT 50% LOAD FACTOR

Year	Amortization & Insurance	O&M	Fuel	Total	Present Worth
					1195.92
26	8.64	14.31	65.95	88.90	41.22
27	8.64	14.31	65.95	88.90	40.02
28	8.64	14.31	65.95	88.90	38.86
29	8.64	14.31	65.95	88.90	37.72
30	8.64	14.31	65.95	88.90	36.63
31	8.64	14.31	65.95	88.90	35.56
32	8.64	14.31	65.95	88.90	34.52
33	8.64	14.31	65.95	88.90	33.52
34	8.64	14.31	65.95	88.90	32.54
35	8.64	14.31	65.95	88.90	31.59
36	8.64	14.31	65.95	88.90	30.67
37	8.64	14.31	65.95	88.90	29.78
38	8.64	14.31	65.95	88.90	28.91
39	8.64	14.31	65.95	88.90	28.07
40	8.64	14.31	65.95	88.90	27.25
41	8.64	14.31	65.95	88.90	26.46
42	8.64	14.31	65.95	88.90	25.69
43	8.64	14.31	65.95	88.90	24.94
44	8.64	14.31	65.95	88.90	24.21
45	8.64	14.31	65.95	88.90	23.51
46	8.64	14.31	65.95	88.90	22.82
47	8.64	14.31	65.95	88.90	22.16
48	8.64	14.31	65.95	88.90	21.51
49	8.64	14.31	65.95	88.90	20.89
50	8.64	14.31	65.95	88.90	20.28
					1935.25

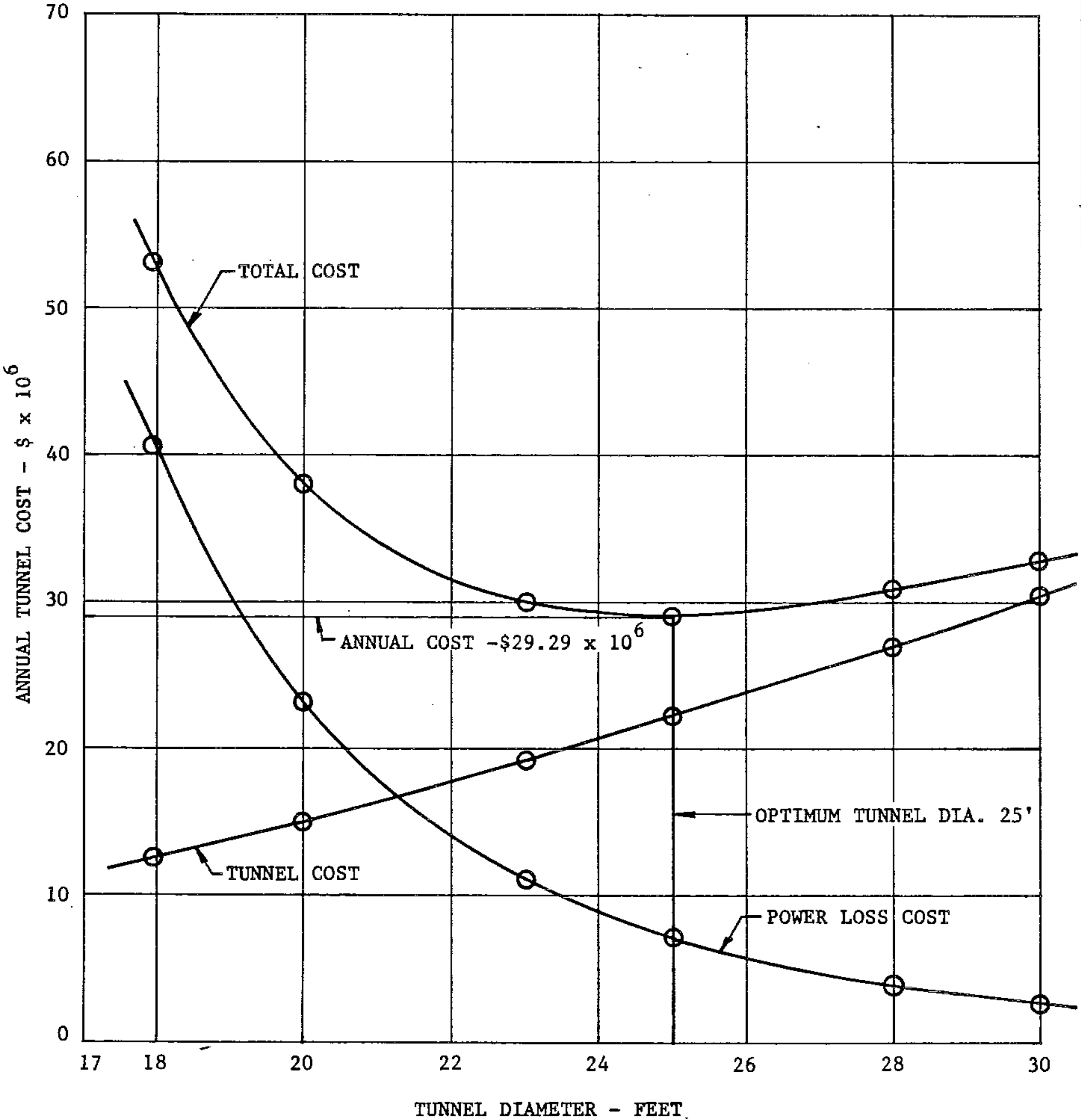
Equivalent Levelized Annual Cost = 75.21 mills/kWh.

9.5 Economic Tunnel Sizing

The economic diameter of the main power tunnel has been investigated by comparing the incremental cost of varying the tunnel diameter with the incremental value of the difference in power produced as a result of such variation in tunnel diameter. For the same powerhouse flow, increasing the tunnel diameter reduces the head losses in the tunnel thereby increasing the total head on the powerhouse with a consequent increase in power production.

In establishing the variation in estimated tunnel construction cost it has been assumed that the tunnel will be fully concrete lined with the typical horseshoe section shown in Figure 3-2 and would be excavated by conventional drill and shoot methods. Future studies should evaluate the merits of a nominally unlined tunnel. It should also be noted that when the method of driving the tunnel by tunnel boring machine was examined in 1982, no attempt was made to refine the economic tunnel diameter.

For the case of Alternatives A & C with no water release to meet instream flow requirements in the Chakachatna River (i.e., all controlled water being diverted for power production purposes), Figure 9-1 shows the plot of estimated tunnel construction cost and value of power production with variation in tunnel diameter. This curve shows that the economic diameter of a concrete lined tunnel is 25 feet. In Alternative B, with the flow diverted to a powerhouse sited on the McArthur River, but with water reserved for instream flow requirements in the Chakachatna River a separate study to establish the economic diameter was not made. Instead, as an approximation, the tunnel diameter was selected such that



ECONOMIC TUNNEL DIAMETER

FIGURE 9-1

the velocity of flow through the tunnel with the generating units operating at full output and at full level at Lake Chakachamna would be the same as that obtained under these same operating conditions in Alternative A for which the economic diameter had been calculated. This approximation gives a 23-foot horseshoe tunnel.

In the case of Alternative D where only an average release of 30 cfs flow is maintained below Chakachamna, Lake, the 25 foot diameter tunnel was retained, since the powerhouse flow differs by less than 1%.

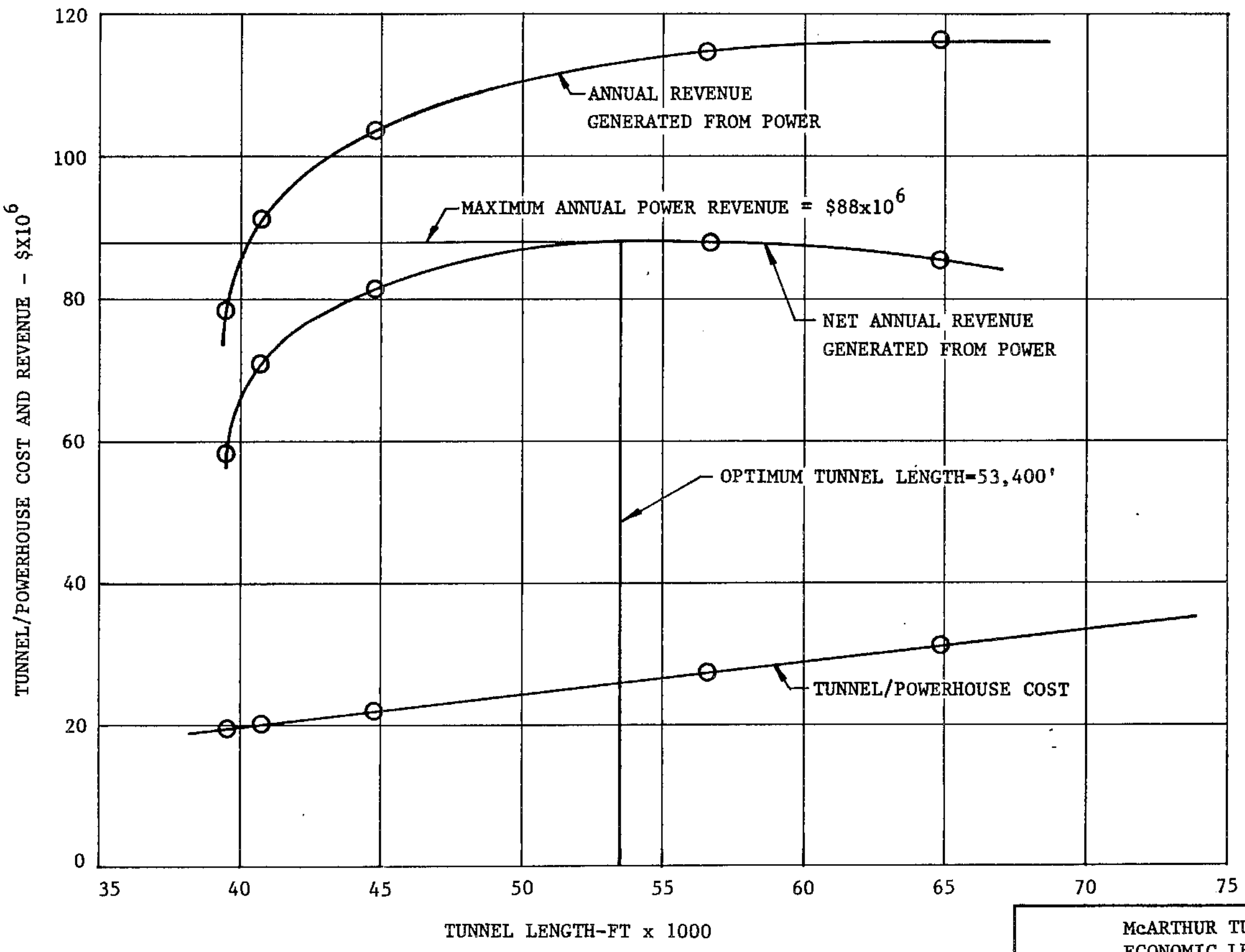
In the case of Alternative E developed in 1982, based on driving the tunnel by tunnel boring machine, a 24 foot diameter circular tunnel was selected. This is hydraulically equivalent to the 23 foot diameter horseshoe shaped tunnel in Alternative B. If future geologic studies confirm the suitability of the rock for machine boring, the economic tunnel diameter should be re-evaluated.

9.6 Economic Tunnel Length

For both basic alternative developments by diversion to the McArthur River or downstream along the Chakachatna River, an examination has been made of the economic tunnel length. As the powerhouse is moved downstream to develop additional head, the power tunnel becomes longer and hence more costly. The economic tunnel length is therefore determined from an economic balance of estimated tunnel construction cost and value of power produced. Based on the value of the hydro generation as discussed in Section 9.4, the present worth of the power produced by 1 foot of head when all controlled water is used for power generation is equal to approximately $3,500,000 which corresponds to $139,000 annually over the 50 year life of the plant at 3% rate of interest.

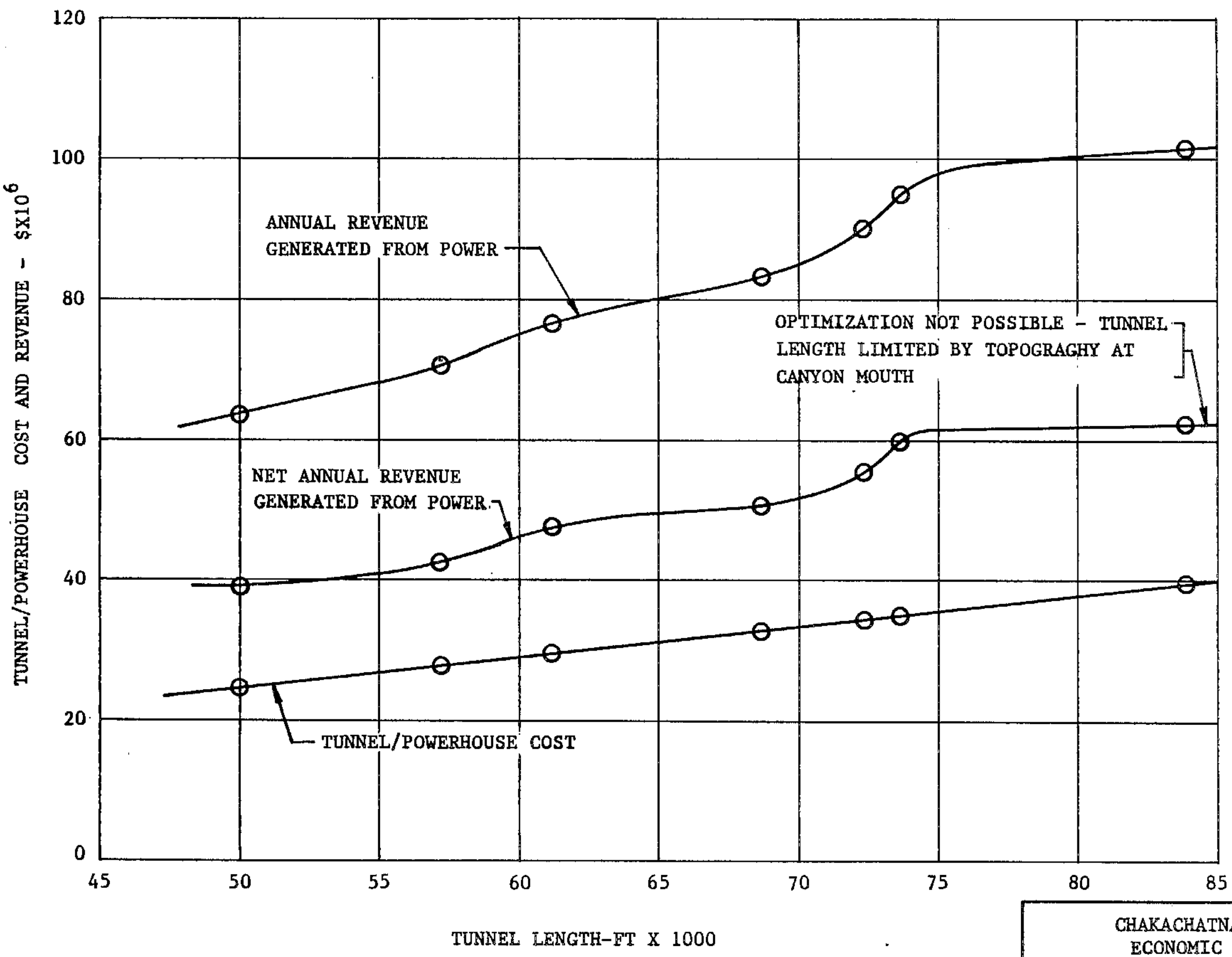
The economic balance includes consideration of the additional estimated tunnel construction cost by increasing the tunnel length, additional powerhouse cost to develop the power produced from the additional head and the value of the additional power generated by the additional head developed. The additional head is based on the increased gross head due to the lower tailwater obtained by extending the tunnel less the increased friction head loss in the longer tunnel.

Figure 9-2 and 9-3 show respectively the plots of the economic tunnel length for the development via the McArthur River and down the Chakachatna River. The final selected tunnel lengths and corresponding powerhouse locations are shown in Figures 3-2 and 3-3.



McARTHUR TUNNEL
ECONOMIC LENGTH

FIGURE 9-2



CHAKACHATNA TUNNEL
ECONOMIC LENGTH

FIGURE 9-3