SUSITNA HYDROELECTRIC PROJECT

TASK 11: REFERENCE REPORT
ECONOMIC, MARKETING AND FINANCIAL EVALUATION

Prepared by:

ACRES

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

TASK 11: REFERENCE REPORT
ECONOMIC, MARKETING AND FINANCIAL EVALUATION

Prepared by:

ACRES

ALASKA POWER AUTHORITY

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
ECONOMIC, MARKETING AND FINANCIAL EVALUATION

TABLE OF CONTENTS

LIST OF TABLES

List of Tables - 3

LIST OF FIGURES

List of Figures - 3

18 - ECONOMIC AND FINANCIAL EVALUATION

18.1 - Economic Evaluation

(a) Introduction

This section provides a discussion of the key economic parameters used in the study and develops the net economic benefits stemming from the Susitna hydroelectric project. Section 18.1 (b) deals with those economic principles relevant to the analysis of net economic benefits and develops inflation and discount rates and the Alaskan opportunity values (shadow prices) of oil, natural gas and coal. In particular the analysis is focused on the longer-term prospects for coal markets and prices. This follows from the evaluation that, in the absence of Susitna, the next-best thermal generation plan would rely on substantial and sustained exploitation of Alaska's coal resources. The future coal price is therefore examined in considerable detail to provide rigorous estimates of prices in the most likely alternative markets and hence the market price of coal at the mine-head within the state.

Section 18.1 (c) presents the net economic benefits of the proposed hydroelectric power investments compared with this thermal alternative. These are measured in terms of present-valued differences between Susitna and non-Susitna system costs. Recognizing that even the most careful estimates will be surrounded by a degree of uncertainty, the benefit-cost assessments are also carried out in a probabilistic framework as shown in Section 18.2. The analysis therefore provides both a most likely estimate of net economic benefits accruing to the state and a range of net economic benefits that can be expected with a likelihood (confidence level) of 95 percent or more.

(b) Economic Principles and Parameters

(i) Economic Principles - Concept of Net Economic Benefits

A necessary condition for maximizing the increase in state income and economic growth is the selection of public or private investments with the highest present-valued net benefits to the state. In the context of Alaskan electric power investments, the net benefits are defined as the difference between the costs of optimal Susitna-inclusive and Susitna-exclusive (predominantly thermal) generation plans.

The energy costs of power generation are initially measured in terms of opportunity values or shadow prices which may differ from accounting or market prices currently prevailing in the state. The concept and use of opportunity values is fundamental to the optimal allocation of scarce resources. Energy investment decisions should not be made solely on the basis of accounting prices in the state if the international value of traded energy commodities such as coal and gas diverge from local market prices. (This divergence may be due in part to institutional and contractual constraints, or gaps between marginal and average energy costs in Alaska.)

The choice of a time horizon is also crucial. If a short-term planning period is selected, the investment rankings and choices will differ markedly from those obtained through a long-term perspective. In other words, the benefit-cost analysis would point to different generation expansion plans depending on the selected planning period. A short-term optimization of state income would, at best, allow only a moderate growth in fixed capital formation; at worst it would lead to underinvestment in not only the energy sector but also in other infrastructure facilities such as roads, airports, hospitals, schools, and telecommunications.

It therefore follows that the Susitna project, as other Alaskan investments, should be appraised on the basis of long-run optimization, where the long term is defined as the expected economic life of the facility. For hydroelectric projects, this service life is typically 50 years or more. The costs of a Susitna-inclusive generation plan will be compared with the costs of the next-best alternative which is the all-thermal generation expansion plan and assessed over a planning period extending from 1982 to 2051, using internally consistent sets of economic scenarios and appropriate opportunity values of Alaskan energy.

Throughout the analysis, all costs and prices are expressed in real (inflation-adjusted) terms using January 1982 dollars. Hence the results of the economic calculations are not sensitive to modified assumptions concerning the rates of general price inflation. In contrast the financial and market analyses, conducted in nominal (inflation-inclusive) terms, will be influenced by the rate of general price inflation from 1982 to 2051.

(ii) Price Inflation and Discount Rates

- General Price Inflation

Despite the fact that the price level is generally higher in Alaska than in the Lower 48, there is little difference in the comparative rates of price changes; i.e., price inflation. Between 1970 and 1978, for example, the U.S. and Anchorage consumer price indexes rose at annual rates of 6.9 and 7.1 percent respectively. From 1977 to 1978, the differential was even smaller: consumer prices increased by 8.8 percent and 8.7 percent in the U.S. and Anchorage. (1)

Forecasts of Alaskan prices extend only to 1986. (2) These indicate an average rate of increase of 8.7 percent from 1980 to 1986.

For the longer period between 1986 and 2010, it is assumed that Alaskan prices will escalate at the overall U.S. rate, or at 5 to 7 percent compounded annually. The average annual rate of price inflation is therefore about 7 percent between 1982 and 2010. As this is consistent with long-term forecasts of the Consumer Price Index (CPI) advanced by leading economic consulting organizations, 7 percent has been adopted as the study value. (3, 4)

- Discount Rates

Discount rates are required to compare and aggregate cash flows occurring in different time periods of the planning horizon. In essence the discount rate is a weighting factor reflecting that a dollar received tomorrow is worth less than a dollar received today. This holds even in an inflation-free economy as long as the productivity of capital is positive. In other words, the value of a dollar received in the future must be deflated to reflect its earning power foregone by not receiving it today. The use of discount rates extends to both real dollar (economic) and escalated dollar (financial) evaluations, with corresponding inflation-adjusted (real) and inflation-inclusive (nominal) values.

. Real Discount and Interest Rates

Several approaches have been suggested for estimating the real discount rate applicable to public projects (or to private projects from the public perspective). Three common alternatives include:

.. the social opportunity cost (SOC) rate,
.. the social time preference (STP) rate, and
.. the government's real borrowing rate or the real cost of debt capital. (5, 6, 7)

The SOC rate measures the real social return (before taxes and subsidies) that capital funds could earn in alternative investments.

If, for example, the marginal capital investment in Alaska has an estimated social yield of X percent, the Susitna hydroelectric project should be appraised using the X percent measure of "foregone returns" or opportunity costs. A shortcoming of this concept is the difficulty inherent in determining the nature and yields of the foregone investments.

The STP rate measures society's preferences for allocating resources between investment and consumption. This approach is also fraught with practical measurement difficulties since a wide range of STP rates may be inferred from market interest rates and socially-desirable rates of investment.

A sub-set of STP rates used in project evaluations is the owner's real cost of borrowing; that is, the real cost of debt capital. This industrial or government borrowing rate may be readily measured and provides a starting point for determining project-specific discount rates. For example, long-term industrial bond rates have averaged about 2 to 3 percent in the US in real (inflation-adjusted) terms. (3, 8) Forecasts of real interest rates show average values of about 3 percent and 2 percent in the periods 1985 to 1990 and 1990 to 2000, respectively. The US Nuclear Regulatory Commission has also analyzed the choice of discount rates for investment appraisal in the electric utility industry and has recommended a 3 percent real rate. (24) Therefore, a real rate of 3 percent has been adopted as the base case discount and interest rate for the period 1982 to 2040.

. Nominal Discount and Interest Rates

The nominal discount and interest rates are derived from the real values and the anticipated rate of general price inflation. Given a 3 percent real discount rate and a 7 percent rate of price inflation, the nominal discount rate is determined as 10.2 percent or about 10 percent.[1]

(iii) Oil and Gas Prices

- Oil Prices

. Opportunity Value of Fuel Oil

In the base period (January 1982), the Alaskan 1982 dollar price of No. 2 fuel oil is estimated at $8.65/MMBtu.

Long-term trends in oil prices will be influenced by events that are economic, political and technological in nature, including the following, to name only a few

.. growth rates in the developed world's economies

.. rates of energy conservation in the developed world

.. rates of addition to currently-proven oil reserves

.. rate of economic development in the Third World and growth in its per capita energy consumption

.. rates of substitution from oil to non-oil energy sources, depending on (among others) the cost competitiveness of synthetic and biomass fuels and new energy conversion technologies such as breeder reactors and laser fusion

---

[1] (1 + the nominal rate) = (1 + the real rate) x (1 + the inflation rate).
= 1.03 x 1.07, or 1.102

.. political stability in OPEC and especially OAPEC countries

.. shifts in the balance of power in the Middle East, Southeast Asia, North and West Africa, and South America.

A survey of forecasts has identified the following projections for world oil prices

.. Data Resources Incorporated, (9): 2 percent (1981-1990)

.. World Bank, January 1981 (10): 3.2 percent (1981-1990)

.. US Department of Energy, Energy Information Administration, Winter 1980 (11): 1.5 percent (low), 3.4 percent (medium), 5.6 percent (high) (1980-2000)

.. National Energy Board of Canada, Ottawa, Canada, October 1981 (12): Zero percent to 2 percent (1980-2000).

Clearly, a wide range of oil price futures may be postulated. This uncertainty surrounding energy price projections calls for the development of several scenarios in a probabilistic framework. Recognizing that probabilistic analysis is required, three oil price futures and associated probabilities have been estimated for the period 1982 to 2040, as shown in Table 18.1.1.

The current softness in world oil markets reflects recessionary conditions in the major oil importing nations. In view of forecasts pointing to a mid-1982 recovery, and a sustained growth in the economics of the industrialized world, Acres has developed the following oil price scenario.

In the most likely (medium) scenario, real oil prices are expected to escalate at 2 percent and 1 percent in the intervals 1982 to 2000 and 2000 to 2040 respectively. In the case of low prices, there is zero escalation in the planning period, and in the high price scenario, the real growth rates are 4 percent (1982 to 2000) and 2 percent (2000 to 2040).

. <u>Battelle Analysis and Acres Study Values</u>

The generation planning (OGP) analysis has adopted the Battelle values for forecast oil prices as shown in Table 18.1.2. These values reflect a 2 percent annual real growth in oil prices from 1982 to 2010.

- <u>Gas Prices</u>

Alaskan gas prices have been forecast using both export opportunity values (netting back CIF prices from Japan to Cook Inlet) and domestic market prices as likely to be faced in the future by Alaskan electric utilities.

. Opportunity Value of Natural Gas

In 1980, 5 percent of Japan's imports of LNG were provided by Alaska at prices competitive with Japan's three other suppliers (13). Japan provides a relatively stable future market for LNG, given its "lack of substantial domestic gas supplies and their great distance from any possible pipeline routes". (14) Japan also appears to be willing to agree to higher charges than most importers for the guarantee of uninterrupted supply. (14)

The opportunity cost of Alaskan natural gas is determined by the best alternative use for the gas, and the above factors indicate that the Japanese market provides the best alternative, both today and as a reliable future source of revenues to Alaska. It should be noted however, that the opportunity value may not be realized if current indications of limited Cook Inlet reserves are confirmed.

.. Current Pricing Trends

Table 18.1.3 illustrates the prices paid for Alaskan LNG, CIF Japan over the period 1975 to April 1980. These prices indicate an average annual growth rate of 27 percent. Prices vary widely even from month to month. "In May 1980, for instance, Japan was paying CIF prices of $5.53 for Alaskan LNG." (15) As of May 1981, LNG deliveries in Japan could command a price of $6.30/MMBtu (CIF). (16)

The opportunity value of Alaskan gas is based on the potential delivered price minus the costs of liquefying and transporting the gas, that is, the plant-gate price. Based on previous Acres studies of transporting LNG over a similar distance, the Alaskan plant-gate price would be about $4.65/MMBtu in January 1982 dollars, with liquefaction and transportation representing about $2.10/MMBtu (1982 dollars).

.. Natural Gas Price Forecasts

Future international prices of natural gas will depend to a large extent on the development of the supply market. Various factors have been hindering this development, such as:

.. the high cost and long lead times involved in putting export projects on-stream

.. the prohibitive cost of transport (as much as five times that of oil)

.. specific importers and markets must be identified and depended on

.. limited flexibility in the network. (For example, some LNG tankers may be incompatible with certain liquefaction projects.) (15)

In order for the natural gas market to develop to its full potential, prices must be high enough to stimulate the supply market. Considering the long-term potential which is created by higher prices, natural gas price forecasts should not be unduly influenced by short-term slow growth demand patterns.

In fact, even in the short term prices are tending to gravitate towards parity with crude oil. Algeria and Libya have pushed for FOB parity with crude prices, while Abu Dhabi, for example, has called for CIF equivalence. In particular, deliveries of LNG to Japan from Alaska and Brunei have both been officially set at parity with the average landed cost of crude in Japan since April. (15)

Given these current trends, long-term forecasts of natural gas prices tend to assume that future gas prices will grow at approximately the same rate as crude oil prices. (9, 13) Accordingly, the natural gas pricing and probability scenarios developed in this section, follow closely the crude oil prices scenarios.

Based on these considerations, Table 18.1.4 shows the probabilities of low, medium, and high gas prices conditional on the three oil price scenarios developed above. The most likely (medium) price scenario, as well as the low and high price cases and corresponding probabilities, are shown in Table 18.1.5. In the most likely case, with a probability of 46 percent, the Alaskan opportunity values escalate at 2.7 percent (1982 to 2000) and 1.2 percent (2000 to 2040). This results from CIF prices (in Japan) that grow at 2 percent (1982 to 2000) and 1 percent (2000 to 2040) and from shipping costs that are constant in real terms. The Cook Inlet opportunity value rises from \$4.65 (1982) to \$12.26 (2040) measured in 1982 dollars.

The low and high price cases have equal probabilities of 27 percent. In the low case, the CIF prices remain constant in real terms, and in the high case the CIF prices grow at real rates of 4 percent (1982 to 2000) and 2 percent (2000 to 2040).

- Domestic Market Prices (Supplied by Battelle)

In contrast to the shadow prices or opportunity values discussed above, the gas prices estimated by Battelle and used in the base case Optimized Generation Planning (OGP) analysis reflect actual and forecast domestic market prices facing Alaskan electric utilities. These year-by-year prices are shown in Table 18.1.6 based on volume-weighted prices applying to CEA and AMLP. The differences between the opportunity values and domestic market prices are significant; by 1990 and 2000 for example, the export opportunity values are expected to exceed domestic prices by 324 percent and 85 percent respectively. Acceptance of the lower values are apparently based on the conclusion that Cook Inlet reserves would remain insufficient to serve new export markets.

(iv) Coal Prices

- Introduction

The shadow price or opportunity value of Beluga and Healy coal is the delivered price in alternative markets less the cost of transportation to those markets. The most likely alternative demand for thermal coal is the East Asian market, principally Japan, South Korea, and Taiwan. The development of 60-year forecasts of coal prices in these markets is conditional on the substitution potential of coal and the procurement policies of the importing nations. These factors, in turn, are influenced to a large extent by the price movements of crude oil.

Coal price forecasts which are based solely on production costs overlook these important factors. In fact, there are indications that "economic rents" (that is, a price that exceeds production costs including a normal return on investment) may be earned by the producers, mine labor and/or governments. For example, in the interests of supply security, a coal importer may be willing to pay a price much higher than actual coal production costs. In addition, oil price increases induce increased demand for coal, thus exerting upward pressure on coal prices. Market imperfections may exist which inhibit the long-term supply response effects on consumer coal prices. Therefore, coal price forecasts cannot be based on production costs alone, they must also reflect the influence of both oil price movements and procurement policies. Historical trends support these observations.

- Historical Trends

Historically it has been observed that export prices of coal are highly correlated with oil prices, and that production cost analysis has not predicted accurately the level of coal prices. Even if the production cost forecast itself is accurate, it will establish a minimum coal price, rather than the market clearing price set by both supply and demand conditions.

- In real terms export prices of U.S. coal showed a 94 percent and 92 percent correlation with oil prices 1950 to 1979 and 1972 to 1979.[2]

- Supply function (production cost) analysis, has estimated Canadian coal at a price of $23.70 (1980 US $/ton) for S.E. British Columbia (B.C.) coking coal, FOB Roberts Bank, B.C.,

[2] Analysis is based on data from the World Bank. (17)

Canada. (18, 23) In fact, Kaiser Resources (now B.C. Coal Ltd.) has signed agreements with Japan at an FOB price of about $47.50 (1980 US $/ton). (19) This is 100 percent more than the price estimate based on production costs.

- The same comparison for Canadian B.C. thermal coal indicates that the expected price of $55.00 (1981 Can $) per metric ton (2,200 pounds) or about $37.00 (1980 US $) per ton would be 60 percent above estimates founded on production costs. (18, 19, 23).

- In longer-term coal export contracts, there has been provision for reviewing the base price (regardless of escalation clauses) if significant developments occur in pricing or markets. That is, prices may respond to market conditions even before the expiry of the contract.[3]

- Energy-importing nations in Asia, especially Japan, have a stated policy of diversified procurement for their coal supplies. They will not buy only from the lowest-cost supplier (as would be the case in a perfectly competitive model of coal trade) but instead will pay a risk premium to ensure security of supply.

Observation of historical coal price trends reveals that FOB and CIF prices have escalated at annual real rates of 1.5 percent to 6.3 percent as shown below:

- Coal prices (bituminous, export unit value, FOB U.S. ports) grew at real annual rates of 1.5 percent (1950 to 1979) and 2.8 percent (1972 to 1979). (17)

- In Alaska, the price of thermal coal sold to the GVEA utility advanced at real rates of 2.2 percent (1965 to 1978) and 2.3 percent (1970 to 1978).

- In Japan, the average CIF prices of steam coal experienced real escalation rates of 6.3 percent per year in the period 1977 to 1981. (20, 21) This represents an increase in the average price from approximately $35.22 per metric ton (mt) in 1977 to about $67.63/mt in 1981.

- <u>Survey of Forecasts</u>

Data Resources Incorporated is projecting an average annual real growth rate of 2.6 percent for U.S. coal prices in the period 1981 to 2000. (19) The World Bank has forecast that the real price of steam coal would advance at approximately the same rate as oil prices (3 percent per year) in the period 1980 to 1990. (10) Canadian Resourcecon Ltd. has recently forecast growth rates of 2 percent

---

[3] This clause forms part of the recently-concluded agreement between Denison Mines and Teck Corporation and Japanese steel makers.

to 4 percent (1980 to 2010) for sub-bituminous and bituminous steam coal. (22)

- Opportunity Value of Alaskan Coal

  . Delivered Prices, CIF Japan

Based on these considerations, the shadow price of coal (CIF price in Japan) was forecast using conditional probabilities given low, medium and high oil price scenarios. Table 18.1.7 depicts the estimated coal price growth rates and their associated probabilities, given the three sets of oil prices. Combining these probabilities with those attached to the oil price cases yields the following coal price scenarios, CIF Japan.

Scenario	Probability	Real Price Growth
Medium (most likely)	49 percent	2 percent (1982-2000) 1 percent (2000-2040)
Low	24 percent	0 percent (1982-2040)
High	27 percent	4 percent (1982-2000) 2 percent (2000-2040)

The 1982 base period price was initially estimated using the data from the Battelle Beluga Market Study. (18) Based on this study, a sample of 1980 spot prices (averaging \$1.66/MMBtu) was escalated to January 1982 to provide a starting value of \$1.95/MMBtu in January 1982 dollars.[4]

As more recent and more complete coal import price statistics became available, this extrapolation of the 1980 sample was found to give a significant underestimate of actual CIF prices. By late 1981, Japan's average import price of steam coal reached \$2.96/MMBtu.[5] An important sensitivity case was therefore developed reflecting these updated actual CIF prices. The updated base period value of \$2.96 was reduced by 10 percent to \$2.66 to recognize the price discount dictated by quality differentials between Alaska coal and other sources of Japanese

---

4 The escalation factor was 1.03 x 1.14, where 3 percent is the forecast real growth in prices (mid-1980 to January 1982) at an annual rate of 2 percent, and 14 percent is the 18-month increase if the CPI is used to convert from mid-1980 dollars to January 1982 dollars.

5 As reported by Coal Week International in October 1981, the average CIF value of steam coal was \$75.50/mt. At an average heat value of 11,500 Btu/lb, this is equivalent to \$2.96/MMBtu.

coal imports, as estimated by Battelle. (18) Tables 18.1.8 and 18.1.9 illustrate the range of recent CIF and FOB prices of steam coal imports to Japan.

- Opportunity Values in Alaska

  - Base Case - Battelle-based CIF Prices, No Export Potential for Healy Coal

    Transportation costs of $0.52/MMBtu were subtracted from the initially estimated CIF price of $1.95 to determine the opportunity value of Beluga coal at Anchorage. In January 1982 dollars, this base period net-back price is therefore $1.43/MMBtu. In subsequent years, the opportunity value is derived as the difference between the escalated CIF price and the transportation cost (estimated to be constant in real terms). The real growth rate in these FOB prices is determined residually from the forecast opportunity values. In the medium (most likely) case the Beluga opportunity values escalate at annual rates of 2.6 percent and 1.2 percent during the intervals 1982 to 2000 and 2000 to 2040 respectively.

    For Healy coal, it was estimated that the base period price of $1.75/MMBtu (at Healy) would also escalate at 2.6 percent (to 2000) and 1.2 percent (2000 to 2040). Adding the escalated cost of transportation from Healy to Nenana results in a January 1982 price of $1.75/MMBtu.[6]

    In subsequent years, the cost of transportation, of which 30 percent is represented by fuel cost (which escalates at 2 percent), is added to the Healy price resulting in Nenana prices that grow at real rates of 2.3 percent (1982 to 2000) and 1.1 percent (2000 to 2040).

  - Sensitivity Case - Updated CIF Prices, Export Potential for Healy Coal

    The updated CIF price of steam coal ($2.66/MMBtu after adjusting for quality differentials) was reduced by shipping costs from Healy and Beluga to Japan to yield Alaskan opportunity values. In January 1982, prices are $2.08 and $1.74/MMBtu at Anchorage and Nenana respectively. The differences between escalated CIF prices and shipping costs result in FOB prices that have real growth rates of 2.5 percent and 1.2 percent for Beluga coal and 2.7 percent and 1.2 percent for Healy coal (at Nenana). Table 18.1.10 shows details of these CIF and FOB prices under the three coal price scenarios. Table 18.1.11 summarizes the coal opportunity values in each of the two cases and three scenarios.

[6] Transportation costs are based on Battelle. (18, 23)

(v) Generation Planning Analysis - Study Values

Based on the considerations presented in Sections (i) through (iv) above, a consistent set of fuel prices was assembled for the base case probabilistic OGP analysis, as shown in Table 18.1.12. The study values include probabilities for the low, medium and high fuel price scenarios. The probabilities are common for the three fuels (oil, gas and coal) within each scenario in order to keep the number of generation planning runs to manageable size. In the case of the natural gas prices, domestic market prices were selected for the base case analysis with the export opportunity values used in sensitivity runs. The base period value of $3 was derived by deflating the 1996 Battelle prices to 1982 by 2.5 percent per year. Coal prices were also selected from the base case using Battelle's 1980 sample of prices as the starting point, with the updated CIF prices of coal reserved for sensitivity runs. Oil prices have been escalated by 2 percent (1982-2040).

(c) Analysis of Net Economic Benefits

(i) Modeling Approach

Using the economic parameters discussed in the previous section, and the data relating to the electrical energy generation alternatives available for the Railbelt, an analysis was made comparing the costs of electrical energy production with and without the Susitna project. The primary tool for the net present worth (PW) benefit analysis was a generation planning model (OGP) which simulates production costs over a planning period extending from 1982 to 2010.

The method of comparing the "with" and "without" Susitna scenarios is based on the long-term PW of total system costs. The planning model determines the total production costs of alternative plans on a year-by-year basis. These total costs for the period of modeling include all costs of fuel and operation and maintenance (O&M) for all generating units included as part of the system, and the annualized investment costs of any generating plant and system transmission added during the period 1993 to 2010. Factors which contribute to the ultimate consumer cost of power but which are not included in this model are: investment cost for all generating plants in service prior to 1993, investment cost of the transmission and distribution facilities already in service and administrative costs of utilities. These costs are common to all scenarios and therefore have been omitted from the study.

In order to aggregate and compare costs on a sufficiently long-term basis, annual costs have been aggregated for the period 1993 to 2051. Costs have been computed as the sum of two components and converted to a 1982 PW at a 3 percent real discount rate (see Section 18.1 (b)). The first component is the 1982 PW of cost output from the first 18 years of model simulation from 1993 to 2010. The second component is the estimated PW of long-term system costs, from 2011 to 2051.

For an assumed set of economic parameters as a particular generation alternative the first element of the PW value represents the amount of cash (not including those costs noted above) needed in 1982 to meet electrical production needs in the Railbelt for the period 1993-2010. The second element of the aggregated PW value is the long-term (2011-2051) PW estimate of production costs. In considering the value to the system of the addition of a hydroelectric power plant, which has a useful life of approximately 50 years, the shorter study period would be inadequate. A hydroelectric plant which is added in 1993 or 2002 would accrue PW benefits for only 17 or 9 years respectively using an investment horizon that extends to 2010. However, to model the system for an additional 40 years it would be necessary to develop future load forecasts and generation alternatives which are beyond the realm of any prudent projections. For this reason, it has been assumed that the production costs for the final study year (2010) would simply reoccur for an additional 41 years, and the PW of these was added to the 18 year PW (1993-2010), to establish the long-term cost differences between methods of power generation.

(ii) Base Case Analysis

- Pattern of Investments "With" and "Without" Susitna

The base case comparison of the "with" and "without" Susitna plans is based on an assessment of PW of production costs as outlined in 18 (c) (i) for the period 1993-2051, using mid-range values for the energy demand and load forecast, fuel prices, fuel price escalation rates, capital costs and capital cost escalation rates. Load forecasts, fuel prices, and construction costs are analyzed in Chapter 5, 18.1 (b), and 16, respectively[7]. As discussed in Section 18.1 (b), a real interest and discount rate of 3 percent is used.

The Susitna plan calls for 680 MW of generating capacity at Watana to be available to the system in 1993. Although the project may come on-line in stages during the year, for modeling purposes, full load generating capability is assumed to be available for the entire year. In the second stage of Susitna, the Devil Canyon project is scheduled to come on-line in 2002. The optimum timing for the addition of Devil Canyon was tested for earlier and later dates. Addition in the year 2002 was found to result in the lowest long-term cost. Devil Canyon will have 600 MW of installed capacity.

The "without" Susitna plan is discussed in Section 6.7[7] and includes three 200 MW coal-fired plants added in Beluga in 1993,

[7] References to Feasibility Report

1994, and 2007. A 200 MW unit is added at Nenana in 1996. In addition, nine 70 MW gas-fired combustion turbines (GT's) are added during the 1997-2010 period.

- Base Case Net Economic Benefits

The economic comparison of the base plan alternatives is shown in Table 18.1.13. During the 1993-2010 study period the 1982 PW cost for the Susitna plan is $3.119 billion. The annual production cost in 2010 is $0.385 billion. The present worth of this level cost which remains virtually constant, for a period extending to the end of the life of the Devil Canyon plant, say 2051, is $3.943 billion. The resulting total cost of the "with" Susitna plan is $7.06 billion (1982 dollars), present valued to 1982.

The non-Susitna plan modeled has a 1982 PW cost of $3.213 billion for the 1993-2010 period, with a 2010 annual cost of $0.491 billion. The total long-term cost has a PW of $8.24 billion. Therefore, the net economic benefit of adopting the Susitna plan is $1.18 billion. In other words, the present-valued cost difference between the Susitna plan and the expansion plan, based on thermal plant addition, is $1.8 billion (1982 dollars). This is equivalent to a net economic benefit of $2,700 per capita for the 1982 population of Alaska. Expressed in 1993 dollars (i.e., at the on-line date of Watana), the net benefits would have a levelized value of $2.48 billion.[8]

It is noted that the magnitude of net economic benefits ($1.18 billion) is not particularly sensitive to alternative assumptions concerning the overall rate of price inflation as measured by the CPI. The analysis has been carried out in real (inflation-adjusted) terms. Therefore, the present-valued cost savings will remain close to $1.18 billion regardless of CPI movements, as long as the real (inflation-adjusted) discount and interest rates are maintained at 3 percent.

- Test of Internal Rate of Return

The Susitna project's internal rate of return (IRR) (i.e., the real (inflation-adjusted) discount rate at which the "with" Susitna plan has a zero net economic benefit, or the discount rate at which the costs of the "with" Susitna and the "alternative" plans are equal) has also been determined. The IRR is about 4.1 percent in real terms, and 11.4 percent in nominal (inflation-inclusive) terms.

[8] $1.118 billion times 2.105, where 2.105 is the general price inflation index for the period 1982 to 1993.

It is emphasized that these net economic benefits and the rate of return stemming from the Susitna project are inherently conservative estimates caused by several assumptions used in the OGP analyses for:

. Zero Growth in Long-term Costs

From 2010 to 2051, the OGP analysis assumed constant annual production costs in both the Susitna and the non-Susitna plans. This has the effect of excluding real escalation in fuel prices and the capital costs of thermal plant replacements, and thereby underestimating the long-term PW costs of thermal generation plans.

. Loss of Load Probabilities

The loss of load probability in the non-Susitna plan is calculated at 0.099 in the year 2010. This means that the system in 2010 is on the verge of adding an additional plant, and would do so in 2011. These costs are however not included in the analysis which is cutoff at 2010. On the other hand, the Susitna plan has a loss of load probability of 0.025, and may not require additional capacity for several years beyond 2010.

. Long-term Energy from Susitna

Some of the Susitna energy output (about 350 GWh) is still not used by 2010. This energy output would be available to meet future increases in projected demand in the summer months. No benefit is attributed to this energy in the analysis.

. Equal Environmental Costs

The OGP analysis has implicity assumed equal environmental costs for both the Susitna and the non-Susitna plans. To the extent that the thermal generation expansion plan is expected to carry greater economic cost savings from the Susitna project are understated. It is conceivable that these so-called negative externalities from coal-fired electricity generation will have been mitigated by 1993 and beyond, as a result of the enactment of new environmental legislation. Such government action would simply internalize the externality by forcing up the production and market costs of thermal power.

(iii) Sensitivity Analysis

Rather than rely on a single comparison to assess the net benefit of the Susitna project, a sensitivity analysis has been carried out to identify the impact of modified assumptions on the results. The sensitivity analysis addressed the following variables:

. Load Forecast
. Real Interest and Discount Rate

- Construction Period
- Period of Analysis
- Capital Costs
  - Susitna
  - Thermal Alternatives
- O&M Costs
- Base Period Fuel Price
- Real Escalation in Capital and O&M Costs and Fuel Prices
- System Reliability
- Chakachamna included in non-Susitna plan
- Planned delay in Susitna project timing.

- <u>Load Forecast</u>

Throughout the Susitna feasibility study, planning for the project has been based on a medium growth range of capacity and energy forecast. It has been realized that this forecast has been made based on a centerpoint of a range of uncertainty, rather than the actual expected occurrence. For this reason, the authorities responsible for demand forecasting have bracketed the range with high and low forecasts.

As part of the sensitivity analysis, the Susitna project has been analyzed under scenarios that reflect these high and low forecasts. The forecasts used in the analysis are the high, medium and low demand forecasts provided by Battelle based on the ISER studies, as discussed in Section 5[9] and summarized in Table 18.1.14.

Since the load forecast is the major consideration which influences the timing and size of capacity additions for the system, the nature of the systems varies greatly depending on the forecasts used.

- <u>Low Forecast</u>

In general, the adoption of a lower forecast requires the installation of smaller amounts of capacity to be added at relatively later timings in the period of study. In the non-Susitna plan, only 600 MW of coal-fired units are added, in the form of two 200 MW units in Beluga and one 200 MW unit at Nenana. These units are added in 1995, 1997, and 2007. In addition, 8 GT's with a total capacity of 560 MW are added periodically after 1996. The pattern of capacity additions is close to that in the medium forecast or base case, but it lags by several years.

The optimal timing for the addition of the Susitna units is also changed from that adopted for the medium forecast. As shown in Table 18.1.15, the selected staging for the project is 680 MW at

---

[9] Reference to Feasibility Report

Watana in 1995, with the 600 MW Devil Canyon plant coming on-line in 2004. The addition of Devil Canyon in 2007 was also tested and resulted in a slightly higher long-term PW cost. Watana, as a single project, was also examined, and long-term PW costs found to be higher than those arising from the later addition of Devil Canyon. It should be noted, however, that the staging of the second project is not as critical as in the other demand forecast. There is however a need for additional capacity on the system in 2004 which Devil Canyon can satisfy. If the project is added in that year, there is a sufficient amount of energy (1000 GWh) which cannot be used by the system for several years into the future.

The long-term cost of the non-Susitna plan is $6.878 billion and that of the Susitna plan is $6.650 billion. Thus, the net benefit to be released by proceeding with the Susitna project is $0.228 billion.

. High Forecast

To meet the system demand under the high forecast, capacity is needed long before 1993. Over the 10-year period prior to 1993, it was found that an addition of nearly 500 MW of other capacity would be needed. This could be met by the addition of a 200 MW gas-fired combined cycle unit in 1987 and 1990, and a 70 MW gas turbine unit in 1992. The selection of combined cycle units was essentially the only choice available for system addition in the 1980s since the coal-fired thermal units could not be available until 1990 because of site development and construction lead time.

Note that the addition of these three units would be common to both the "with" and "without" Susitna plans. Therefore, the annual investment costs arising from capital costs expended on these pre-1993 plans have not been included in the long-term PW cost.

In the non-Susitna plan, 1000 MW of coal units would be required, with four 200 MW units at Beluga and one at Nenana. In addition, eleven 70 MW GT units would be added. The long-term cost of the non-Susitna plan is $10.859 billion.

For the "with" Susitna plan, Watana is added in 1993; the Devil Canyon addition is advanced five years to 1997. In addition, a 70 MW GT unit is added in each of the years between 2006 and 2010. The long-term PW cost of the Susitna plan under the high forecast is $9.247 billion. The Susitna plan therefore has a net benefit of $1.612 billion.

- Real Interest and Discount Rate

The base case OGP runs have been made with the interest rates set at 3 percent in real terms. This rate has been selected on the basis of the analysis contained in Section 18.1 (e) above, and is consistent with APA guidelines.

The required real return on investment will be a state policy decision. It is realized that the state may require a rate of return higher or lower than 3 percent. It has been considered reasonable that the desired real rate of return could vary within the range of 2 percent to 5 percent. The economic analysis of the project has been carried out at real rates of 2, 3, 4 and 5 percent. The results of the evaluation are summarized in Table 18.1.15. At 2 percent, the net benefits of the Susitna project are $2.617 billion. At the high end of the range, a 5 percent real discount rate results in negative net benefits of $513 million. The "breakeven" discount rate or IRR is about 4.1 percent in real terms.

- Construction Period

Variability on the construction period has the impact of increasing interest during construction charges. Using economic parameters, the interest during construction is small and does not increase significantly as the construction period is extended by one or two years. Should a project be delayed several years, alternative forms of generation may be required in place of the planned unit. However, this change would not significantly impact on the generation planning analysis since the alternative unit would, most likely, be a 70 MW gas turbine which has little impact on the long-term PW cost if only operated for a limited number of years until the larger generating plant comes on-line. The construction schedule for Susitna has been analyzed in detail in the study risk assessment described in Chapter 18.2.

- Period of Analysis

The system planning period over which the OGP model was used extended from 1982 to 2010, the same period covered by the system demand forecasting model. However, the Susitna project is added to the system with Watana on-line in 1993 and Devil Canyon in 2002. Large hydroelectric projects of the size and nature of Susitna have a service life of at least 50 years. Therefore, the analysis of the project has taken into account system costs to a period covering the 50 years from 2002, the service life of the Devil Canyon stage. The conservative nature of this approach has been reviewed in Section 18.1 (d) (ii) above.

The impact of truncated planning horizons may be determined by reviewing the base case results shown in Table 18.1.13. The shortest period for analysis may be considered to extend only to 2010. However, this would account for only 8 years operation for Devil Canyon, well short of its 50-year economic life. In this case, the Susitna project would provide PW net benefits of $93 million, compared with a value of $1.180 billion from the more appropriate base case period extending to 2051.

If an interim point were selected based on say 30 years of operation for Devil Canyon, the net benefits of the Susitna project would be $0.718 billion. This is derived as the difference between the costs of the non-Susitna plan ($6.431 billion) and the Susitna plan ($5.713 billion). The net benefits in this case are 60 percent of those calculated in the base case.

- Capital Costs

Capital costs have a considerable impact on the present worth costs of the "with" and "without" Susitna scenarios. Capital cost analysis has been approached by varying the costs of the non-Susitna and the Susitna plans.

The capital costs for the alternative to Susitna have been estimated by Ebasco, as part of the Battelle alternatives study. There is some concern that these estimates are based on a less detailed study and are at a lower level of confidence than those pertaining to the Susitna project. Thus, the non-Susitna costs were varied by using "high" and "low" costs of 120 percent and 90 percent of the base estimate.

The second test concerned Susitna capital costs. These were varied using a "low" capital cost equal to the base estimate less 17 percent. For a "high" estimate, a 17 percent increase was allowed.

Table 18.1.17 shows the results of this sensitivity analysis. Note that the Susitna plan remains cost competitive in all cases examined. In the low and high non-Susitna cases, the net benefits of the Susitna project are 73 percent and 168 percent of the base case value. The net benefits are also sensitive to modified assumptions concerning the Susitna project costs. If the "low" capital cost is used, the Susitna plan would provide net benefits of $2.1 billion. In contrast, the "high" value results in net benefits that drop to $264 million.

- Operation and Maintenance Costs

The O&M component of production costs is relatively low, representing only 8 percent to 12 percent of the total production costs in any given year. Therefore, if the O&M estimates were varied in a manner similar to capital costs, there would be only a 1 percent to 2 percent impact on present worth costs. For this reason, the sensitivity of the results to O&M costs was not tested by further OGP analysis.

- Base Period Coal Price

As shown in the earlier parts of this Chapter, Section 18.1 (b) (iv), there is evidence that based on recent statistics, the base price (opportunity value) for coal could be as high as

$2.08/MMBtu, compared to the initial estimate of $1.43/MMBtu developed by Battelle. This updated starting price was tested in the "with" and "without" cases as shown in Table 18.1.18. This is a significant sensitivity case as the initial estimates of base period (January 1982) prices were established by Battelle on the basis of sample data for 1980. Net economic benefits in this case are $1.968 billion, or 167 percent of the base case value.

- Real Escalation Rates

  . Capital and O&M Cost Escalation

  It has been forecast that there could be real escalation in the capital costs of power plants averaging 1.8 percent per year until 1992 and 2 percent per year thereafter. These escalation rates were incorporated into the base case. In order to test the sensitivity of results to this assumption, tests were made with zero real escalation in capital and O&M costs, double the rate or about 4 percent real escalation, and 1.4 percent real escalation from 1982 to 2010 as estimated by Battelle. Of these three, the lower values appear to be more likely since, unlike finite fuel reserves, construction labor and materials are not a depletable resource and should not experience sustained real cost escalation.

  Results of this analysis are shown in Table 18.1.19. The variance in these escalation factors changes the net benefits in a manner similar to the analysis of variance in capital costs. Zero real escalation in capital and O&M costs raises net benefits by one-third. Doubling the rate of escalation causes the net benefits to fall one-third. In the high case, it should be noted that the non-Susitna plan changes from four coal units to two, with the capacity difference made up by GT and combined cycle additions. In the "Battelle" case, net benefits are increased by 10 percent relative to the base case.

  . Fuel Price Escalation

  As non-renewable resources, the prices of coal, gas, and oil are expected to increase at a rate greater than the general price level, as discussed in Section 18.1 (b). The base case escalation rates were 2.6, 2 and 2.5 percent until 2000 and 1.2, 2 and 2 percent respectively until 2010. Model runs were also carried out with high and low levels of fuel escalation. The low rate was established as zero percent real escalation. The upper limit was set at 5.2 percent for coal, 4 percent for oil, and 5 percent for gas from 1982 to 2000, and 2.2 percent, 2 percent and 2 percent, respectively beyond 2000. The results are summarized in Table 18.1.19.

In the low price escalation scenario, the Susitna plan results in negative net benefits of $1.078 billion. In the case of high energy price escalation, the net benefits rise to $2.070 billion.

- System Reliability

A generating system loss of load probability of one day in ten years has been used in system modeling. Variation of this factor would cause the system to add more or less capacity, thus potentially changing the staging of alternatives. However, since this is a predetermined criterion rather than an assumption or projection, no sensitivity analysis was carried out.

The Battelle AREEP model has the capability to calculate a target reserve margin based on variable load forecast. It is possible that given the load forecasts projected by Battelle, a reserve margin would be recommended greater than that calculated using the loss of load probability.

- Chakachamna

As discussed earlier, the Chakachamna project has not been included in the base non-Susitna plan. It has been included as a test case however, and found to lower the net benefits of the Susitna plan to $837 million, as shown in Table 18.1.20.

- Planned Delay in Susitna Project Timing

As shown in Table 18.1.21, the Susitna project's net benefits are essentially insensitive to a planned one- or two-year delay in timing. A one-year postponement of the Watana stage to 1994 would result in net benefits that are 4 percent below those in the base case. A one- or two-year delay in both the Watana and Devil Canyon stages would provide net economic benefits that are 96 percent to 97 percent of the base case values.

(d) Conclusion

The preceding discussion of sensitivity analysis shows that in terms of impacts on net benefits, the most sensitive variables are base period coal prices, fuel escalation rates, discount rates, Susitna capital costs, and load forecasts. As these assumptions are varied through a reasonable range of values, the Susitna plan is shown to retain positive net economic benefits relative to the costs of non-Susitna plans. Table 18.1.22 provides a summary of the various sensitivity analyses.

A multivariate analysis in the form of probability trees has also been undertaken to test the joint effects of several assumptions in combination rather than individually. This probabilistic analysis provides a range of expected net economic benefits and probability distributions that identify the chances of exceeding particular values of net benefits at given levels of confidence. The results of the probabilistic analysis are presented in Section 18.2.

TABLE 18.1.1: REAL (INFLATION-ADJUSTED) ANNUAL GROWTH IN WORLD OIL PRICES

(Percent)

	Growth Rates		
	1982-2000	2000-2040	Probability
Low Case	0	0	0.3
Medium (most likely case)	2.0	1.0	0.5
High Case	4.0	2.0	0.2

TABLE 18.1.2: STUDY ASSUMPTIONS: OIL PRICES

Year	Average Price of No. 2 Fuel Oil (1982 $/MMBtu)
1982 - 1985	6.70
1986 - 1990	7.33
1991 - 1995	8.08
1996 - 2000	8.93
2001 - 2005	9.86
2006 - 2010	10.88

TABLE 18.1.3: JAPANESE IMPORT PRICES (C.I.F.) OF ALASKAN LNG

Year	US$/MMBtu
1975	1.40
1976	1.70
1977	2.01
1978	2.26
1979	2.37
January 1980	3.51
February 1980	3.44
March 1980	3.48
April 1980	4.63

Source: Segal & Niering, (15)

TABLE 18.1.4: GAS PRICE ESCALATION AND ASSOCIATED CONDITIONAL PROBABILITIES

Gas Price Escalation	Oil Price Escalation		
	Low	Medium	High
Low (0 percent 1982 - 2040)	0.7	0.1	0.05
Medium (2 percent 1982 - 2000; 1 percent 2000 - 2040)	0.2	0.7	0.25
High (4 percent 1982 - 2000; 2 percent 2000 - 2040)	0.1	0.2	0.7

TABLE 18.1.5: OPPORTUNITY VALUE OF NATURAL GAS AT COOK INLET, ALASKA, 1982 - 2040

	CIF Price in Japan (1982 $/MMBtu)			Transportation Costs (1982 $/MMBtu)	Opportunity Value Gas at Cook Inlet (1982 $/MMBtu)		
	Medium	Low	High		Medium	Low	High
Probability	46%	27%	27%	N/A	46%	27%	27%
1982	6.75	6.75	6.75	2.10	4.65	4.65	4.65
1985	7.16	6.75	7.59	2.10	5.06	4.65	5.49
1990	7.91	6.75	9.24	2.10	5.81	4.65	7.14
2000	9.64	6.75	13.67	2.10	7.54	4.65	11.57
2010	10.65	6.75	16.66	2.10	8.55	4.65	14.56
2020	11.77	6.75	20.31	2.10	9.67	4.65	18.21
2030	13.00	6.75	24.76	2.10	10.90	4.65	22.66
2040	14.36	6.75	30.18	2.10	12.26	4.65	28.08
Annual Growth Rates							
1982 - 2000	2%	0	4%	0	2.7%	0	5.2%
2000 - 2040	1%	0	2%	0	1.2%	0	2.2%

TABLE 18.1.6: VOLUME WEIGHTED COOK INLET NATURAL GAS PRICE TO AMLP AND CEA

Period	Average Price (1982 $/MMBtu)
1982 - 1985	0.84
1986 - 1990	1.33
1991 - 1995	3.03
1996 - 2000	4.56
2001 - 2005	5.10
2006 - 2010	5.63

TABLE 18.1.7: COAL PRICE ESCALATION AND ASSOCIATED CONDITIONAL PROBABILITIES

Coal Price Escalation	Oil Price Escalation Low	Medium	High
Low (0 percent 1982 - 2040)	0.6	0.1	0.05
Medium (2 percent 1982 - 2000; 1 percent	0.3	0.7	0.25
High (4 percent 1982 - 2000; 2 percent 2000 - 2040)	0.1	0.2	0.7

TABLE 18.1.8: STEAM COAL IMPORTS BY JAPAN, SEPTEMBER AND OCTOBER 1981

Origin	Volumes September (metric tons)	Volumes October (metric tons)	CIF Prices \$/mt- (\$/MMBtu)* September	CIF Prices \$/mt- (\$/MMBtu)* October
US	127 037	276 467	75.10 (2.97)	81.33 (3.21)
South Africa	53 709	92 448	65.95 (2.61)	55.90 (2.21)
Australia	475 751	384 487	65.80 (2.60)	78.59 (3.11)
China	125 476	99 912	65.00 (2.57)	72.25 (2.86)
Soviet Union	33 805	25 826	65.47 (2.59)	73.68 (2.91)
Canada	28 468	130 033	67.79 (2.68)	70.55 (2.79)
TOTAL	826 246	1 009 173	67.17 (2.65)	75.47 (2.98)

* Based on an assumed heat value of 11 500 Btu/lb.

Source: Coal Week International

TABLE 18.1.9: CURRENT INTERNATIONAL SPOT PRICES OF STEAM COAL

Port of Origin	Btu/lb	Sulphur Percent	Ash Percent	FOB Price US$/long ton Jan. 6, 1982	CIF Price Japan[1] US$/long ton Jan. 6, 1982	FOB Price US$/MMBtu Jan. 1982	CIF Price Japan US$/MMBtu Jan. 1982
US							
Hampton Roads/	11 800	1.3	14.0	55.00[2]	73.00 - 74.50	2.08	2.76 - 2.82
Norfolk	(11 500)	(1.5)	(15.0)	(52.50)[2]	(70.50 - 72.00)	(2.04)	(2.74 - 2.80)
Baltimore	12 000	1.0	15.0	57.00[2]	75.00 - 76.50	2.12	2.79 - 2.85
	(12 000)	(1.0)	(13.5)	(52.00)[3]	(70.00 - 71.50)	(1.93)	(2.60 - 2.66)
Mobile	12 000	1.5	15.0	51.00[2]	69.00 - 70.50	1.90	2.57 - 2.62
	(11 300)	(1.3)	(15.5)	(50.00)[3]	(68.00 - 59.50)	(1.98)	(2.69 - 2.75)
South Africa							
Richards Bay	11 900	1.0	15.0	50.25[2]	57.25 - 61.25	1.89	2.15 - 2.30
	(10 800)	(1.0)	(15.0)	(47.75)[3]	(54.75 - 58.75)	(1.97)	(2.26 - 2.43)
Australia							
Newcastle	12 000	1.0	14.0	56.50	66.50 - 67.50	2.10	2.47 - 2.51
Port Kembla	(12 000)	(1.0)	(14.0)	(53.00)[2 & 3]	(63.00 - 64.00)	(1.97)	(2.34 - 2.38)

---

[1] Calculated using transportation rates from Coal Week International, December 23, 1981. Bracketed figures refer to November 1981 data.

[2] Contract quotes. All other prices are spot prices defined by Coal Week International as single shipments to be delivered within one year.

[3] Coal Week International and Energy Economist, December 1981.

TABLE 18.1.10: EXPORT OPPORTUNITY VALUES OF ALASKAN COAL - SENSITIVITY CASE[1]

	Medium (Most Likely) Coal Price Scenario							Low Coal Price Scenario				High Coal Price Scenario			
	CIF Price Japan	Shipping Cost	FOB Price Anchorage	Shipping Cost	FOB Price Healy	Shipping Cost Healy to Nenana	Price At Nenana	CIF Price Japan	FOB Price Anchorage	FOB Price Healy	Price At Nenana	CIF Price Japan	FOB Price Anchorage	FOB Price Healy	Price At Nenana
January															
1982	2.66	0.58	2.08	0.65	1.43	0.31	1.74	2.66	2.08	1.43	1.74	2.66	2.08	1.43	1.74
1985	2.82	0.58	2.24	0.66	1.58	0.32	1.90	2.66	2.08	1.42	1.74	2.99	2.41	1.75	2.07
1990	3.12	0.58	2.54	0.68	1.86	0.33	2.19	2.66	2.08	1.40	1.73	3.64	3.06	2.38	2.71
2000	3.80	0.58	3.22	0.74	2.48	0.35	2.83	2.66	2.08	1.34	1.69	5.39	4.81	4.07	4.42
2010	4.20	0.58	3.62	0.77	2.85	0.36	3.21	2.66	2.08	1.31	1.67	6.57	5.99	5.22	5.58
2020	4.64	0.58	4.06	0.80	3.26	0.38	3.64	2.66	2.08	1.28	1.66	8.01	7.43	6.63	7.01
2030	5.12	0.58	4.54	0.84	3.70	0.39	4.09	2.66	2.08	1.24	1.63	9.76	9.18	8.34	8.73
2040	5.66	0.58	5.08	0.88	4.20	0.41	4.61	2.66	2.08	1.20	1.61	11.90	11.32	10.44	10.85
Annual Growth Rates															
1982 to 2000	2%	0%	2.5%	0.7%	3.1%	0.7%	2.7%	0%	0%	-0.4%	-0.2%	4%	4.8%	6.0%	5.3%
2000 to 2040	1%	0%	1.2%	0.4%	1.3%	0.4%	1.2%	0%	0%	-0.3%	-0.1%	2%	2.2%	2.4%	2.3%
1982 to 2040	1.3%	0%	1.6%	0.5%	1.9%	0.5%	1.7%	0%	0%	-0.3%	-0.1%	2.6%	3.0%	3.5%	3.2%

[1] CIF Prices based on updated (late 1981) import prices of coal in Japan. Assumes export potential for Healy coal.

TABLE 18.1.11: SUMMARY OF COAL OPPORTUNITY VALUES

Base Case Battelle Base Period CIF Price	Base Period (Jan. 1982) Value ($/MMBtu)	Annual Real Growth Rate 1980-2000 (%)	Annual Real Growth Rate 2000-2040 (%)	Probability of Occurrence (%)	Conditional Probability Given Low Oil Prices (%)	Conditional Probability Given Medium Oil Prices (%)	Conditional Probability Given High Oil Prices (%)
Medium Scenario							
CIF Japan	1.95	2.0	1.0	49	30	70	25
FOB Beluga	1.43	2.6	1.2	49	30	70	25
Nenana	1.75	2.3	1.1	49	30	70	25
Low Scenario							
CIF Japan	1.95	0.0	0.0	24	60	10	5
FOB Beluga	1.43	0.0	0.0	24	60	10	5
Nenana	1.75	0.1	0.1	24	60	10	5
High Scenario							
CIF Japan	1.95	4.0	2.0	27	10	20	70
FOB Beluga	1.43	5.0	2.2	27	10	20	70
Nenana	1.75	4.5	1.9	27	10	20	70
Sensitivity Case							
Updated Base Period CIF Price[1]							
Medium Scenario							
CIF Japan	2.66	2.0	1.0	49	30	70	25
FOB Beluga	2.08	2.5	1.2	49	30	70	25
FOB Nenana	1.74	2.7	1.2	49	30	70	25
Low Scenario							
CIF Japan	2.66	0.0	0.0	24	60	10	5
FOB Beluga	2.08	0.0	0.0	24	60	10	5
FOB Nenana	1.74	-0.2	-0.1	24	60	10	5
High Scenario							
CIF Japan	2.66	4.0	2.0	27	10	20	70
FOB Beluga	2.08	4.8	2.2	27	10	20	70
FOB Nenana	1.74	5.3	2.3	27	10	20	70

1 Assuming a 10 percent discount for Alaskan coal due to quality differentials

TABLE 18.1.12: SUMMARY OF FUEL PRICES USED IN THE OGP PROBABILITY TREE ANALYSIS

	Fuel Price Scenario		
	Low	Medium	High
Probability of occurrence	25%	50%	25%
Base period January 1982 prices		(1982$/MMBtu)	
- Fuel Oil	6.50	6.50	6.50
- Natural Gas	3.00	3.00	3.00
- Coal			
. Beluga	1.43	1.43	1.43
. Nenana	1.75	1.75	1.75
Real escalation rates per year		(percent)[1]	
- Fuel Oil			
. 1982 - 2000	0.0	2.0	4.0
. 2000 - 2040	0.0	2.0	2.0
- Natural Gas			
. 1982 - 2000	0.0	2.5	5.0
. 2000 - 2040	0.0	2.0	2.0
- Beluga Coal			
. 1982 - 2000	0.0	2.6	5.0
. 2000 - 2040	0.0	1.2	2.2
- Nenana Coal			
. 1982 - 2000	0.1	2.3	4.5
. 2000 - 2040	0.1	1.1	1.9

[1] Beyond 2010, the OGP analysis used zero real escalation in all cases.

TABLE 18.1.13: ECONOMIC ANALYSIS SUSITNA PROJECT - BASE PLAN

			$\$ \times 10^6$ 1982 PRESENT-WORTH OF SUSITNA COSTS			
PLAN	ID	COMPONENTS	1993 - 2010	2018	ESTIMATED 2010 - 2051	1993 - 2051
Non-Susitna	A	600 MW Coal-Beluga 200 MW Coal-Nenana 630 MW GT	3213	491	5025	8238
Susitna	C	680 MW Watana 600 MW Devil Canyon 180 MW GT	3119	385	3943	7062
Net Economic Benefit of Susitna Plan						1176

TABLE 18.1.14: SUMMARY OF LOAD FORECAST USED FOR SENSITIVITY ANALYSIS

YEAR	MEDIUM		LOW		HIGH	
	MW	GWh	MW	GWh	MW	GWh
1990	892	4456	802	3999	1098	5703
2000	1084	5469	921	4641	1439	7457
2010	1537	7791	1245	6303	2165	11435

Source: Battelle, Railbelt Alternative Study, December 1981

TABLE 18.1.15: LOAD FORECAST SENSITIVITY ANALYSIS

PLAN	ID	COMPONENTS	$ x 10^6 1982 PRESENT-WORTH OF SYSTEM COSTS 1993 - 2010	2010	ESTIMATED 2011 - 2051	1993 - 2051	NET ECONOMIC BENEFIT
Non-Susitna Low Forecast	K_1	400 MW Coal-Beluga 200 MW Coal-Nenana 560 MW GT	2640	404	4238	6878	
Susitna Low Forecast	K_2	680 MW Watana (1995) 600 MW Devil Canyon (2004)	2882	360	3768	6650	228
Non-Susitna High Forecast	J_1	800 MW Coal-Beluga 200 MW Coal-Beluga 770 MW GT 430 MW Pre-1993	4176	700	6683	10859[1]	
Susitna High Forecast	J_2	680 MW Watana (1993) 600 MW Devil Canyon (1997) 350 MW GT 430 MW Pre-1993	3867	564	5380	9247[1]	1612

1 From 1993 to 2040

TABLE 18.1.16: DISCOUNT RATE SENSITIVITY ANALYSIS

			$ x 10^6 1982 PRESENT-WORTH OF SYSTEM COSTS				
PLAN	ID	REAL DISCOUNT RATE (percent)	1993 - 2010	2010	ESTIMATED 2011 - 2051	1993 - 2051	NET BENEFIT
Non-Susitna	Q_1	2	3701	465	7766	11167	
Susitna	Q_2	2	3156	323	5394	8550	2617
Non-Susitna	A	3	3213	491	5025	8238	
Susitna	C	3	3119	385	3943	7062	1176
Non-Susitna	S_1	4	2791	517	3444	6235	
Susitna	S_2	4	3080	457	3046	6126	109
Non-Susitna	P_1	5	2468	550	2478	4946	
Susitna	P_2	5	3032	539	2426	5459	(513)

TABLE 18.1.17: CAPITAL COST SENSITIVITY ANALYSIS

			$\$ \times 10^6$ 1982 PRESENT-WORTH OF SYSTEM COSTS				
PLAN	ID	REAL DISCOUNT RATE (percent)	1993 - 2010	2010	ESTIMATED 2011 - 2051	1993 - 2051	NET ECONOMIC BENEFIT
Alternative Capital Costs + 20%							
Non-Susitna	G		3460	528	5398	8858	
Susitna	C[1]		3119	385	3943	7062	1976
Alternative Capital Costs - 10%							
Non-Susitna	G_1		3084	472	4831	7915	
Susitna	C[1]		3119	385	3943	7062	853
Susitna Capital Costs Less 17%							
Non-Susitna	A		3213	491	5025	8238	
Susitna	X_2		2710	336	3441	6151	2087
Susitna Capital Costs Plus 17%							
Non-Susitna	A		3213	491	5025	8238	
Susitna	Y_2		3529	434	4445	7974	264

[1] An adjustment calculation was made regarding the plus or minus capital cost of the 3 GT units added in 2007 - 2010 since the difference was less than $\$10 \times 10^6$. Beyond 2010, this effect was included.

TABLE 18.1.18: SENSITIVITY ANALYSIS - UPDATED BASE PERIOD (JANUARY 1982) COAL PRICES

Base Case	Base Period Coal Price (1982 $/MMBtu)	$ x 10^6 1982 Present Worth of Sustina Costs: Costs of Non-Susitna Plan	Costs of Susitna Plan	Net Economic Benefits
Base Case	1.43	8238	7062	1176
Sensitivity (Update) Use	2.08	9030	7062	1968*

* The value is produced by "forcing" the system to use the same coal fired plants as in the base case. If the system is allowed to optimite, however, combined cycle units are selected in lieu of coal fired plants and the net economic benefit is essentially the same as in the base case.

TABLE 18.1.19: SENSITIVITY ANALYSIS - REAL COST ESCALATION

		$ \$ \times 10^6$ 1982 PRESENT-WORTH OF SYSTEM COSTS				
PLAN	ID	1993 - 2010	2010	ESTIMATED 2011 - 2051	1993 - 2051	NET BENEFIT
Zero Escalation in Capital Costs and O&M						
Non-Susitna	0_1	2838	422	4319	7157	
Susitna	0_2	2525	299	3060	5585	1572
Escalation in Capital Costs and O&M (Battelle)[1]						
Non-Susitna	X_1	3142	477	4881	8023	-
Susitna	X_2	2988	366	3745	6737	1286
Double Escalation in Capital Costs and O&M						
Non-Susitna	P_1	3650	602	6161	9811	
Susitna	R_2	3881	503	5148	9029	782
Zero Escalation in Fuel Prices						
Non-Susitna	V_1	2233	335	3427	5660	
Susitna	V_2	3002	365	3736	6738	(1078)
High Escalation in Fuel Prices						
Non-Susitna	W_1	4063	643	6574	10367	
Susitna	W_2	3267	403	4121	7388	2979

[1] Capital and O&M costs assumed to escalate at 1.4 percent 1982 to 2010

TABLE 18.1.20: SENSITIVITY ANALYSIS - NON-SUSITNA PLAN WITH CHAKACHAMNA

			$ x 10^6 1982 PRESENT-WORTH OF SYSTEM COSTS				
PLAN	ID	COMPONENTS	1993 - 2010	2010	ESTIMATED 2011 - 2051	1993 - 2051	NET BENEFIT
Non-Susitna with Chakachamna	B	330 MW Chakachamna 400 MW Coal-Beluga 200 MW Coal-Nenana 440 MW GT	3038	475	4861	7899	
Susitna	C	680 MW Watana 600 MW Devil Canyon 180 MW GT	3119	385	3943	7062	837

TABLE 18.1.21: SENSITIVITY ANALYSIS - PLANNED DELAY IN SUSITNA PROJECT TIMING

	ID	$ x 10^6 1982 Present Worth of System Costs	$ x 10^6 Net Economic Benefit
Susitna Base Case	C	7,062	1,176
One-year delay for Watana (1994)	C3	7,105	1,133
One-year delay for Watana and Devil Canyon (1994, 2003)	C4	7,165	1,134
Two-year delay for Watana and Devil Canyon (1995, 2004)	C5	7,230	1,138

TABLE 18.1.22: SUMMARY OF SENSITIVITY ANALYSIS - INDEXES OF NET ECONOMIC BENEFITS

	Index Value
BASE CASE ($1,176 MILLION)	100
Fuel Escalation -	
- High	253[1]
- Low	-92[2]
Discount Rates	
- High-High (5%)	-44
- High (4%)	9
- Low (2%)	223
Susitna Capital Cost	
- High	23
- Low	178
Load Forecast	
- High	137
- Low	19
Non-Susitna (Thermal) Capital Costs	
- High	168
- Low	73
Capital and O&M Cost Escalation	
- High	67
- Intermediate (Battelle)	109
- Low	134
Chakachamna (included in Non-Susitna Plan)	71
Updated Base Coal Price	167
Planned Delay in Susitna Project	
- One-year delay, Watana	96
- One-year delay, Watana and Devil Canyon	96
- Two-year delay, Watana and Devil Canyon	97

[1] High fuel escalation case provides net benefits equal to 253 percent of the base value, 2.53 x $1,176, or $2,975.

[2] Low fuel escalation case provides minus 92 percent of the base case net benefits, -.92 x $1,176, or -$1,082.

18.2 - Probability Assessment and Risk Analysis

(a) Introduction to Multivariate Sensitivity Analysis

The feasibility study of the Susitna Project included an economic analysis based upon a comparison of generation system production costs. The system costs were estimated with and without the proposed project using a computerized model of the Railbelt generation system. In order to carry out this analysis, numerous projections and forecasts of future conditions were made. In order to address these uncertain conditions, a sensitivity analysis on key factors was done. This analysis focused on the variance in each of a number of parameters and determined the impact of this variance on the economic feasibility of the project. Each factor was varied singularly with all other variables held constant.

The purpose of the analysis was served by constructing a probability tree of future conditions for the Alaskan Railbelt electrical system, with and without the Susitna project. Each branching of the tree represents three values for a given variable which were assigned a high, medium and low value as well as a corresponding high, medium and low probability of occurrence. The three values represent the expected range and mid-point for a given variable. In some cases, the mid-point represents the most likely value which would be expected to occur. End limbs of the probability tree represent scenarios of mixed variable conditions and a probability of occurrence for the scenario.

The computer production cost model was then used to determine the PW cost of the electric generation system for each scenario. Using the probabilities assigned to each branch, the PW costs for each "with" and "without" Susitna scenario were plotted against the corresponding cumulative probability. Net benefits of the project have also been calculated and analyzed in a probabilistic manner.

(b) Approach to Probability Assessment

The method followed in the multivariate analysis involved four stages:

- Selection of key variables
- Probability tree development
- Modeling of system costs
- Analysis of results

(i) Selection of Key Variables

The sensitivity tests performed in the economic analysis (see Section 18.1) identified a list of variables which could significantly affect the economic feasibility. This list included:

- Construction Period
- Period of Analysis
- Capital Costs
  - Susitna
  - Thermal Alternatives
- O&M Costs
- Base Period Fuel Price
- Real Escalation in Capital and O&M Costs and Fuel Prices
- System Reliability
- Chakachamna included in non-Susitna plan
- Planned delay in Susitna project timing.

Of this list, several of the inputs are considered to be policy or methodology decisions and are not included in the probabilistic analysis. These include the interest and discount rate, the period of analysis and system reliability criteria. The single variable sensitivity analysis demonstrated that other criteria such as the construction period and O&M costs had little or no impact on the comparison of "with" and "without" Susitna system costs.

Although sensitivity results based on varying the real escalation of capital and O&M costs had a measurable influence on PW costs, it was not included in the probabilistic analysis. The range of capital cost escalation rates tested in the sensitivity analysis extended from 0 percent to 4 percent per year from 1982 to 2010. The mid-range was approximately 2 percent. It is believed that this range accurately covers the minimum and maximum rates anticipated for construction cost escalation. Sensitivity of net benefits to capital and O&M cost excalations was found to be moderate relative to other variables. Therefore, this variable was excluded from the probability assessments.

The three remaining variables were used in the probabilistic analysis. These are the load forecast, capital cost estimates, both for generation alternatives and for the Susitna Project, and real escalation in fuel prices. The variable values and probabilities are discussed in (ii) below.

(ii) Probability Tree

Given the three selected "key" variables for the non-Susitna analysis (four for Susitna), a probability tree was constructed based on the high, medium and low value for each of the variables.

The non-Susitna tree consists of 3 variables and 3 values (high, medium and low) for each, resulting in 27 possible combinations, as shown in Figure 18.2.1. The numbering system selected for this analysis ranges from T01 to T27 where T01 refers to the thermal (non-Susitna) case, high load forecast, high alternative capital cost and high fuel cost escalation. At the lower end of the tree, T27 refers to the thermal case, low load forecast, low alternative capital cost and low fuel cost escalation scenario.

The Susitna probability tree (see Figure 18.2.2) could have a maximum of 4 variables and 3 values for each, resulting in 3^4, or 81 branches. However, a review of the Susitna base plans developed in the economic analysis showed that the medium plan calls for the addition of only three 70 MW gas turbines in the last three years of study. A check on the effect of varying the cost of these units indicated an impact on long-term costs of less than 0.5 percent. Thus, it was assumed that in the medium "branches" there is no variability in thermal alternatives cost.

In the low forecast there is no need for thermal alternative generation in the 1993-2010 period during which the "with" Susitna scenario is being considered. Accordingly, the alternative capital cost variable is removed from that branch. As a result, both the medium and low forecast portions of the probability tree are reduced by a factor of 3. These adjustments reduce the number of ultimate scenarios from 81 to 45 without affecting the accuracy of the multivariate analysis.

A similar numbering system was adopted for the Susitna analysis ranging from S01 to S45 where S01 to S27 refer to high load forecast scenarios, S28 to S36 refer to medium load forecast scenarios, and S37 to S45 represent low load forecast scenarios.

(iii) Present Worth of Long-term Cost and Net Benefit Approach

The OGP production cost model was used to determine the PW (in 1982 dollars) of production costs for each scenario, as described in Section 18.1 (c). For each tree, the scenario costs were ranked from lowest to highest and the probability associated with each scenario was used to provide a plot of cumulative probability versus PW cost. Additionally, the scenario costs were weighted with their associated probabilities to provide an expected value of the PW cost.

A second method of cost comparison used in Section (d) below is by comparing net benefits. The net benefit can be estimated by comparing similar "with" and "without" Susitna scenarios, and by examining the difference in PW long-term costs. For example, in a "with" Susitna scenario with PW costs of $6 billion compared to a similar non-Susitna scenario with $7 billion PW costs, the PW of the production cost saving over the long-term would be $1 billion. This difference is the net benefit and again, these net benefits were ranked from low to high and a cumulative probability calculated from the individual probabilities. An expected value of net benefits was also calculated.

(c) Variables and Ranges

(i) Load Forecast

As a single variable, the variance of load forecast remains one of the most important factors. The selection of type and timing of alternative units is dependent on the selected forecast.

In terms of the multivariate sensitivity analysis, the load forecast variation represents the first level of uncertainty in the probability tree. The forecasts used were generated by the Battelle Railbelt Alternative Study group in December 1981 with the use of their Railbelt Electric Demand (RED) model, which relates economic activity, energy prices, and government expenditures to energy demand. The range of variability in the load forcast is presented in Table 18.2.1. Note that these forecasts differ slightly from the final forecasts produced in January 1982 by Battelle.

The probability of the low, medium or high forecast occurring was estimated as a symmetrical pattern of .2, .6 and .2 respectively. These estimates of probability were based upon the estimate by Battelle that the probability of exceedance of their forecasts was approximately 90 percent for the low forecast and 10 percent for the high forecast.

The plans used in the probabilistic analysis are identified as follows:

Low Load Forecast:

Non-Susitna - first 200 MW of thermal capacity added in 1995

Susitna - Watana 600 MW in 1995
- Devil Canyon 600 MW in 2004

Medium Load Forecast:

Non-Susitna - first 200 MW of thermal capacity added in 1993

Susitna - Watana 680 MW in 1993
- Devil Canyon 600 MW in 2002

High Load Forecast:

1982 - 1992 period: (common to both cases)

200 MW of thermal combined cycle capacity added in 1987

200 MW of thermal combined cycle capacity in 1990

70 MW of thermal gas turbine in 1992

together with:

Non-Susitna - first 200 MW of thermal capacity added in 1993

Susitna - Watana 680 MW in 1993
- Devil Canyon 600 MW in 1997

(ii) Alternative Capital Cost

Consistent with the univariate economic analysis, the base capital cost estimate plus 20 percent was used as the high value and the base capital cost estimate minus 10 percent was used as the low value. These figures were selected based on a review of the Railbelt Alternatives Study Coal Cost Estimate report prepared by Ebasco for Battelle. The discussion contained in the report indicated that there was a greater likelihood of cost increase than decrease.

The base (medium), high and low capital costs for the coal, gas turbine and gas-fired combined cycle plants are shown in Table 18.2.2. These capital costs include allowance for interest during construction based on an S-shaped expenditure curve and the medium economic parameters used throughout the study. In addition, the first unit sited in the Beluga area and the single unit at Nenana district carry the appropriate costs of transmission system strengthening and interconnection. The probability of the occurrence for the high, medium and low capital costs were estimated as a .20, .60, and .20.

(iii) Fuel Cost and Escalation

Considerable effort has been concentrated on defining fuel prices and escalation rates of the various fuels for alternative forms of generation Railbelt, both by Acres and by Battelle for their Railbelt Alternative Study.

The low, medium and high cases are all linked to the forecast escalation rate in the world market price for oil, as shown in Section 18.1 (b).

- Coal

As outlined in Section 18.1 coal reserves available to the Railbelt include coal mined at Healy and a potential coal supply from the as yet undeveloped Beluga field. Furthermore, Healy coal could be transported to Nenana for use as fuel in a potential 200 MW coal-fired plant located there due to air quality restrictions at Healy. Three starting coal prices based on point of use were developed for input into the multivariate sensitivity analysis. For each of these starting coal prices, three escalation rate scenarios were developed, a low, a medium or most likely case, and a high case. Probabilities of occurrence of .25, .50 and .25 respectively were assigned to the three escalation rates. These probabilities are discussed in detail in Section 18.1 (b). Table 18.2.3 summarizes these prices and escalation rates.

- Natural Gas

Cook Inlet natural gas is presently sold to Anchorage utilities at existing contract rates. It is generally agreed that the price is artificially low and will increase significantly as these contracts are renegotiated. Thus, a world market opportunity value was selected as the base starting price for modeling purposes. Based on the Battelle medium price forecast, a 1982 opportunity value of $3/MMBtu was selected. This value when coupled with Acres medium fuel escalation rates yields values equal to Battelle's assumptions during the 1993-2010 study period. In the low case, prices were assumed constant at $3/MMBtu throughout the study period. The medium case escalation rate was 2.4 percent (1982-2000) and 2 percent (2001-2010). The high case escalation rate was set at 5 percent (1982-2000) and 2 percent (2001-2010). Table 18.2.3 summarizes these forecasts of gas prices.

- Distillate Oil

Table 18.2.3 summarizes the low, medium and high oil price trends used in this analysis assuming a 1982 rate of $6.50/MMBtu, based on Battelle estimates.

(iv) Susitna Capital Cost

The potential for variation in the Susitna Project capital cost has been analyzed in the feasibility study. In general, the approach has been to produce an estimated capital cost with a relatively high level of confidence that the ultimate project cost will be less than the "upper limit" cost (in 1982 dollars). As shown in Section 18.2 (f) through (g), the risk analysis has indicated that the estimated capital cost has a 17 percent chance of being equalled or exceeded given the low probability but high impact risks which could occur during construction (i.e., major seismic event or flood).

During earlier sensitivity tests, capital costs were allowed to vary from 83 percent of the project estimate to 117 percent. These capital costs are presented in Table 18.2.4.

Assignment of probabilities to the three levels of estimate was based upon the feasibility study risk assessment. The approach to the "upper limit" value for the Susitna capital cost was an attempt to bound the base estimate with a high level of confidence that the overall project cost will be less than this estimate. Therefore, the assignment of probabilities of occurrence are somewhat different than for the non-Susitna alternatives. Based on the risk analysis, a probability of .6 was assigned to the low case and values of .25 and .15 were assigned to the medium and high values. These values reflect the expectation that ultimate costs of the project will be less than the current estimate (in 1982 dollars).

(d) Results

This section presents the results from the analysis of the two probability trees and of the input data in accordance with the methodology described in Section (b).

(i) Probability Tree: Non-Susitna

The parameters for the twenty-seven scenarios defined by the probability tree in Figure 18.2.1 were entered into the simulation model to determine the 1982 PW of system costs. These results are presented in Table 18.2.5 and Figure 18.2.1.

The PW cost varied by nearly 350 percent from the lowest cost scenario ($4.41 billion) to the highest cost scenario ($15 billion). The low cost relates to the case of low load forecast, low capital costs for thermal units and zero real escalation in fuel costs. Conversely, the high case includes the high forecast for each of these variables. The large spread from low to high cost seems most dependent on the fuel cost escalation rate used. The wide range in fuel costs during the study period and the reliance on fossil fuels in the non-Susitna cases led to the wide spread in PW costs.

Table 18.2.5 also shows the calculation of costs versus cumulative probability. This plot is derived as the summation of the probabilistic increments of costs for each scenario. The increment is the product of a scenario's PW cost and its probability. For the non-Susitna case, the expected value of PW costs is $8.48 billion.

Visual representation of the data from Table 18.2.5 is shown in Figure 18.2.3. This graph is based on a histogram of PW cost versus cumulative probability.

(ii) Probability Tree: Susitna

The 45 scenarios in the "with" Susitna case shown in Figure 18.2.2 were also run using the simulation model to obtain the system production costs. The results are shown in Table 18.2.6. The overall variability of PW costs in the Susitna case is much less than the non-Susitna case. The range from lowest to highest is $5.54 billion to $11.59 billion, a range of about 200 percent as compared to 350 percent for the non-Susitna alternatives. The expected value of PW costs is $7.03 billion.

(iii) Comparison of Present Worth of Long-term Costs

Figure 18.2.3 presents the two histograms of long-term costs for the "with" and "without" Susitna cases. From these it is seen that the non-Susitna plan costs could be expected to be significantly less than the Susitna plan costs about 6 percent of the time, approximately equal to the Susitna costs 16 percent of the time, and significantly greater 78 percent of the time.

A comparison of the expected value of long-term costs for the "with" and "without" cases yields an expected value net benefit of $1.45 billion. This value represents the difference between the non-Susitna PW cost of $8.48 billion and the Susitna PW cost of $7.03 billion.

(iv) Net Benefits

A second method of examining the "with" and "without" Susitna probability trees is to make a direct comparison of similar scenarios and to calculate the net benefit of each comparison. This method is discussed in more detail in section (b). Table 18.2.7 lists the 81 comparisons of similar scenarios between the 27 non-Susitna case and 45 Susitna case scenarios. As was done for the individual tree cases, the net benefits were ranked from low to high and plotted against cumulative probability, as shown in Figure 18.2.4. The net benefits vary from minus $2.92 billion with an associated probability of .0015 to a high of $4.80 billion with an associated probability of .018. The single comparison with the highest probability of occurrence of .108 has a net benefit of $2.09 billion.

The plot of net benefits shows a "breakeven" between the "with" and "without" Susitna cases at about 23 percent, consistent with the previous comparison, i.e., positive net benefits will accrue from the Susitna project with a probability of 77 percent.

(e) Extensions to the Multivariate Analysis

Introduction

The initial probability analysis was carried out under the implicit assumption that energy prices and load forecasts (energy demand) are not correlated. The probabilities attached to high (H), medium (M) and low (L) energy prices were therefore constant across the L, M, and H load forecasts.

Given the importance of energy prices to the Alaskan economy it may be postulated however, that energy demand could be either positively or negatively correlated with prices and that the probabilities of H, M, and L demand should be conditional on the levels of energy prices. These conditional probabilities would reflect the elasticity of demand with respect to energy prices. Two cases were explored, corresponding to positive and negative correlation and elasticity.

(i) Case 1 - Positive Price/Demand Correlation

This case depicts a scenario in which higher (lower) energy prices provide an increase (decrease) in state revenues, incomes and overall economic activity, leading to higher (lower) energy consumption in general, and higher (lower) electricity demand in particular. In essence, it is assumed that the income effect outweighs the price effect stemming from higher or lower energy prices.[1] As shown in Table 18.2.8 the probability tree was modified such that higher (lower) demand is more likely to be associated with higher (lower) energy prices than with lower (higher) prices. Note that the initial tree was altered only with respect to the conditional probabilities of the load forecasts. It is also noted that the revised probabilities correspond to an elasticity of about +0.15 [2].

Based on these probabilities, the cumulative probability distributions of present valued costs were constructed for the Susitna (S) and thermal (T) plans. These show that the chances of an S plan being more costly than the T plan are 25 percent. The costs of the S and T plans are approximately equal with a probability of 6 percent, and the S plan is distinctly less costly with a probability of 69 percent. In comparison, the initial probability analysis indicated that the chances of more-costly, equal-cost, and less-costly S plans were about 16 percent, 6 percent and 78 percent respectively.

(ii) Case 2 - Negative Price/Demand Correlation

In this scenario, it is hypothesized that higher (lower) energy prices would on balance result in lower (higher) energy consumption and electricity demand. In contrast to Case 1, Case 2 depicts a

---

1 There is a further possibility that larger state revenues from higher energy prices would lead to substantial subsidies to the cost of electrical energy to Alaskan consumers and hence further increase the positive correlation between energy prices generally and demand. Since such subsidies are a political policy decision they cannot be forecast and are therefore not taken into account. This factor could, however, only reinforce the conclusions reached.

2 The elasticity is defined as the percent change in the expected value of demand divided by the percent change in real prices. For example, in 2010, the expected values of the load forecast given L and M energy prices are 7 263 GWh and 8 223 GWh respectively, a difference of 13 percent. The percent difference between L and M energy prices in 2010 is 99 percent. Thus the elasticity is 13 percent (13/99) or .13. Similar elasticities were measured for the L-H and M-H pairs of load forecasts and energy prices.

situation in which the price effect outweighs the income effect resulting from a shift in energy prices and corresponding levels of Alaskan economic activity. As shown in Table 18.2.9 the initial probability tree was modified such that higher (lower) energy prices are more (less) likely to lead to lower energy demand and load forecasts. The revised conditional probabilities reflect an elasticity of demand of about minus 13, calculated as in Case 1 above. Cumulative probability distributions of PW system costs were developed for the S and T plans. These indicated an even higher likelihood for positive net benefits from the S plan with a 91 percent chance that the S plan would be the less costly alternative. In this case there is no region of "ambiguity" with equal costs attached to the S and T plans; therefore, it is asserted that there is only a 9 percent probability that the T plan would be cost-competitive. Table 18.2.10 summarizes these results and compares them with those obtained in the initial probability tree analysis.

(f) Approach to Risk Analysis

As the preceding paragraphs demonstrate, the Susitna hydroelectric project is viable in economic terms through a broad range of possible deviations from expected values of key parameters. Even so, net project benefits are sensitive to Susitna capital cost variations; and alternative financing plans are predicated on the assumption that the proposed project schedule will be met. Every reasonable effort was made to prepare conservative cost estimates and to produce an achievable schedule. Yet, uncertainties are involved and their potential importance demands that they be given appropriate consideration at various stages in project development.

A risk analysis was undertaken as the basis for determining the extent to which perceived risks are likely to influence capital costs and schedule. In addition, because a mature Susitna project would represent a major portion of the total generation system, a further risk analysis was accomplished to assess the probability and consequences of a long-term outage of the proposed transmission system. This section summarizes the risk analyses. A more detailed report is included in the project documentation for Subtask 11.03, Risk Analysis.

Any major construction effort is inevitably exposed to a large number of risks. Floods may occur at crucial times. Accidents should not happen, but they sometimes do. Sub-surface investigations, no matter how thorough, do not always tell the whole story about what will be found when major excavation work goes on. The normal estimation process implicitly accounts for a set of reasonably "normal" expectations as direct costs are developed, adding a contingency to the directly-computed total on the grounds that problems usually do occur even though their specific nature may not be accurately foreseen at the outset.

The Susitna Risk Analysis took explicit account of 21 different risks, applying them as appropriate to each major construction activity. The effort involved combining reasonably precise data (e.g., the probability that a particular flood crest will occur in any given year can be determined from analysis of hydrologic records) with numerous subjective judgments (e.g., until a particular flood crest does occur, we cannot know with any degree of certainty what havoc it will wreak). The over-all methodology is illustrated in Figure 18.2.5 and is briefly described below:

(i) The base cost and schedule estimation effort was reviewed to determine important underlying assumptions, areas of uncertainty, proposed construction methods and sequence.

(ii) A risk list was developed, providing an initial statement of major areas of uncertainty to be considered in the analysis. It was important at this stage to begin to make initial gross assessments of how each risk might affect the project at various stages of completion, as well as to estimate the extent to which dependency existed between one risk and another. (In this regard, for example, the risk of a major flood is independent of the risk that geologic conditions will differ from those expected. On the other hand, it can be reasonably asserted that the risk that any given contractor will experience a construction accident is at least partially dependent on the risk that the same contractor will have poor construction quality control.)

(iii) Upon completion of the estimate review and concurrent with development of an initial risk list, a review was made of proprietary risk analysis software as the basis for specifying particular modifications which would permit proper treatment of all data elements.

(iv) A data collection effort was accomplished for each identified risk and a determination was made of the probability that each of a selected range of risk magnitudes would be realized in any given year. Where data gaps existed, a decision analysis process was used to produce required information.

(v) Transformation criteria were developed so that individual risk analysts could more easily view the consequences of realizing any single risk in terms of "natural" criteria. For example, it is easier to think in terms of the volume of earth involved in a slope failure than to think directly of its cost impact. Transformation criteria can then be used to convert to cost and schedule implications.

(vi) Software revisions were made in accordance with specifications noted at sub-paragraph (iii) above concurrent with the analysis of risks.

(vii) For each major construction activity at each dam site, the consequences of realizing each possible risk magnitude were assessed and estimated. Responses (actions which will be taken if a particular consequence is realized) were developed.

(viii) As the work proceeded, reviews and revisions were made to introduce collective judgments from diverse disciplines into the process.

(ix) The initial data set was run and interpreted. Anomalies were identified and risks emerging as most significant were further reviewed to ensure that their consequences had been adequately accounted for.

(x) Whereas the primary risk analysis effort focused upon the construction phase, a separate analysis of the transmission system was also made to assess the likelihood and the consequences of a major transmission outage. A similar methodology was followed in this sub-analysis.

(xi) All input data was updated based on the results of step (ix) above.

(xii) A final run was made to compute expected values of costs and completion schedules as well as to create probability distributions for these items. This final output provided the basis for interpretation.

(g) Elements of the Analysis

Figure 18.2.6 graphically depicts important questions which were addressed at the start and relates them to elements of the analysis. Each element is further subdivided as follows:

(i) Configurations

Three primary configurations were considered:

- the Watana hydroelectric project (with transmission)
- the Devil Canyon hydroelectric project (with transmission)
- the Susitna transmission system alone.

Separate risk studies of these configurations permitted the production of data which can be aggregated in various ways to accommodate alternative "power-on-line" dates which differ according to the various demand forecasts.

(ii) Configuration States

Two configuration states were considered:

- Construction Period - applicable to Watana and Devil Canyon;
- Operation Period - applied only to the transmission system configuration.

(iii) Risks

Twenty-one risks were identified for consideration in the analysis and were grouped as follows:

- Natural Risks

  - flood
  - ice
  - wind
  - seismic
  - permafrost deterioration
  - geologic conditions
  - low streamflow.

- Design Controlled Risks

  - seepage/piping erosion
  - groundwater.

- Construction Risks

  - equipment availability
  - labor strikes/disputes
  - material availability
  - equipment breakdown
  - material deliveries
  - weather.

- Human Risks

  - contractor capability
  - construction quality control
  - accidents
  - sabotage/vandalism.

- Special Risks

  - regulatory delay
  - estimating variance.

(iv) Activities

For each configuration state involving construction, up to 22 activities were considered. For Watana, for example, these included:

- main access
- site facilities
- diversion tunnels

- cofferdams
- main dam excavation
- main dam fill initial portion
- main dam fill final portion
- relict channel protection
- chute spillway
- emergency spillway
- service spillway tunnels
- intake
- penstock
- powerhouse
- transformer gallery
- tailrace and surge chambers
- turbine-generators
- mechanical/electrical equipment
- switchyard
- transmission
- impoundment
- test and commission.

(v) Damage Scenarios

Up to ten different damage scenarios were associated with each logical risk-activity combination. While these varied significantly from one risk-activity combination to another, they generally described a range of possibilities which accounted for discrete increments extending from "no damage" to "catastrophic loss".

(vi) Criteria

The consequences of realizing particular risk magnitudes for each activity were measured in terms of the following criteria:

- cost implications
- schedule implications
- manpower requirements.

(vii) Boundary Conditions

The following assumptions and limitations were established to permit a reasonable and consistent analysis of the problem:

- All cost estimates were made in terms of January 1982 dollars. Thus, results are presented in this report in terms only of real potential cost variations, exclusive of inflation.

- The analysis was limited only to the construction periods for Watana and Devil Canyon since the greatest potential cost and schedule variance would be possible during these periods. The risk analysis for the operating period was associated solely with the transmission system since that configuration represents the most likely source of a major system outage during project operation.

- The risk analysis was accomplished concurrently with finalization of the total project cost estimate and was necessarily associated with the feasibility level design. There is clearly some potential for design change as the project proceeds and a future risk analysis should be undertaken coincident with completion of final detailed design and prior to commitment to major construction activities. Even so, the "estimating variance" risk takes into account the fact that some design changes are likely to appear as detailed design effort proceeds.

- A great deal of subjective judgment was necessarily involved in assessing certain probabilities and in predicting possible damage scenarios. This effort was accomplished initially by individual qualified professionals in the various disciplines and was subjected to iterative group review and feedback efforts. To the extent that individual biases entered the analysis, their effects were probably mutually offsetting. Even so, sensitivity tests were made for risks which were important contributors to the final results.

- The risk list does not include the important possibility of funding delays or of financing problems. These issues were dealt with in a separate financial risk analysis as discussed in paragraph 18.5 below.

(h) Risk Assessments

For each of the risks identified in paragraph 18.2 (g) (iii) above, the assessment commenced with detailed definition of credible events. Whereas flood was identified as a risk, for example, a definition was sought of the magnitudes of floods which could occur and, with each magnitude, the probability that it would occur. Depending upon the particular risk under consideration, data sources included reasonably accurate scientific data (particularly applicable to the natural risk category), historical experience on water resources projects, and, where data gaps existed, subjective group judgments.

In each case, the effort was to identify some maximum credible event (what is the most extreme event, albeit highly unlikely, that could occur?). This choice set an upper limit on a scale of possible events which always began with a minimum magnitude corresponding to a "no damage" situation. Continuing with flood as an example, the maximum credible event was considered to be the probable maximum flood which had been computed in the hydrologic studies (corresponding to a return period of more than 10,000 years and an annual probability of occurrence of less than .0001). The minimum magnitude "no damage" event at the lower end of the scale varied from activity to activity. (In this regard for example, a cofferdam built early in the construction period and designed to withstand a 50-year flood event can be expected to suffer damage if a 100-year event actually occurs. Late in the project a 100-year event would not only cause no damage to structures in place, but also it might be regarded as fortuitous because it could improve the reservoir impoundment schedule.)

Once risks were defined and logical risk-activity combinations were reviewed, a concept of the consequences of realizing each selected risk magnitude was postulated (e.g., if this risk magnitude is realized, will a partially completed structure be damaged? Will it fail? If it fails, is some other work in progress disrupted?). Clearly, it cannot be determined with certainty what precise damage scenario should be associated with a given risk magnitude for a particular activity. Thus, a range of damage scenarios was defined and associated with each of them a probability of occurring if a particular risk magnitude is realized.

Even if a particular risk level is realized <u>and</u> a particular damage scenario is suffered, there is no certainty as to the cost of restoring the activity, nor can we be sure how long it will take to do so. Things do go exceedingly well every once in a while. Occasionally they go very badly, indeed. Each of the risk analysts was asked to provide three values for each criterion:

- A minimum corresponding, for instance, to the one time in twenty that the weather is particularly good, materials are readily available, no accidents occur, and the like.

- A modal value associated with the most likely expectation of the analyst.

- A maximum value corresponding to the one time in twenty that everything is more difficult than expected.

In the computerized calculation process, the three criterion values supplied by the risk analysts were fitted to a triangular distribution, which approximated the Beta distribution illustrated at the bottom of Figure 18.2.7. In effect, then, designation of the three conceptual criterion values led to generation of a histogram with relatively narrow intervals and a nearly-continuous range of possible values over a relatively-wide spectrum.

Figure 18.2.7 illustrates the structural relationship for handling risk-activity combinations, damage scenarios, and criterion values.

While the procedure described above is generally applicable, some commentary on particular aspects of its application and on certain unique risks is appropriate:

(i) The terminology "damage scenario" has been used for convenience since most identified risks will normally be thought of as reasons that the cost will be higher than had been estimated or that the schedule will be exceeded. In fact, however, the process does permit consideration of what might be regarded as a "negative" damage scenario. The geologic conditions risk is an excellent example. The cost estimate was produced on the basis of estimates of requirements for some concrete lining in the penstocks, extensive grouting, a certain level of rock bolting, and the like. If geologic conditions are found to be better than currently assumed, the costs could be less and the schedule might be accelerated.

(ii) The estimating variance risk was treated in a special way because it cannot easily be conceptualized in physical terms. It accounts for inevitable differences which do occur between estimates and actual bids, and between bids and actual activity costs - even in the absence of any other identified risks. Its probability of occurrence and associated range (fractions or multiples of the basic estimate) were determined from historical data on water resources projects. It includes, but is not necessarily limited to, such considerations as:

- the influence of competition and market pressures;
- estimating discrepancies or errors in unit quantities on the parts of both owner's estimator and bidder;
- particular contract forms and the owner's acceptance/non-acceptance of certain risks;
- labor market conditions and the nature of project labor agreements;
- productivity and efficiency changes over time;
- the cost implications of variances between activity schedules and actual activity durations;
- the potential for scope changes over time;
- extraordinary escalation of construction costs above the underlying inflation rate.

(iii) In addition to estimating variance, a second special risk is associated with regulatory matters. Various legislated controls will most certainly be applied to the Susitna project and it is a relatively simple matter to compute the minimum time in which regulatory requirements could be satisfied. It is a far more difficult task indeed to estimate the precise nature and duration of possible future regulatory delays. It would also clearly be inappropriate to attempt to apply regulatory risks at the activity level.

This risk was handled by developing a separate distribution for a range of periods necessary for satisfaction of important licensing and permitting requirements.

Data used in arriving at a distribution was based on recent experiences on other water resources projects, as well as on discussions with staff members of the Federal Energy Regulatory Commission. The effect of applying the regulatory risk is primarily one of shifting the starting time for commencement of construction activities, leading to corresponding change in the projected completion time. A lesser effect of the regulatory risk was to introduce delays during construction.

Regulatory requirements have been an important influence during the past decade on major construction costs and schedules, though it is difficult to isolate their effects. In order to separately consider estimating variance risks and regulatory risks, "estimating variance" probability determination relied heavily upon water resources construction data developed for projects essentially completed prior to the passage of the National Environmental Policy Act (NEPA). As noted above, regulatory risk probability distributions were derived from more recent projects.

(iv) Each of the various risk magnitude probabilities was originally calculated as an annual value. On a risk-activity by risk-activity basis, these annual values were then converted by standard computational procedures to provide a probability of occurrence during the duration of the activity.

(v) The concept of "response" is particularly important in the formal risk analysis process. As the terminology suggests, a "response" represents the action to be taken if a particular event occurs.

There are two kinds of "response". The first - and most often used - is an expected reaction to the occurrence of a particular damage level (i.e., if this damage level is incurred, then what actions must be taken to restore the activity to its pre-damage status? And what costs, schedule, and manpower implications (consequences) will result?). A second kind of response can also be considered and it provides an important link between the design team and the risk analysis team. This latter is the "preventive response" (i.e., what changes might reasonably be made in the design and/or construction procedures which would permit us to avoid or reduce a particular damage level? Is the cost and schedule change which might ensue worthwhile when compared to the probability and magnitude of the consequences which would otherwise be incurred?). A number of preventive responses were identified by risk analysts during the risk study and several of these were incorporated into the project design and design criteria. There may be further opportunities for preventive response. Since none would be chosen unless it offered a net benefit to cost and/or schedule, it may reasonably be concluded that as detailed design proceeds and as subsequent risk analysis updates are accomplished, a gradual reduction in the spread of possible values can be expected.

(i) Interpretation of Results

(i) Presentation of Data

A variety of formats is available for presentation of risk analysis results. Figure 18.2.8 illustrates three common methods. The choice of a particular graphic display and of "expected value" calculations is explained as follows:

- The density form ((2) on Figure 18.2.8) plots the probability that a particular value will occur against its value. This kind of distribution was used in the preparation of histograms for risks and damage levels, as may be seen on Figure 18.2.7. Insofar as presentation and interpretation of final outputs are concerned, however, the density form is not as meaningful. The decision makers tend to be more concerned about the confidence they can have that a particular value will not be exceeded than that the same value will actually be achieved. (In other words, it is more meaningful to know that there is a 90 percent chance that a certain cost will be $100 million or less than it is to know that there is a 5 percent chance that the cost will be between $95 million and $100 million.)

- The reverse cumulative form ((3) on Figure 18.2.8) provides a measure of the probability that a particular criterion value will be exceeded (e.g., such a distribution might indicate that there is a 10 percent chance that a particular activity will cost <u>more</u> than $100 million).

- The cumulative form ((1) on Figure 18.2.8) provides a measure of the probability that a particular value will not be exceeded. This latter form was selected for presentation of results since it relates directly to the decision maker's need to know how confident he can be that total costs will be within certain limits and it also allows him to understand that further exposure may exist.

- The "expected value" is the value which would appear on the average if a large number of projects of this type were constructed independently under the same conditions.

Minor variations in activity costs were generated by the estimating team concurrent with development of the risk analysis. In addition, account was taken of the expectation that construction costs will escalate at a faster rate than normal inflation - both in the economic analyses and the risk analyses. To avoid confusion regarding absolute cost values, the results of the risk analysis are presented in this section as percentages of the estimated project cost or as ratios between actual costs and estimated costs.

(ii) Watana Cost-Probability Distribution

Figure 18.2.9 provides the cumulative distribution of total direct costs and their related non-exceedance probabilities as determined in the risk analysis. Certain important points noted on the figure are interpreted as follows:

- The project cost estimate was presented in Chapter 16 of the Feasibility Report. Point "A" on Figure 18.2.9 corresponds to this project estimate. As may be read directly from the display, the analysis suggests that the probability of completing Watana for less than the project estimate is about 73 percent. Said another way, the chance of underrun (in January 1982 dollars) is 73 percent.

- When the low cost estimate (as tested in the sensitivity analysis) is considered, Point "B" results. The probability that Watana will be completed for less than the low cost estimate is about 46 percent.

  The fact that this probability is lower than that cited above is, of course, to be expected. It will be noted that the percentage value on the horizontal scale at Point "B" is 83 percent, arrived at from the ratio between low cost estimate and project estimate.

- In spite of the relatively comfortable chance of underrun (or said another way, the degree of confidence we may have in the project cost estimate), it is nonetheless true that the project remains exposed to some potential for costs well above the total estimated costs. Point "C" on Figure 18.2.9 corresponds to the high cost estimate. It will be recalled that a sensitivity analysis was undertaken to determine the effect of such a cost on total project economics. The risk analysis suggests that there is a 90 percent probability that the high cost estimate will not be exceeded.

- As will be noted from Figure 18.2.9, there remains a small but measurable possibility that the project costs will exceed even the high value at Point "C". It can be argued that the degree of conservatism which was used in the analysis has overstated the possibility of extreme upper limits on total cost. The paragraph on comparison with available data below addresses this conservatism issue, comparing our results with historical data.

- The expected value of the actual cost is 90.25 percent of the project estimate.

(iii) Devil Canyon - Probability Distributions

Figure 18.2.10 provides the cumulative probability distribution for Devil Canyon costs. Points "A", "B", and "C" on the curve correspond to those discussed above for Watana and are associated with probabilities of 74 percent, 47 percent, and 90 percent respectively, for actual percentages of the project estimate being less than indicated values. Once again, a not insignificant long "tail" in the extreme upper right-hand portion of the distribution provides a measure of the potential exposure to large overruns. The expected value of the actual cost is 91.5 percent of the project estimate.

(iv) Total Project Distribution

Figure 18.2.11 combines the separate Watana and Devil Canyon projects, providing a cumulative distribution for the Susitna hydroelectric project as a whole. Points "A", "B", and "C" now have associated probabilities of non-exceedance of 73 percent, 47 percent, and 90 percents, respectively. Taken as a whole, the figure suggests a very broad range of total project cost ratios is possible. Even between the 10 percent and 90 percent probability interval, the cost range spans nearly $3 billion. If the project follows historical patterns, it may be expected that this range will narrow over time as detailed design and construction proceeds. A word of caution is important enough to deserve repetition at this point: the cost distributions are in every case based upon January 1982 dollars and they do not account for the effects of inflation. Nor do they include interest during construction or finance charges. Only the potential for extraordinary construction cost escalation (over and above inflation) has been taken into account. It follows that if the project is completed in the next several decades, the final "actual" cost will have to be adjusted to equivalent 1982 dollars if it is to be compared with risk analysis results as presented herein.

(v) Comparison with Available Data

During the assessment of the important "estimating variance" risk (see paragraph 18.2 (h) (ii) above), historical data for 48 federal water resources projects completed prior to passage of NEPA were considered. While certain important limitations apply to the use of this data, it is nonetheless worthwhile to compare it with our Susitna Risk Analysis results. Recognizing that each of the historical projects differed from another in terms of cost, schedule, and complexity, we have once again chosen to normalize the data by displaying a cost ratio scale rather than an actual absolute cost value. Figure 18.2.12 offers a cumulative probability histogram for various cost ratios. In each case, the cost ratio reflects the actual project cost (after adjustment for inflation) divided by the "initial" estimated cost. As may be seen from the display, relatively large overruns have occurred in the past and they were almost inevitably the basis for widely publicized "finger pointing". Less well known, but particularly important, is the evidence that a substantial number of water resources projects have been accomplished for less than the originally estimated costs.

In order to compare this information with the Susitna Risk Analysis results, it is necessary to determine the meaning of "initial" estimate in terms of the historical data. In each case, the "initial" estimate is the estimate presented to the Congress at the time a request was made for project authorization. Thus, it would be inappropriate to regard the current Susitna estimate (as discussed in Chapter 16) as an "initial" estimate in the federal sense. Fortunately, however, the Susitna project does have a long history of federal involvement. Indeed, the Corps of Engineers provided a detailed "initial" estimate in 1975 as the basis for seeking authorization for important design activities. This "initial" estimate was further updated by a second "initial" estimate in 1979 after some additional exploratory work and further analysis were requested by the Office of Management and Budget. Inclusive of contingencies and excluding lands, the direct cost "initial" Corps of Engineers' estimate (from the 1979 report) in January 1982 dollars for the Watana/Devil Canyon (thin arch dam) project was used as the denominator for display of possible Susitna cost ratios.

Figure 18.2.13 overlays the results of the Susitna Risk Analysis on the historical data. Note that the cost ratios differ on this display from those on Figure 18.2.11 because of the necessity to use the "initial" estimate for comparison purposes.

As may be seen from Figure 18.2.13, the Susitna Risk Analysis results reflect a more pessimistic expectation at low cost levels than the historical data would appear to indicate is reasonable. The degree of pessimism appears appropriate, however, for the following reasons:

- The pre-NEPA data base largely excludes cost implications of regulatory requirements. Our own assessment indicates that regulatory matters do impose some additional important cost burdens on post-NEPA projects. These have largely been accounted for in the project estimate, but some uncertainty must remain.

- The data base includes a variety of time intervals between the "initial" estimate and the actual realized cost. By disaggregating the data to include only those water resources projects reflecting ten years or more between "initial" estimate and actual costs, a new histogram can be generated as shown on Figure 18.2.14. The Susitna results continue to appear pessimistic at the lower end in light of historical data, but the difference is seen to have diminished on this display. Some optimism is reflected for higher cost possibilities, but the Susitna estimate is well above the mean of the values in the data set. The distribution also reflects a longer tail at the extreme upper end than the data set displays.

- The data base included water resources projects which are not directly comparable to Susitna. Removing such projects as canals, harbors, and locks permits generation of a third histogram for dams and reservoirs as shown on Figure 18.2.15. As may be seen from this display, the Susitna Risk Analysis appears to offer an even more conservative expectation than the total data base had reflected.

In short, it appears reasonable to assert that the results of the risk analysis are consistent with historical data and, if any bias is evident, it is on the side of conservatism.

(vi) Schedule Risks

At the same time that minimum, modal, and maximum cost values were estimated for each damage scenario in each risk-activity set, estimates were also made of similar values for potential schedule changes. As a result, schedule probability distributions were generated for each major activity. These individual distributions could not be combined in the same way as was accomplished on the cost side, however. Delays in certain activities can be tolerated with no expectation of change in total project schedule. Delays in other areas may bear a one-to-one relationship with total project delay.

A critical path network was prepared for the entire set of activities for each configuration. Individual probability distributions for critical activities were then combined to yield a distribution for the total project schedule.

Several critical paths were identified in the process since a long delay on a non-critical activity can, of course, place that activity on a new critical path. The raw schedule delay distribution was then considered in the context of a one-year schedule contingency which had been built into the original estimate[3] and in light of regulatory delay risks. The resulting distributions are discussed and interpreted as follows:

- Figure 18.2.16 provides a cumulative probability distribution for months from the scheduled completion date for the Watana project. It reflects all risk contributions except those posed by regulatory requirements. It is based upon a critical path through the

[3] It is important to note that with the exception of the "regulatory" and "estimate variance" risks, all criterion values were estimated as increments or decrements to the direct cost or schedule estimate. The assertion by the estimating team that a one-year contingency was included in the schedule distribution was accounted for by shifting the raw probability distribution one year to a new centerpoint.

main dam and it takes into account the one-year schedule contingency. As may be read directly from the figure, the probability of completing the project ahead of schedule or on time is about 65 percent. There is only a 17 percent chance of completing the project a year early (i.e., in 1992).

- Figure 18.2.17 provides a similar distribution after regulatory risks are accounted for. Two components are included: (1) prior to the start of construction a license must be issued by the Federal Energy Regulatory Commission. There is a small chance (25 percent) that the license will be issued a year earlier than the current 30-month licensing schedule anticipates. The probability of meeting or bettering the 30-month estimate is about 72 percent and there is a 90 percent probability that not more than 39 months will be required; (2) during the construction period, regulatory delays may be imposed as a result of various permitting requirements, injunctions, and the like. These delays yield only increases in schedule and range from a 50 percent probability of delays of a month or less to a 95 percent probability that regulatory delays during construction will not exceed 12 months. As may be seen from Figure 18.2.17, the net effect of the regulatory risks is to broaden the range of possible values. At the lower end of the distribution, it will be noted that the chances of completing at least a year early have increased to nearly 40 percent -- primarily because of the chance of getting a license early and therefore starting early. No significant change appears for the probability of meeting or bettering the schedule. A substantial effect is evident in the upper portion of the curve where the chances of long regulatory delays have pushed out the 95 percent confidence level to an expectation of no more than three years' delay -- a significant change from the 12 to 13 months attributable to risks other than regulatory, as may be seen on Figure 18.2.16.

While similar distributions can be plotted for Devil Canyon, they are less meaningful since there is flexibility associated with its starting date.

(vii) Transmission Line Risks

The separate risk analysis of the Susitna transmission system was conducted to determine the probability of significant power supply interruptions at the two major load centers in Anchorage and Fairbanks. The methodology was generally similar to that described in preceding paragraphs. Recognizing that the system is assumed to be in an operating mode, those risks which had applied only for construction in the preceding analysis (e.g., contractor capability) were eliminated from the risk list. Additions to the list were made to account for the potential effects of lightning, aircraft collisions, and anchor-dragging in Knik Arm (applicable to the submarine cable segment). Account was taken of redundancies designed into the system (e.g., a loss of one line in the three-line system extending south toward Anchorage can be tolerated with no loss of energy delivery capability).

In addition, special attention was given to dependencies (e.g., an earthquake which causes the loss of two lines will very likely knock out the third. On the other hand, vandalism which causes an outage on one line is only infrequently expected to extend to all lines). Important assumptions included the availability of well-trained repair crews and equipment, and a reasonable supply of spare components.

The results of the analysis provide the cumulative probability of not exceeding a given number of days of reduced energy delivery capability. Figures 18.2.18 and 18.2.19 display this information for Anchorage and Fairbanks, respectively. Interpretations are as follows:

- In the particular case of Anchorage (Figure 18.2.18), it will first be noted that the probability scale includes only the extreme upper range of non-exceedance probabilities. The intersection of the distribution curves on the probability axis indicates that the probability of no lost energy delivery capability in a given year is .958 and of not having 50 percent reduction is .955. Beyond these points the curves rise sharply, indicating that outages beyond 5 days are extremely unlikely. The "expected" annual value of .0696 days for a total delivery loss may be compared with the "loss of load probability" of .1 (one day in 10 years) which had been used in the generation planning efforts in the economic studies. In short, the risk analysis confirms that the reliability of the transmission system for energy delivery to Anchorage is consistent with the requirements of the overall Railbelt generation system. The "expected" annual value of .09171 days for a 50 percnet reduction in energy delivery appears to be similarly acceptable when compared to assumed loss of load probability.

- The cumulative probability distribution for Fairbanks (Figure 18.2.19) has a slightly different intercept on the probability axis and its shape is also slightly different from those for Anchorage. These differences stem from the fact that delivery to Fairbanks requires no submerged crossing and certain other risks (e.g., flood, temperature extremes) would be expected to have different probabilities for northern and southern segments of the system. In spite of the absolute differences, it may be seen from the display that the "expected" annual value of .08116 does not exceed the loss of load probability criterion of .1 day per year. No 50 percent loss for Fairbanks is shown since the loss of one of two lines causes no reduction in delivery capability. Two lines lost is, of course, a 100 percent loss.

(viii) Emergency Response

In spite of the apparent reliability of the transmission system, it is nonetheless true that a small but finite chance of relatively long-term outages does exist. It is also unfortunately true that certain extreme risk magnitudes (e.g., combination of extreme low temperature, wind, and ice) which could lead to an outage also tend to coincide with high demands by users on the generating system. The "response" in this case is extremely important. The final report for Subtask 11.03, Risk Analysis, provides such a response in the form of a preliminary emergency plan which includes such measures as shedding non-essential loads, putting reserve capacity on line, and energy transfers from military generation systems. Prior to the time that the Susitna hydroelectric project begins operation, this plan should be updated and occasional tests should be made of its practicality.

(j) Conclusions

Based upon the risk analysis, it is concluded that:

- The probabilities that actual costs will not exceed values subjected to sensitivity tests in the economic analysis are as follows:

Value	Probability that value will not be exceeded
. Project estimate	73 percent
. Low capital cost tested in the economic analysis	47 percent
. High capital cost tested in the economic analysis	90 percent

- Exposure to potential costs above the project estimate does exist and there is about a 1 percent chance that an overrun of 40 percent or more (in 1982 dollars) will occur.

- The annual probability that no interruption in energy delivery to major load centers will occur as a result of transmission line failures is in excess of 95 percent.

  Expected values of energy delivery interruptions are less than one day in ten years and are consistent with loss of load probabilities assumed in the generation planning efforts.

- There is a 65 percent probability that the Watana project will be completed prior to the scheduled time in 1993. Exposure to schedule delays is heavily influenced by regulatory requirements and there is a 10 percent probability that the Watana project will not be completed until 1995 or later.

TABLE 18.2.1

PROBABILITY ASSESSMENT
LOAD FORECASTS[1]

Year	Low MW	Low GWh	Medium MW	Medium GWh	High MW	High GWh
1990	802	3999	892	4456	1098	5703
1995	849	4240	983	4922	1248	6464
2000	921	4641	1084	5469	1439	7457
2005	1066	5358	1270	6428	1769	9148
2010	1245	6303	1537	7791	2165	11435
Probability of Occurrence	0.20		0.60		0.20	

[1] Battelle Pacific Northwest Laboratories, December 1981.

TABLE 18.2.2

PROBABILITY ASSESSMENT
ALTERNATIVES-CAPITAL COST ANALYSIS[1]

Type/Size MW	Low $/kW[2]	Medium $/kW[2]	High $/kW[2]
Coal/200MW/ @ Beluga	2018	2242	2690
Coal/200 MW @ Nenana	2073	2303	2764
Gas Turbine/ 70 MW	572	636	763
Combined Cycle/ 200 MW	996	1107	1328
Probability of Occurrence	0.20	0.60	0.20

1 Developed by Ebasco for the Railbelt Alternatives Study by Battelle

2 Includes AFDC

TABLE 18.2.3

PROBABILITY ASSESSMENT
FUEL COST AND ESCALATION[1]

Probability of Occurrence	0.25	0.50	0.25
Healy Coal @ Healy (cents/MMBtu)			
Year	Low	Medium	High
1990	146	179	216
1995	146	204	275
2000	146	232	351
2005	146	246	391
2010	146	261	436
Healy Coal @ Nenana (cents/MMBtu)			
1990	175	210	249
1995	175	235	310
2000	175	264	387
2005	175	279	425
2010	175	295	467
Beluga Coal (cents/MMBtu)			
1990	143	176	211
1995	143	200	269
2000	143	227	343
2005	143	241	382
2010	143	256	426
Natural Gas (cents/MMBtu)			
1990	300	300	443
1995	300	327	565
2000	300	480	722
2005	300	530	797
2010	300	585	880
Oil (cents/MMBtu)			
1990	650	762	890
1995	650	841	1083
2000	650	928	1317
2005	650	1025	1954
2010	650	1132	1605

---

1 Base prices and escalation patterns derived from Battelle and Acres meetings and research

TABLE 18.2.4

PROBABILITY ASSESSMENT
SUSITNA CAPITAL COST ANALYSIS[1]

Dam/Size MW	Low $/kW[2]	Medium $/kW[2]	High $/kW[2]
	January 1982$		
Watana 680 MW	5018/kW	6021/kW	7025/kW
Devil Canyon 600 MW	2265	2718	3171
Probability of Occurrence	0.60	0.25	0.15

1 Based on the 1280 MW Susitna Project estimate of $5,117 million

2 Includes AFDC and transmission line costs.

Note: Low capital cost is computed as medium divided by 1.20 and is equal to a zero percent contingency. High capital cost is computed as the low times 1.4 and represents a double (40 percent) contingency.

TABLE 18.2.5

LONG-TERM COSTS AND PROBABILITY
NON-SUSITNA TREE

Rank (Low to High)	ID[1]	(1982 $) $ x 10^6 Long-Term Cost	Probability	Cumulative Probability	Expected LTC[2]
1	T27	4412	.01	.01	44.12
2	T24	4590	.03	.04	137.70
3	T21	4856	.01	.05	48.56
4	T18	5489	.03	.08	164.67
5	T15	5661	.09	.17	509.49
6	T12	5991	.03	.20	179.73
7	T26	6101	.02	.22	122.02
8	T23	6878	.06	.28	412.68
9	T09	7184	.01	.29	71.84
10	T06	7313	.03	.32	219.39
11	T20	7460	.02	.34	149.20
12	T03	7624	.01	.35	76.24
13	T17	7915	.06	.41	474.90
14	T14	8238	.18	.59	1482.84
15	T25	8492	.01	.60	84.92
16	T22	8746	.03	.63	262.38
17	T11	8858	.06	.69	531.48
18	T19	9253	.01	.70	92.53
19	T16	10321	.03	.73	309.63
20	T08	10503	.02	.75	210.06
21	T13	10637	.09	.84	957.33
22	T05	10859	.06	.90	651.54
23	T10	11272	.03	.93	338.16
24	T02	11569	.02	.95	231.38
25	T07	13742	.01	.96	137.42
26	T04	14194	.03	.99	425.82
27	T01	15058	.01	1.00	150.58
			1.00		

[1] Relates to Figure 18.2.1

[2] LTC - Long-term Costs.

TABLE 18.2.6

LONG-TERM COSTS AND PROBABILITY
SUSITNA TREE

Rank (Low to High)	ID[1]	(1982 \$) \$ x 10^6 Long-Term Cost	Probability	Cumulative Probability	Expected LTC[2]
1	S45	5543	.03	.0300	166.29
2	S42	5757	.06	.0900	345.42
3	S36	5827	.09	.1800	524.43
4	S39	6097	.03	.2100	182.91
5	S33	6151	.18	.3900	1107.18
6	S44	6437	.0125	.4025	80.46
7	S30	6477	.09	.4925	582.93
8	S41	6650	.025	.5175	166.25
9	S35	6738	.0375	.5555	252.67
10	S38	6991	.0125	.5675	87.38
11	S32	7062	.075	.6425	529.65
12	S27	7087	.006	.6485	42.52
13	S18	7108	.018	.6665	127.94
14	S09	7151	.006	.6725	42.91
15	S43	7331	.0075	.6800	54.98
16	S29	7388	.0375	.7175	277.05
17	S40	7543	.015	.7325	113.15
18	S34	7650	.0225	.7550	172.12
19	S37	7884	.0075	.7625	59.13
20	S31	7974	.045	.8075	358.83
21	S26	7986	.0025	.8100	19.96
22	S17	8008	.0075	.8175	60.06
23	S08	8050	.0025	.8200	20.12
24	S24	8326	.012	.8320	99.91
25	S15	8347	.036	.8680	300.49
26	S28	8371	.0225	.8905	188.35
27	S06	8390	.012	.9025	100.68
28	S25	8886	.0015	.9040	13.33
29	S16	8908	.0045	.9085	40.09
30	S07	8951	.0015	.9100	13.43
31	S23	9225	.005	.9150	46.12
32	S14	9247	.015	.9300	138.70
33	S05	9290	.005	.9350	46.45
34	S21	9614	.006	.9410	57.68
35	S12	9758	.018	.9590	175.64
36	S03	9784	.006	.9650	58.70
37	S22	10126	.003	.9680	30.38
38	S13	10147	.009	.9770	91.32
39	S04	10190	.003	.9800	30.57
40	S20	10514	.0025	.9825	26.29

TABLE 18.2.6 (Continued)

LONG-TERM COSTS AND PROBABILITY
SUSITNA TREE

Rank (Low to High)	ID[1]	(1982 \$) \$ x 10^6 Long-Term Cost	Probability	Cumulative Probability	Expected LTC[2]
41	S11	10658	.0075	.9900	79.94
42	S02	10683	.0025	.9925	26.70
43	S19	11414	.0015	.9940	17.12
44	S10	11558	.0045	.9985	52.01
45	S01	11584	.0015	1.0000	17.38
			1.000		

[1] Relates to Figure 18.2.2

[2] Long-term Costs

TABLE 18.2.7

NET BENEFIT - CALCULATED VALUES

Comparison	T-ID	S-ID	P	T-LTC	S-LTC	Net Benefit
1	T01	S01	.0015	15058	11584	3474
2	T01	S02	.0025	15058	10683	4375
3	T01	S03	.006	15058	9784	5274
4	T02	S04	.003	11569	10190	1379
5	T02	S05	.005	11569	9290	2279
6	T02	S06	.012	11569	8390	3179
7	T03	S07	.0015	7624	895?	(1327)
8	T03	S08	.0025	7624	8051	(427)
9	T03	S09	.006	7624	7151	473
10	T04	S10	.0045	14194	11558	2636
11	T04	S11	.0075	14194	10658	3536
12	T04	S12	.018	14194	9758	4436
13	T05	S13	.009	10859	10147	712
14	T05	S14	.015	10859	9247	1612
15	T05	S15	.036	10859	8347	2512
16	T06	S16	.0045	7313	8908	(1595)
17	T06	S17	.0075	7313	8008	(695)
18	T06	S18	.018	7313	7108	205
19	T07	S19	.0015	13742	11414	2328
20	T07	S20	.0025	13742	10514	3228
21	T07	S21	.006	13742	9614	4128
22	T08	S22	.003	10503	10126	377
23	T08	S23	.005	10503	9225	1278
24	T08	S24	.012	10503	8326	2177
25	T09	S25	.0015	7184	8886	(1702)
26	T09	S26	.0025	7184	7986	(802)
27	T09	S27	.006	7184	7087	97
28	T10	S28	.0045	11272	8371	2901
29	T13	S28	.0135	10637	8371	2266
30	T16	S28	.0045	10321	8371	1950
31	T10	S29	.0075	11272	7388	3884
32	T13	S29	.0225	10637	7388	3249
33	T16	S29	.0075	10321	7388	2933
34	T10	S30	.018	11272	6477	4795
35	T13	S30	.054	10637	6477	4160
36	T16	S30	.018	10321	6477	3844
37	T11	S31	.009	8858	7974	844
38	T14	S31	.017	8238	7974	264
39	T17	S31	.009	7915	7974	(59)
40	T11	S32	.015	8858	7062	1796
41	T14	S32	.045	8238	7062	1176
42	T17	S32	.015	7915	7062	853

TABLE 18.2.7 (Continued)

NET BENEFIT - CALCULATED VALUES

Comparison	T-ID	S-ID	P	T-LTC	S-LTC	Net Benefit
43	T11	S33	.036	8858	6151	2707
44	T14	S33	.108	8238	6151	2087
45	T17	S33	.036	7915	6151	1764
46	T12	S34	.0045	5991	7650	(1659)
47	T15	S34	.0135	5561	7650	(1989)
48	T18	S34	.0045	5489	7650	(2161)
49	T12	S35	.0075	5991	6738	(747)
50	T15	S35	.0225	5661	6738	(1077)
51	T18	S35	.0075	5489	6738	(1249)
52	T12	S36	.018	5991	5827	164
53	T15	S36	.054	5661	5827	(166)
54	T18	S36	.018	5489	5827	(338)
55	T19	S37	.0015	9253	7884	1369
56	T22	S37	.0045	8746	7884	862
57	T25	S37	.0015	8492	7884	608
58	T19	S38	.0025	9253	6991	2262
59	T22	S38	.0075	8746	6991	1755
60	T25	S38	.0025	8492	6991	1501
61	T19	S39	.006	9253	6097	3156
62	T22	S39	.018	8746	6097	2649
63	T25	S39	.006	8492	6097	2395
64	T20	S40	.003	7460	7543	(83)
65	T23	S40	.009	6878	7543	(655)
66	T26	S40	.003	6101	7543	(1442)
67	T20	S41	.005	7460	6650	810
68	T23	S41	.015	6878	6650	228
69	T26	S41	.005	6101	6650	(549)
70	T20	S42	.012	7460	5757	1703
71	T23	S42	.036	6878	5757	1121
72	T26	S42	.012	6101	5757	344
73	T21	S43	.0015	4856	7331	(2475)
74	T24	S43	.0045	4590	7331	(2741)
75	T27	S43	.0015	4412	7331	(2919)
76	T21	S44	.0025	4856	6437	(1581)
77	T24	S44	.0075	4590	6437	(1847)
78	T27	S44	.0025	4412	6437	(2025)
79	T21	S45	.006	4856	5543	(687)
80	T24	S45	.018	4590	5543	(953)
81	T27	S45	.006	4412	5543	(1131)

TABLE 18.2.8

CASE 1 - POSITIVE CORRELATION BETWEEN ENERGY DEMAND AND PRICES

	Conditional Probabilities of Energy Demand		
	High Load Forecast	Medium Load Forecast	Low Load Forecast
High Energy Prices	0.6	0.3	0.1
Medium Energy Prices	0.2	0.6	0.2
Low Energy Prices	0.1	0.3	0.6

TABLE 18.2.9

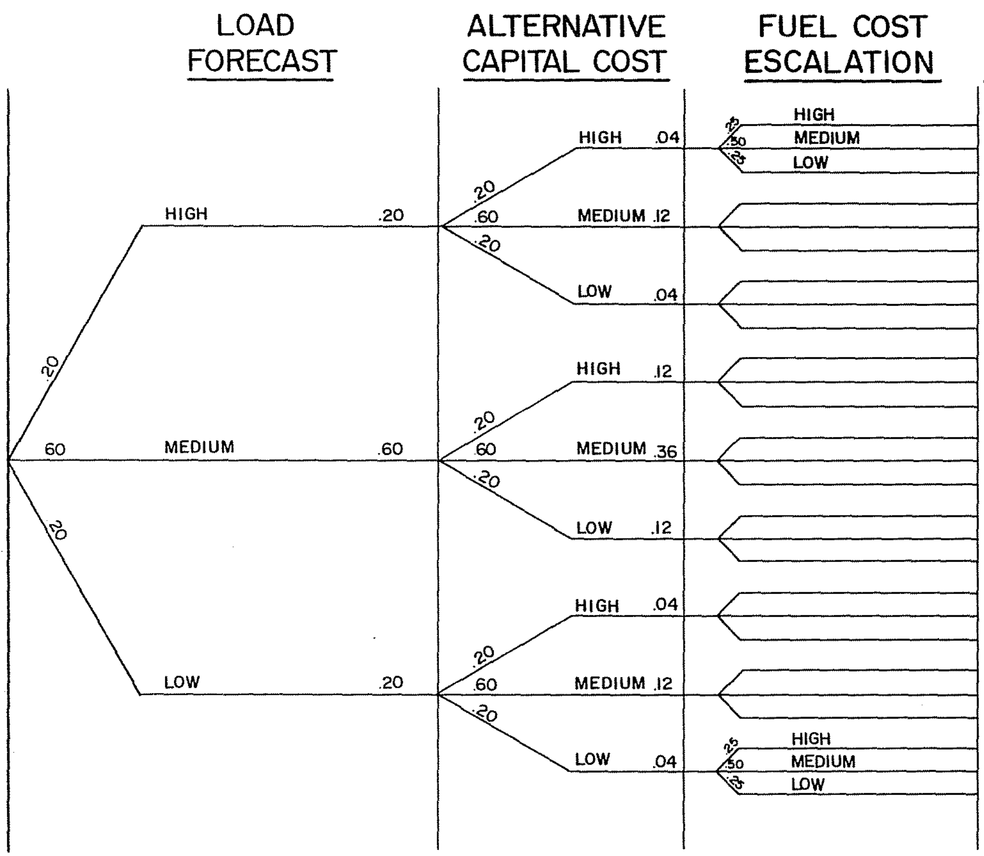
CASE 2 - NEGATIVE CORRELATION BETWEEN ENERGY DEMAND AND PRICES

	Conditional Probabilities of Energy Demand		
	High Load Forecast	Medium Load Forecast	Low Load Forecast
High Energy Prices	0.1	0.3	0.6
Medium Energy Prices	0.2	0.6	0.2
Low Energy Prices	0.6	0.3	0.1

TABLE 18.2.10

SUMMARY OF PROBABILITY ASSESSMENT

	Case 1 Positive Correlation Between Energy Prices and Demand	Case 2 Negative Correlation Between Energy Prices and Demand	Initial Case Zero Correlation Between Energy Prices and Demand
Probability that			
(a) Thermal plan is more costly than the Susitna plan	69 percent	91 percent	78 percent
(b) Thermal plan is less costly than the Susitna plan	25 percent	9 percent	16 percent
(c) Thermal and Susitna plans are equal cost	6 percent	0 percent	6 percent

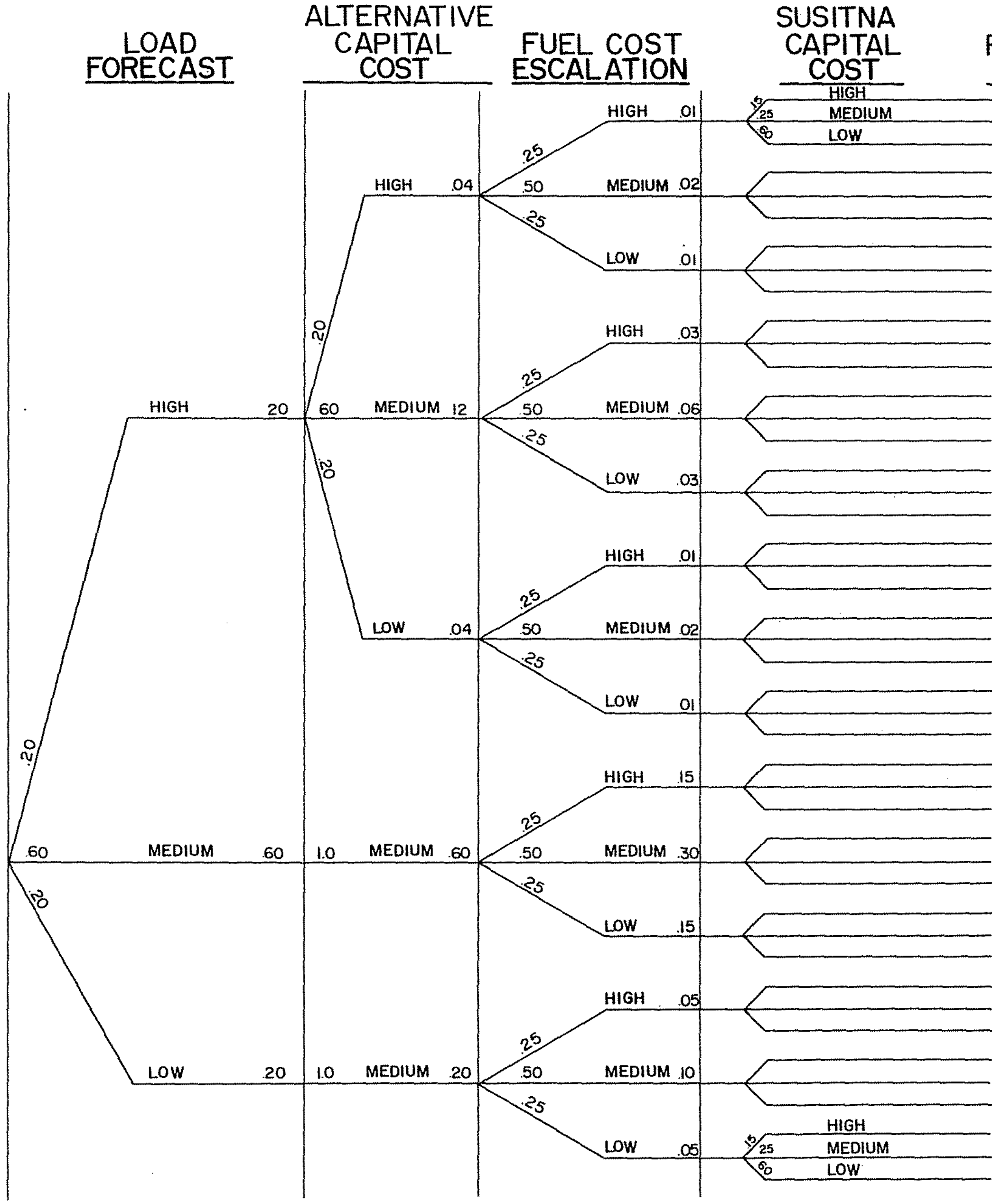


RESULT ID	PROBABILITY	LONG-TERM COST PRESENT WORTH
T01	.01	$15,058
T02	.02	11,569
T03	.01	7,624
T04	.03	14,194
T05	.06	10,859
T06	.03	7,313
T07	.01	13,742
T08	.02	10,503
T09	.01	7,184
T10	.03	11,272
T11	.06	8,858
T12	.03	5,991
T13	.09	10,637
T14	.18	8,238
T15	.09	5,661
T16	.03	10,321
T17	.06	7,915
T18	.03	5,489
T19	.01	9,253
T20	.02	7,460
T21	.01	4,856
T22	.03	8,746
T23	.06	6,878
T24	.03	4,590
T25	.01	8,492
T26	.02	6,101
T27	.01	4,412

$\Sigma = 1.00$

FIGURE 18.2.1 – PROBABILITY TREE – SYSTEM WITH ALTERNATIVES TO SUSITNA

ACRES



RESULT ID	PROBABILITY	LONG-TERM COST PRESENT WORTH
S01	.0015	$11,584
S02	.0025	10,683
S03	.0060	9,784
S04	.0030	10,190
S05	.0050	9,290
S06	.0120	8,390
S07	.0015	8,951
S08	.0025	8,050
S09	.0060	7,151
S10	.0045	11,558
S11	.0075	10,658
S12	.0180	9,758
S13	.0090	10,147
S14	.0150	9,247
S15	.0360	8,347
S16	.0045	8,908
S17	.0075	8,008
S18	.0180	7,108
S19	.0015	11,414
S20	.0025	10,514
S21	.0060	9,614
S22	.0030	10,126
S23	.0050	9,221
S24	.0120	8,326
S25	.0015	8,886
S26	.0025	7,986
S27	.0060	7,081
S28	.0225	8,371
S29	.0375	7,388
S30	.0900	6,477
S31	.0450	7,974
S32	.0750	7,062
S33	.1800	6,151
S34	.0225	7,650
S35	.0375	6,738
S36	.0900	5,827
S37	.0075	7,884
S38	.0125	6,991
S39	.0300	6,097
S40	.0150	7,543
S41	.0250	6,650
S42	.0600	5,757
S43	.0075	7,331
S44	.0125	6,437
S45	.0300	5,543

$\Sigma = 1.000$

FIGURE 18.2.2 – PROBABILITY TREE – SYSTEM WITH SUSITNA

ACRES

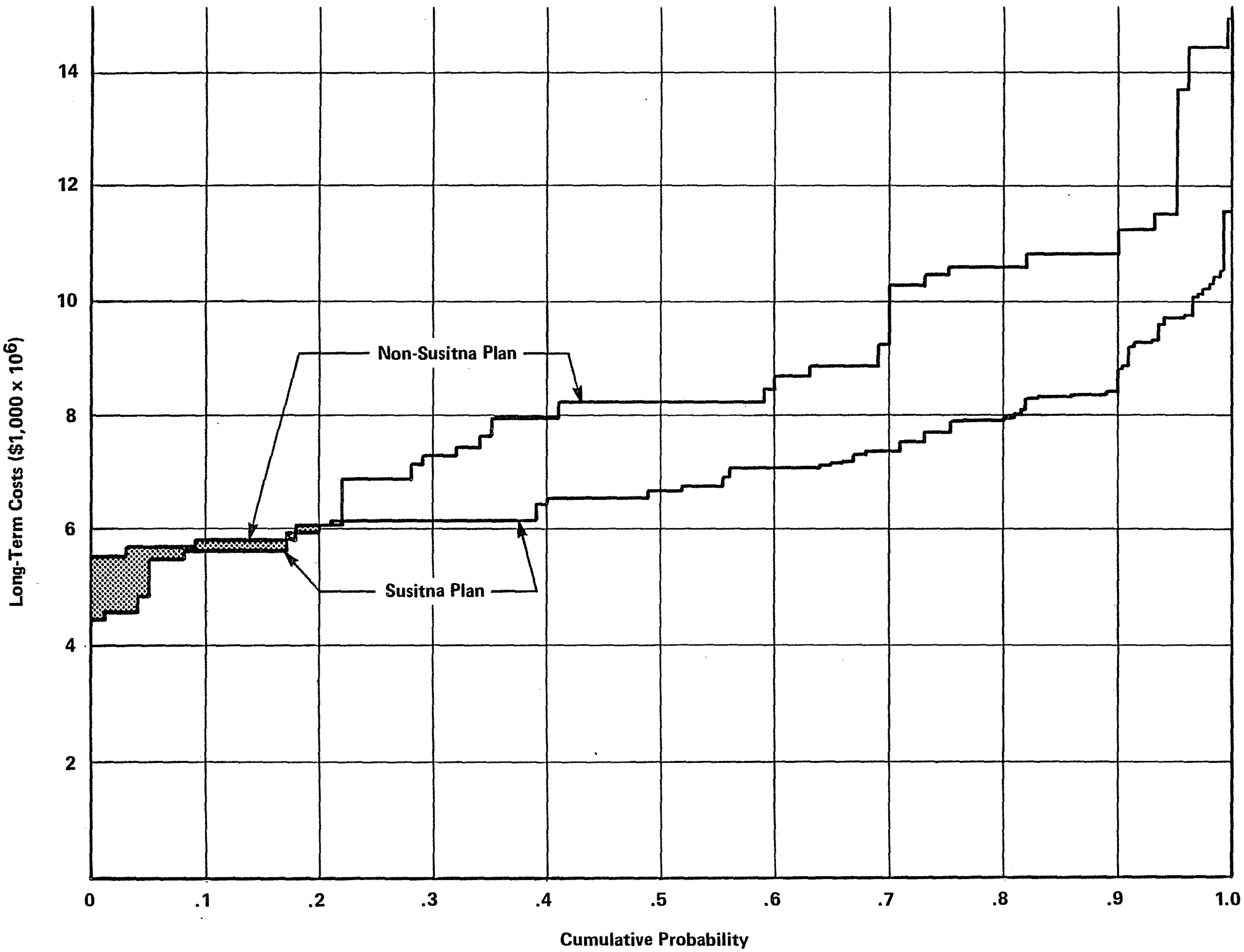


FIGURE 18.2.3 – SUSITNA MULTIVARIATE SENSITIVITY ANALYSIS – LONG-TERM COSTS VS CUMULATIVE PROBABILITY

ACRES

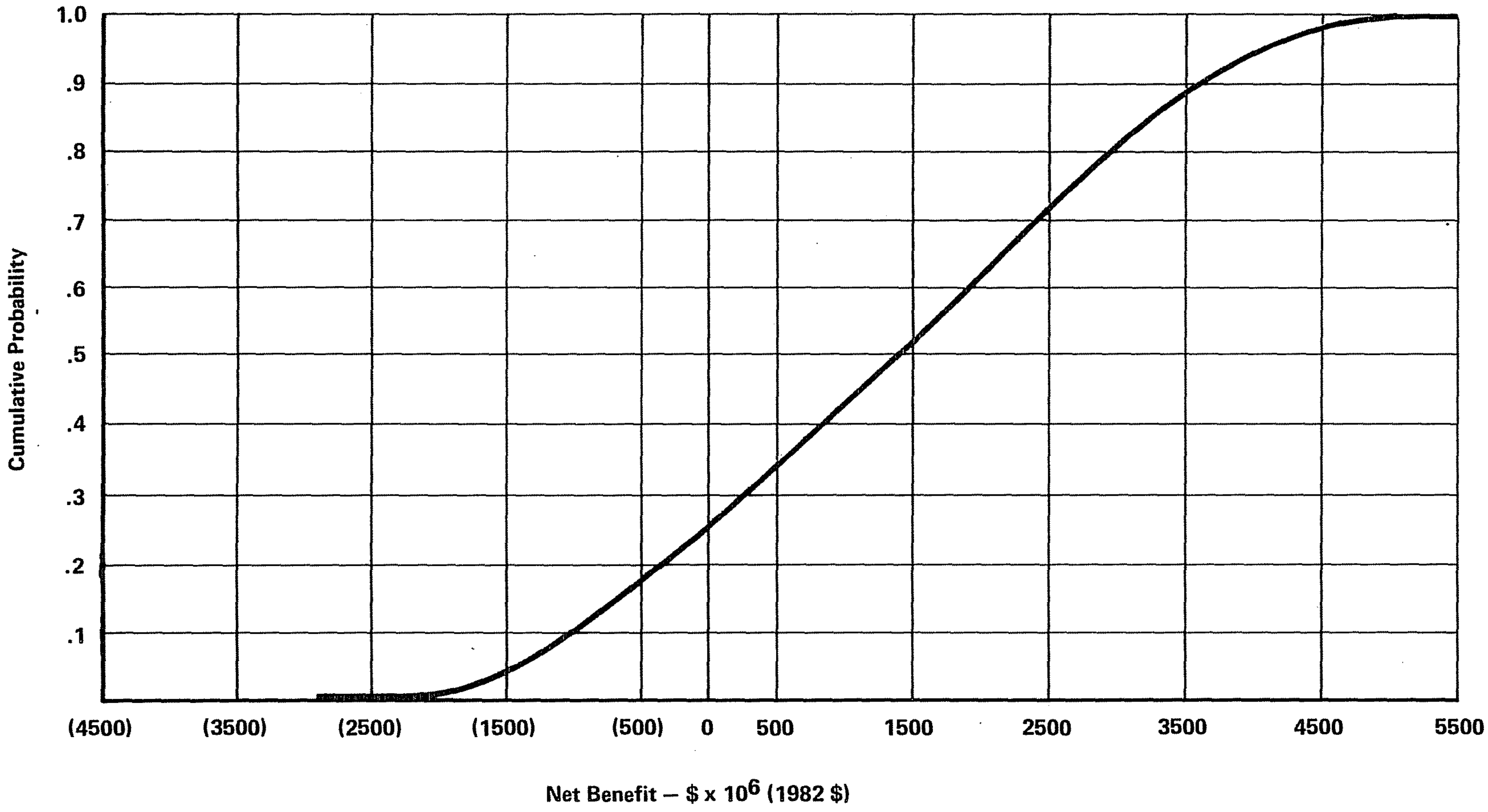
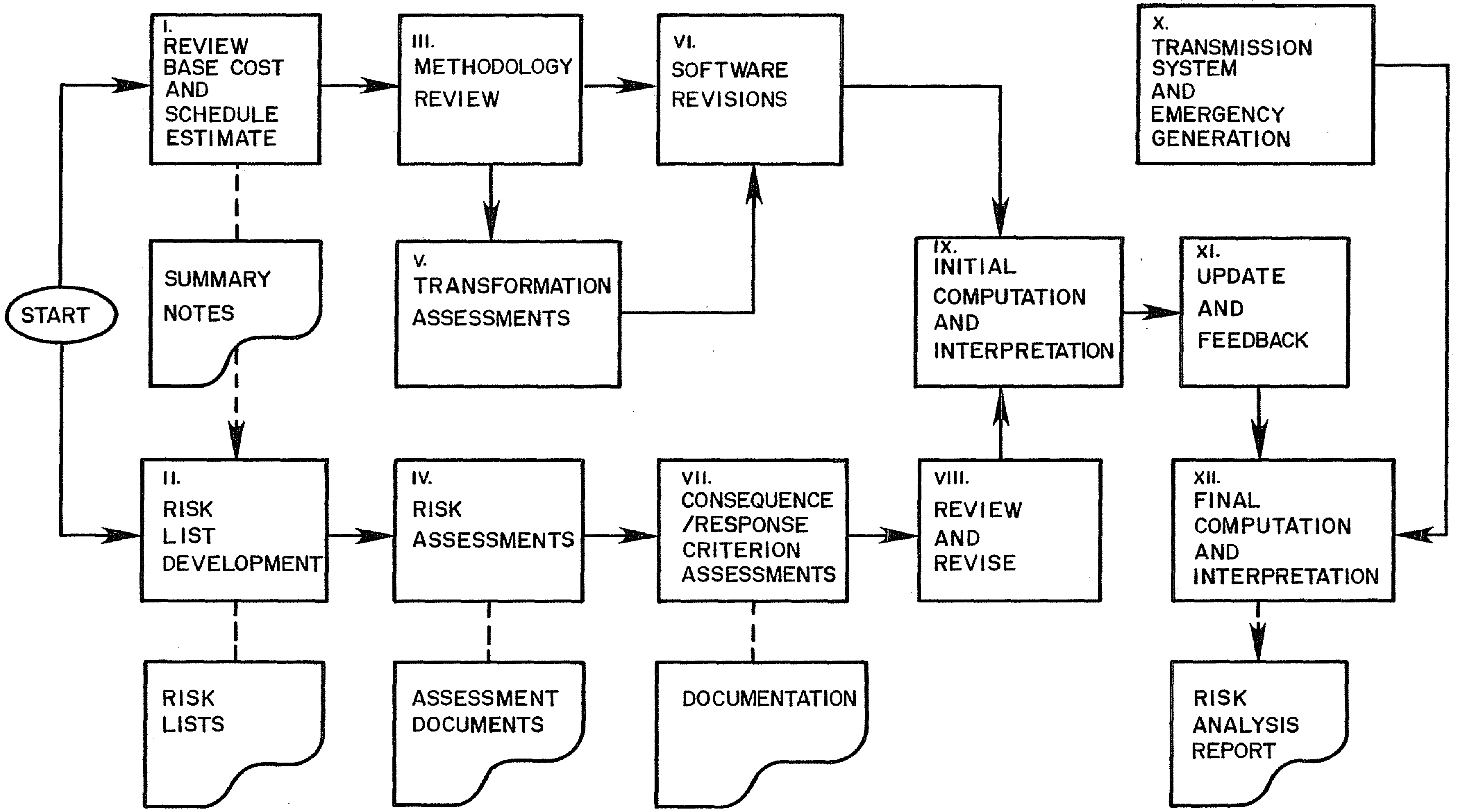


FIGURE 18.2.4 – SUSITNA MULTIVARIATE SENSITIVITY ANALYSIS – CUMULATIVE PROBABILITY VS NET BENEFITS

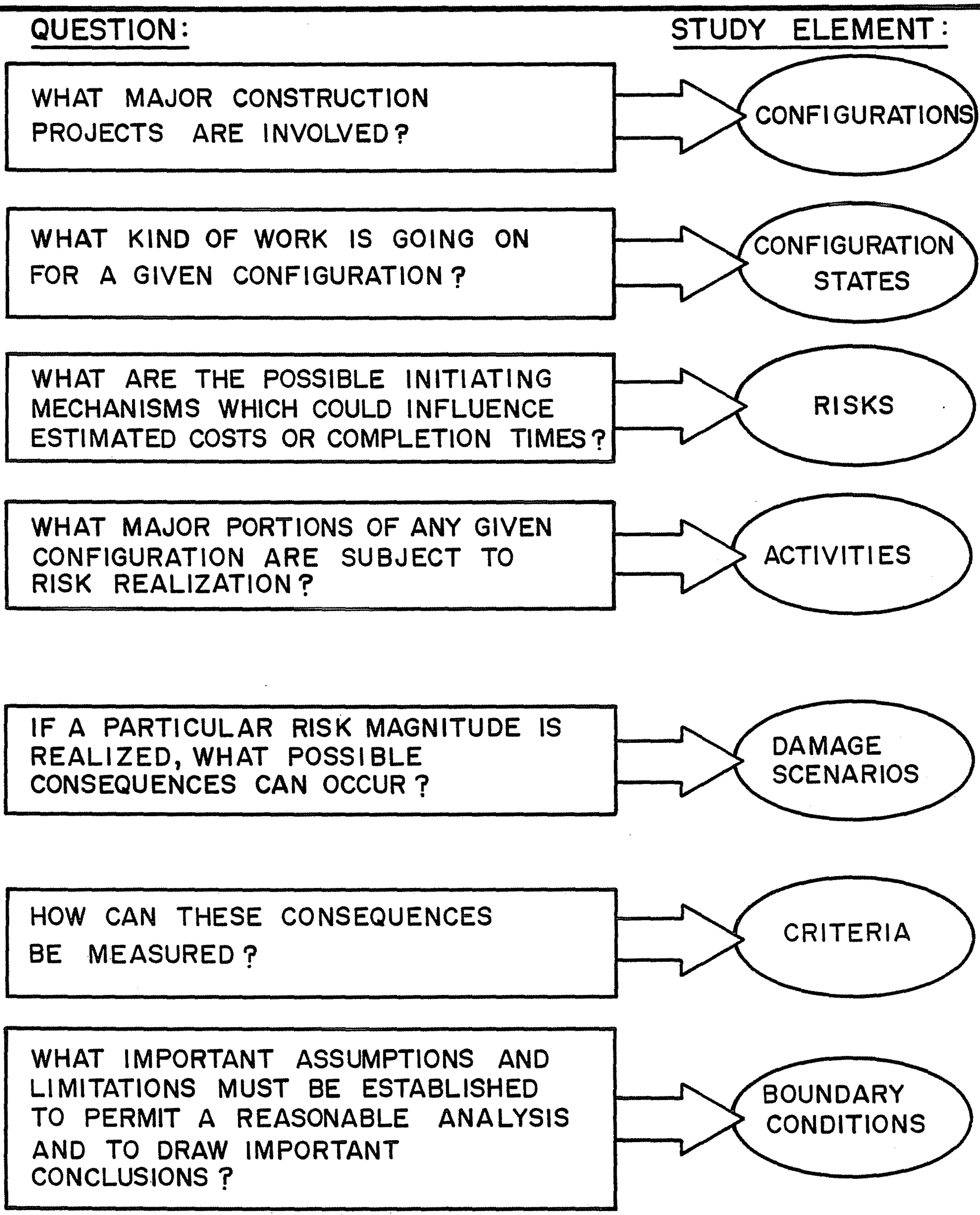
ACRES



RISK ANALYSIS STUDY METHODOLOGY

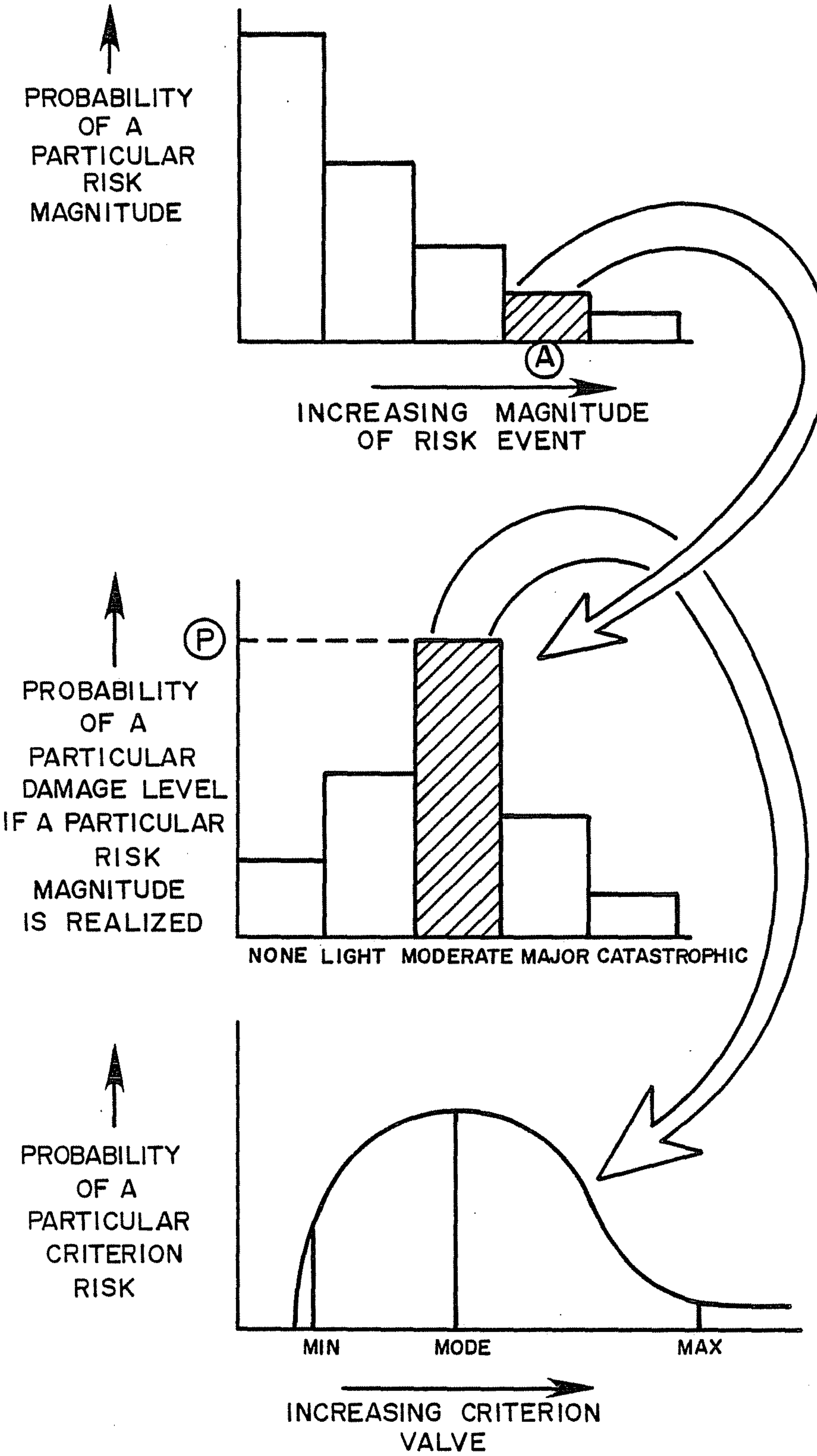
FIGURE 18.2.5

ACRES



ELEMENTS OF THE RISK ANALYSIS

FIGURE 18.2.6



(1) A SERIES OF DISCRETE RISK PROBABILITY LEVELS EXISTS FOR EACH RISK-ACTIVITY COMBINATION. THE ANNUAL PROBABILITY OF EACH IS DETERMINED.

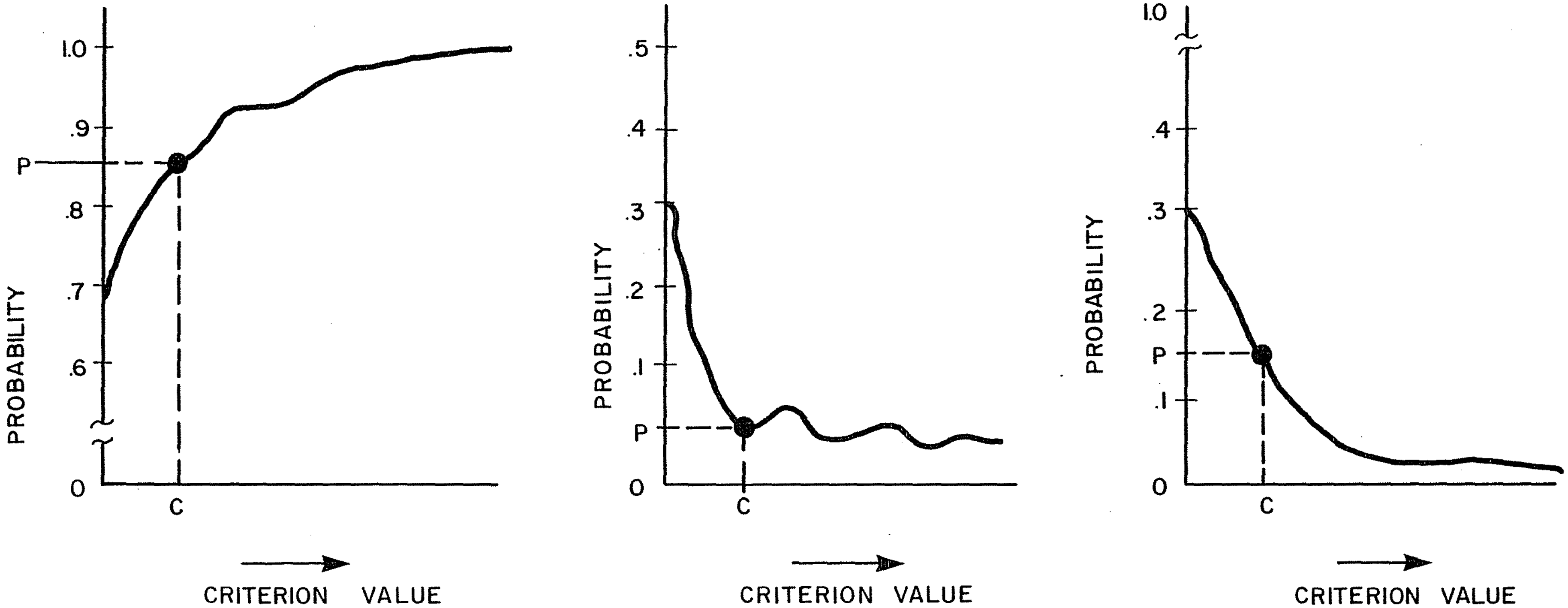
(2) IF A RISK EVENT OCCURS, IT CAN CAUSE A NUMBER OF POSSIBLE DAMAGE LEVELS, EACH WITH A PARTICULAR PROBABILITY OF OCCURENCE. IF RISK MAGNITUDE (A) OCCURS, THE PROBABILITY IT WILL CAUSE MODERATE DAMAGE IS THE VALUE OF (P) ON THE DIAGRAM.

(3) FOR ANY GIVEN DAMAGE LEVEL, THREE CRITERION VALVES ARE ESTIMATED AND FIT TO A MODIFIED BETA DISTRIBUTION.

STRUCTURAL RELATIONSHIP FOR HANDLING RISK ACTIVITY COMBINATIONS, DAMAGE SCENARIOS AND CRITERION VALUES

FIGURE 18.2.7

ACRES



(1.) CUMULATIVE DISTRIBUTION

ANY POINT ON THE CURVE INDICATES THE PROBABILITY (P) THAT THE CRITERION VALUE (C) WILL NOT BE EXCEEDED.

(2.) DENSITY FORM

ANY POINT ON THE CURVE INDICATES THE PROBABILITY (P) THAT A PARTICULAR CRITERION VALUE (C) WILL BE INCURRED.

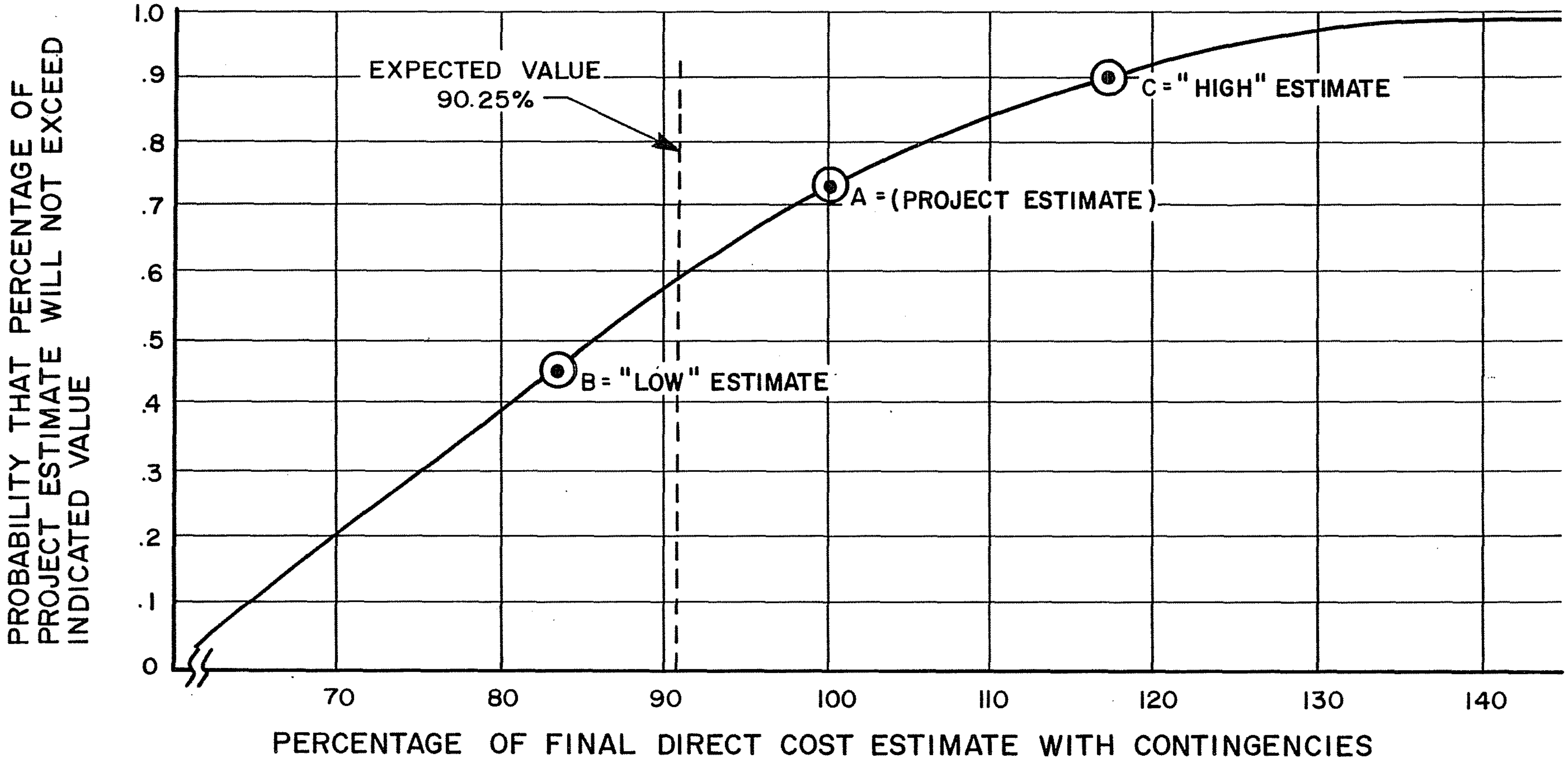
(3.) REVERSE CUMULATIVE

ANY POINT ON THE CURVE INDICATES THE PROBABILITY (P) THAT THE CRITERION VALUE (C) WILL BE EXCEEDED.

ALTERNATIVE FORMATS FOR
PRESENTING THE ANALYTICAL RESULTS

FIGURE 18.2.8

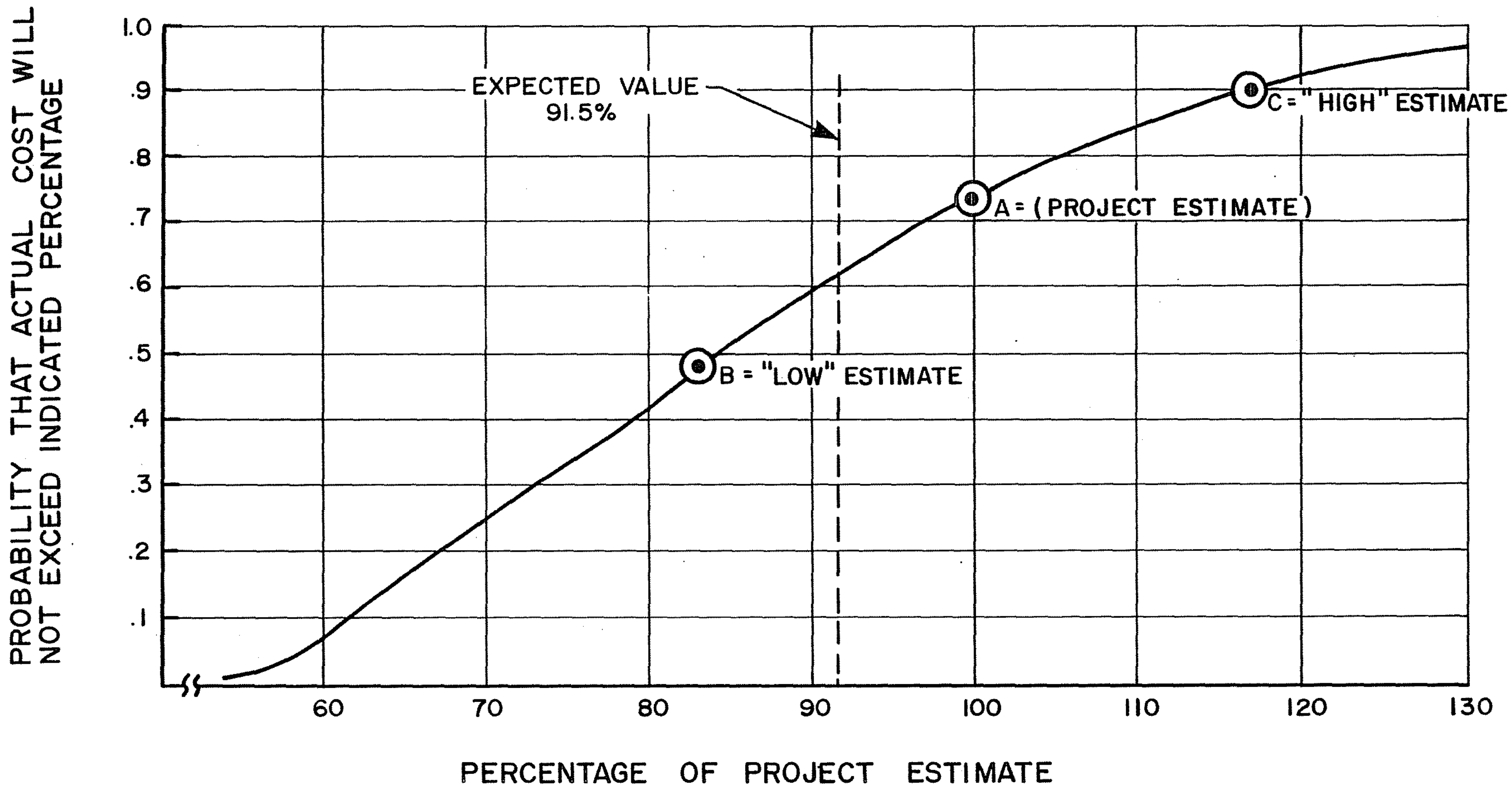
ACRES



CUMULATIVE PROBABILITY DISTRIBUTION
FOR WATANA PROJECT COST

FIGURE 18.2.9

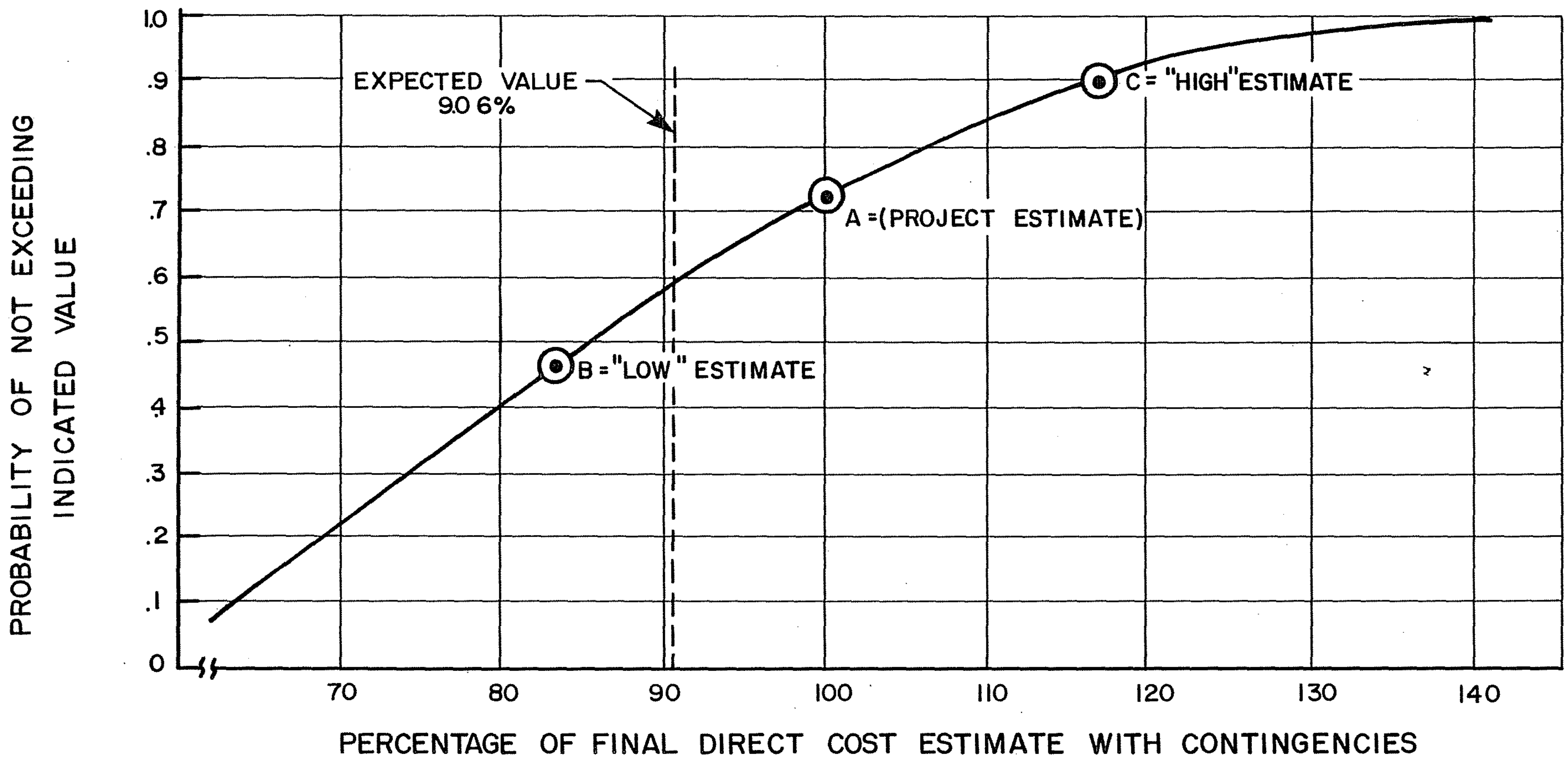
ACRES



CUMULATIVE DISTRIBUTION
OF DEVIL CANYON COSTS

ACRES

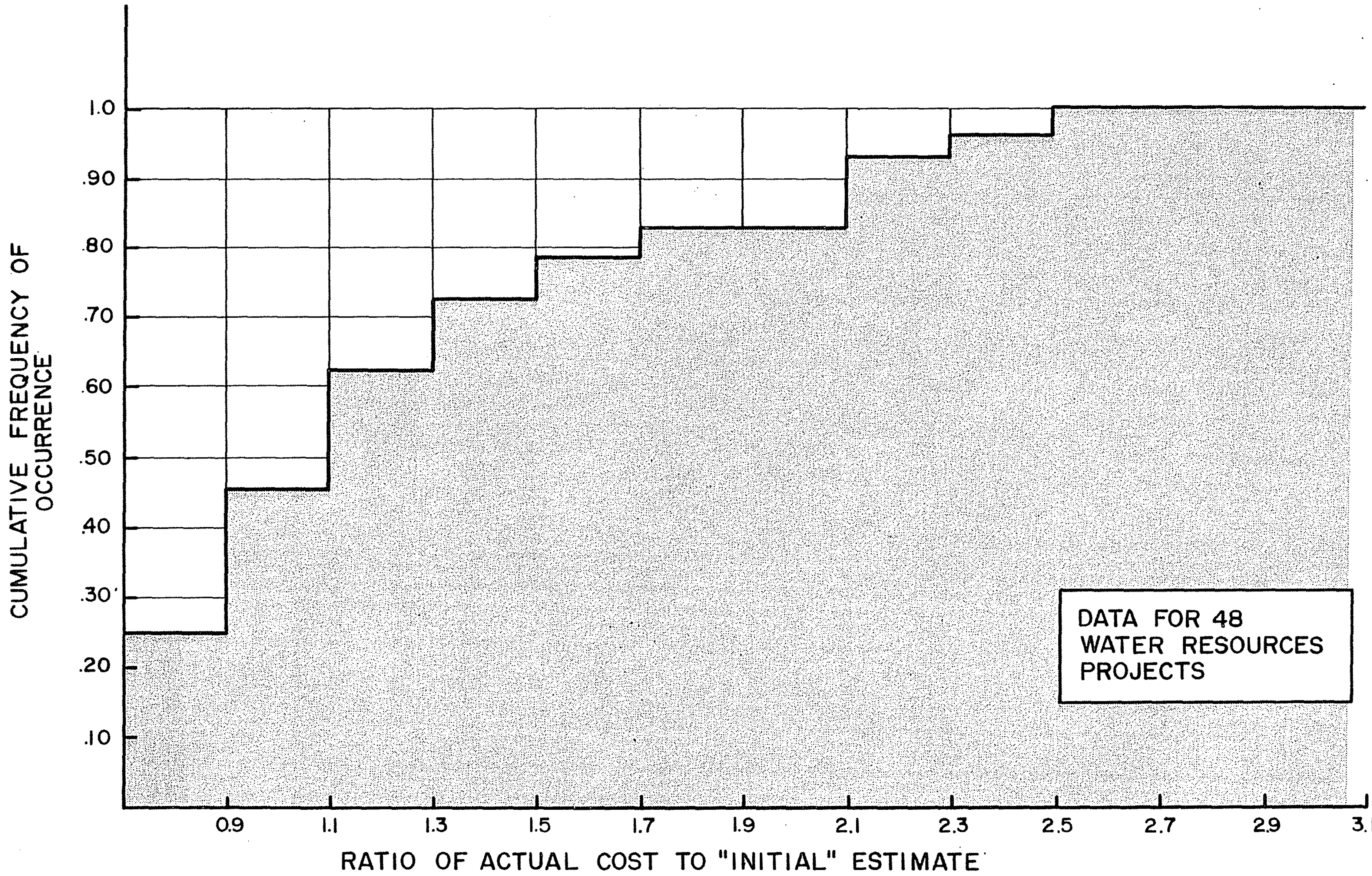
FIGURE 18.2.10



CUMULATIVE PROBABILITY DISTRIBUTION
FOR SUSITNA HYDROELECTRIC PROJECT

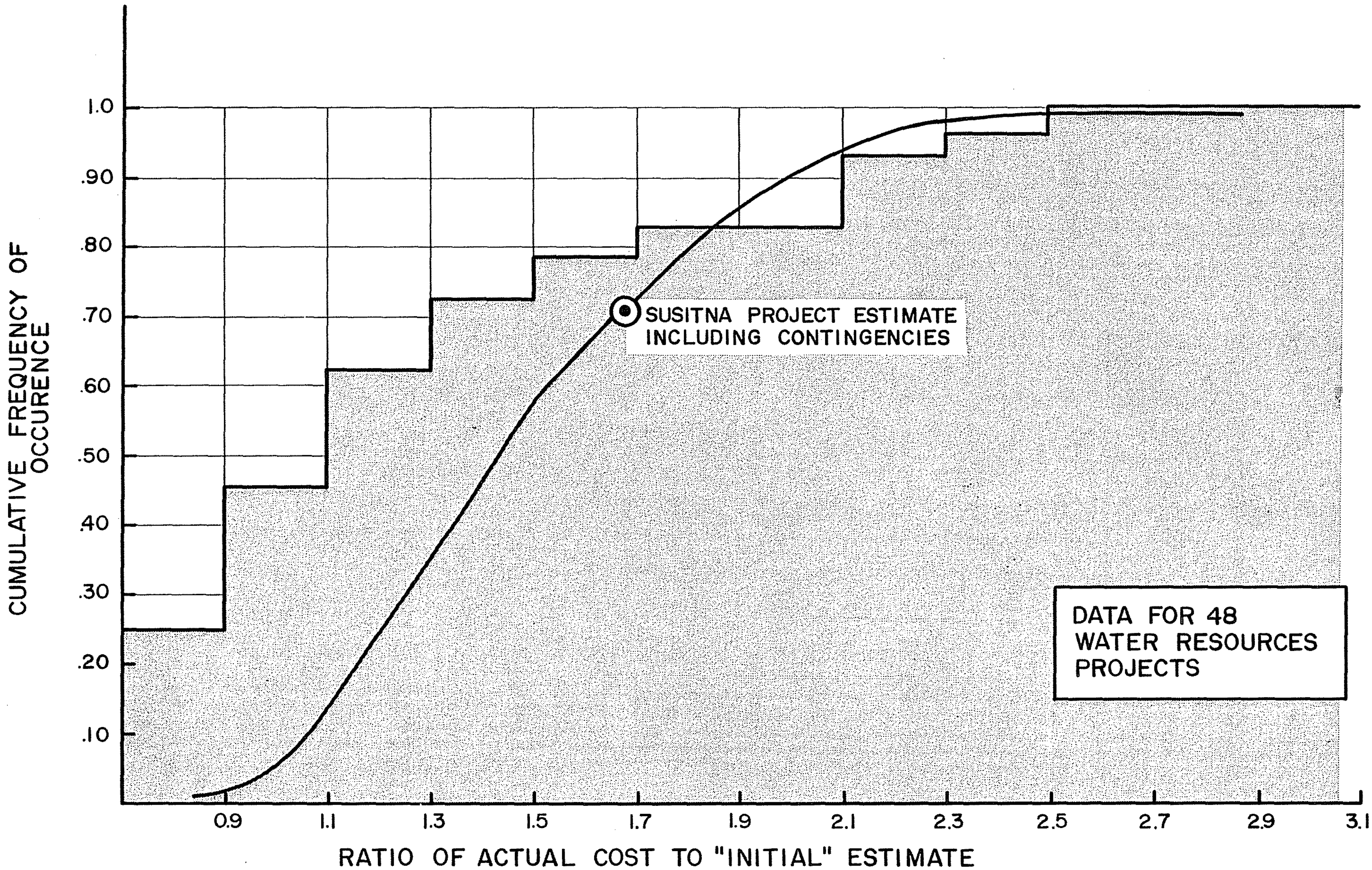
FIGURE 18.2.11

ACRES



HISTORICAL WATER RESOURCES
PROJECT COST PERFORMANCE (48 PROJECTS)

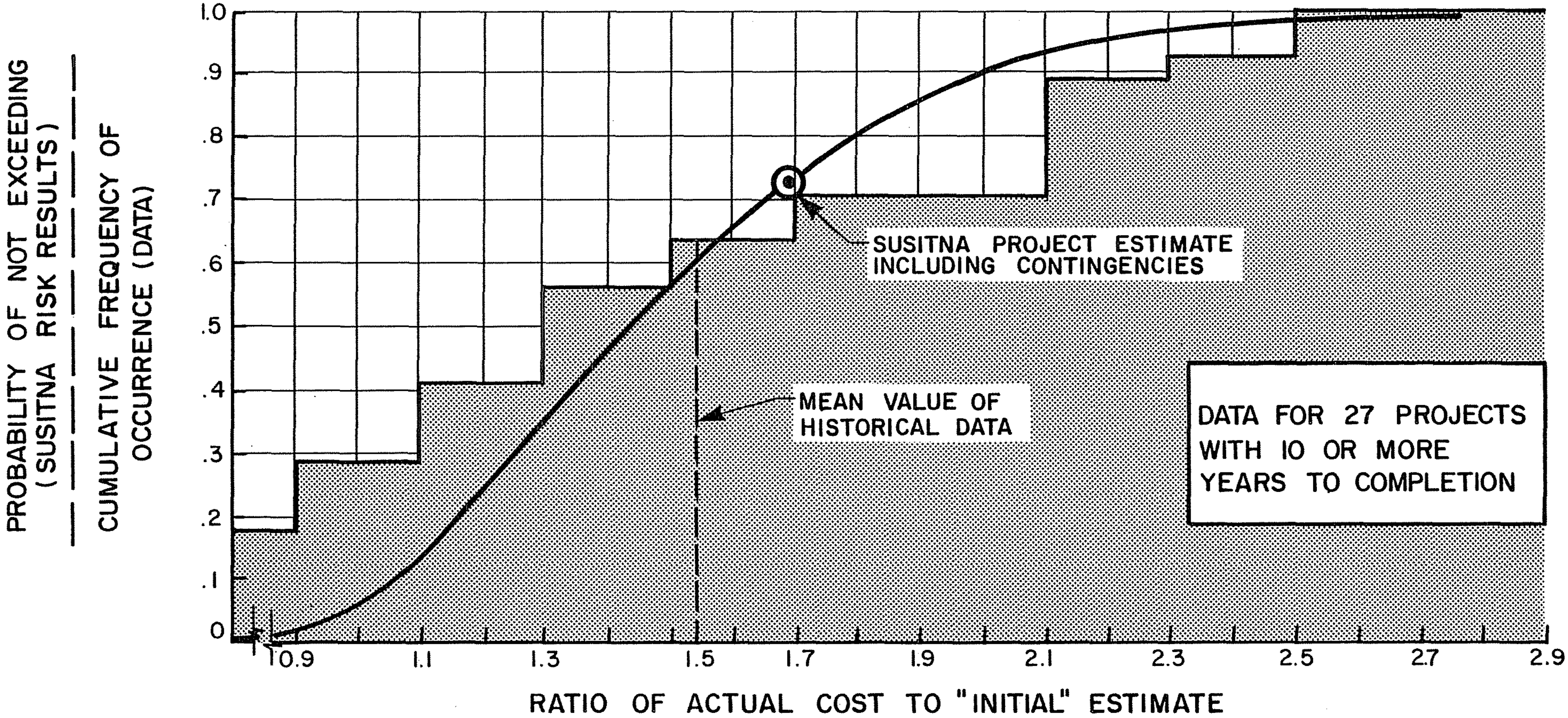
FIGURE 18.2.12



COMPARISON OF SUSITNA RISK RESULTS WITH HISTORICAL WATER RESOURCES PROJECT COST PERFORMANCE (48 PROJECT)

FIGURE 18.2.13

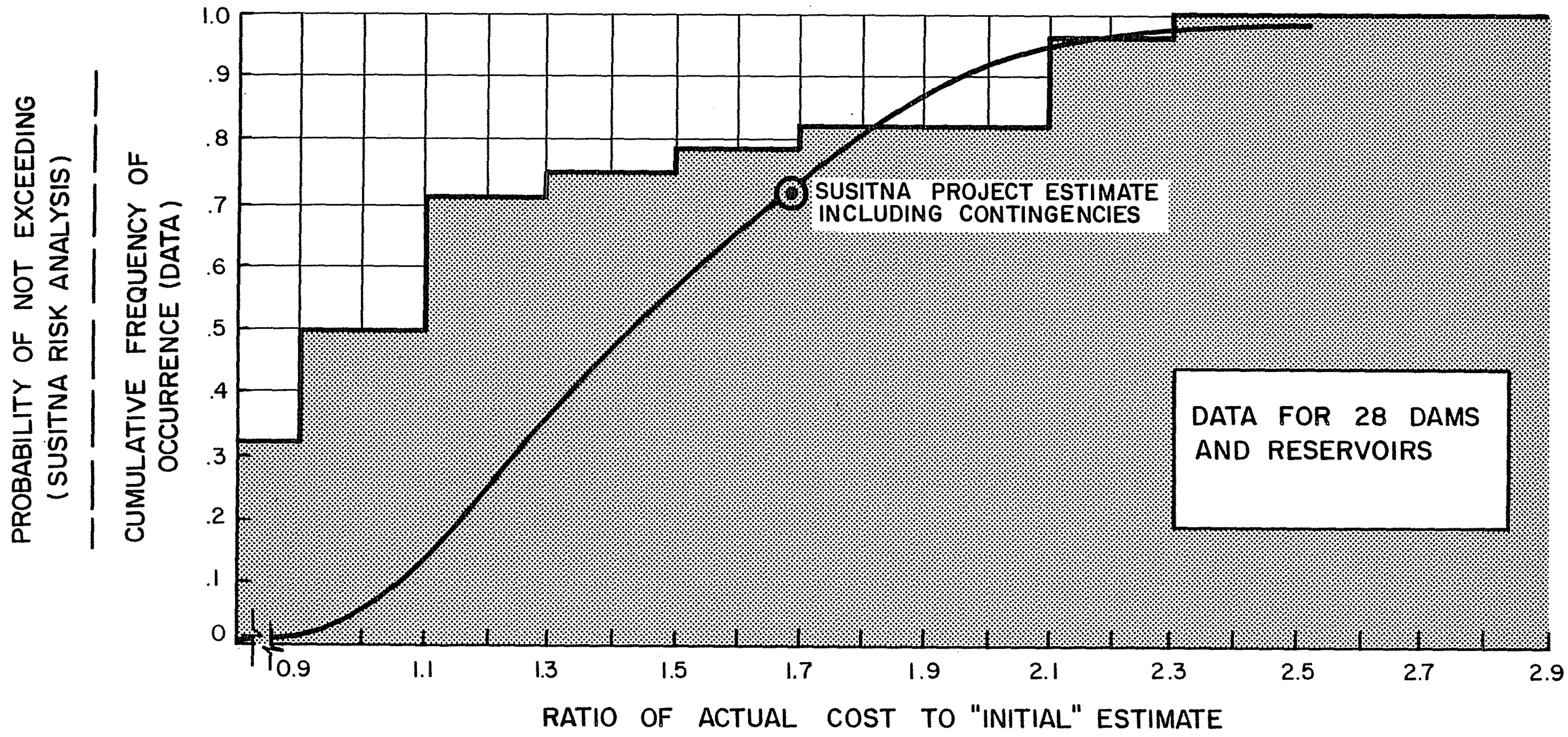
ACRES



COMPARISON OF SUSITNA RISK RESULTS WITH HISTORICAL DATA FOR PROJECTS WITH 10 OR MORE YEARS BETWEEN "INITIAL" ESTIMATE AND COMPLETION

FIGURE 18.2.14

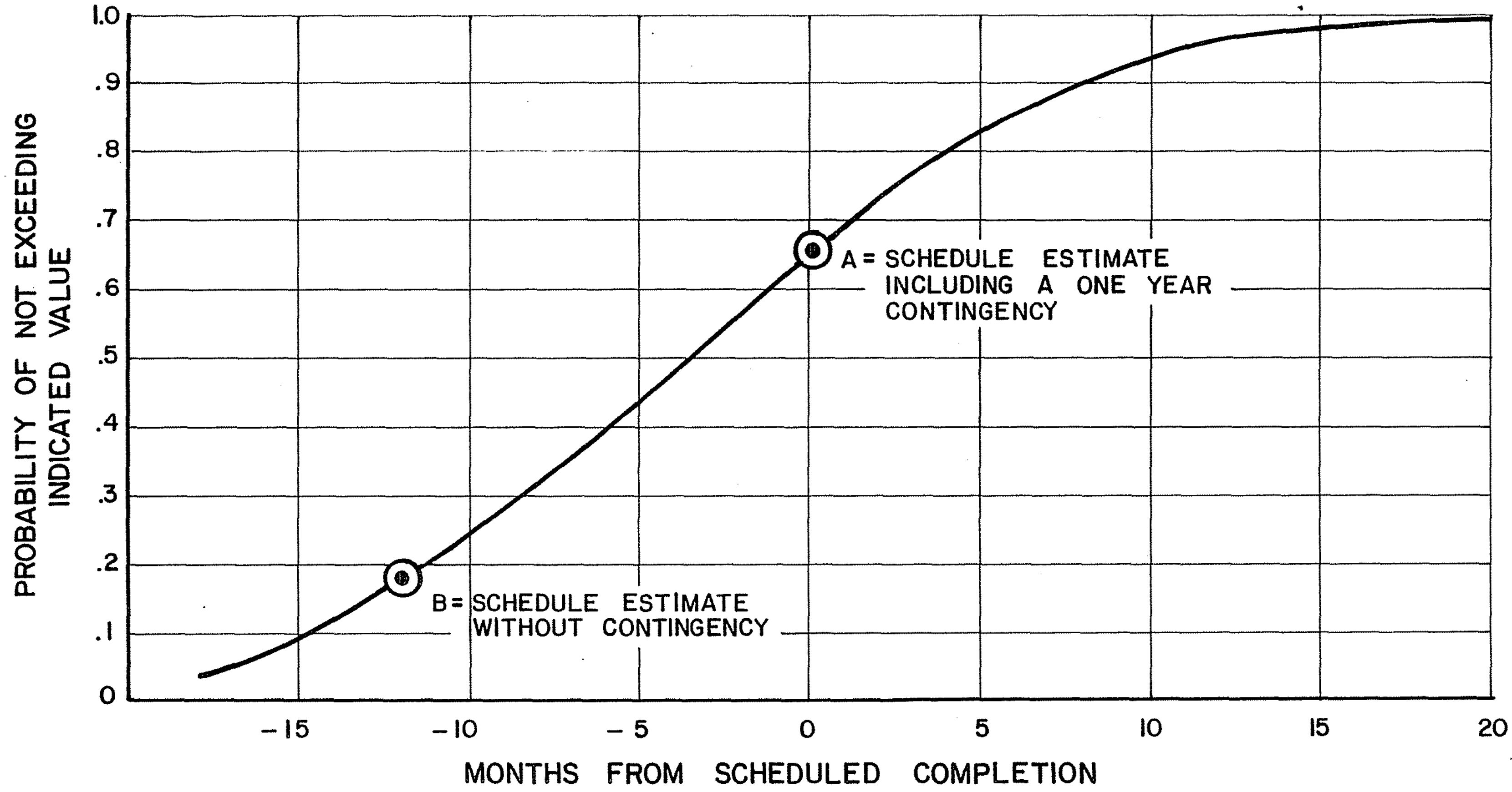
ACRES



COMPARISON OF SUSITNA RISK ANALYSIS RESULTS
WITH HISTORICAL DATA FOR DAMS AND RESERVOIRS

FIGURE 18.2.15

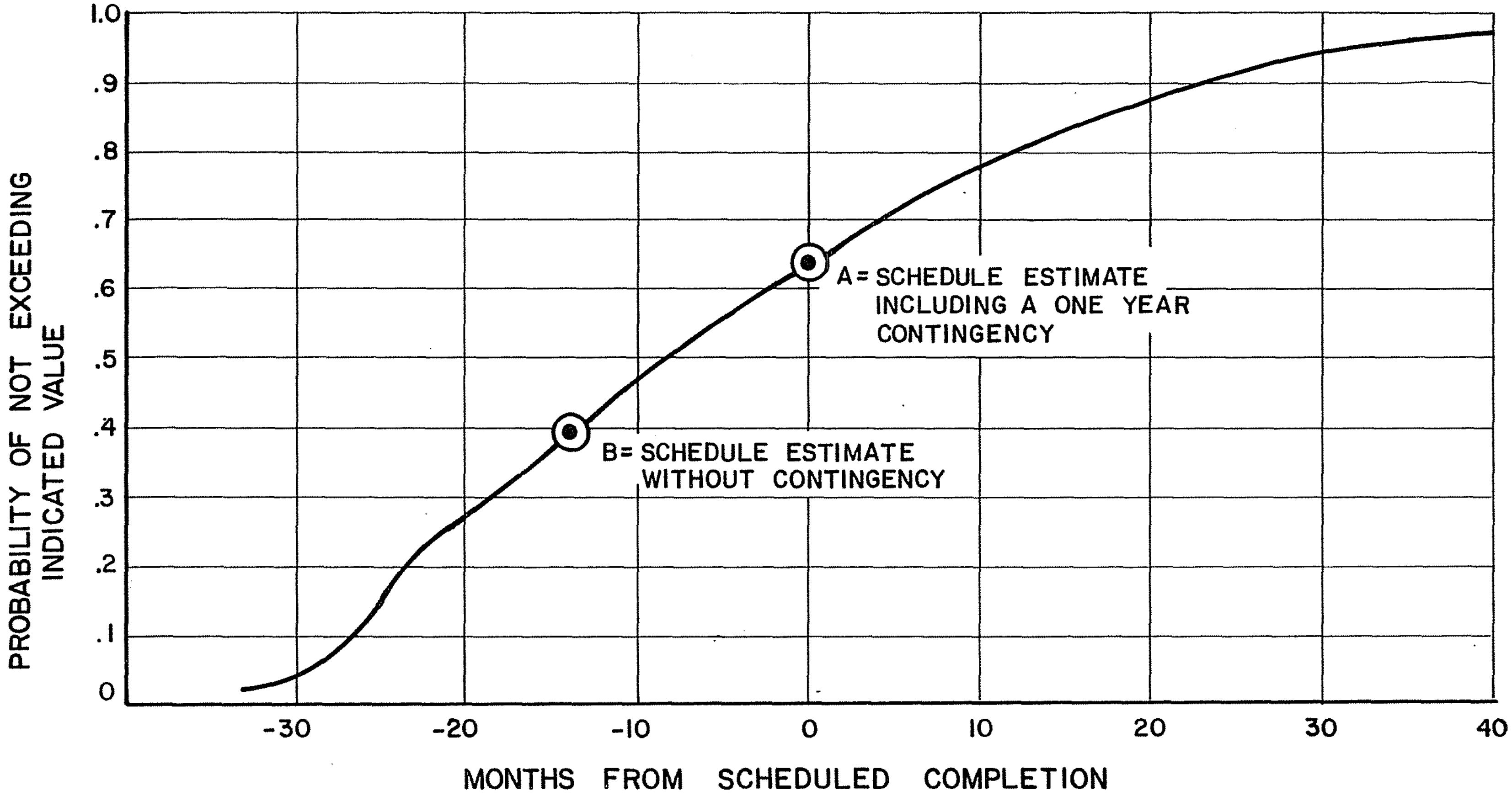
ACRES



WATANA SCHEDULE DISTRIBUTION
EXCLUSIVE OF REGULATORY RISKS

FIGURE 18.2.16

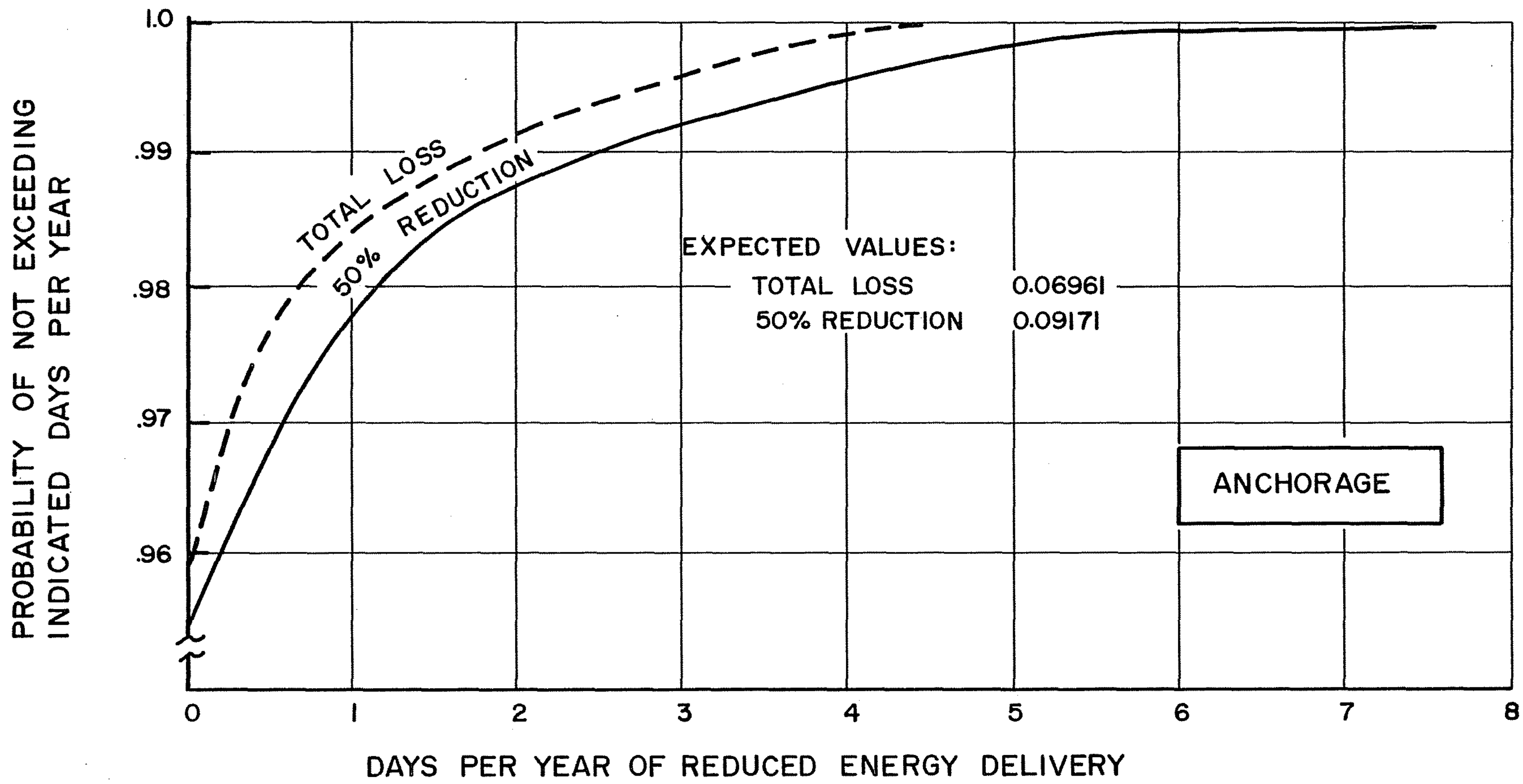
ACRES



WATANA SCHEDULE DISTRIBUTION
INCLUDING THE EFFECT OF REGULATORY RISKS

FIGURE 18.2.17

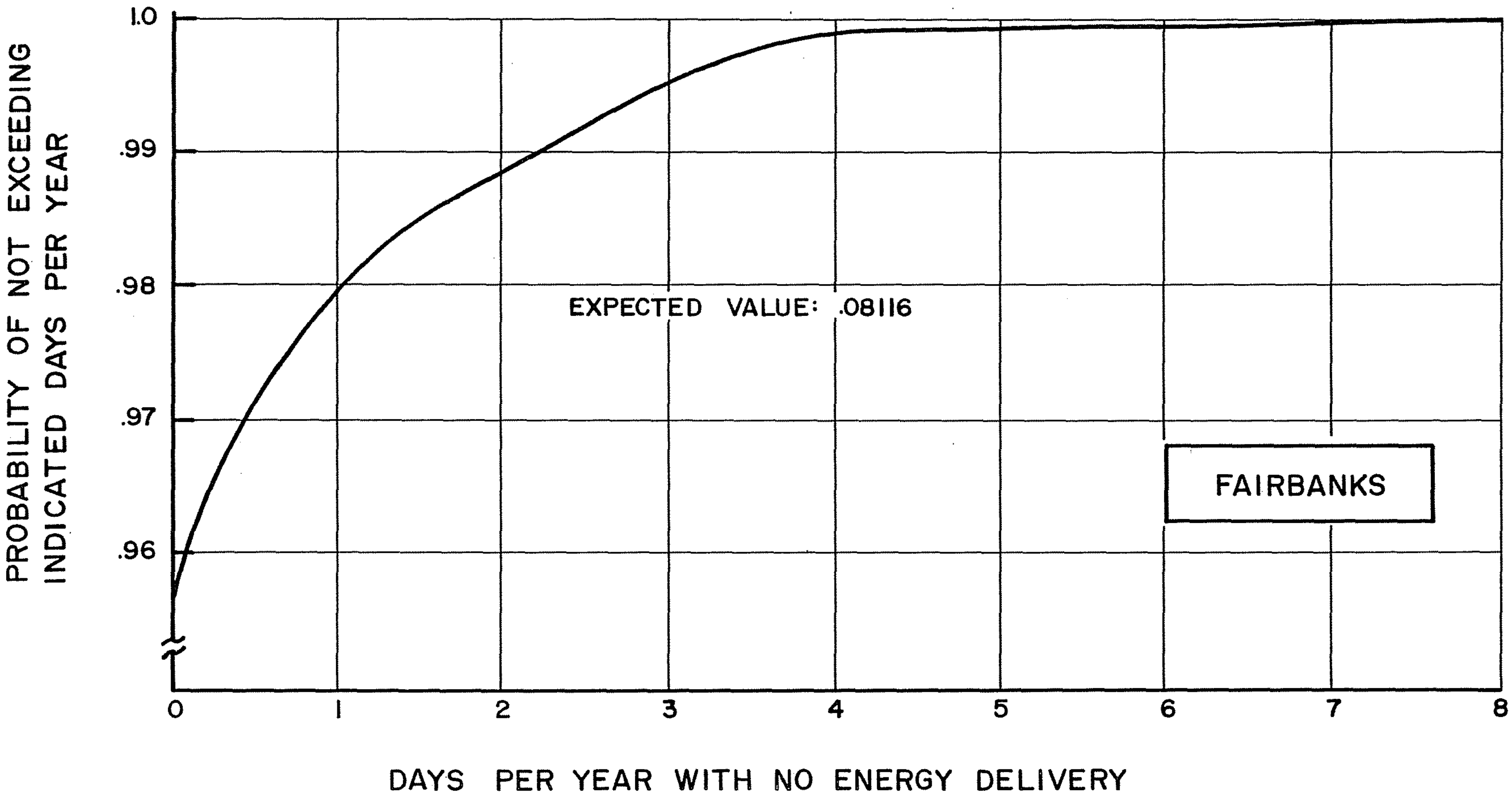
ACRES



CUMULATIVE PROBABILITY DISTRIBUTION FOR DAYS OF REDUCED ENERGY DELIVERY TO ANCHORAGE

FIGURE 18.2.18

ACRES



CUMULATIVE PROBABILITY DISTRIBUTION FOR DAYS PER YEAR WITH NO SUSITNA ENERGY DELIVERY TO FAIRBANKS

FIGURE 18.2.19

ACRES

18.3 - Marketing

Introduction

This section presents an assessment of the market in the Railbelt region for the energy and capacity of the Susitna hydroelectric development. A range of rates at which this could be priced in the year of first power and the price in succeeding years is also considered as well as a basis for contracting for supply of Susitna energy.

(a) The Railbelt Power System

It is necessary to consider first the basic characteristics of the Railbelt region electric power demand and supply, load resource analysis for the period during which Watana and Devil Canyon come into operation in 1993 and 2002 respectively.

The power system to which Susitna capacity and energy would be delivered is defined as the Railbelt Region interconnected system which will result from the linking of the Anchorage and Fairbanks systems through a transmission intertie to be completed in the mid-1980s.

(i) Delineation of Region

The Railbelt Region covers the Anchorage-Cook Inlet area, the Fairbanks-Tanana Valley area and the Glennallen-Valdez area as shown in Figure 18.3.1. The utilities, military installations and university for which electric generating facilities are included in this report are listed in Table 18.3.1. The approximate location of service areas of these utilities are shown in Figure 18.3.2 and the generating plants servicing the region are listed in Table 18.3.3.

- Anchorage-Cook Inlet Area

There are five electric utility companies in the Anchorage-Cook Inlet area. The two largest are Anchorage Municipal Light and Power (AMLP) which serves the Anchorage municipal area and Chugach Electric Association (CEA), serving the Anchorage suburban and surrounding rural areas. Homer Electric Association (HEA) serves the western portion of the Kenai Peninsula, including Seldovia, across the bay from Homer. Matanuska Electric Association (MEA) serves the town of Palmer and the surrounding rural area in the Matanuska and Susitna Valleys. Seward Electric System (SES) serves the city of Seward. Alaska Power Administration operates the Eklutna hydroelectric plant and markets wholesale power to CEA, AMLP and MEA. Chugach Electric Association also provides power at wholesale rates to HEA, SES and MEA.

There are also two major national defense installations in the Anchorage area: Elmendorf Air Force Base and Fort Richardson.

- Fairbanks-Tanana Valley Area

There are two electric utility companies in the Fairbanks-Tanana Valley area. Fairbanks Municipal Utilities System (FMUS) serves the Fairbanks municipal area, and Golden Valley Electric Association (GVEA) serves the rural areas. The University of Alaska at Fairbanks owns and operates an electric generating plant and its capacity is included in this report. The other generating facilities in the area are those at three major national defense installations: Eilson Air Force, Fort Greeley and Fort Wainwright. Clear Air Force Base, which is not interconnected with any local utility, is not included.

- Glenallen-Valdez Area

There is only one electric utility company in the Glenallen-Valdez area, the Copper Valley Electric Association (CVEA).

(ii) Ownership

The Railbelt Region is presently served by nine major utility systems. Five are rural electric cooperatives, three are municipally owned and operated, and one is a federal wholesaler. In 1980 the rural electric cooperatives supplied 70 percent of total net energy generated by the Railbelt utilities, the municipal systems 23 percent and the Alaska Power Administration 7 percent (see Figure 18.3.4a). Wholesale energy supply represented 28 percent of total net generation.

The total nameplate generating capacity for each of the utilities, military installations and the university in the Railbelt Region is given in Table 18.3.1. The rural electric cooperatives own 58 percent of total generating capacity, the municipal systems 27 percent, national defense organizations 10 percent, the Alaska Power Administration 3 percent and the University of Alaska at Fairbanks 2 percent (see Figure 18.3.4b). The 1980 net energy generation from each of the utilities is provided in Table 18.3.1.

Although national defense installations have represented a major portion of the total installed capacity in the past, they now constitute only 10 percent of the total in the Railbelt Region. It is expected that the national defense installation will become a less significant part of the total generating capacity, with the projected stability of military sites and the relative growth of the utilities.[1]

---

[1] U.S. Department of the Army, Corps of Engineers, "South-Central Railbelt Area, Alaska, Upper Susitna River Basin, Supplemental Feasibility Report", Appendix - Part II, Section G Marketability Analysis, February 1979.

There are three industrial plants in the Kenai Peninsula that operate their own power plants: Union 76 Chemical Division Plant, Kenai Liquified Natural Gas Plant and Tesoro Refinery Plant. These plants are connected to the HEA system and are buying either energy or standby capacity from HEA to supplement their own generation in meeting their needs. There are other self-supplied industrial generators including oil platform and pipeline terminal facilities in the Cook Inlet area.

In general, industries own and operate generating facilities only for their own use. They were not included in this analysis.

(iii) Types of Fuel

The net energy generated by the Railbelt utilities by types of fuel is shown in Figure 18.3.4c. As shown in this figure, 76 percent of the total net energy generated in 1980 was based on natural gas, 12 percent on coal, 2 percent on oil and 10 percent from hydroelectric plants.

The relative mix of the generating capacity of the Railbelt utilities by type of generating capacity is shown in Figure 18.3.4d. Most of the generating capacity (55 percent) is powered by simple cycle gas or oil-fired combustion turbines.

(iv) Existing Power Sales

In the Anchorage-Cook Inlet area the two major wholesalers of electricity are Alaska Power Administration, operating the Eklutna hydroelectric project, and CEA. In 1980 the Alaska Power Administration sold a total of 180,376 MWh made up of deliveries to CEA, 57,717 MWh; AMLP, 90,854 MWh and MEA, 31,805 MWh. CEA sold a total of 550,548 MWh made up of deliveries to HEA, 287,966 MWh; MEA, 236,209 MWh and SES, 26,373 MWh, in 1980. In the same year AMLP sold 10 MWh to Elmendorf Air Force Base.

The 1980 energy sales by each of the Railbelt utilities are stated by category of customer (Table 18.3.1). The Anchorage-Cook Inlet area had an 81 percent share of the total electricity sales in the Railbelt Region, the Fairbanks-Tanana Valley area 17 percent and the Glenallen-Valdez Valley area 2 percent.

(v) Transmission System

The existing transmission systems in the Railbelt Region are indicated on Figure 18.3.2. In the Anchorage-Cook Inlet area the utilities are at present loosely interconnected through facilities of Alaska Power Administration and the CEA. CEA has interconnections with MEA, HEA, SES and Eklutna. AMLP has an emergency 20 MW connection to Elmendorf Air Force Base.

In the Fairbanks-Tanana Valley area, CVEA has interconnections with FMUS, Fort Wainwright, Eilson Air Force Base and the University of Alaska. The CVEA serves both Glenallen and Valdez.

(vi) Power Exchanges and Interchange Contracts

The 1980 energy transfers between utilities in the Railbelt Region are summarized in Table 18.3.3. As discussed earlier, the main deliveries of electricity were made within the Anchorage-Cook Inlet area. At present, the Anchorage-Cook Inlet and the Fairbanks-Tanana Valley areas operate independently. The existing transmission system between Anchorage and Willow consists of a network of 115 kV and 138 kV lines with interconnection at Palmer.

Fairbanks is primarily served by a 138 kV line from the 28 MW coal-fired plant at Healy. Communities between Willow and Healy are served by local distribution.

In 1980, 28 percent of the total supply was purchased under wholesale interutility arrangements. At present there are power sales agreements between the following utilities:

(1) Alaska Power Administration and CEA, AMLP, MEA, and

(2) CEA and HEA, Matanuska Electric Association, and

(3) GVEA and the University of Alaska.

SES and HEA have long-term purchase contracts with CEA for non-emergency power supplies. The coordination of area power exchange between systems is, at present, not formalized and takes the form of mutual assistance and unstructured interchange agreements.[1]

The power sales contracts between the Alaska Power Administration and the utilities are in pursuance of the Act of Congress approved July 13, 1950 (48. U.S.C. Section 312-312d) and all amendments and supplements.

(vii) Anchorage and Fairbanks Interconnection

It is considered likely that an electrical interconnection between Anchorage and Fairbanks will be established before the Susitna project comes into operation. The intertie has been found to be

[1] The 1976 Alaska Power Survey, Volume I, FERC.

feasible[1] and its operation will result in significant economic benefits to both areas. The recommended construction plan will involve the following steps:

(1) Construct approximately 160 miles of new transmission line designed for future operation at 345 kV.
(2) Add 138 kV circuit breakers at Healy, Willow and Teeland sub-stations.
(3) Add a new 138/24 kV transformer at Willow sub-station along with a 138 kV connection.
(4) Possibly add a 138 kV voltage regulating transformer at Point Mackenzie sub-station if studies in preparation for design show a need for it.
(5) Install approximately 70 MVAR of switched capacitors to control voltage across the interconnection.

The interconnection will allow a transfer of power between Anchorage and Fairbanks in capacity up to approximately 70 MW in either direction. It will provide opportunity for the economy interchange of energy from Anchorage to the Fairbanks area. An average of 260,000 MWh per year from 1984 to 1993 can be exchanged. The intertie will result in an estimated reserve sharing starting from 18 MW as early as 1985 to a maximum of 135 MW in 1994.

The proposed plan of interconnection includes provisions for a future operating voltage of 345 kV that allows for integrating the new line into the future transmission facilities for Susitna or other regional generation source. Transmission facilities with respect to Susitna project are discussed in further detail in Chapter 12 of the Feasibility Report.

(viii) Impacts of the Interconnection

In the feasibility study of the Anchorage-Fairbanks electrical interconnection, it has been indicated that with the tie-line no additional generating capacity will be required in the Fairbanks area before 1993, but the Anchorage area may require approximately 120 MW of additional capacity by that time. The Anchorage and Fairbanks systems however will require additional thermal generating capacity, even with the tie-line in service, if Susitna is not built.

It was also found in the interconnection study that, if the Susitna project and its associated transmission facilities are placed in service in 1994, the Susitna transmission will interconnect the Anchorage and Fairbanks areas and greatly increase the transfer capability between the areas.

---

[1] Engineering Report R-2274, May 1981 Gilbert/Commonwealth

(b) Regional Electric Power Demand and Supply

(i) Socioeconomic Conditions

The Railbelt Region, as shown in Figure 18.3.1, includes Anchorage, Fairbanks, the Kenai Peninsula, and the Valdez-Glennallen area. The 1980 Railbelt population was 284,822 comprising 72 percent of the state's population of 400,142 (U.S. Bureau of Census). Anchorage is the Railbelt's major urban center with 61 percent of the total regional population. Fairbanks, with 19 percent of the total, represents the next major population center. Major industries in the Railbelt include fisheries, petroleum, timber, agriculture, construction, tourism, and transportation. Development of Alaska's natural resources represents current and potential economic activity (Alaska Department of Commerce and Economic Development, 1978). The Federal Government provides employment in both the military and civilian sectors, although these sectors are presently declining. A review of the socioeconomic scenarios upon which forecasts of electric power demand were based is presented in Chapter 5 of the Feasibility Report.

(ii) Electric Power Demand

Demand in terms of electric energy and peak load in the Railbelt Region for the period 1980-2010 has been presented in detail in Section 5 of the Feasibility Report. The forecasts adopted in this report are the mid-range levels presented by Battelle Northwest in December 1981. Subsequent forecasts which introduce price/demand elasticity considerations have not been used at this stage. The relatively wide range of demand scenarios associated with price-dependent sales of electrical energy in the Railbelt deserve particular consideration later.

The results of studies reported in Section 5 of the Feasibility Report call for Watana to come into operation in 1993 and deliver a full year's energy generation in 1994. Devil Canyon would come into operation in 2002 and deliver a full year's energy in 2003. Figure 18.3.4 shows the mid-range forecast of energy demand corresponding to moderate growth and the energy outputs planned from the Susitna hydroelectric development.

(c) Market and Price for Watana Output in 1994

In this assessment of the market for energy output from Susitna energy in 1994 it will be assumed initially that this energy will be supplied at a single wholesale rate on a free market basis, that is on the basis that no utility has any obligation to purchase but will choose to do so on grounds of the single wholesale price set for Susitna energy compared with other alternatives. It should be noted that these marketing conditions, and in particular the single wholesale rate, constitute a very exacting market, for they preclude the possibility of securing markets by discriminatory pricing or of long-term contracts based on concessionary prices. In effect these marketing conditions require that all Susitna energy is based on a wholesale price which is attractive even to the utility with the lowest cost alternative source of energy.

(i) Organizational and Contractual Preconditions for Susitna Energy Sales

Optimum economic operation of Watana and Devil Canyon hydroelectric plants require that they are operated as close as possible to full capacity. This is because of the inherent characteristics of hydro power developments which result in effectively zero incremental cost of additional energy when the facilities are operating at less than full capacity. If it is determined, therefore, that Susitna is to proceed it will be most important, in terms of obtaining the least-cost energy system in the Railbelt, to plan for the introduction of Watana as an operating plant in a systematic and orderly manner. Specifically, the APA and the Railbelt utilities should consult on any significant additions to the system capacity which the utilities might consider in the years prior to Watana coming on-stream in 1993 and Devil Canyon in 2002 to avoid costly duplication of facilities and consequent "over building" of capacity.

The APA should also commence power contract negotiations with the four major electric utilities (CEA, AMPL, FMUS and GVEA) for the output of Susitna as soon as any decision in principle is reached to proceed with Susitna. Given that the utilities are wholly independent, it must be expected that they will bargain for costs no higher than the cost of energy from the best thermal option available to them. It is on this assumption that the marketing plan given below is developed. It is essential, however, that appropriate contracts are established between the APA and the major utilities as a precondition for the actual commencement of Susitna. The reasons for this are firstly, that such contracts will be required (see Section 18.4) to support bond issues required to fund the construction of the project and are, therefore, a precondition of Susitna financing. Secondly such precontract would be necessary and desirable if equitable terms were to be arrived at. If the contractual negotiations were left until construction was substantially underway, the contractual bargaining would be on a most unequal basis, given that Susitna would then be virtually a "trapped" resource with no alternative markets other than that provided by the Railbelt utilities.

Subject to tax considerations noted in Section 18.4, power supply contracts, entered into as a precondition of proceeding with Susitna, should also be on the basis of utilities taking whole blocks of energy long term at a price which is the lesser of either the cost of energy from the best thermal option (as developed below) or the APA wholesale rate, as laid down by Senate Bill 25. The ceiling set by the best thermal option cost should also be considered over a period of years so that, for example, the maximum price charged for Susitna energy over ten years might be the average price of the energy from the best thermal option rather than the year-to-year estimates of this cost. (In the following analysis, however, it is assumed that the ceiling set by the best thermal option cost is a year-to-year limitation as presently required by Senate Bill 25.) It should be noted that these general principles would enable any benefits arising from the subsidization of Susitna (Section 18.4 below) to be passed on to the utilities and to Alaskan consumers. They would also ensure that, under no circumstances, would Alaskan consumers be disadvantaged by Susitna energy pricing.

(ii) Maximum Price for Watana Output

The first issue to be considered is the maximum price which could be charged for the output of Watana (3387 GWh) in 1994 (the second year of output and the first year of normal costs) and leave the Railbelt consumers with no higher cost electricity than would have been the case under the best thermal option had this been implemented in the early 1990s. Identification of this price is important since it is assumed that as a matter of policy the State of Alaska would wish this limit to be retained to avoid imposing any additional burden on the Railbelt consumers. Moreover, under the present system of decentralized independent utilities, it must be expected that the maximum price which they would be prepared to pay is the cost of this, the next best option to Susitna.

The marketing position for Watana Stage I in 1994 is set out in Figure 18.3.5. The basis of the figure is first the incremental costs (i.e., cost over and above those already incurred by way of capital investment on the system by the early 1980's) that would result if the best thermal option to Susitna were chosen. The major incremental cost would arise from the 400 MW Beluga coal fired thermal power station producing 2554 GWh in 1994. Since this would be new capacity its whole cost (capital investment, fuel and O&M) would be added to that for the overall system. The rest of the generating plant required to meet the 1994 demand, primarily combined cycle and gas turbines and all already installed, would involve incremental costs equal only to fuel and O&M cost of this equipment.

Figure 18.3.5 shows, on the far right of the figure, the area in which costs of the best thermal and the Susitna options are common and arise from plant required in both system configurations to meet the full generating requirements of 1994. Watana, coming on-stream at that time would effectively "avoid" all costs represented by the shaded area. These costs divided by the Watana output of 3387 GWh gives a wholesale energy rate of approximately 145 mills/kWh (in 1994 dollars) which is the maximum which could be charged if consumers were to be neither better nor worse off in 1994 by the decision to proceed with Susitna, rather than the best thermal option. This confirms the estimate of 148 mills/kWh which is produced by the more detailed OGP.5 analysis, the results of which are given in Figure 18.3.6.

(iii) The Entry Price Problem

The entry price problem for Watana in 1993 (as for Devil Canyon later) arises because its wholesale energy rate must be competitive not only with the cost of the best thermal option (i.e., the 145 mills/kWh above) but also with the avoided operating costs of all supplied by existing equipment and this situation would continue until such time as the equipment is retired and becomes due for replacement or until the system needs additional capacity.

Unless appropriate measures are taken therefore, the entry price of Watana might be constrained by the need to make it competitive with the lowest significant block of avoided cost arising from existing capacity. This could give rise to a situation in which the pricing policy, which maximized revenue from Watana, was not to reduce its wholesale price to a point at which all of its output was sold, but maintain a higher price and "spill" the unsold energy. Such a policy, while it might be effective in terms of increasing the operating revenues of Watana, evidently would not be efficient for the system as a whole. The system would incur operating costs of around 70-80 mills/kWh for even the least-cost thermal energy while Watana is "spilling" energy which would cost virtually nothing to supply. It would therefore be far cheaper for the system to use the Watana energy rather than operate any of the thermal sources still available.

This entry price problem could be resolved in a number of ways to achieve the lowest possible cost for the system as a whole. It should in large measure be avoided by the pre-contract arrangements described in (c) (i) above. Under such contracts the major utilities would agree to take the Watana output in contracted-for blocks of energy at an average price of 145 mills/kWh in 1994 rather than to take whatever amount minimized their costs on a year-to-year basis, regardless of the cost to the system as a whole. It would be realistic for the major utilities to accept pre-contract arrangements on this basis as the system will clearly require substantial additions to generating capacity involving heavy investment in the early nineties and this, as shown above, will bring the cost up to 145 mills/kWh. Under such block purchase pre-contract arrangements, utilities would effectively be in a "take-or-pay" position under which it would be more economic for them to avoid using existing capacity on an operating cost-only basis.

The second solution to the entry price problem, (which would be supplementary to the block pre-contract arrangements and not a substitute), would directly address the underlying cause of the problem. This is that the single wholesale rate obliges the Susitna output to be sold on the basis of an average price which takes no recognition of the basic fact that, as long as there is any of the hydroelectric capacity unused, its incremental cost is virtually zero. This situation could be remedied by a two-part tariff system with a demand charge and incrementally-priced energy supplied at less than the operating cost of the existing equipment. This would encourage utilities to absorb the maximum amount of the Watana output, thus minimizing the cost to the system as a whole.

It is recognized that there may be grounds for opposing multi-part tariff systems as possibly discriminating unfairly against particular categories of consumer. It should nevertheless be possible in the context of the Railbelt system, as it will exist in 1994, to devise a tariff which could be fairly and generally applied even if only on an interim basis.

(d) Market and Price for Watana Output 1995 - 2001

After its initial entry into the market in 1994 the price and market for the 3387 MWh of Watana output is consistently upheld over the years up to 2001 by the 20 percent increase in total demand over this period, and the 70 percent increase in cost savings which this output is providing compared with the cost of the best thermal option. These savings per unit of output are shown in Figure 18.3.6 and are, as noted above, derived from the OGP5 analysis. The very substantial increase in the cost savings per unit of Watana output which occurs in the latter half of the 1990s reflects the fact that, but for this hydroelectric plant, it would have been necessary to bring on a further 200 MW coal station at Nenana in 1996. Another major influence on the cost savings arising from Watana over this period is the rapidly escalating cost of natural gas as existing contracts are renegotiated. This rising curve of cost savings attributable to the Watana output therefore again represents the maximum price at which the output could be marketed if, within the constraint of the single wholesale energy rate system, it was possible for Watana to recapture the whole of the savings which it confers on the system compared with the best thermal option.

(e) Market and Price for Watana and Devil Canyon Output in 2003

Devil Canyon comes on-stream in the year 2002, but its first full year of normal costing is 2003 and it is with reference to this year that we consider the pricing and marketing problems involved in selling the additional 2450 GWh made available and usable on the Railbelt system.

A diagramatic analysis of the total cost savings which the combined Watana and Devil Canyon output will confer on the system in the year 2003 compared with the best thermal option is shown in Figure 18.3.7. By this year, under the thermal option, the costs of the system would have been dominated by the three 200 MW coal plants completed in the years 1994 and 1996. The diagram shows the total savings brought about by the usable output from Susitna in this year. Again, dividing these total savings by the energy contributed by Susitna we arrive at the 250 mills/kWh price which represents the maximum price which can be charged for Susitna output on a basis that enabled the project to recapture the whole of the savings which it confers on the system compared with the best thermal option.

Again, the practical marketing problem which would need to be resolved in the year 2003 is that of making the entry price of Susitna energy competitive, not merely with the best thermal option, but also immediately competitive with the actual combined cycle, gas turbines, plants, etc., which the additional output from Devil Canyon will displace. It is this capacity (combined with the output of Watana and other hydroelectric plants) that will have been supplying the whole Railbelt energy demand in the years immediately preceding the start-up of Devil Canyon. It could therefore still be available as an alternative power generating mode open to the utilities wherever this is more economical than paying the single wholesale rate charged for Susitna.

If the wholesale rate charged for Susitna would be at the 250 mills/kWh level (designed to recapture wholly the savings conferred by the project in that year) it will be seen from Figure 18.3.7 that it would be more economical for some utilities to keep in operation part of the combined cycle and gas turbine generating capacity since their operating costs would be considerably less than the 250 mills. This is expected however to be only a relatively short term problem, one reason being that some of these remaining facilities will be approaching retirement.[1] At that time new capital costs would need to be incurred for generation expansion and this would clearly render much of this plant uneconomic given the option of a supply from Susitna at a cost of 250 mills/kWh (in 2003). As in the case of Watana in 1993-94 a block sale arrangement or a multi-part tariff might be used as a temporary measure to guide the system to the least overall cost generating plan.

It is also probable that by 2003 the Railbelt electrical supply system (which will be about one-third larger than in 1994) will have developed an appropriate institutional structure to ensure that overall costs are minimized. It might reasonably be assumed that rationalization of the power supply function in the Railbelt area would lead to a demand for all available and usable energy from Susitna since its incremental cost is virtually zero.

Only about 90 percent of the total energy output of Susitna will be absorbed by the system in 2002; the remaining output would be progressively picked up over the following decade or so. This will provide increasing total savings to the system from Susitna for no increase in operating costs and thus progressively reduce the cost per unit of the Susitna output. This, combined with the continuing escalation in the cost of thermal fuel, will again progressively consolidate the market position of the project and make Susitna the central element in the system.

---

1 It is also probable that, at this stage, some combined-cycle generating capacity will be required for standby purposes given that hydroelectric plants in these early years of the century, will account for almost all the system needs. How such standby capacity is factored into the system will depend upon the institutional arrangements at that time for the ownership of generating capacity, and the distribution network.

(f) Potential Impact of State Appropriations Reducing The Cost of Susitna Energy Below The Best Thermal Option

In the preceding analysis we have identified the maximum prices at which the Susitna energy could be sold. Whether or not the energy is sold at these prices will depend upon the magnitude of any possible appropriation designed to reduce the cost of Susitna energy in the earlier years when, without such appropriations, it would be more expensive than energy from the best thermal option. The demand forecasts used to analyze the market for Susitna energy in the preceding sections have been based on the assumption that the policy of "full cost" pricing obtains for electrical energy. At significantly lower prices and on the basis of the unit elasticity of demand estimated by Battelle, the total system demand could be substantially higher than assumed. It is nevertheless possible that the state appropriation of funds for the project might be of a magnitude (see Section 18.4) that the Susitna energy would be supplied at a price materially below that of the best thermal option. If this were the case then it would evidently make it correspondingly easier to market the output from Watana and Devil Canyon. As the preceding analysis shows, however, a viable and strengthening market exists for the energy from these two facilities even where they are priced up to the full cost that it would be possible to charge for the best thermal option.

(g) Conclusions

Based on the assessment of the market for power and energy output from the Susitna hydroelectric project it has been concluded that, with the appropriate level of state appropriation and with pricing as defined in Senate Bill 25, an attractive basis exists, particularly in the long term, for the Railbelt utilities to derive benefit from the project. It should be recognized that contractual arrangements covering purchase of Susitna ouput will be an essential pre-condition for the actual commencement of project construction.

UTILITY	Generating Capacity 1981 MW at 0°F Rating	Predominant Type of Generation	Tax Status Re: IRS Section 103	Purchases Wholesale Electrical Energy	Provides Wholesale Supply	Utility Annual Energy Demand 1980 GWh
IN ANCHORAGE-COOK INLET AREA						
Anchorage Municipal Light and Power	221.6	SCCT	Exempt	*	–	585.8
Chugach Electric Association	395.1	SCCT	Non-Exempt	*	*	941.3
Matanuska Electric Association	0.9	Diesel	Non-Exempt	*	–	268.0
Homer Electric Association	2.6	Diesel	Non-Exempt	*	–	284.8
Seward Electric System	5.5	Diesel	Non-Exempt	*	–	26.4
Alaska Power Administration	30.0	Hydro	Non-Exempt	–	*	–
National Defense	58.8	ST	Non-Exempt	–	–	–
Industrial – Kenai	25.0	SCCT	Non-Exempt	–	–	–
IN FAIRBANKS – TANANA VALLEY						
Fairbanks Municipal Utility System[1]	68.5	ST/Diesel	Exempt	–	–	116.7
Golden Valley Electric Association[1]	221.6	SCCT/Diesel	Non-Exempt	–	–	316.7
University of Alaska	18.6	ST	Non-Exempt	–	–	–
National Defense[1]	46.5	ST	Non-Exempt	–	–	–
IN GLENALLEN/VALDEZ AREA						
Copper Valley Electric Association	19.6	SCCT	Non-Exempt	–	–	37.4
TOTAL	1114.3					2577.1

[1]Pooling Arrangements in Force

TABLE 18.3.1 – RAILBELT UTILITIES PROVIDING MARKET POTENTIAL

ACRES

	NET GENERATION (1980 – MWh)				
	Rural Electric Cooperatives	Municipal Systems	Alaska Power Administration	Total	Generation for Wholesale
ANCHORAGE-COOK INLET AREA					
Alaska Power Administration			184,285	184,285	184,285
Anchorage Municipal Light & Power		493,531		493,531	
Chugach Electric Association	1,444,104			1,444,104	550,548
Homer Electric Association	1)			–	
Matanuska Electric Association	2)			–	
Seward Electric System		3)		–	
FAIRBANKS-TANANA VALLEY AREA					
Fairbanks Municipal Utilities System		116,685		116,685	
Golden Valley Electric Association	316,705			316,705	2,453
GLENNALLEN-VALDEZ AREA					
Copper Valley Electric Association				43,982	
TOTAL					
MWh	1,794,791	610,216	184,285	2,589,292	737,286
Percent	70	23	7	100	28

1) Homer Electric Association purchased its energy from Chugach Electric Association, 284,810 MWh in 1980.

2) Matanuska Electric Association purchased its energy from Alaska Power Administration and Chugach Electric Association, 31,805 MWh and 236,208.7 MWh respectively in 1980.

3) Seward Electric System received most of its energy from Chugach Electric Association 26,373.6 MWh in 1980.

Sources: Based on data from US Department of Energy, FPC Form No. 12, 1980.

TABLE 18.3.2 – ENERGY SUPPLY FROM RAILBELT UTILITIES

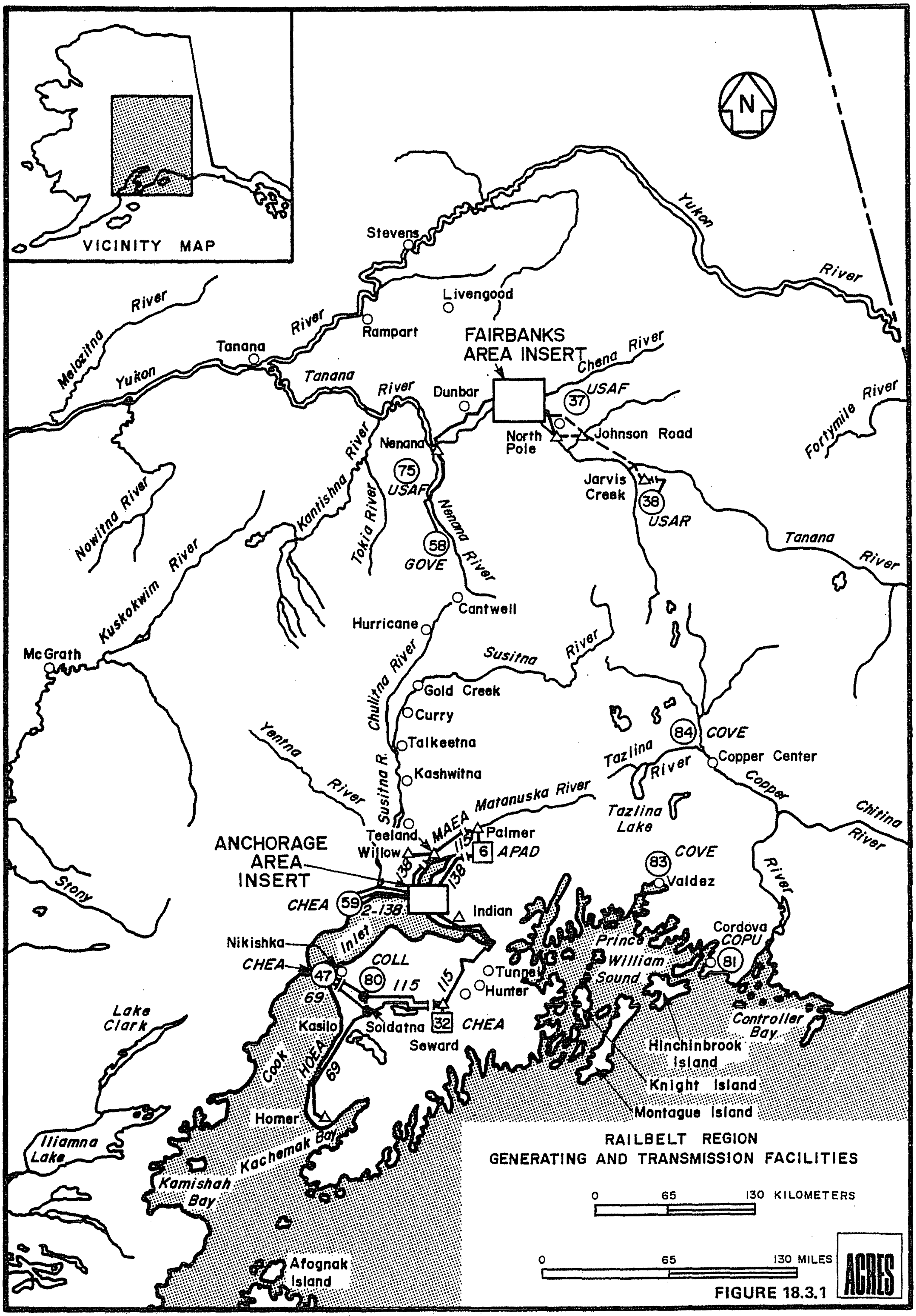
ACRES

PLANT LIST

PLANT No.	NAME OF PLANT	UTILITY	TYPE OF OWNERSHIP
2	Anchorage No. 1	Anchorage Municipal Light and Power	Municipal
3	Anchorage	Anchorage Municipal Light and Power	Municipal
6	Eklutna	Alaska Power Administration	Federal
7	Chena	Fairbanks Municipal Utilities System	Municipal
10	Knik Arm	Chugach Electric Association, Inc.	Cooperative
22	Elmendorf-West	United States Air Force	Federal
23	Fairbanks	Golden Valley Electric Association, Inc.	Cooperative
32	Cooper Lake	Chugach Electric Association, Inc.	Cooperative
34	Elmendorf-East	United States Air Force	Federal
35	Ft. Richardson	United States Army	Federal
36	Ft. Wainright	United States Air Force	Federal
37	Eilson	United States Air Force	Federal
38	Ft. Greeley	United States Army	Federal
47	Bernice Lake	Chugach Electric Association, Inc.	Cooperative
55	International Station	Chugach Electric Association, Inc.	Cooperative
58	Healy	Golden Valley Electric Association, Inc.	Cooperative
59	Beluga	Chugach Electric Association, Inc.	Cooperative
75	Clear AFB	United States Air Force	Federal
80	Collier-Kenai	Collier-Kenai	Municipal
81	Eyak	Cordova Public Utilities	Municipal
82	North Pole	Golden Valley Electric Association, Inc.	Cooperative
83	Valdez	Golden Valley Electric Association, Inc.	Cooperative
84	Glennallen	Golden Valley Electric Association, Inc.	Cooperative

TABLE 18.3.3 – LIST OF GENERATING PLANTS SUPPLYING RAILBELT REGION

ACRES



VICINITY MAP
N
Stevens
Livengood
Rampart
Yukon River
Melozitna River
Tanana
Yukon River
Tanana River
FAIRBANKS AREA INSERT
Chena River
Dunbar
37 USAF
North Pole
Johnson Road
Fortymile River
Nenana
75 USAF
Jarvis Creek
38 USAR
Nowitna River
Kantishna River
Tokia River
Nenana River
58 GOVE
Tanana River
Kuskokwim River
Cantwell
Hurricane
McGrath
Chulitna River
Susitna River
Gold Creek
Curry
Talkeetna
Yentna River
Kashwitna
Susitna R.
84 COVE
Copper Center
Tazlina River
Copper
Matanuska River
Tazlina Lake
Chitina River
Teeland
MAEA
Palmer
Willow
6 APAD
ANCHORAGE AREA INSERT
83 COVE
Valdez
River
Stony
CHEA 59
2-138
138
115
Indian
Inlet
Nikishka
CHEA
47
COLL
80
115
Tunnel
Hunter
Prince William Sound
Cordova COPU
81
69
Kasilo
Soldatna
32 CHEA
Seward
Lake Clark
Controller Bay
Hinchinbrook Island
Knight Island
Montague Island
Cook
HOEA
69
Homer
Iliamna Lake
Kachemak Bay
Kamishah Bay
Afognak Island
RAILBELT REGION
GENERATING AND TRANSMISSION FACILITIES
0 65 130 KILOMETERS
0 65 130 MILES
ACRES

FIGURE 18.3.1

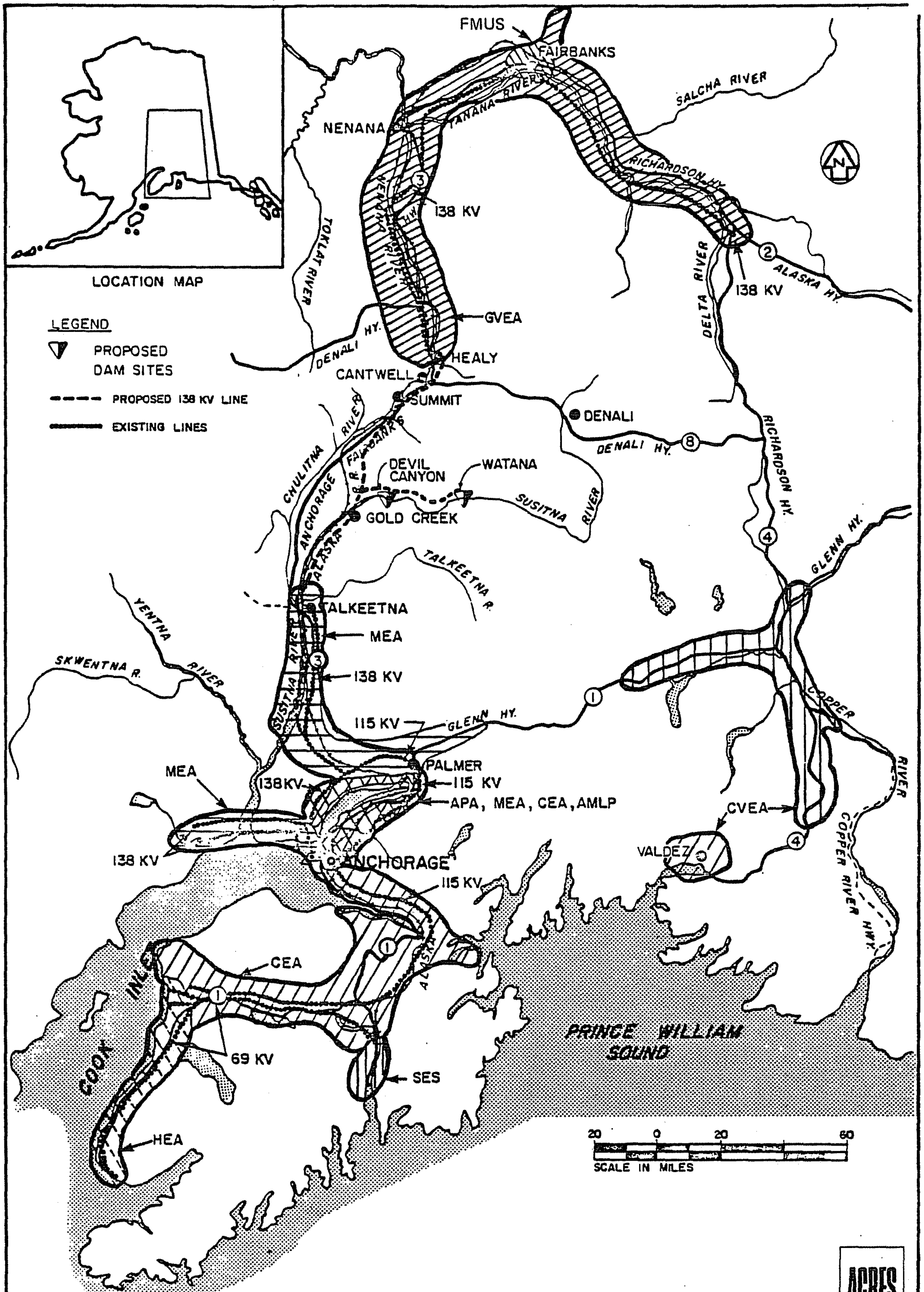
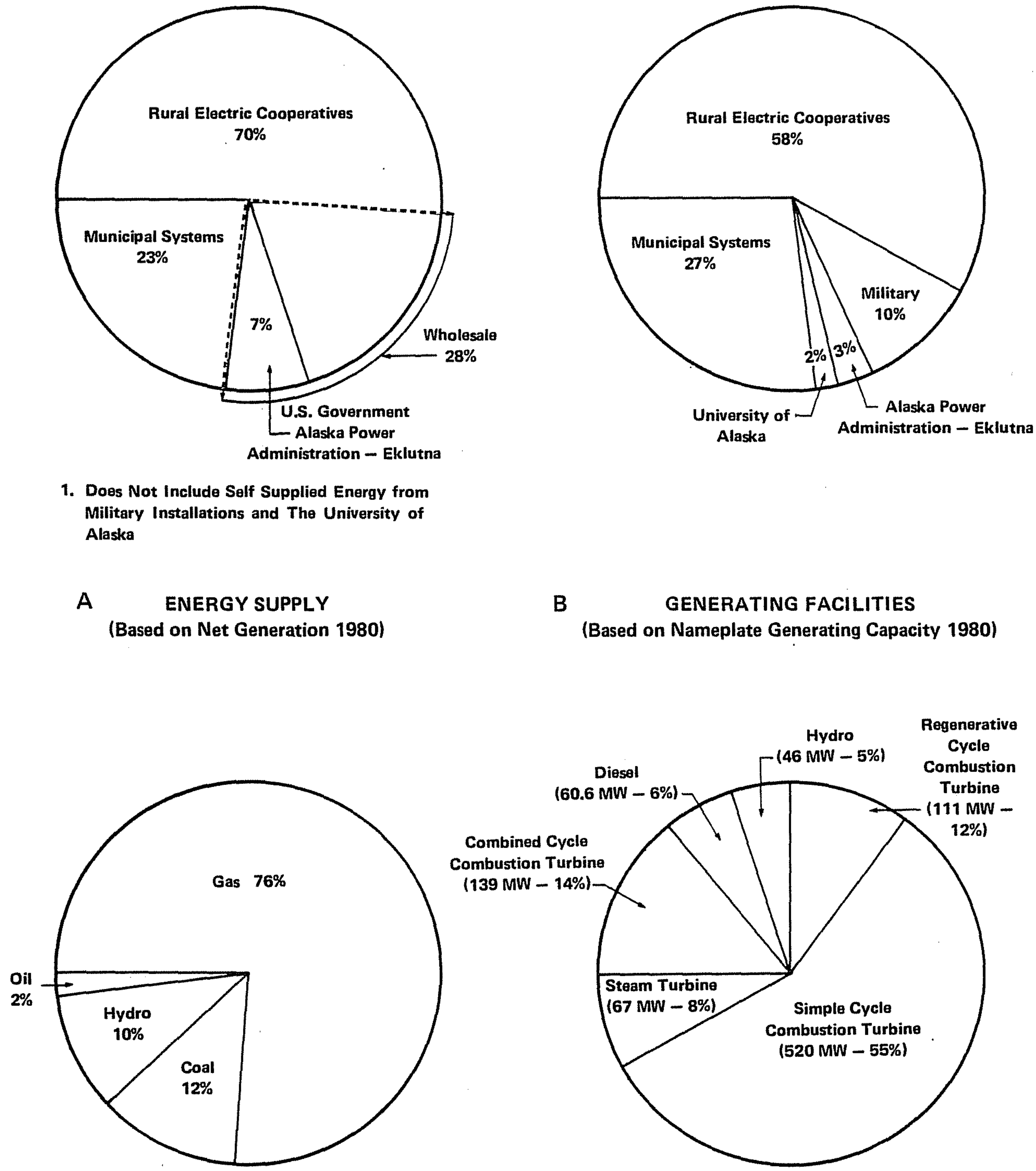


FIGURE 18.3.2 – SERVICE AREAS OF RAILBELT UTILITIES

ACRES



1. Does Not Include Self Supplied Energy from Military Installations and The University of Alaska

A ENERGY SUPPLY
(Based on Net Generation 1980)

B GENERATING FACILITIES
(Based on Nameplate Generating Capacity 1980)

1. Does Not Include Generation by Military Installations and The University of Alaska

C NET GENERATION BY TYPES OF FUEL
(Based on Net Generation 1980)

D RELATIVE MIX OF ELECTRICAL GENERATING TECHNOLOGY – RAILBELT UTILITIES – 1980

FIGURE 18.3.3

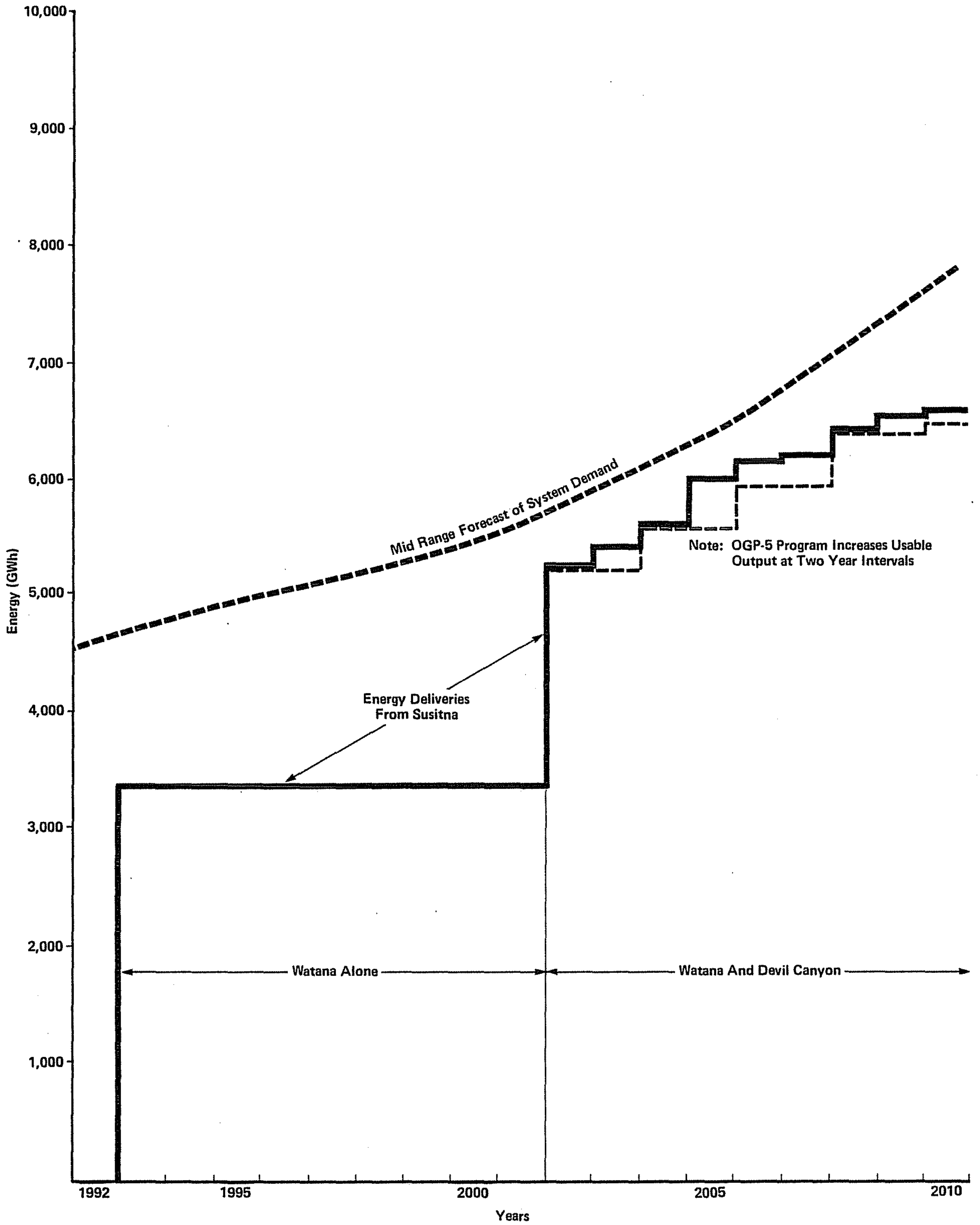


FIGURE 18.3.4 – ENERGY DEMAND AND DELIVERIES FROM SUSITNA

ACRES

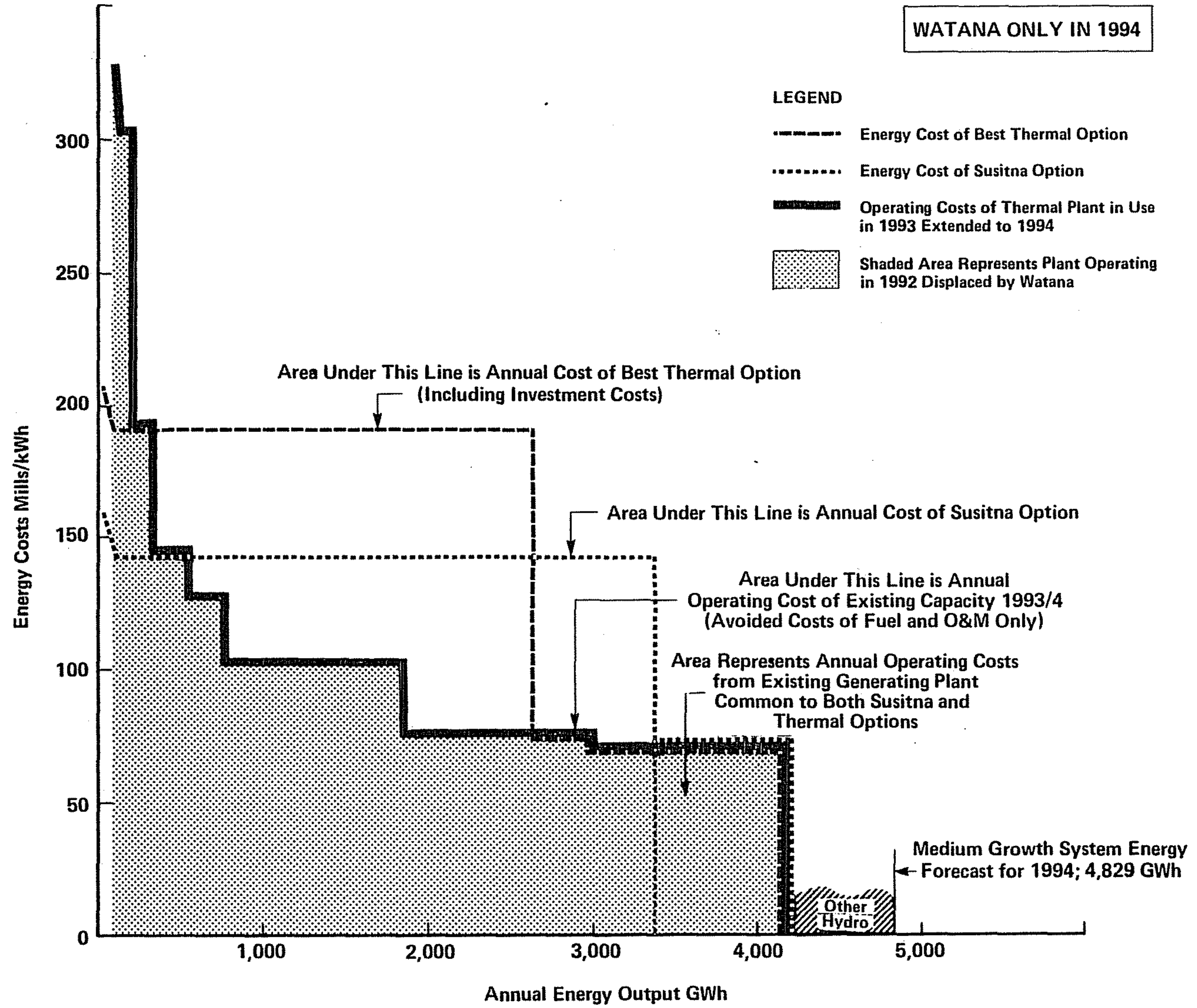


FIGURE 18.3.5 – ENERGY PRICING COMPARISONS – 1994

Rev. 1

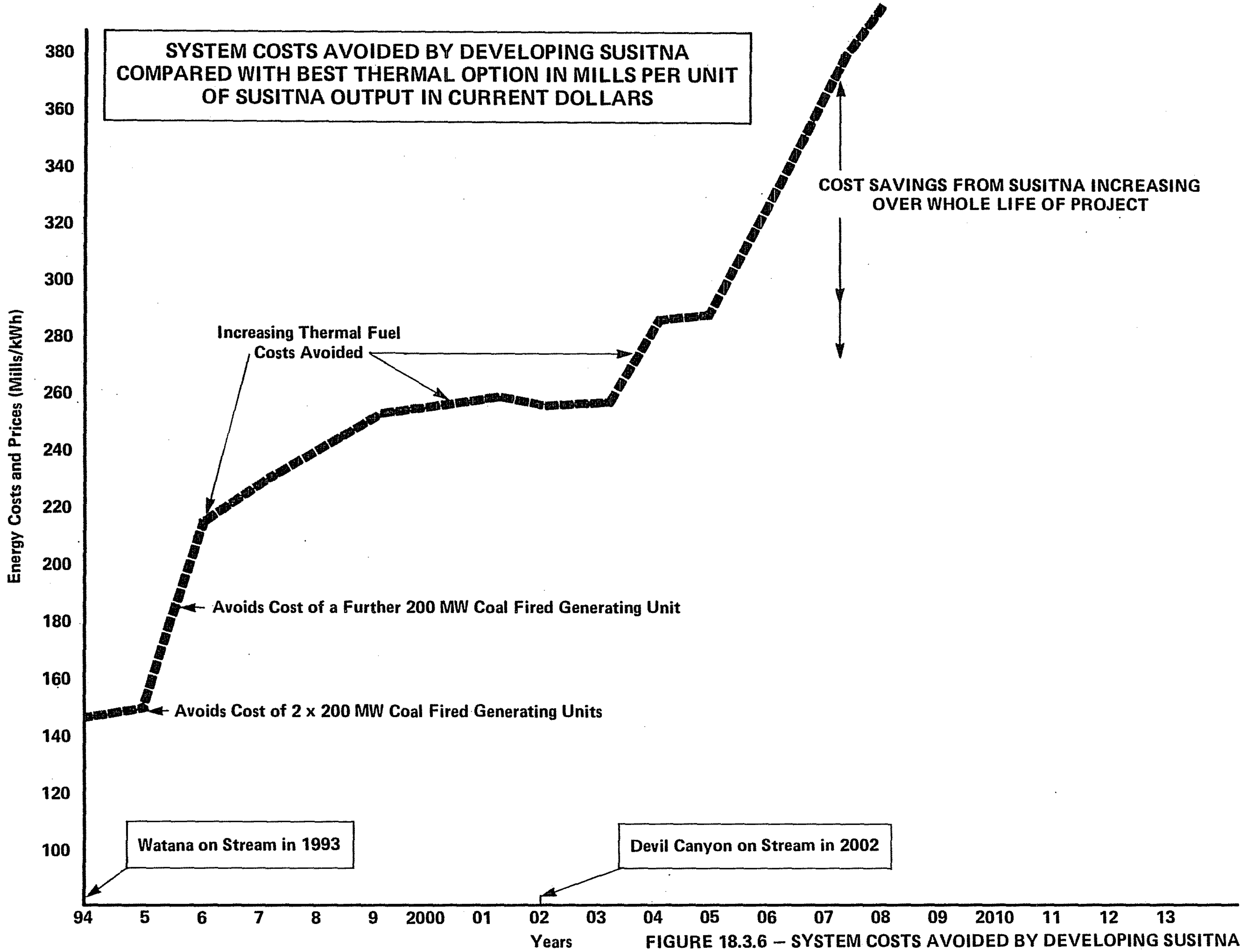


FIGURE 18.3.6 – SYSTEM COSTS AVOIDED BY DEVELOPING SUSITNA

ACRES

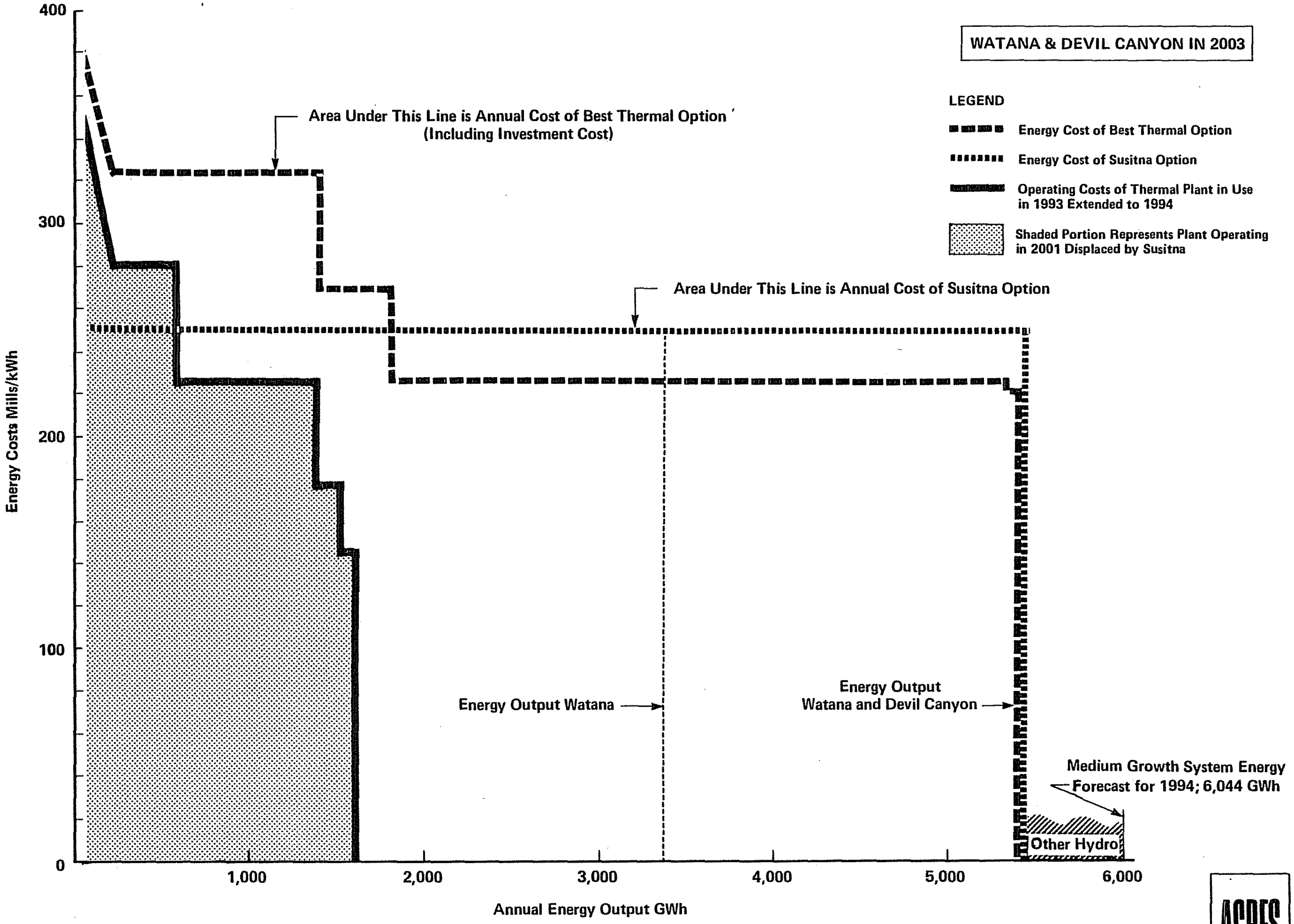


FIGURE 18.3.7 – ENERGY PRICING COMPARISONS – 2003

ACRES

18.4 - Financial Evaluation

Introduction

This section considers the basic financial characteristics of Susitna and a range of financial plans under which the project might proceed. It also considers the relationship between the economic and financing characteristics of Susitna and the impact of inflation. This demonstrates the manner in which inflation, without it changing the real economic worth of the project, creates the major financing problem for the project if it is largely debt financed, in the form of an "inflationary financing deficit" in the early years.

The basic financing options which would effectively meet this inflationary financing deficit while maintaining the Susitna output at a price competitive with alternative energy options are then developed. The main issues involved in these options are then considered in some detail with particular reference to levels of possible state appropriation and securing tax-exempt bond financing.

The actual financial outcome for the project will depend not only on the real - i.e., constant dollar - characteristics of the project such as the constant dollar capital cost but also on a range of financial characteristics including the rate of inflation, the rate of interest at which debt financing is secured, magnitudes of funding through possible State appropriation, etc. The actual range of possible financial outcomes depends upon the interaction of this range of real and financial factors.

In this section the analysis is confined to the financing outcomes for the central forecasts of the real economic factors as developed in Section 18.1, and the particular rate of interest and inflation given in the text. For convenience of reference the real and financial estimates used are detailed in Table 18.4.1. Forecasts of the main financial factors, i.e., rates of interest and inflation, are discussed in sub-section 18.4 (a) below.

The content of this section also concentrates on the problems of financial planning as represented by the analyses of the basic financing options. The problems of financial risk - i.e., the problems arising from the range of possible financial outcomes as both the real economic factors and the financial factors are allowed to vary - are considered in the following Section 18.5.

(a) Forecast Financial Parameters

(i) Interest Rates on Possible Susitna G.O. and Revenue Bond Financing

Unless Susitna is 100 percent state financed residual bond financing will be required. A key factor here will be the level of interest rates. Interest rates are determined by many complex political and economic forces acting nationally and internationally. It is therefore evidently difficult to forecast with any degree of certainty what the prevailing level of interest rates will be in the period 1985 to 2002 when the Susitna bond financing is likely to take place. The authoritative Data Resources Incorporated long-term projections are, however, given in the following Table 18.4.4.

TABLE 18.4.4

	Annual Percentages Rates					
	Historical		Forecast			
	1970 to 1975	1975 to 1980	1980 to 1985	1985 to 1990	1990 to 1995	1995 to 2000
CPI	6.8	8.9	8.6	8.1	7.3	6.8
Interest Rate for High Grade Industrial Bonds	8.0	9.4	11.3	10.7	9.8	8.8

The long-term rate of interest on high grade bonds over the period from 1985 to the year 2000 is forecast to drop progressively from 10.7 percent through 9.8 to 8.8 percent as the rate of inflation falls from 8.1 to 6.8 percent.

The tax-exempt bond rate implied by these figures will depend in part upon the supply of these bonds relative to the markets which have traditionally supported such issues. These have tended to be high tax bracket investors, insurance companies and banks. The reduction in U.S. tax rates and cyclical factors have reduced the demand for tax-exempt bonds by insurance companies and banks. These factors, as well as an increased supply of tax-exempt bonds, has tended to push their yields closer into line with comparable non-tax-exempt bonds, reducing their favorable differential from around 25 to 35 percent of the comparable rate down to only 9 percent in December 1981.

The differential which will apply in the future again cannot be estimated with any certainty since it depends substantially on the future pattern of Federal tax rates and supply of tax-exempt bonds. Subject to these qualifications, it can be argued that the present very low differential between tax-exempt and non-tax-exempt bonds will widen again in the future. With tax-exempt bonds trading at an interest rate 80 percent of that of high grade industrials (with which we might expect Susitna bonds to be comparable), the tax-exempt bond financing over the successive 5-year period from 1985 might be of the order of 8.6, 7.8 and 7 percent.

As already stated, these estimates must be regarded as having a very wide range of uncertainty. Given this and the very much higher level of tax-exempt bond interest rates (13.3 percent in January 1982) the financing plan as developed above has been based on interest rates of 10 and 12 percent for Susitna financing in order to arrive at relatively conservative estimates of project financing characteristics. A wider range of possible interest rates and rates of inflation is developed in Section 18.5 dealing with the financing risk.

(ii) Rates of Inflation

The reference inflation index is taken as that of the Consumer Price Index (CPI). The rate of inflation used in the projections given in the preceding section was taken for simplicity at 7 percent throughout the period 1982 to 2010. On the basis of the DRI estimates this rate is approximately one percentage point too low for the 1985 to 1990 period although approximately correct for the following decade. The impact of this on the basic financing analysis in terms of bond financing requirements in 1982 dollars is, however, negligible. The impact of a wide range of inflation and interest rates is considered in the following Section 18.5.

(b) The Inflationary Financing Deficit

Under inflationary conditions long life capital-intensive projects will automatically tend to produce "inflationary financing deficits" in their early years of operation. Figure 18.4.1 demonstrates schematically the relationship between this deficit and the long-term gain on a hypothetical project which might well be a highly economic and attractive undertaking in the long term.

The Susitna hydroelectric development with its long life and high capital investment would, if financed in a conventional manner with debt funds, have similar inflationary financing deficit of the actual magnitude illustrated on Figure 18.4.2. This figure shows the energy cost to the Railbelt system which would arise from supply from the next-best (predominantly coal) thermal power generation plan (see Section 18.1). This energy would be expected to cost 148 mills/kWh in 1994 (the first normal year of operation of Watana, the first phase of the Susitna development). With a general inflation rate of 7 percent and an approximate additional inflation of 2 percent per annum in the price of coal, on which the new thermal power generation would be based, the cost of electricity generated by this means would increase from 148 mills/kWh to 287 mills/kWh within a decade.

The economic justification for Susitna described in Section 18.1 is based on the present worth of the total savings to the system with Susitna compared with the thermal option and shows that, despite being more costly in the early years, the net present worth of the savings over the life of the project is $1,176 million in 1982 dollars.

If Susitna were 100 percent debt financed at a 10 percent rate of interest, the price it would have to charge for its output is as shown by the higher line in the Figure 18.4.2. Almost the whole of this cost would be made up by interest and debt repayments since the operating costs of the hydroelectric system would be only about 5 percent of the total cost in the year 1994. On this financing basis it would be some 14 years before the cost of thermal-generated electricity overtakes that of the generation output from Susitna.

Thereafter, however, there would be an ever-increasing, favorable gap stretching out into the almost indefinite future, recognizing the very long life of the hydroelectric generating facilities.

In this inflationary world, therefore, the costs of supporting a major hydroelectric development such as Susitna on a 100 percent debt-financed basis are out of time phase with its benefits, giving rise to a deficit (i.e., a difference between cost and potential revenues). Being a direct result of inflation this may appropriately be termed "the inflationary financing deficit". However, if inflation were to cease completely in the year 1993 (i.e., after the completion of the Watana segment of Susitna), the cost of electricity developed by the best thermal option would no longer grow at approximately 9 percent, but drop back to an annual rate of around 2 percent, (i.e., the rate by which the rate of inflation in thermal energy costs is expected to exceed that of general inflation).

The effect on Susitna energy production costs would be even more marked. This is because in a world of zero inflation, interest rates would no longer be 10 percent but, on historical experience, would be about 3 percent. This means that the cost of electricity generated by Susitna would very rapidly be lower than the cost of the best thermal option as shown in Figure 18.4.2. It is in this sense that the inflationary financing deficit can be viewed as a direct result of inflation. Without inflation it would not exist.

Inflation, however, does not change the real economics of Susitna. In terms of present worth and 1982 money the net benefits are exactly the same as they would be in the absence of general inflation. This is principally because inflation does not make debt financing more expensive over the 35-year term of the bond financing that is expected for Susitna. It merely makes the bond financing more costly in the earlier years (in terms of 1982 money) and correspondingly less expensive in the later years. For example, in terms of dollars of equal purchasing power, inflation at 7 percent will nearly halve the burden of the interest and debt repayments for Susitna every 10 years. This means that within 20 years of the project coming into operation, interest and debt repayment in terms of 1982 purchasing power will be only 26 percent of the level existing in 1994. In contrast the cost of electricity generated by the best thermal option is forecast to have increased by 24 percent in constant money terms over the 20 years from 1994.

In summary, inflation, without necessarily changing the economics of the project, will automatically create a large inflationary financing deficit for projects which are capital intensive and largely or wholly debt financed. This inflationary financing deficit must be met either by consumers or by the state if such projects are to be undertaken and their substantial advantages in terms of economic benefit and long-term stabilization of energy prices are to be realized. The following analysis of the financing options available for Susitna therefore considers the various means by which the State of Alaska might meet Susitna's inflationary financing deficit and ensure the ensuing benefits.

As shown from the cost benefit analysis in 18.1 (c) (ii), the project has a rate of return of 11.4 percent, taking into account all the capital invested. This shows that it would be possible, in the long term, for the state to recover the whole of its investment with this rate of return. Since this is in excess of the forecast cost of capital at that time, state appropriation of funds to meet Susitna's inflationary financing deficit can be justified on economic grounds.

(c) Basic Financing Options

A wide range of options exist for possible state participation in meeting the inflationary financing deficit for Susitna. Three basic financing options have been reviewed. To illustrate these, central estimates of capital cost, thermal prices, etc., are used throughout. As noted above the inflation rate is assumed to be 7 percent and the interest rate 10 percent. Detailed printouts of the financial projections for the cases considered are provided in Tables 18.4.5 to 18.4.8. The cases cover:

(i) 100 Percent State Appropriation of Total Capital Cost ($5.1 billion 1982 dollars)

Under this case 100 percent of Susitna capital cost is financed by the state. This conforms with a possible outcome of Senate Bill 25 and represents the simplest financing option.[1]

The year-by-year appropriation required in then current dollars to meet the $5.1 billion capital cost (in 1982 dollars) is given in Table 18.4.5 (line 461).

The Alaska Power Authority, under the present wholesale energy rate-setting requirements incorporated in Senate Bill 25, would not be able to charge more for the output of Susitna than a wholesale energy rate necessary to provide:

- operation, maintenance and equipment replacement costs
- debt service on bonds issued for the power project, if any, and
- safety inspections and investigations of the project by the Authority.

These costs would enter into a wholesale rate which would be determined by aggregating costs from all projects provided for by the Power Development Fund established in AS44-83-382[1].

In this 100 percent state-financed case only the relatively small year-to-year operating costs could therefore be charged as the cost of output. For all practical purposes therefore, the energy developed by Susitna would be supplied to the consuming utilities at a price representing only a small fraction of the cost of power from

---

1 Reference: State of Alaska Senate Bill 25. "An Act relating to energy projects and programs of the Alaska Power Authority."

alternative sources.[2] Evidently, in this case there would be no financing or marketing problems. The major problem might well be that of devising appropriate means of equitably sharing out this major low cost energy supply between the different utilities taking the output since demand would exceed supply.

(ii) $3 billion (1982 dollars) State Appropriation with Residual Bond Financing

The financing scenario which would arise if the state appropriated only $3 billion (in 1982 dollars) and the residual financing requirements were met by bond issues is summarized in Figure 18.4.6. This again shows the cost of electricity on vertical axis over the first years of operation of Susitna. The plot representing the "best thermal option" is again the central estimate of the year-to-year costs of providing the same energy as Susitna by the least cost thermal power generation system based on the costs as detailed in Section 18.1 of the report and assuming an interest rate of 10 percent - the same rate assumed in determining the Susitna costs applies to the cost of thermal units.

As already noted, the wholesale price of the electricity supply from Susitna (and other projects provided for from the Power Development Fund) would be limited to the actual costs incurred including the cost of debt service. On the central estimates this would lead to an almost constant wholesale price for Susitna's output over the period up to the completion of Devil Canyon. This is because virtually the whole of the costs would be accounted for by debt service which would not change until Devil Canyon came on-stream.

Interest incurred on the bonds issued to finance Devil Canyon would be capitalized and, therefore, have no effect upon price until Devil Canyon was completed in the year 2002. At this time the cost of Susitna energy would increase as it became necessary for the project to recover the costs of Devil Canyon. This "step-up" results from the fact that the $3 billion state appropriation would in effect have been wholly expended in meeting the capital costs of Watana (thus producing low-cost energy from Watana). Devil Canyon, on the other hand, will have been wholly financed by interest-bearing bonds so that its per-unit cost of energy output will be correspondingly higher than that from Watana.

It should also be noted that after the completion of Devil Canyon the most meaningful basis of comparison is the Susitna cost excluding excess debt service cover. This is because this excess debt service charge is then available to finance other power generation projects and could, under certain conditions, be "refunded" to consumers (up until this date the excess charge is used to help finance Devil Canyon).

[2] This conclusion would be modified if, as proposed by Senate Bill 646, the APA is required to repay the state appropriation from the revenues generated by the project.

However, after the step-up as Devil Canyon comes on-stream in 2002, the future unit price of Susitna energy would be falling for some years before becoming virtually constant, despite an assumed annual rate of inflation of 7 percent and an additional escalation of about 2 percent in operating and maintenance costs. (This fall is due to the effect of increased sales of Susitna energy after 2002.) In terms of constant 1982 dollars, therefore, the cost of energy supplied from Susitna will be falling markedly.

Under this scenario Susitna will again provide ever-increasing savings to Alaskan consumers in terms of the difference between its falling and then nearly-constant price energy and the ever-escalating cost of the thermal alternative as shown in Figure 18.4.3.

(iii) "Minimum" State Appropriation $2.3 billion (1982 dollars) with Residual Bond Financing

The "minimum" state appropriation is taken as the minimum amount required to meet debt service cover of 1.25 on the residual debt financing by revenue bonds and to make Susitna's wholesale energy price competitive with the best thermal option in its first normal cost year of operation (i.e., 1994). The basic characteristics of this scenario are shown in Figure 18.4.7. Again the results shown are based upon central estimates for interest rates, inflation, capital cost, etc. If these estimates were achieved, the $2.3 billion (1982 dollars) state appropriation would be just sufficient to result in Susitna meeting its debt service cover and operating costs in the first year.

As is seen from Figure 18.4.7, however, with an appropriation of $2.3 billion (in 1982 dollars) Susitna will again, after the completion of Devil Canyon, provide a falling and then virtually stable cost of electricity indefinitely and ever-increasing cost savings compared with the thermal option.

Slightly lower appropriations would still be consistent with financial viability of the project based on the central estimates. These would however result in Susitna being unable, in its first normal year of operation (1994), to meet fully debt service cover, i.e., it would be unable to earn the 1.25 times debt service requirement which must be expected as the minimum if the project were residually financed by revenue bonds. Under such "less-than-minimum" scenario, therefore, it must be assumed that this residual bond financing in the earlier years is on the basis of a state guarantee or general obligation (G.O.) bonds as detailed below. At any substantially lower state appropriation than $2.3 billion (in 1982 dollars), Susitna would have a correspondingly large, early year inflationary financing deficit unless it was possible to wholesale its energy output at a higher price than that which would apply under the best thermal option. If it was not possible to secure such higher price contracts there might also be significant financing difficulties as discussed in (d) (vi) below.

(d) Issues Arising From the Base Financing Options

(i) Need for Financial Restructuring

If substantial revenue bond financing is to be secured for Susitna, it will have to be based on firm power contracts from the major Railbelt utilities. These contracts will, however, need to be supported by adequate financial strength on the part of the utilities themselves if they are to constitute acceptable security to bondholders. Whether Susitna or any other alternative element of generating capacity is chosen to meet the Railbelt energy requirements over the next decade, the same issue of the financial strength of the Railbelt utilities will arise if revenue bond financing is to be secured. On these grounds it is assumed that independently of Susitna, financial restructuring will take place to ensure that all the major Railbelt utilities will be able to offer adequate financial security relative to their power contract commitments.

(ii) Tax-exempt Bond Financing

Tax exemption for its bond financing is important to the economics of Susitna insofar as it is, in substantial measure, to be financed by G.O. or revenue bonds. Tax-exempt bonds have tended to trade at interest rates some 25 to 30 percent less than the rate of interest on comparable securities. Since interest charges account for some 90 percent of the total price for Susitna's output (in 1994 under the $2.3 billion state appropriation scenario), loss of tax exemption would have a serious adverse affect on the economics of the project.

The conditions under which bonds will secure tax-exempt status are covered in the Internal Revenue Code Section 103. These are designed to prevent the benefits of tax-exempt bond financing passing to non-exempt entities. The only significant tax-exempt entities in the Railbelt area likely to purchase Susitna energy are AMLP and FMUS. All other potential customers for Susitna energy (representing approximately two-thirds of the potential market) are private utilities or co-ops which are not tax-exempt.

This issue has been considered in detail by the consultants and reviewed by tax advisers. It has been concluded, that with an appropriate degree of financial restructuring referred to above, it will prove possible to meet the conditions required for any bond financing for Susitna to obtain tax exempt status.

(iii) Options for Residual Financing

Tables 18.4.2 and 18.4.3 set out the estimated requirements for bond financing and state appropriations of $2.3 billion and $3 billion respectively.

- Several options are available to meet these financing needs and these are summarized below.

  . Revenue Bonds with a Completion Guarantee

  A completion guarantee must be assumed to be a precondition of bond financing at the Watana stage (up to 1993). A State of Alaska guarantee of project completion would probably enable all residual financing to be met by revenue bonds.

  . Guaranteed Revenue Bonds with Post-completion Refinancing

  If the revenue bonds were guaranteed by the State of Alaska, this could be expected to limit the requirement for a completion guarantee.

  . G.O. Bonds with Post-completion Refinancing

  G.O. bonds which have the "full faith and credit" of the State of Alaska share a common security feature with guaranteed revenue bonds and would limit the support required from a completion guarantee. Furthermore, G.O. bond financing would have a beneficial effect on energy pricing arising from reduced debt service cover requirements.

  In this case, as with that of guaranteed revenue bonds, the burden on the credit of the state could be minimized by making the bonds subject to "call" after a few years (when project viability was established) and refinancing into non-guaranteed revenue bonds.

- Revenue Bonds with Completion Guarantee

  The first option is that of revenue bond financing for the whole of the residual capital requirements. It is probable that such financing will only be obtainable on the basis of bond holders being protected from pre-completion risk including (a) the risk of overruns and (b) the risk of actual non-completion. Neither the Railbelt utilities nor the APA could provide a wholly satisfactory guarantee covering both (a) and (b). The guarantee would have to be provided by the State of Alaska.

  The precise form of this completion guarantee cannot be determined at this stage. It will depend on the extent to which the power sales contracts accept any escalation in wholesale energy price based on capital costs and on the magnitude of the state appropriation since it is primarily these factors which will determine the residual financing risk. With appropriate power contracts and a sufficiently large state appropriation, the state completion guarantee might be limited to guaranteeing bond holders against non-completion due to natural hazards or national emergencies. In other cases it might also be necessary to provide a contingent authorization permitting a given maximum amount of subordinated G.O. bonds to be issued to ensure completion.

- Guaranteed Revenue Bonds with Post-completion Refinancing

  If revenue bonds were guaranteed by the State of Alaska they could be issued without any requirement for a completion guarantee. This is because the strength of the state guarantee would make any other security unnecessary. It is assumed, however, that in the interest of avoiding unnecessary burdens on its 'credit', the State of Alaska would wish to see the guarantee terminated at the earliest possible date. This could be achieved by making the bonds subject to "call" (repayment at the option of the issuer) 15 years after issue in the case of bonds financing Watana and 10 years after issue of bonds to finance Devil Canyon. The state guarantee would, of course, ensure repayment at the call dates. Coverage level conditions at these call dates (2005 at the earliest) are seen from Figures 18.4.3 and 18.4.4 to be such as to offer adequate security without state guarantees and therefore, subject to market conditions at the time, permit refinancing into non-guaranteed revenue bonds.

- G.O. Bonds with Post-completion Refinancing

  As an alternative to guaranteed revenue bonds, G.O. bonds on the "full faith and credit" of the State of Alaska could be issued. These are effectively identical to bonds carrying a comparable state guarantee. Again they could be subject to "call" and as such be converted to revenue bonds without state guarantee when the project was fully established.

(iv) Borrowing Requirements for the Residual Financing Options

On the assumption that the residual source of finance for Watana is revenue bonds, the estimate of year-by-year requirements up to the completion of Watana are shown in Table 18.4.2 and 18.4.3 for the minimum state appropriation of $2.3 billion and the $3 billion scenarios respectively (1982 dollars). These again take the central capital cost estimate as the starting point and estimate the bond financing requirements year-by-year for a 7 percent rate of inflation up to the date of completion of Watana.

The requirements are given in the form of then-actual money and in terms of dollars at 1982 purchasing power. It is the latter on which the assessment should focus since, even with 7 percent inflation, the value of the bonds issued for the completion of Watana in 1993 will be worth only 48 cents of a dollar in 1982. It is these "today's purchasing power dollars" which most accurately reflect the financing burden of Susitna. Even in this, the "minimum" $2.3 billion state appropriation scenario, the issuance of $1.7 billion of bonds (in 1982 purchasing power) over the 4 years from 1990 appears to be well within the financing capability of the State of Alaska. The possible impact of such an issue on the credit rating of the state is however considered below.

(v) Refinancing Watana and the Financing of Devil Canyon

As already noted it is assumed that it would be the policy of the State of Alaska to ensure that any guaranteed revenue bonds were refinanced into non-guaranteed revenue bonds at as early a date as possible. When this would in fact be possible would depend both on the revenues actually obtainable from Susitna at the Watana stage of development and on the conditions of the bond market at that time.

A dominant consideration, as regards the date at which refinancing into non-guaranteed revenue bonds will be possible, will be the magnitude of the initial state appropriation. In the $3 billion (1982 dollars) scenario such refinancing should be possible for a very wide range of outcomes. This is apparent in Figure 18.4.3 which shows that on the central estimates Susitna could be financed with revenue bonds on a 1.25 cover basis and be charging a wholesale energy price of approximately 236 mills/kWh (i.e., 20 mills/kWh less than the cost of the best thermal option) in 2003. This price would thereafter show rapid and ever-increasing divergence from the cost of the best thermal option. In this case only a relatively extreme combination of adverse eventualities in terms of interest rates, capital cost overruns, etc., could result in it not being possible to undertake refinancing into non-guaranteed revenue bonds within a few years of completion.

Capital expenditures for Devil Canyon for completion in the year 2002 will begin almost immediately after the completion of Watana. On the basis of the central forecasts, the outcome, as depicted in summary form in Figures 18.4.3 and 18.4.4, is that it would be possible to finance this stage wholly by non-guaranteed revenue bonds and without a completion guarantee where the initial state appropriation is at the $2.3 billion or $3 billion level for the total project (in 1982 dollars).

The grounds for this conclusion are that (a) Devil Canyon is a considerably smaller capital project than Watana ($1.48 billion as compared with $3.65 billion in 1982 dollars) and (b) the major construction risks would have been fully explored during the Watana stage. Also seen from Figures 18.4.3 and 18.4.4 on the central forecast, the cost of energy from the best thermal option would be 23 percent or more costly than that from Susitna in 2005. This comparative cheapness (and therefore the scope for substantially-increased revenues if necessary) is the basic security which the project would offer to bond holders.

The magnitude of the revenue bond financing required for the Devil Canyon stage in the $2.3 billion state appropriation scenario is shown in Table 18.4.2. The financing requirements are given for a 7 percent inflation rate and in then-actual money terms as well as in the purchasing power of 1982 dollars. The amount of $2.1 billion (in 1982 dollars) as a bond financing burden on the State of Alaska does not appear excessively large. The financing requirements in the $3 billion appropriation case are given in Table 18.4.3.

(vi) Importance of Adequate Appropriation to Subsequent Financing

In the "minimum" scenario (i.e., a state appropriation of $2.3 billion) refinancing into non-guaranteed revenue bonds would still be possible on the central estimates with the completion of Watana in 1993. On any less favorable outcome than that resulting from the central estimates, however, G.O. bond refinancing could be delayed until the ceiling on the Susitna energy price, set by the best thermal option, was high enough for Susitna energy prices to be increased to a level at which it could offer the 1.25 times debt service cover which would probably be required by revenue bond holders in the absence of guarantees.

This scenario is illustrated in Figure 18.4.8 for a state appropriation of only $1.8 billion. (See also Table 18.4.8.) In this case it would be necessary to increase the price of Susitna's energy each year (within the limit set by the cost of energy from the best thermal option) and use the additional revenue to refinance with non-guaranteed revenue bonds. In this scenario complete refinancing into revenue bonds would not take place until 1995.

Timely and adequate funding for Susitna is of great importance in minimizing dependance on state guarantees. There is the likelihood that inadequate initial funding would result in insufficient potential earnings cover in the early years of Devil Canyon. This might necessitate state guarantees for the financing of Devil Canyon as well as Watana. This possibility is also illustrated in Figure 18.4.8, where the Susitna price is forced to "track" the cost of the best thermal option over the years 2002-2004. These considerations point to the importance of adequate initial funding to the establishment of Susitna at the Watana stage as a project fully capable of securing both tax-exempt low interest revenue bond financing for the Devil Canyon stage and subsequent refinancing into non-guaranteed bonds of the issues made to finance Watana.

A further consideration of basic importance is the influence of adequate and timely state appropriation in minimizing construction bid prices. It must be expected that any perceived inadequacy in funding, creating possible delay in payment or uncertainties in the construction schedule, would be fully reflected in the level of bid prices.

(vii) <u>Impact on State Credit Rating of Susitna G.O. Bond Financing</u>

Where the financing plan actually undertaken is near the "minimum" ($2.3 billion) state appropriation, the guaranteed revenue bond or G.O. bond financing at the Watana stage may be of a magnitude that warrants consideration of its effect upon the overall credit rating of the State of Alaska.

As at November 1981 the State of Alaska had approximately $681.7 million of G.O. bonds outstanding. In late 1981 these were rated "AA" by Moody's and "Aa-" by Standard & Poors.

The impact on the state's credit rating of Susitna guaranteed or G.O. bond financing of $1.7 billion (in 1982 dollars) for the $2.3 billion state appropriation case will depend upon a wide range of factors. The most important will obviously be the strength of the credit standing of the State of Alaska at that time, taking into account the total amount of bonds which it has issued and outstanding. The second factor will be the economic prospects for Susitna itself - that is the extent to which it is perceived by the bond market as likely to be able to meet the interest burden on the bonds issued to finance its construction. The impact has been assessed by the Alaskan Power Authority's investment banking and financial advisers First Boston Corporation and First Southwest Company. They have concurred in the following statement.

> "We are only able to render a conditional estimate of the possible impact on the credit of the State of Alaska as a result of the contemplated general obligation bond financing of $1.7 billion for the Watana stage of the Susitna Hydroelectric Project. Alaska's presently favorable ratings are greatly influenced by its low debt to assessed value ratio which helps to overcome the unusually high per capita debt statistics. Given the dramatic growth of assessed valuation and in the fact that interest expense through start-up of Watana is to be capitalized from bond proceeds the envisaged financing should not significantly impair the credit of the state. Even if the State of Alaska's general obligation bond rating were reduced one full letter grade, the cost in terms of interest rates on future bond issues would likely be in the approximate range of 1/4 percent to 1/2 percent per annum."

(e) <u>Financing Options Under Senate Bill 646 and House Bill 655</u>

Senate Bill 646 and House Bill 655 have been proposed and if enacted would offer alternative financing options to those considered above. These options are briefly reviewed in this sub-section.

In summary, Senate Bill 646 and House Bill 655 propose funding for approved energy projects from the Power Development Fund on the basis of such funding being recovered at a rate of 3 percent per annum together with an uplift to reflect past inflation. The latter is determined at 10 yearly intervals and increases the 3 percent recovery by the average rate of inflation in the CPI over the preceding 33 years.

(i) 100 Percent State Appropriation

First to be considered is the total appropriation required to finance Susitna wholly under this proposed legislation. In terms of total state appropriation this is the same as the outright appropriation case considered in 18.4 (c) (i). As seen from Figure 18.4.6 and Table 18.4.9, however, the resulting cost of power is very different. For the 'outright' appropriation case the cost of power would be only 19 mills/kWh in 1994. For the Senate Bill 646 case it would be 81 mills/kWh.

(ii) "Minimum" State Appropriation of $3 Billion (in 1982 dollars) with Residual Bond Financing

To identify the impact of Senate Bill 646 and House Bill 655, where residual bond financing is required, some details of the proposed bills need to be clarified. Specifically:

- Whether the state recovery is subordinate to interest and debt repayments on the revenue or G.O. bonds.
- Whether, in the event of any failure to meet the state recovery, the APA would be deemed in default and the payment made be a debt of the APA and attract interest.

Both questions are important to residual financing by revenue bonds. In the following analysis it is assumed that, to facilitate bond financing, the state recovery will be wholly subordinate and failure to meet payment would not be deemed a default. This assumption has the important effect in terms of the pricing of Susitna energy that the state recovery of funding could be largely made out of the .25 excess debt service cover and not need to be additional to it.

It is again assumed that the ceiling price of the Susitna output is set by the cost of the best thermal option, and that 1.25 times cover would be required for the revenue bonds.

The results are shown in Figure 18.4.7 and Table 18.4.10. This shows that an appropriation of $3 billion (in 1982 dollars) would be enough to provide sufficient earnings cover for the $0.9 billion (in 1982 dollars) of bond financing required to complete Watana. In 1994 a further $2.3 billion of revenue bonds would be required to achieve the completion of Devil Canyon.

The $3 billion appropriation would, however, be the "minimum" in the sense that the Susitna output would need to be priced up to the full cost of the best thermal option in the first year of operation of Devil Canyon. As will be seen from Figure 18.4.7 this Senate Bill 646 scenario would result in a selling price for Susitna energy of 120 mills/kWh in 1994 compared with 80 mills/kWh in the $3 billion outright appropriation case ((c) (ii) above). This scenario would nevertheless be effective in terms of the twin objectives of meeting the inflationary financing deficit and reducing the cost of power to Alaskan consumers and might be regarded as similar in these characteristics and in state appropriation to the $3 billion outright appropriation already noted.

(f) Future Development and Resolution of Uncertainties

Prior to the decision to proceed with actual construction of Susitna, several significant uncertainties affecting the project will have been reduced. Demand forecasts will be more certain and the impact of the electrical intertie between Anchorage and Fairbanks will be known. Fuel cost trends and energy prices from alternative generation sources will be more precisely known. More advanced engineering work and definition of the basis for construction contracts will have firmed up requirements for capital funds. In addition, the passage of time will have allowed better definition of the level of state appropriation required and of the ability of the state to provide the necessary financial support.

The development of the institutional structure of the Railbelt utilities by this date should also permit power contracts and legislative proposals to be drawn up which would equitably share these then more clearly delineated risks between the utilities, the APA and the State of Alaska. The key requirements for state guarantees and financing could then be more precisely defined in an appropriately limited form which would be acceptable to the state and adequate for project financing.

(g) Conclusion

Early year inflationary financing deficits have been seen to be inevitable in the case of capital-intensive debt-financed projects being built under inflationary conditions. Such inflationary financing deficits have no bearing on the economic viability of the project but instead directly result from inflation. As a highly capital-intensive, long-life project, Susitna has a substantial inflationary financing deficit despite its strong economic viability. If the project is to go forward and its advantages in terms of indirect economic benefit and stablization of Alaskan electrical energy prices realized, major state appropriation of funds will be required.

In terms of the magnitude of appropriation an amount of not less than $2.3 billion (in 1982 dollars) would represent an assured and effective means of meeting the inflationary financing deficit. This would ensure that Susitna energy could be made available in the first year of operation at a price competitive with the cost from the appreciable increase in the Railbelt system energy cost which would be otherwise occurring at that time as a result of the rising cost of fuel and other factors. Substantially lesser levels of appropriation might create appreciable difficulties or costs as regards the residual debt financing. In particular such inadequacies might create the need for a more prolonged period of guaranteed revenue bond or G.O. bond financing, or involve higher electricity costs.

Finally, it is important to distinguish between appropriations to meet the inflationary deficit and appropriations designed to reduce the cost of electricity to Alaskan consumers. The economics of Susitna are such that it could, long term, repay with an adequate rate of return, all of the state appropriations used to finance Susitna's inflationary financing deficit. State financing of the magnitude indicated is therefore economically justifiable in terms of meeting the inflationary financing deficit in an efficient and adequate manner to enable an economically viable and important project to proceed. The decision to allow all or part of this appropriation to be retained in the project, long term, or to provide even larger appropriations to subsidize the cost of electrical energy to Alaskan consumers, is a separate issue to be decided as a matter of public policy and is beyond the terms of reference of this study.

TABLE 18.4.1: FORECAST FINANCIAL PARAMETERS

	Watana	Devil Canyon	Total
Project Completion - Year	1993	2002	
Energy Level - 1993			3 387 GWh
- 2002			5 223 "
- 2010			6 616 "
Costs in January 1982 Dollars			
Capital Costs	$ 3.647 billion	$1.470 billion	$ 5.117 billion
Operating Costs - per annum	$10.0 million	$5.42 million	$15.42 million
Provision for Capital Renewals - per annum (0.3 percent of Capital Costs)	$10.94	$4.41	$15.35
Operating Working Capital	15 percent of Operating Costs 10 percent of Revenue		
Reserve and Contingency Fund	100 percent of Operating Costs 100 percent of Provision for Capital Renewals		
Interest Rate	10 percent per annum		
Debt Repayment Period	35 years		
Inflation Rate	7 percent per annum		
Real Rate of Increase in Operating Costs			
- 1982 to 1987	1.7 percent per annum		
- 1988 on	2.0 percent per annum		
Real Rate of Increase in Capital Costs			
- 1982 to 1985	1.1 percent per annum		
- 1986 to 1992	1.0 percent per annum		
- 1993 on	2.0 percent per annum		

TABLE 18.4.2 FINANCING REQUIREMENTS - $ BILLION

For $2.3 billion State Appropriation Scenario

	Interest Rate 10% Inflation Rate 7% Actual	1982 Purchasing Power
	$ billion	
1985 State Appropriation	0.4	0.3
86 "	0.5	0.4
87 "	0.5	0.3
88 "	0.5	0.3
89 "	0.9	0.6
90 "	0.7	0.4
Total State Appropriation	3.5	2.3
1990 Guaranteed or G.O Bonds	0.8	0.5
1 " "	1.3	0.7
2 " "	0.9	0.4
3 " "	0.3	0.1
Total Watana Bonds	3.3	1.7
1994 Revenue Bonds	0.2	0.1
5 " "	0.3	0.1
6 " "	0.4	0.2
7 " "	0.3	0.1
8 " "	1.1	0.4
9 " "	1.4	0.4
2000 " "	1.5	0.4
1 " "	1.4	0.4
2 " "	0.2	-
Total Devil Canyon Bonds	6.8	2.1
Total Susitna Bonds	10.1	3.8

TABLE 18.4.3: FINANCING REQUIREMENTS - $ BILLION

For $3 billion State Appropriation Scenario

	Interest Rate 10% Inflation Rate 7% Actual	1982 Purchasing Power
	$ billion	
1985 State Appropriation	0.4	0.3
86 "	0.5	0.4
87 "	0.5	0.3
88 "	0.5	0.3
89 "	0.9	0.6
90 "	1.5	0.9
91 "	0.5	0.2
Total State Appropriation	4.8	3.0
1990 Guaranteed or G.O Bonds	-	-
1 " "	0.8	0.4
2 " "	0.7	0.4
3 " "	0.3	0.1
T 'al Watana Bonds	1.8	0.9
1994 Revenue Bonds	0.2	0.1
5 " "	0.4	0.1
6 " "	0.4	0.2
7 " "	0.4	0.1
8 " "	1.2	0.4
9 " "	1.4	0.4
2000 " "	1.6	0.5
1 " "	1.5	0.4
2 " "	0.1	0.1
Total Devil Canyon Bonds	7.2	2.3
Total Susitna Bonds	9.0	3.2

DATA10K WATANA-DC (ON LINE 1993-2002) INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73	ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521	REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.65	7.98
466	INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520	PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.94	18.59
	-----INCOME-----------------										
516	REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	63.0
170	LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517	OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.6
214	ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550	LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391	LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
548	NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.5
	-----CASH SOURCE AND USE----										
543	CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.5
445	STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	333.1	229.7
143	LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
248	WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549	TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	431.1	276.9
320	LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	333.1	259.2
448	LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260	LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444	CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371	OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6600.9	6860.1
465	CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6698.9	6975.8
461	STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6600.9	6830.6
462	RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.5
555	DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554	DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542	ANNUAL DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543	CUM. DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519	DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

100% STATE APPROPRIATION OF TOTAL CAPITAL COST ($5.1 BILLION IN 1982 DOLLARS)

TABLE 18.4.5

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)- ·INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521 REAL PRICE-MILLS	8.24	8.38	8.74	8.88	9.04	9.17	9.30	7.66	8.84	8.68
466 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520 PRICE-MILLS	20.55	22.36	24.93	27.13	29.53	32.06	34.79	30.64	37.86	39.80
-----INCOME-----------------										
516 REVENUE	69.6	75.7	84.4	91.9	100.0	108.6	117.8	160.0	204.9	223.1
170 LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517 OPERATING INCOME	37.6	40.8	46.3	50.2	54.6	59.0	63.7	69.0	105.5	114.6
214 ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550 LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	19.8	21.0	33.8	36.3
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
548 NET EARNINGS FROM OPERS	32.2	35.1	38.3	41.8	45.6	49.8	54.4	59.3	90.9	99.2
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	32.2	35.1	38.3	41.8	45.6	49.8	54.4	59.3	90.9	99.2
446 STATE CONTRIBUTION	363.1	382.1	303.8	1028.3	1177.5	1204.8	913.1	303.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549 TOTAL SOURCES OF FUNDS	403.4	446.5	353.3	1082.4	1233.7	1265.1	979.8	490.3	115.6	142.0
320 LESS CAPITAL EXPENDITURE	395.3	417.2	342.1	1070.1	1223.2	1254.6	967.5	362.3	90.9	99.2
448 LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371 OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	7255.4	7672.6	8014.7	9084.8	10308.0	11562.6	12530.1	12892.5	12983.3	13082.5
465 CAPITAL EMPLOYED	7379.2	7825.7	8179.0	9261.4	10495.1	11760.2	12740.0	13230.3	13345.9	13487.9
461 STATE CONTRIBUTION	7193.7	7575.8	7879.6	8907.9	10085.4	11290.3	12203.4	12506.4	12506.4	12506.4
462 RETAINED EARNINGS	61.6	96.8	135.1	176.9	222.6	272.4	326.7	386.1	477.0	576.1
555 DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	197.6	209.9	337.8	362.6	405.4
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542 ANNUAL DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

100% STATE APPROPRIATION OF TOTAL CAPITAL COST ($5.1 BILLION IN 1982 DOLLARS)

TABLE 18.4.5

ACRES

DATA10K WATANA-OC (ON LINE 1993-2002) ·INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

		2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
73	ENERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521	REAL PRICE-MILLS	8.18	8.27	8.33	8.24	8.30	8.35	8.48	8.57	8.67	0.00
466	INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520	PRICE-MILLS	40.12	43.39	46.75	49.49	53.35	57.45	62.39	67.48	73.02	0.00
	-----INCOME-----------------										
515	REVENUE	244.4	266.7	292.1	320.3	349.1	380.1	414.1	449.4	487.9	4530.0
170	LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517	OPERATING INCOME	126.0	137.4	151.1	166.3	181.1	196.7	214.0	231.0	249.5	2328.0
214	ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
550	LESS INTEREST ON SHORT TERM DEBT	40.5	44.2	49.3	55.2	59.8	64.4	69.6	73.4	77.5	746.6
391	LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
546	NET EARNINGS FROM OPERS	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	1993.8
	-----CASH SOURCE AND USE----										
548	CASH INCOME FROM OPERS	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	1993.8
446	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12506.4
143	LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
243	WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549	TOTAL SOURCES OF FUNDS	144.7	169.4	188.2	186.5	199.4	219.6	220.6	240.8	262.8	15319.9
320	LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	14500.2
443	LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260	LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444	CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	248.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371	OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	13190.7	13308.9	13437.8	13578.5	13732.1	13899.7	14082.6	14282.3	14500.2	14500.2
465	CAPITAL EMPLOYED	13632.6	13801.9	13990.2	14176.7	14376.1	14595.7	14816.3	15057.1	15319.9	15319.9
461	STATE CONTRIBUTION	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4
462	RETAINED EARNINGS	684.4	802.5	931.4	1072.1	1225.7	1393.3	1576.3	1775.9	1993.8	1993.8
555	DEBT OUTSTANDING-SHORT TERM	441.8	493.1	552.4	598.2	644.0	696.0	733.7	774.8	819.7	819.7
554	DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542	ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543	CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519	DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

100% STATE APPROPRIATION OF TOTAL CAPITAL COST ($5.1 BILLION IN 1982 DOLLARS)

TABLE 18.4.5

DATA10K WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.74	34.38
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.76	80.08
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	219.3	271.2
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	192.4	241.9
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	154.0	183.4
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	54.3
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	54.3
446 STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	1550.4	462.4	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	784.7	754.9	294.6	211.6
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549 TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	754.9	431.1	283.7
320 LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	754.9	333.1	259.2
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.8
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6346.3	6679.4	6938.6
465 CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6346.3	6777.4	7054.3
461 STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	4344.3	4806.7	4806.7	4806.7	4806.7
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	92.8
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	784.7	1539.5	1834.2	2039.0
542 ANNUAL DEBT DRAWHDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	412.6	371.0	135.3	90.8
543 CUM. DEBT DRAWHDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	412.6	783.6	918.9	1009.7
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.25	1.25

$3 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE 18.4.6

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521 REAL PRICE-MILLS	32.59	30.81	29.37	27.83	26.39	25.04	23.79	58.55	55.54	50.49
466 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520 PRICE-MILLS	81.25	82.18	83.81	84.97	86.24	87.54	89.00	234.36	237.89	231.37
-----INCOME-----------------										
516 REVENUE	275.2	278.3	283.8	287.8	292.1	296.5	301.4	1224.0	1287.8	1296.7
170 LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517 OPERATING INCOME	243.1	243.4	245.7	246.2	246.6	246.9	247.3	1132.9	1188.4	1188.2
214 ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550 LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	20.0	21.9	34.7	36.3
391 LESS INTEREST ON LONG TERM DEBT	182.7	182.0	181.2	130.3	179.3	178.2	177.0	883.4	895.7	891.5
548 NET EARNINGS FROM OPERS	55.0	55.7	56.6	57.5	58.4	59.5	60.7	239.0	277.2	281.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	55.0	55.7	56.6	57.5	58.4	59.5	60.7	239.0	277.2	281.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	368.9	427.7	395.4	1163.0	1432.3	1604.7	1473.5	137.8	0.0	0.0
243 WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549 TOTAL SOURCES OF FUNDS	432.0	512.8	463.1	1232.7	1501.3	1674.7	1546.5	504.8	301.9	324.3
320 LESS CAPITAL EXPENDITURE	416.4	475.3	442.9	1210.5	1479.8	1654.5	1527.9	362.3	90.9	99.2
448 LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260 LESS DEBT REPAYMENTS	7.4	8.2	9.0	9.9	10.9	12.0	13.2	14.5	42.6	46.8
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	-2.3	-6.8	0.0	143.7	135.4
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	2.3	6.8	0.0	-9.1	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	134.6	135.4
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371 OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	7355.0	7830.3	8273.2	9483.7	10963.5	12618.0	14145.9	14508.2	14599.1	14698.3
465 CAPITAL EMPLOYED	7478.8	7983.4	8437.5	9660.3	11150.6	12815.6	14355.8	14846.1	14961.7	15103.7
461 STATE CONTRIBUTION	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7
462 RETAINED EARNINGS	147.8	203.5	260.1	317.5	376.0	435.5	496.2	735.2	877.8	1023.8
555 DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	199.8	219.0	346.9	362.6	405.4
554 DEBT OUTSTANDING-LONG TERM	2400.5	2820.0	3206.4	4359.4	5780.8	7373.5	8833.8	8957.1	8914.6	8867.7
542 ANNUAL DEBT DRAWDOWN $1982	148.0	160.4	138.5	380.8	438.3	459.0	393.9	34.4	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	1157.7	1318.0	1456.6	1837.4	2275.7	2734.7	3128.6	3163.0	3163.0	3163.0
519 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25

$3 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE 18.4.6

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

		2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
73	ENERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521	REAL PRICE-MILLS	43.82	40.97	38.08	34.79	32.53	30.45	28.74	27.13	25.63	0.00
466	INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520	PRICE-MILLS	214.89	214.98	213.79	208.98	209.12	209.41	211.54	213.62	215.95	0.00
	-----INCOME-----										
516	REVENUE	1309.0	1321.4	1336.1	1352.4	1368.4	1385.3	1404.1	1422.6	1442.9	18656.4
170	LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517	OPERATING INCOME	1190.6	1192.2	1195.0	1198.5	1200.4	1202.0	1204.0	1204.2	1204.5	16454.4
214	ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
550	LESS INTEREST ON SHORT TERM DEBT	40.5	44.2	49.3	55.2	59.8	64.4	69.6	73.4	77.5	748.6
391	LESS INTEREST ON LONG TERM DEBT	886.8	881.6	876.0	869.7	862.9	855.3	847.0	837.9	827.9	12013.6
548	NET EARNINGS FROM OPERS	286.1	291.2	296.9	303.1	310.0	317.5	325.8	335.0	345.0	4104.6
	-----CASH SOURCE AND USE----										
548	CASH INCOME FROM OPERS	286.1	291.2	296.9	303.1	310.0	317.5	325.8	335.0	345.0	4104.6
446	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4806.7
143	LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9049.0
243	WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549	TOTAL SOURCES OF FUNDS	322.5	342.5	356.2	349.0	355.9	369.5	363.6	376.1	389.9	18780.1
320	LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	16115.9
443	LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260	LESS DEBT REPAYMENTS	51.5	56.7	62.3	68.6	75.4	83.0	91.3	100.4	110.4	880.9
141	CASH SURPLUS(DEFICIT)	126.3	116.4	105.6	93.9	81.0	67.0	51.6	34.9	16.7	963.5
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444	CASH RECOVERED	126.3	116.4	105.6	93.9	81.0	67.0	51.6	34.9	16.7	963.5
	-----BALANCE SHEET-----										
225	RESERVE AND CONT. FUND	249.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371	OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	14806.5	14924.6	15053.6	15194.3	15347.9	15515.5	15698.4	15898.1	16116.0	16116.0
465	CAPITAL EMPLOYED	15248.3	15417.7	15605.9	15792.4	15991.9	16211.4	16432.1	16672.9	16935.7	16935.7
461	STATE CONTRIBUTION	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7
462	RETAINED EARNINGS	1183.5	1358.3	1549.6	1758.9	1987.9	2238.5	2512.7	2812.8	3141.1	3141.1
555	DEBT OUTSTANDING-SHORT TERM	441.3	493.1	552.4	598.2	644.0	696.0	733.7	774.8	819.7	819.7
554	DEBT OUTSTANDING-LONG TERM	8816.2	8759.5	8697.2	8628.6	8553.2	8470.2	8378.9	8278.6	8168.1	8168.1
542	ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3163.0
543	CUM. DEBT DRAWDOWN $1982	3163.0	3163.0	3163.0	3163.0	3163.0	3163.0	3163.0	3163.0	3163.0	3163.0
519	DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.00

$3 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

Sheet 3 of 3

TABLE 18.4.6

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$2.3 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.85	58.76
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110.73	136.90
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	375.0	463.6
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	348.1	434.3
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	303.1	331.9
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	98.3
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	98.3
446 STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	738.4	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	812.0	1328.3	890.4	288.1	173.2
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549 TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1328.3	890.4	431.1	289.2
320 LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1550.4	1328.3	890.4	333.1	259.2
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.2
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5672.6	6563.0	6896.1	7155.3
465 CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5672.6	6563.0	6994.1	7271.0
461 STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	3532.4	3532.4	3532.4	3532.4	3532.4
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	143.3
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	812.0	2140.2	3030.7	3318.7	3479.6
542 ANNUAL DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	456.8	698.4	437.6	132.3	74.3
543 CUM. DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	456.8	1155.3	1592.9	1725.2	1799.5
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.15	1.25

$2.3 BILLION (1982 DOLLARS) MINIMUM STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

Sheet 1 of 3

TABLE 18.4.7

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$2.3 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73	ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521	REAL PRICE-MILLS	55.38	52.11	49.27	46.43	43.78	41.29	38.96	63.57	59.90	55.83
466	INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520	PRICE-MILLS	138.06	139.00	140.63	141.79	143.06	144.36	145.75	254.47	256.58	255.86
	-----INCOME-----------------										
516	REVENUE	467.6	470.8	476.3	480.2	484.5	488.9	493.6	1329.0	1389.0	1434.0
170	LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517	OPERATING INCOME	435.6	435.8	438.1	438.6	439.1	439.3	439.5	1237.9	1289.6	1325.5
214	ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550	LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	19.8	21.0	33.8	36.3
391	LESS INTEREST ON LONG TERM DEBT	330.6	329.3	327.8	326.2	324.4	322.4	320.3	982.5	994.1	988.8
548	NET EARNINGS FROM OPERS	99.5	100.8	102.3	104.0	105.8	107.7	109.9	245.8	280.8	321.3
	-----CASH SOURCE AND USE----										
548	CASH INCOME FROM OPERS	99.5	100.8	102.3	104.0	105.8	107.7	109.9	245.8	280.8	321.3
446	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	LONG TERM DEBT DRAWDOWNS	326.5	381.2	344.2	1106.6	1370.3	1538.8	1405.6	142.8	0.0	0.0
248	WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549	TOTAL SOURCES OF FUNDS	434.2	511.3	457.7	1222.8	1486.6	1657.0	1527.8	516.5	305.5	364.2
320	LESS CAPITAL EXPENDITURE	412.6	467.2	430.2	1192.7	1456.3	1624.8	1491.6	362.3	90.9	99.2
448	LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260	LESS DEBT REPAYMENTS	13.5	14.8	16.3	17.9	19.7	21.7	23.9	26.2	53.9	59.3
141	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	136.0	162.8
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444	CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	136.0	162.8
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371	OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	7567.9	8035.1	8465.3	9657.9	11114.2	12739.1	14230.7	14593.0	14683.8	14783.0
465	CAPITAL EMPLOYED	7691.7	8188.2	8629.6	9834.5	11301.4	12936.6	14440.5	14930.8	15046.4	15188.4
461	STATE CONTRIBUTION	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4
462	RETAINED EARNINGS	242.8	343.7	446.0	550.0	655.7	763.4	873.3	1119.1	1263.9	1422.4
555	DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	197.6	209.9	337.8	362.6	405.4
554	DEBT OUTSTANDING-LONG TERM	3792.7	4159.0	4486.9	5575.6	6926.2	8443.3	9825.0	9941.5	9887.6	9828.2
542	ANNUAL DEBT DRAWWDOWN $1982	131.0	142.9	120.6	362.4	419.4	440.1	375.7	35.7	0.0	0.0
543	CUM. DEBT DRAWWDOWN $1982	1930.5	2073.4	2194.0	2556.3	2975.7	3415.8	3791.5	3827.2	3827.2	3827.2
513	DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.22	1.22	1.25

$2.3 BILLION (1982 DOLLARS) MINIMUM STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE 18.4.7

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$2.3 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY

===($MILLION)====

	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
73 ENERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521 REAL PRICE-MILLS	48.42	45.23	41.99	38.32	35.80	33.46	31.55	29.75	28.07	0.00
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520 PRICE-MILLS	237.42	237.31	235.75	230.18	230.09	230.15	232.21	234.23	236.49	0.00
-----INCOME-----------------										
516 REVENUE	1446.3	1458.6	1473.3	1489.6	1505.6	1522.6	1541.3	1559.8	1580.1	21929.6
170 LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517 OPERATING INCOME	1327.8	1329.4	1332.3	1335.7	1337.6	1339.2	1341.2	1341.4	1341.7	19727.6
214 ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
550 LESS INTEREST ON SHORT TERM DEBT	40.5	44.2	49.3	55.2	59.8	64.4	69.6	73.4	77.5	746.6
391 LESS INTEREST ON LONG TERM DEBT	982.8	976.3	969.1	961.2	952.5	943.0	932.5	920.9	908.2	14428.0
543 NET EARNINGS FROM OPERS	327.3	333.8	341.0	348.9	357.5	367.1	377.6	389.2	401.9	4965.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	327.3	333.8	341.0	348.9	357.5	367.1	377.6	389.2	401.9	4965.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3532.4
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10107.8
248 WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549 TOTAL SOURCES OF FUNDS	363.7	385.0	400.2	394.7	403.4	419.0	415.3	430.3	446.8	19425.3
320 LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	16200.7
448 LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260 LESS DEBT REPAYMENTS	65.2	71.8	78.9	86.8	95.5	105.1	115.6	127.1	139.9	1165.5
141 CASH SURPLUS(DEFICIT)	153.8	143.9	133.1	121.3	108.4	94.4	79.1	62.4	44.1	1239.3
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	153.8	143.9	133.1	121.3	108.4	94.4	79.1	62.4	44.1	1239.3
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	248.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371 OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	14891.3	15009.4	15138.3	15279.0	15432.6	15600.2	15783.2	15982.8	16200.7	16200.7
465 CAPITAL EMPLOYED	15333.1	15502.5	15690.7	15877.2	16076.6	16296.2	16516.8	16757.6	17020.5	17020.5
461 STATE CONTRIBUTION	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4
462 RETAINED EARNINGS	1595.9	1785.8	1993.7	2221.2	2470.3	2743.0	3041.5	3368.3	3726.1	3726.1
555 DEBT OUTSTANDING-SHORT TERM	441.8	493.1	552.4	598.2	644.0	696.0	733.7	774.8	819.7	819.7
554 DEBT OUTSTANDING-LONG TERM	9763.0	9691.2	9612.3	9525.4	9429.9	9324.8	9209.2	9082.1	8942.2	8942.2
542 ANNUAL DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3827.2
543 CUM. DEBT DRAWWDOWN $1982	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2
519 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.00

$2.3 BILLION (1982 DOLLARS) MINIMUM STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

Sheet 3 of 3

TABLE 18.4.7

ACRES

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

DATA10K WATANA-DC (ON LINE 1993-2002)-$1.8 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73	ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521	REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.85	62.99
466	INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520	PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110.73	146.75
	-----INCOME-----------------										
516	REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	375.0	497.0
170	LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517	OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	348.1	467.7
214	ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550	LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1
391	LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	411.1	444.4
548	NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-63.0	12.8
	-----CASH SOURCE AND USE----										
543	CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-63.0	12.8
446	STATE CONTRIBUTION	403.7	472.7	479.7	499.5	797.9	0.0	0.0	0.0	0.0	0.0
143	LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	140.4	1564.4	1417.6	988.6	396.1	229.7
248	WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549	TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1564.4	1417.6	988.6	431.1	260.2
320	LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1564.4	1417.6	988.6	333.1	259.2
448	LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260	LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4
141	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-33.1
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.1
444	CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371	OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4358.4	5775.9	6764.6	7097.7	7356.9
465	CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4358.4	5775.9	6764.6	7195.7	7472.6
461	STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5
462	RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-63.0	-50.2
555	DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	161.0	211.8
554	DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	140.4	1704.8	3122.4	4111.0	4444.1	4657.4
542	ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	84.5	880.2	745.4	485.8	181.9	98.6
543	CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	84.5	964.7	1710.1	2196.0	2377.9	2476.5
519	DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.85	0.99

Sheet 1 of 3

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE 18.4.8

DATA10K WATANA-DC (ON LINE 1993-2002)-$1.8 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY

===($MILLION)====

		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73	ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521	REAL PRICE-MILLS	61.36	69.57	65.59	61.68	58.03	54.61	51.40	63.57	59.90	62.52
466	INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520	PRICE-MILLS	152.95	185.56	187.18	188.34	189.61	190.92	192.30	254.47	256.58	286.53
	-----INCOME-----------------										
516	REVENUE	518.0	628.4	633.9	637.9	642.2	646.6	651.3	1329.0	1389.0	1605.9
170	LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517	OPERATING INCOME	486.0	593.5	595.8	596.2	596.7	597.0	597.2	1237.9	1289.6	1497.4
214	ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550	LESS INTEREST ON SHORT TERM DEBT	21.2	24.2	27.1	28.2	29.5	30.5	31.6	32.8	45.6	48.4
391	LESS INTEREST ON LONG TERM DEBT	442.8	441.0	439.0	436.8	434.4	431.8	428.9	1088.3	1111.8	1105.3
543	NET EARNINGS FROM OPERS	28.2	135.0	137.0	139.2	141.6	144.3	147.2	128.1	151.4	364.5
	-----CASH SOURCE AND USE----										
548	CASH INCOME FROM OPERS	28.2	135.0	137.0	139.2	141.6	144.3	147.2	128.1	151.4	364.5
446	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	LONG TERM DEBT DRAWDOWNS	386.1	363.6	324.8	1085.4	1346.9	1513.1	1377.3	269.3	0.0	0.0
248	WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549	TOTAL SOURCES OF FUNDS	422.4	527.9	473.0	1236.8	1499.1	1667.8	1536.7	525.4	176.1	407.3
320	LESS CAPITAL EXPENDITURE	418.2	478.8	440.0	1200.6	1462.1	1628.3	1492.5	362.3	90.9	99.2
443	LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260	LESS DEBT REPAYMENTS	18.0	19.8	21.8	24.0	26.4	29.0	32.0	35.1	64.1	70.5
141	CASH SURPLUS(DEFICIT)	-22.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-3.6	194.8
249	SHORT TERM DEBT	22.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	-58.7
444	CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	136.1
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371	OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	7775.1	8253.9	8693.9	9894.5	11356.6	12984.9	14477.4	14839.7	14930.5	15029.7
465	CAPITAL EMPLOYED	7898.9	8407.0	8858.3	10071.1	11543.7	13182.5	14687.2	15177.5	15293.1	15435.1
461	STATE CONTRIBUTION	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5
462	RETAINED EARNINGS	-22.0	113.0	250.1	389.3	530.9	675.1	822.3	950.4	1101.8	1330.2
555	DEBT OUTSTANDING-SHORT TERM	241.9	271.2	232.4	294.7	305.2	315.7	328.0	455.9	484.3	468.4
554	DEBT OUTSTANDING-LONG TERM	5025.5	5369.2	5672.2	6733.6	8054.1	9538.1	10883.4	11117.6	11053.5	10983.0
542	ANNUAL DEBT DRAWDOWN $1982	154.9	136.3	113.8	355.4	412.2	432.8	368.1	67.3	0.0	0.0
543	CUM. DEBT DRAWDOWN $1982	2631.3	2767.7	2881.5	3236.9	3649.1	4081.8	4450.0	4517.3	4517.3	4517.3
519	DEBT SERVICE COVER	1.02	1.25	1.25	1.25	1.25	1.25	1.25	1.08	1.07	1.25

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE 18.4.8

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$1.8 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

		2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
73	ENERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521	REAL PRICE-MILLS	53.98	50.38	46.72	42.59	39.74	37.11	34.95	32.91	31.02	0.00
465	INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520	PRICE-MILLS	264.68	264.32	262.31	255.84	255.46	255.25	257.23	259.16	261.34	0.00
	-----INCOME-----------------										
516	REVENUE	1612.3	1624.7	1639.3	1655.7	1671.6	1688.6	1707.3	1725.9	1746.1	24625.8
170	LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517	OPERATING INCOME	1493.9	1495.5	1498.3	1501.8	1503.6	1505.3	1507.2	1507.5	1507.8	22423.8
214	ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
550	LESS INTEREST ON SHORT TERM DEBT	46.8	50.5	55.6	61.5	66.1	70.7	75.9	79.7	83.8	925.8
391	LESS INTEREST ON LONG TERM DEBT	1098.3	1090.5	1082.0	1072.6	1062.3	1050.9	1038.4	1024.7	1009.6	16744.9
548	NET EARNINGS FROM OPERS	371.5	379.3	387.8	397.2	407.5	418.9	431.4	445.1	460.3	5165.4
	-----CASH SOURCE AND USE----										
548	CASH INCOME FROM OPERS	371.5	379.3	337.8	397.2	407.5	418.9	431.4	445.1	460.3	5165.4
446	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2653.5
143	LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11403.2
248	WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549	TOTAL SOURCES OF FUNDS	408.0	430.5	447.1	443.0	453.4	470.8	469.1	486.3	505.2	20041.9
320	LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	16447.4
448	LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260	LESS DEBT REPAYMENTS	77.6	85.3	93.9	103.2	113.6	124.9	137.4	151.2	166.3	1410.7
141	CASH SURPLUS(DEFICIT)	185.7	175.8	165.0	153.3	140.4	126.4	111.0	94.3	76.1	1364.1
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444	CASH RECOVERED	185.7	175.8	165.0	153.3	140.4	126.4	111.0	94.3	76.1	1364.1
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	248.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371	OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	15138.0	15256.1	15385.0	15525.7	15679.3	15846.9	16029.9	16229.5	16447.4	16447.4
465	CAPITAL EMPLOYED	15579.8	15749.2	15937.4	16123.9	16323.3	16542.9	16763.5	17004.3	17267.2	17267.2
461	STATE CONTRIBUTION	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5	2653.5
462	RETAINED EARNINGS	1516.0	1719.5	1942.3	2186.3	2453.4	2745.9	3066.3	3417.1	3801.3	3801.3
555	DEBT OUTSTANDING-SHORT TERM	504.8	556.1	615.3	661.1	707.0	759.0	796.7	837.8	882.7	882.7
554	DEBT OUTSTANDING-LONG TERM	10905.4	10820.1	10726.2	10622.9	10509.4	10384.4	10247.0	10095.8	9929.6	9929.6
542	ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4517.3
543	CUM. DEBT DRAWDOWN $1982	4517.3	4517.3	4517.3	4517.3	4517.3	4517.3	4517.3	4517.3	4517.3	4517.3
519	DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.00

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

Sheet 3 of 3

TABLE 18.4.8

ACRES

DATA10K2 WATANA-DC (ON LINE 1993-2002)-100% BILL646 FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 2-MAR-82

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.49	34.60
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	66.39	80.61
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	224.9	273.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0	243.7
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0	239.5
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0	239.5
446 STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	333.1	229.7
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549 TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	629.1	487.0
320 LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	333.1	259.2
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0	210.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6600.9	6860.1
465 CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6698.9	6975.8
461 STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6600.9	6830.6
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.5
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542 ANNUAL DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SENATE BILL 646 100% STATE WITH 7% INFLATION AND 10% INTEREST

TABLE 18.4.9

ACRES

DATA10K2 WATANA-DC (ON LINE 1993-2002)-100% BILL646 FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 2-MAR-82

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521 REAL PRICE-MILLS	34.64	34.56	34.69	34.62	34.56	34.48	34.39	32.27	32.73	31.90
466 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520 PRICE-MILLS	86.35	92.17	99.01	105.72	112.91	120.53	128.66	129.17	140.17	146.19
-----INCOME-----------------										
516 REVENUE	292.5	312.2	335.3	358.1	382.4	408.2	435.8	674.6	758.8	819.3
170 LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517 OPERATING INCOME	260.4	277.2	297.2	316.4	337.0	358.6	381.6	583.5	659.4	710.8
214 ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550 LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	19.8	21.0	33.8	36.3
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
548 NET EARNINGS FROM OPERS	255.0	271.6	289.2	308.0	328.1	349.5	372.3	573.9	644.8	695.5
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	255.0	271.6	289.2	308.0	328.1	349.5	372.3	573.9	644.8	695.5
446 STATE CONTRIBUTION	363.1	382.1	303.8	1028.3	1177.5	1204.8	913.1	303.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549 TOTAL SOURCES OF FUNDS	626.2	683.0	604.2	1348.6	1516.1	1564.7	1297.7	1004.8	669.5	738.3
320 LESS CAPITAL EXPENDITURE	395.3	417.2	342.1	1070.1	1223.2	1254.6	967.5	362.3	90.9	99.2
448 LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
395 LESS PAYMENT TO STATE	222.9	236.5	250.9	266.2	282.4	299.6	317.9	514.5	553.9	596.3
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371 OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	7255.4	7672.6	8014.7	9084.8	10308.0	11562.6	12530.1	12892.5	12983.3	13082.5
465 CAPITAL EMPLOYED	7379.2	7825.7	8179.0	9261.4	10495.1	11760.2	12740.0	13230.3	13345.9	13487.9
461 STATE CONTRIBUTION	7193.7	7575.8	7879.6	8907.9	10085.4	11290.3	12203.4	12506.4	12506.4	12506.4
462 RETAINED EARNINGS	61.6	96.8	135.1	176.9	222.6	272.4	326.7	386.1	477.0	576.1
555 DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	197.6	209.9	337.8	362.6	405.4
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SENATE BILL 646 100% STATE WITH 7% INFLATION AND 10% INTEREST

TABLE 18.4.9

ACRES

DATA10K2 WATANA-DC (ON LINE 1993-2002)-100% BILL646 FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 2-MAR-82

CASH FLOW SUMMARY
===($MILLION)====

	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
73 ENERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521 REAL PRICE-MILLS	29.67	29.70	29.53	28.84	28.79	28.75	28.93	29.08	29.23	0.00
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520 PRICE-MILLS	145.50	155.81	165.77	173.22	185.08	197.73	212.90	228.96	246.28	0.00
-----INCOME-----------------										
516 REVENUE	886.3	957.7	1036.0	1121.0	1211.1	1308.1	1413.1	1524.8	1645.5	16378.6
170 LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517 OPERATING INCOME	767.9	828.4	895.0	967.1	1043.1	1124.7	1213.0	1306.4	1407.2	14176.6
214 ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
550 LESS INTEREST ON SHORT TERM DEBT	40.5	44.2	49.3	55.2	59.8	64.4	69.6	73.4	77.5	746.6
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
548 NET EARNINGS FROM OPERS	750.1	809.1	872.8	941.5	1015.6	1095.6	1181.9	1275.0	1375.5	13842.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	750.1	809.1	872.8	941.5	1015.6	1095.6	1181.9	1275.0	1375.5	13842.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12506.4
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549 TOTAL SOURCES OF FUNDS	786.5	860.4	932.1	987.3	1061.5	1147.5	1219.6	1316.2	1420.5	27168.5
320 LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	14500.2
448 LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
395 LESS PAYMENT TO STATE	641.9	691.0	743.9	800.8	862.0	928.0	999.0	1075.4	1157.6	11848.5
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	248.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371 OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	13190.7	13308.9	13437.8	13578.5	13732.1	13899.7	14082.6	14282.3	14500.2	14500.2
465 CAPITAL EMPLOYED	13632.6	13801.9	13990.2	14176.7	14376.1	14595.7	14816.3	15057.1	15319.9	15319.9
461 STATE CONTRIBUTION	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4
462 RETAINED EARNINGS	684.4	802.5	931.4	1072.1	1225.7	1393.3	1576.3	1775.9	1993.8	1993.8
555 DEBT OUTSTANDING-SHORT TERM	441.8	493.1	552.4	598.2	644.0	696.0	733.7	774.8	819.7	819.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SENATE BILL 646 100% STATE WITH 7% INFLATION AND 10% INTEREST

TABLE 18.4.9

ACRES

DATA10K2 WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) BILL646 FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 2-MAR-82

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.08	51.98
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	95.97	121.10
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	325.0	410.1
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	298.2	380.8
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	154.0	187.3
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	144.2	189.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	144.2	189.4
446 STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	1550.4	462.4	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	784.7	754.9	333.1	229.7
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549 TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	754.9	575.3	436.8
320 LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	754.9	333.1	259.2
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	144.2	153.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6346.3	6679.4	6938.6
465 CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6346.3	6777.4	7054.3
461 STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	4344.3	4806.7	4806.7	4806.7	4806.7
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.4
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	784.7	1539.5	1872.6	2095.4
542 ANNUAL DEBT DRAWHDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	412.6	371.0	153.0	98.6
543 CUM. DEBT DRAWHDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	412.6	783.6	936.5	1035.1
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.94	1.94

SENATE BILL 646 "MINIMUM" APPROPRIATION OF
$3.0 BILLION WITH 7% INFLATION AND 10% INTEREST

TABLE 18.4.10

ACRES

DATA10K2 WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) BILL646 FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 2-MAR-82

CASH FLOW SUMMARY
===($MILLION)====

		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73	ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521	REAL PRICE-MILLS	50.47	48.94	47.73	46.41	45.17	44.00	42.90	63.06	59.90	59.73
466	INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520	PRICE-MILLS	125.82	130.55	136.22	141.71	147.60	153.84	160.51	252.41	256.58	273.72
	-----INCOME-----------------										
516	REVENUE	426.1	442.1	461.4	479.9	499.9	521.0	543.6	1318.2	1389.0	1534.1
170	LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517	OPERATING INCOME	394.1	407.2	423.2	438.3	454.5	471.4	489.5	1227.1	1289.6	1425.6
214	ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550	LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	19.8	21.0	33.8	41.3
391	LESS INTEREST ON LONG TERM DEBT	186.6	185.8	185.0	184.1	183.0	181.9	180.7	897.7	926.5	922.1
548	NET EARNINGS FROM OPERS	202.1	215.7	230.3	245.8	262.5	280.3	299.4	319.9	348.5	483.0
	-----CASH SOURCE AND USE----										
548	CASH INCOME FROM OPERS	202.1	215.7	230.3	245.8	262.5	280.3	299.4	319.9	348.5	483.0
446	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	LONG TERM DEBT DRAWDOWNS	386.1	443.7	409.7	1175.2	1442.0	1613.5	1483.1	303.0	0.0	0.0
248	WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549	TOTAL SOURCES OF FUNDS	596.3	688.7	651.2	1433.3	1715.0	1904.2	1794.8	750.8	373.2	525.9
320	LESS CAPITAL EXPENDITURE	418.2	478.8	448.0	1217.1	1487.6	1663.3	1537.5	362.3	90.9	99.2
448	LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260	LESS DEBT REPAYMENTS	7.6	8.4	9.2	10.1	11.1	12.2	13.5	14.8	43.9	48.3
395	LESS PAYMENT TO STATE	162.3	172.2	182.7	193.9	205.7	218.3	231.6	245.7	264.5	284.7
141	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-50.8	50.8
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.8	-50.8
444	CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371	OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	7356.8	7835.6	8283.6	9500.7	10988.3	12651.6	14189.1	14551.4	14642.3	14741.4
465	CAPITAL EMPLOYED	7480.7	7988.7	8448.0	9677.3	11175.4	12849.1	14398.9	14889.2	15004.8	15146.8
461	STATE CONTRIBUTION	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7
462	RETAINED EARNINGS	76.2	119.6	167.1	219.1	275.9	337.9	405.8	479.9	563.9	762.2
555	DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	197.6	209.9	337.8	413.4	405.4
554	DEBT OUTSTANDING-LONG TERM	2473.9	2909.2	3309.7	4474.9	5905.7	7506.9	8976.6	9264.7	9220.8	9172.5
542	ANNUAL DEBT DRAWWDOWN $1982	154.9	166.3	143.6	384.8	441.3	461.5	396.4	75.7	0.0	0.0
543	CUM. DEBT DRAWWDOWN $1982	1190.0	1356.4	1499.9	1884.8	2326.0	2787.5	3184.0	3259.6	3259.6	3259.6
519	DEBT SERVICE COVER	2.00	2.07	2.14	2.21	2.29	2.38	2.47	1.33	1.31	1.45

SENATE BILL 646 "MINIMUM" APPROPRIATION OF $3.0 BILLION WITH 7% INFLATION AND 10% INTEREST

TABLE 18.4.10

ACRES

DATA10K2 WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) BILL646 FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 2-MAR-82

CASH FLOW SUMMARY
===($MILLION)====

	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
73 ENERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521 REAL PRICE-MILLS	50.93	48.59	46.11	43.04	41.16	39.42	38.11	36.87	35.72	0.00
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520 PRICE-MILLS	249.74	254.95	258.86	258.52	264.55	271.12	280.46	290.31	300.99	0.00
-----INCOME-----------------										
516 REVENUE	1521.3	1567.0	1617.7	1673.0	1731.1	1793.6	1861.6	1933.3	2011.1	24060.4
170 LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517 OPERATING INCOME	1402.9	1437.8	1476.7	1519.1	1563.1	1610.3	1661.4	1714.9	1772.7	21858.4
214 ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
550 LESS INTEREST ON SHORT TERM DEBT	40.5	44.2	49.3	55.2	59.8	64.4	69.6	73.4	77.5	751.7
391 LESS INTEREST ON LONG TERM DEBT	917.3	911.9	906.1	899.7	892.6	884.8	876.3	866.8	856.5	12386.5
548 NET EARNINGS FROM OPERS	467.9	506.6	548.4	593.8	643.0	696.3	754.1	816.7	884.6	9132.6
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	467.9	506.6	548.4	593.8	643.0	696.3	754.1	816.7	884.6	9132.6
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4806.7
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9358.6
248 WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549 TOTAL SOURCES OF FUNDS	504.3	557.8	607.7	639.6	688.9	748.3	791.8	857.9	929.5	24117.6
320 LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	16159.1
448 LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260 LESS DEBT REPAYMENTS	53.1	58.4	64.3	70.7	77.8	85.6	94.1	103.5	113.9	907.6
395 LESS PAYMENT TO STATE	306.5	330.0	355.2	382.4	411.6	443.1	477.0	513.5	552.8	6231.2
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	248.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371 OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	14849.7	14967.8	15096.7	15237.4	15391.0	15558.6	15741.6	15941.2	16159.1	16159.1
465 CAPITAL EMPLOYED	15291.5	15460.9	15649.1	15835.6	16035.0	16254.6	16475.2	16716.0	16978.9	16978.9
461 STATE CONTRIBUTION	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7
462 RETAINED EARNINGS	923.5	1100.1	1293.4	1504.8	1736.2	1989.3	2266.4	2569.6	2901.4	2901.4
555 DEBT OUTSTANDING-SHORT TERM	441.8	493.1	552.4	598.2	644.0	696.0	733.7	774.8	819.7	819.7
554 DEBT OUTSTANDING-LONG TERM	9119.4	9060.9	8996.6	8925.9	8848.1	8762.5	8668.4	8564.9	8451.0	8451.0
542 ANNUAL DEBT DRAWHDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3259.6
543 CUM. DEBT DRAWHDOWN $1982	3259.6	3259.6	3259.6	3259.6	3259.6	3259.6	3259.6	3259.6	3259.6	3259.6
519 DEBT SERVICE COVER	1.43	1.46	1.50	1.54	1.58	1.63	1.68	1.73	1.79	0.00

SENATE BILL 646 "MINIMUM" APPROPRIATION OF
$3.0 BILLION WITH 7% INFLATION AND 10% INTEREST

Sheet 3 of 3

TABLE 18.4.10

ACRES

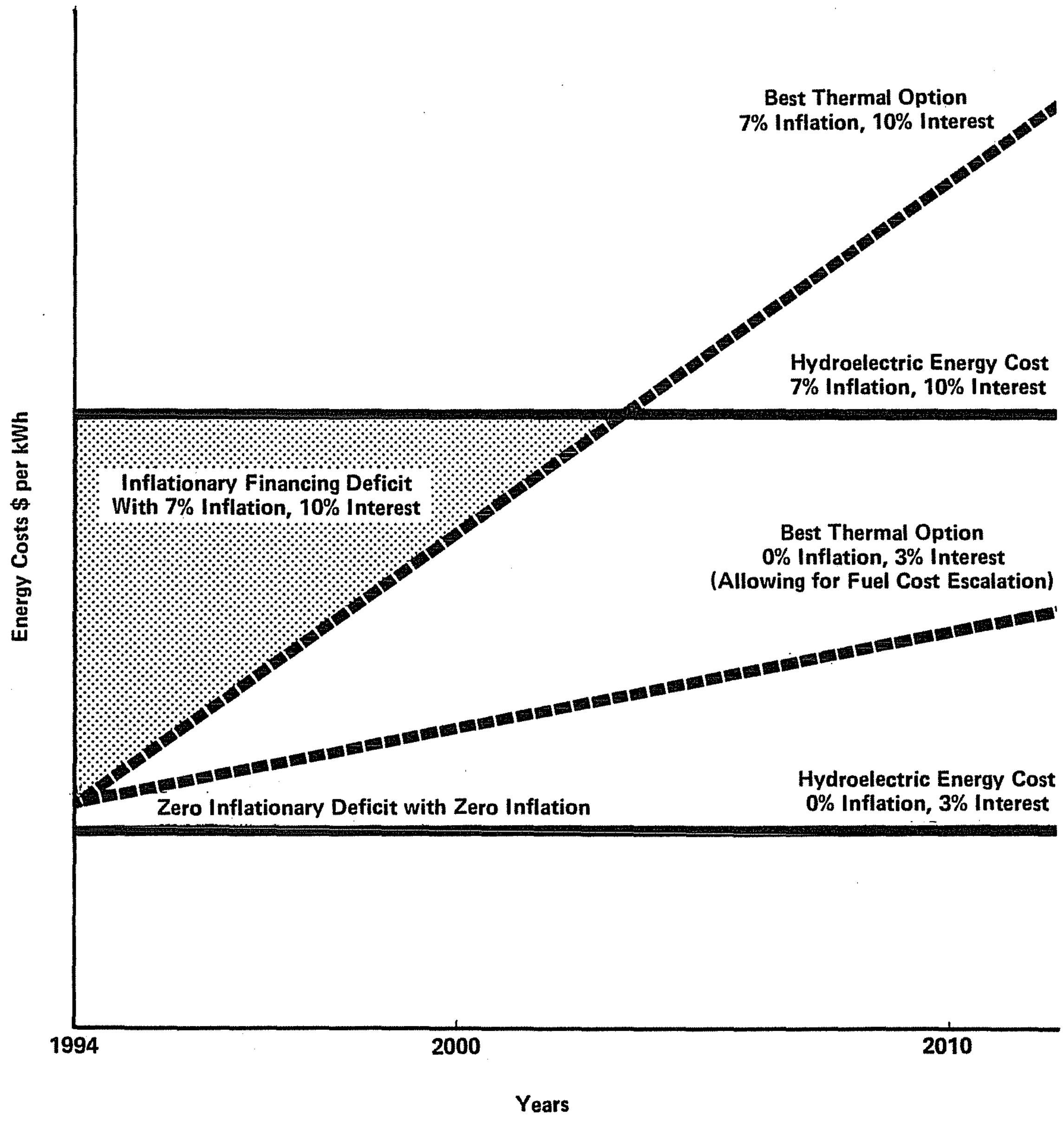


FIGURE 18.4.1 – DIAGRAMATIC COMPARISON ENERGY COSTS – 0 AND 7% INFLATION

Rev. 1

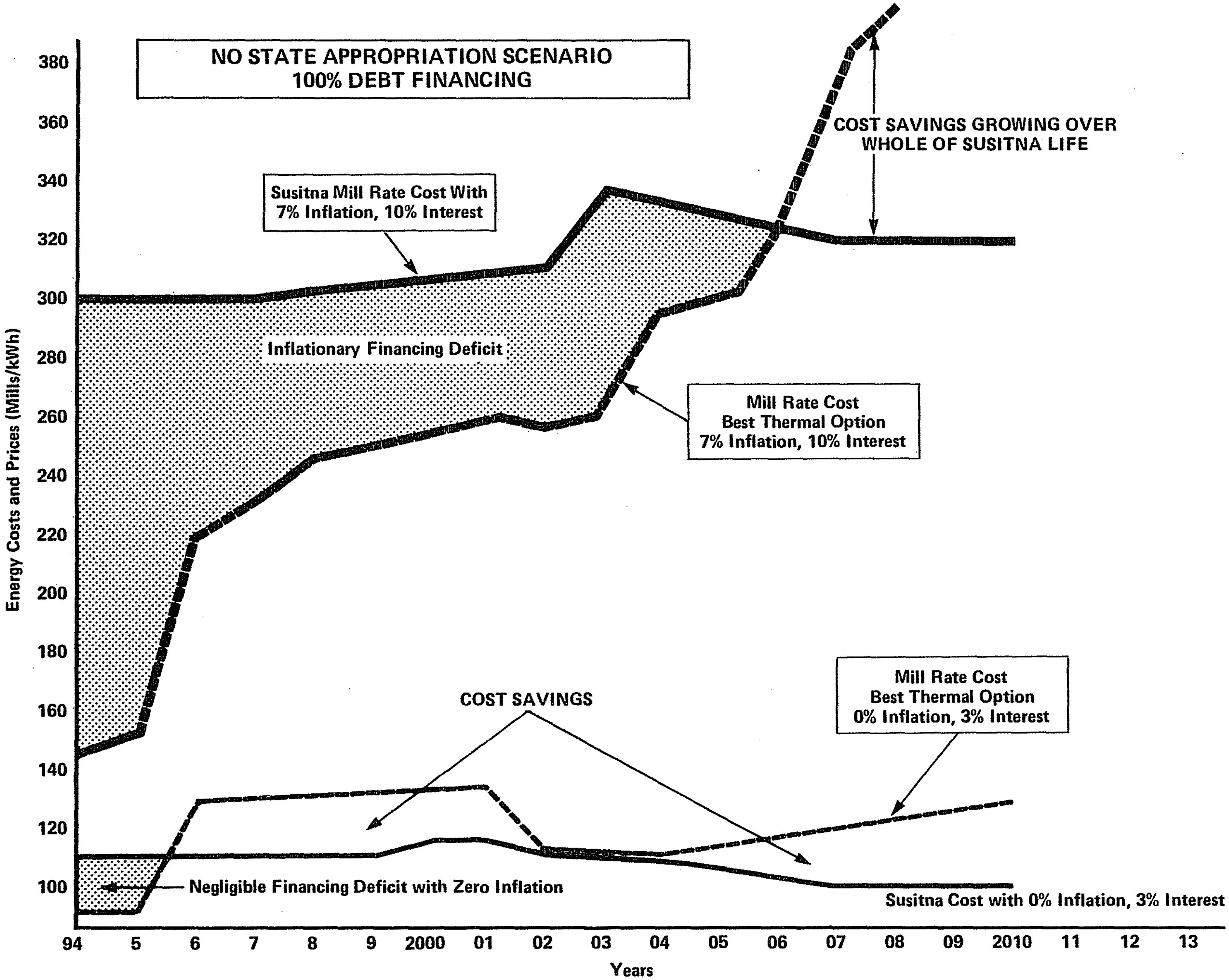


FIGURE 18.4.2 – ENERGY COST COMPARISON – 100% DEBT FINANCING 0 AND 7% INFLATION

ACRES

Rev. 1

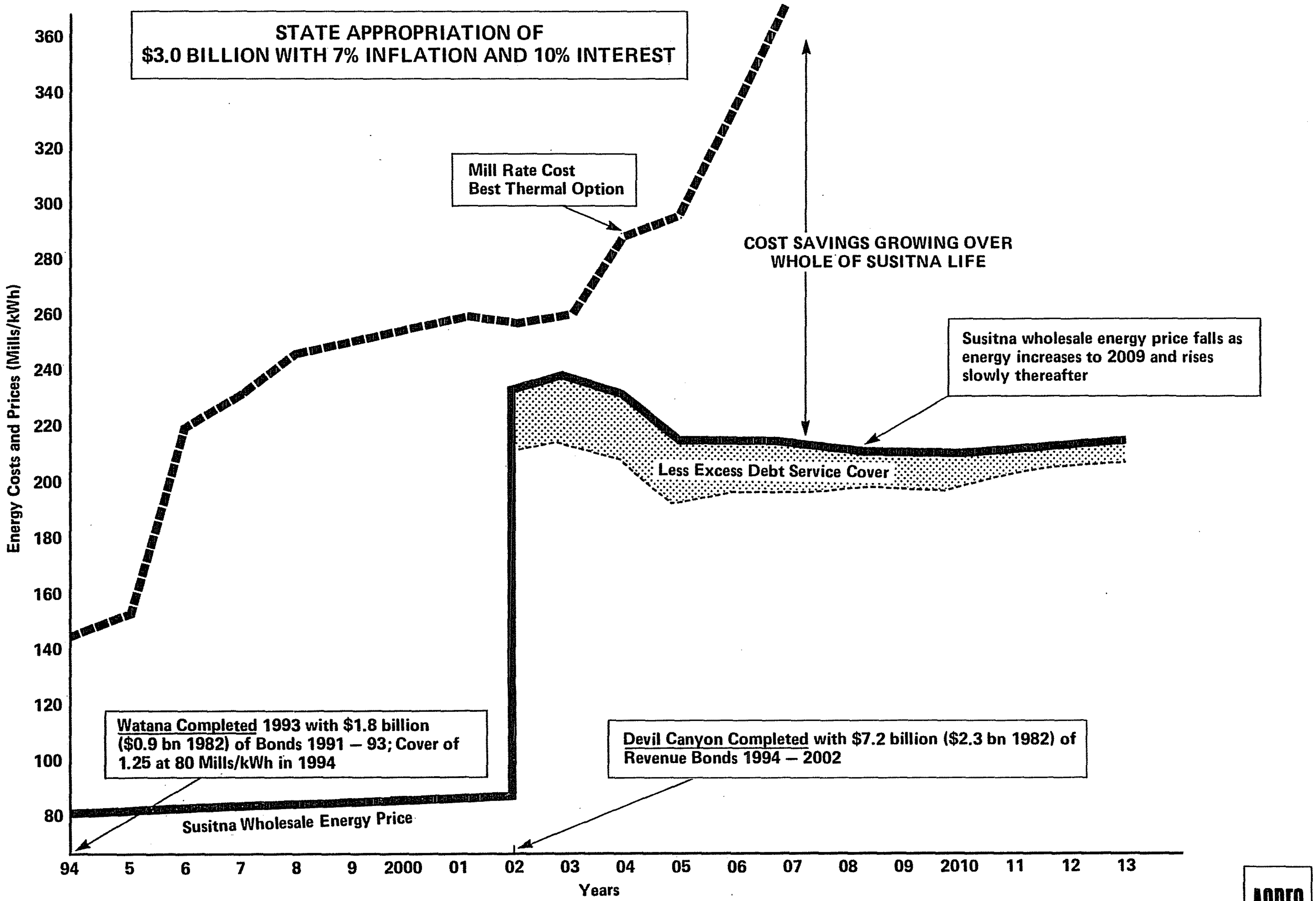


FIGURE 18.4.3 – ENERGY COST COMPARISON STATE APPROPRIATION $3 BILLION (1982 $)

ACRES

Rev. 1

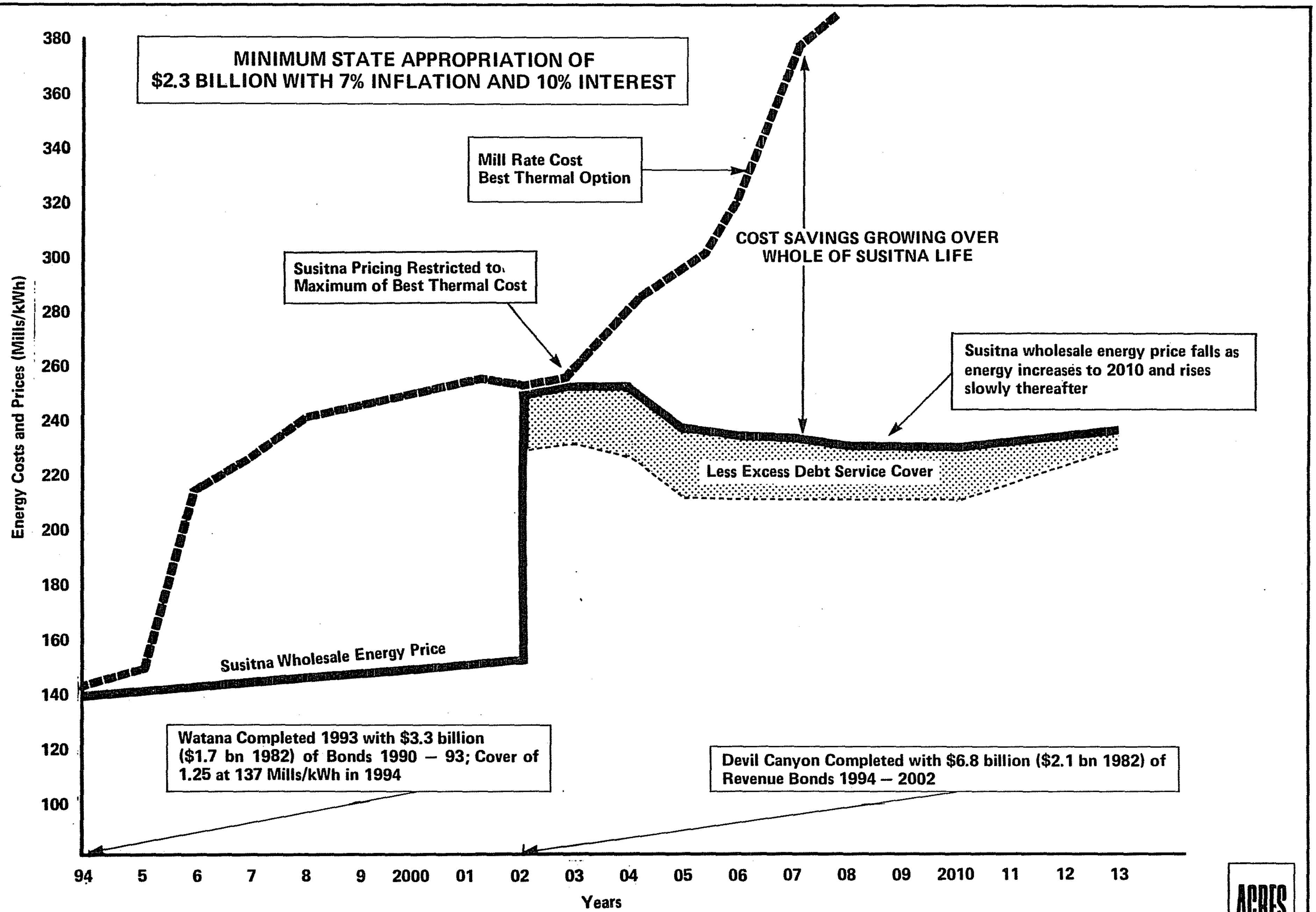


FIGURE 18.4.4 – ENERGY COST COMPARISON $2.3 BILLION "MINIMUM" STATE APPROPRIATION

ACRES

Rev. 1

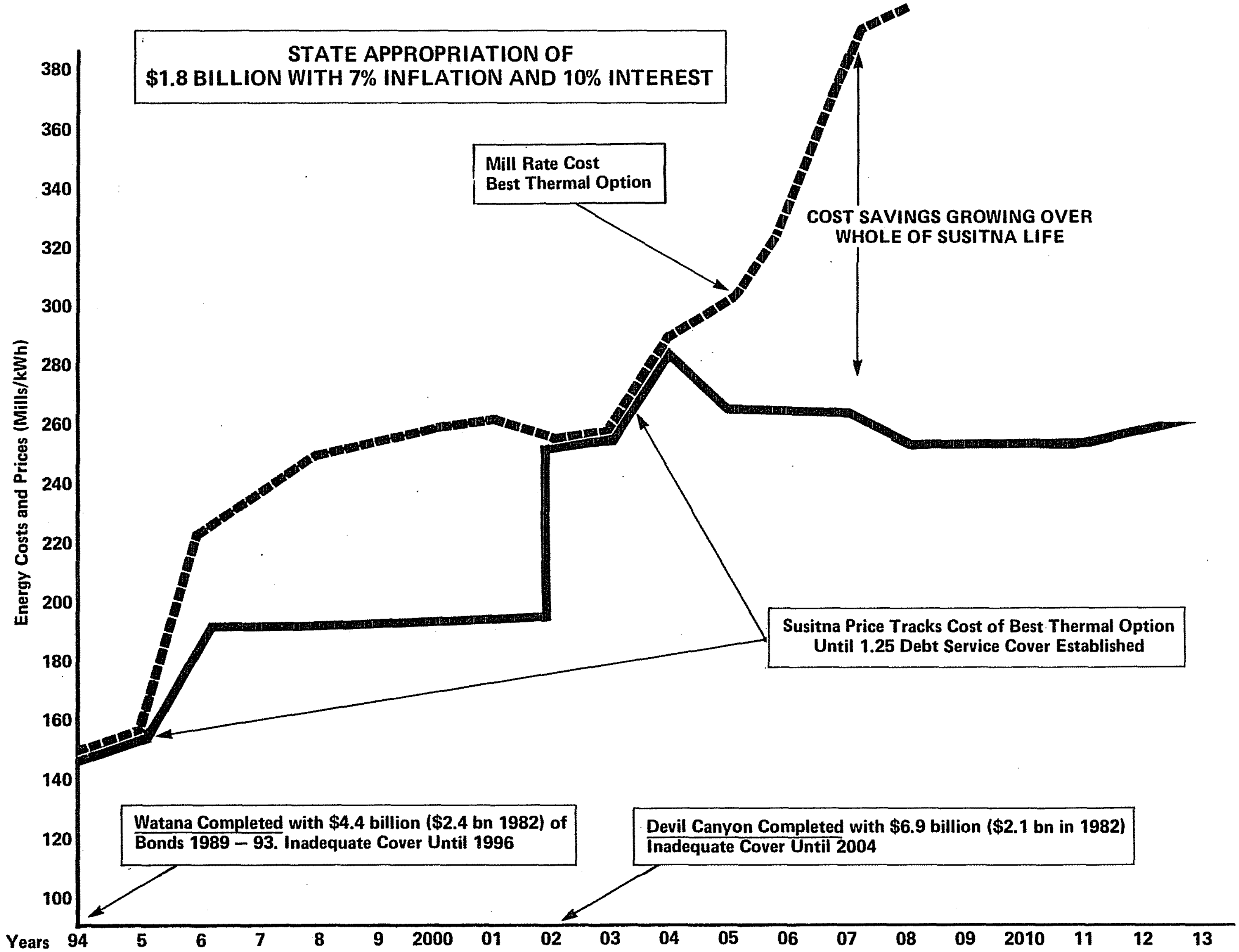


FIGURE 18.4.5 – ENERGY COST COMPARISON WITH PRICING RESTRICTED 1994 – 1995 AND 2003 – 2004 ($1.8 BILLION STATE APPROPRIATION)

ACRES

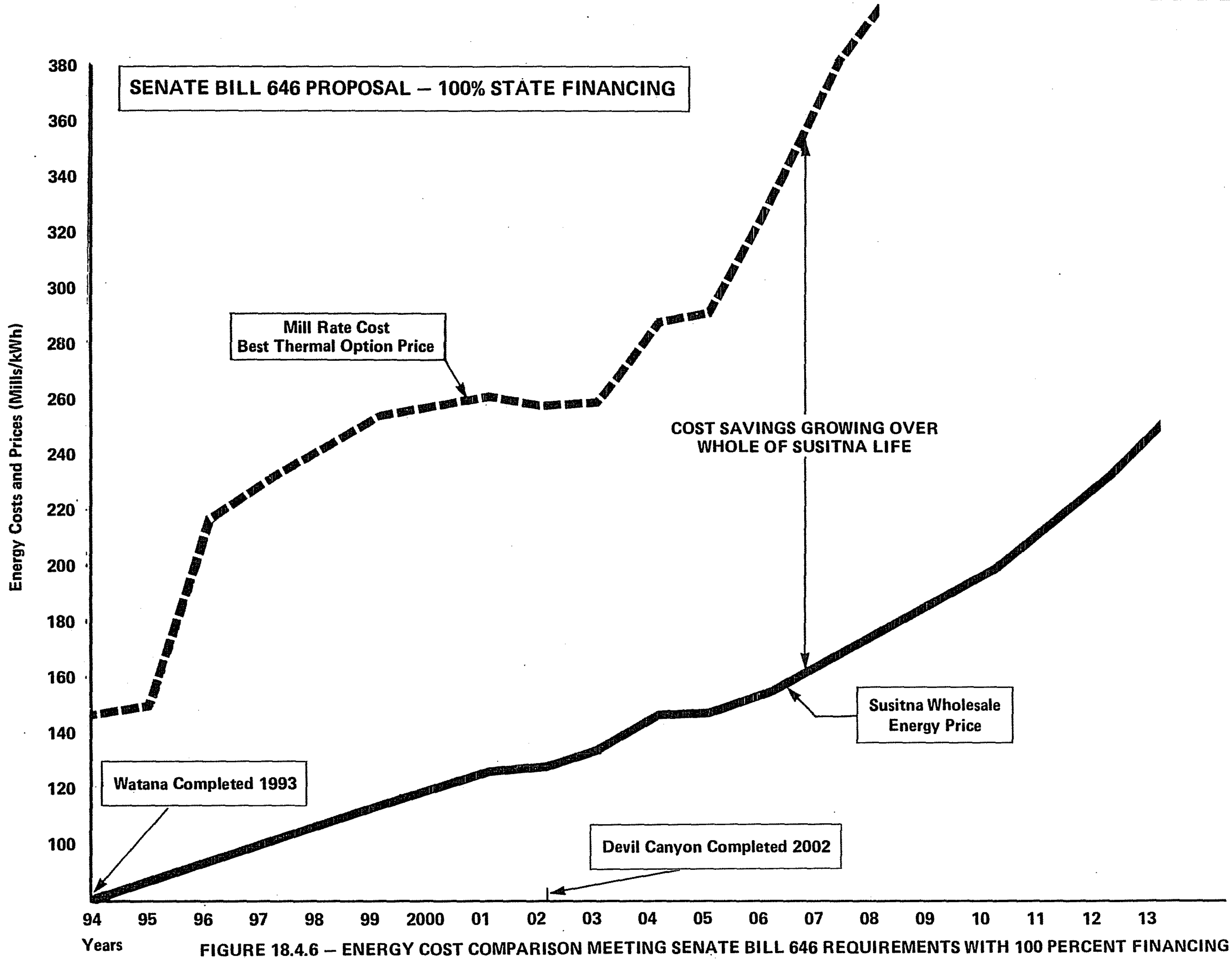


FIGURE 18.4.6 – ENERGY COST COMPARISON MEETING SENATE BILL 646 REQUIREMENTS WITH 100 PERCENT FINANCING

ACRES

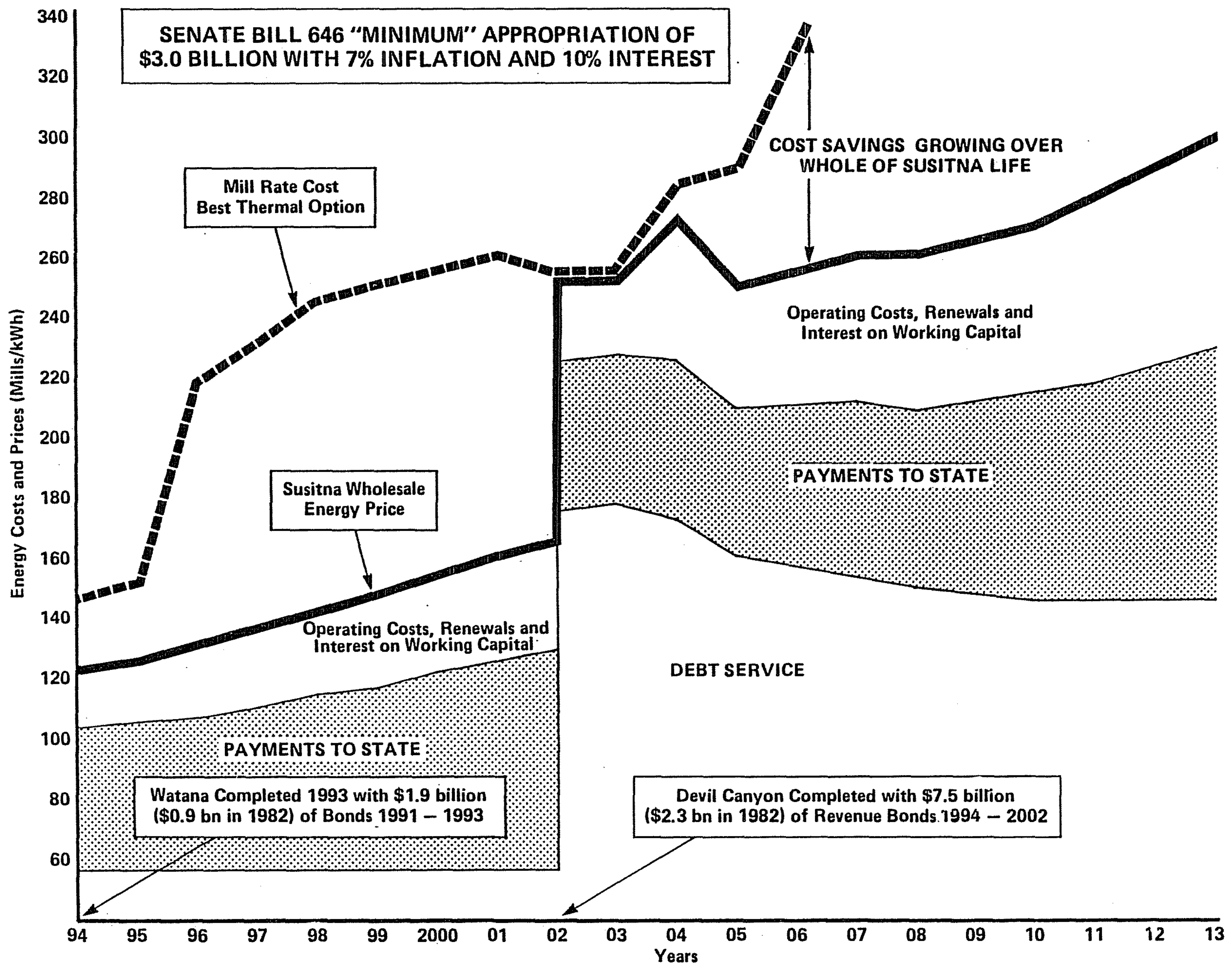


FIGURE 18.4.7 – ENERGY COST COMPARISON MEETING SENATE BILL 646 REQUIREMENTS WITH $3 BILLION APPROPRIATION

ACRES

18.5 - Financial Risk

This section of the report considers the financial risks arising to the entities potentially financing Susitna. These entities are the State of Alaska, Alaskan consumers and bond holders. Under the financing schemes described in Section 18.4, the only risks to bond holders would arise in the later stages of the project's life when either the G.O. bonds had been converted into revenue bonds or the revenue bonds were no longer guaranteed. These financing plans would therefore protect bond holders from all risks from Susitna until the project was fully established and fully met the normal standards of security for bond holders. It can be taken therefore that the proposed financing schemes would, in effect, hold the bond holders free from all abnormal risk. On these grounds only, the risk arising to the State of Alaska and Alaskan consumers will be considered.

The analysis is also confined to Watana completion and operation up to the year 2001. This is firstly because Watana accounts for more than two-thirds of the total capital cost of the Susitna Project. Secondly, as can be seen from Figure 18.4.3 to 18.4.5, the long-term viability of Susitna (i.e., its costs compared with the best thermal option) is such that, long term, there is very little risk that the project would be unable to meet all financing costs when charging a price which is more favorable to consumers than the best thermal option. This means that there is little likelihood of any additional burden falling on Alaskan consumers (compared with that imposed by the best thermal option) after Devil Canyon comes on-stream. Risk to the State of Alaska in terms of being called upon to permit Devil Canyon to be financed by guaranteed revenue bonds or G.O. Bonds is correspondingly small. These considerations, and the extreme uncertainty attaching to any detailed financing scenarios some two decades hence, support the approach followed here of concentrating on the risk at the Watana stage of project development.

The analysis considers risk in terms of pre-completion and post-completion risk. It concludes that there is very little pre-completion risk as measured by likelihood of non-completion. The major specific risks at the pre-completion phase (i.e., risk of capital overruns, higher-than-forecast interest rates, etc.) have their effect in the post-completion phase by giving rise to additional financing requirements, inadequacy of debt service and delay in conversion to non-guaranteed revenue bonds. Each of these specific risks is considered and their probability of occurrence estimated. Also considered is the critically important aggregative risk relating to project earnings expressed in terms of the cumulative net operating deficit or surplus.

The general conclusion is that, in terms of failure to achieve estimated forecasts in 1982 dollars, both specific and aggregative risks have well defined probability limits which should be acceptable having regard to the long-term net benefits and the energy price stabilization advantages of the project.

(a) Pre-completion Risk

The first major risk, considered in the pre-completion phase, is the risk that the project will not be completed. The scenarios which might lead to this conclusion are possibly that major and unforeseen natural hazards are identified in the construction phase or alternatively that an actual natural calamity prevents completion. The possibilities of seismic and other natural hazards are dealt with in Sections 9 and 10 of the Feasibility Report for the Susitna Hydroelectric Project. The analysis given there supports the conclusion that the chance of unforeseen natural hazards of a magnitude sufficient to prevent completion, occurring during the construction phase, is negligible. The probability of construction being permanently halted by occurrence of a major natural hazard is also identified in that section and is assessed as very small. It may be concluded therefore, that the risks arising from non-completion owing to natural hazards are negligible.

In considering the risk of non-completion owing to capital overruns it is necessary to differentiate between capital overruns which are the result merely of general inflation and capital overruns which represent constant (1982) dollar increases in the capital cost of the project should its costs rise faster than the general rate of inflation. It was noted in the Section 18.4 (c) which deals with the basic financing plan that the general rate of inflation is inherently unpredictable in the long term, since it is the result of complex worldwide political and economic forces which also cannot be predicted. Providing, however, that such inflation has a uniform effect on prices and leaves the real rate of interest unchanged, it will have zero impact on the net benefits of the project. The capital required to complete the project will certainly increase in line with inflation but, given that the net benefits are not adversely affected, this should not lead to any significant risk that the project will not be completed. Additional inflation, far from challenging the viability of long term price stabilizing investments such as Susitna, should generally make them more desirable and urgent in the preference scale of the majority of consumers.

In contrast to such inflationary capital overruns which should not adversely affect the economic viability of the project, capital overruns in excess of inflation could, if sufficiently large, result in the project being abandoned. In this context, however, we must note that:

(i) The project involves only well established and proven technology and hence is not exposed to technological risk;

(ii) Construction will be undertaken on a well-defined and carefully surveyed site so that the project should be free from the extensive and unsurveyed terrain problems which led to environmental and geotechnical factors giving rise to major real capital overruns in the case of the Aleyska pipeline; and

(iii) The risk of any constant (1982) dollar overrun has been extensively examined by Acres on the basis of standard engineering approaches and formal probability analysis and estimated to have only a 20 to 27 percent probability of occurrence.

Taking these factors into account and considering the economic logic which would require that already-incurred costs be disregarded in any completion decision, it may be concluded that the risk of non-completion due to capital cost overruns is negligible.

(b) Post-completion Risks

(i) The Generation of Post-completion Risks

Any major project, dependent for its outcome on a range of different factors, can be regarded as a risk-generating mechanism. The risks, in terms of their actual outcome, can be either favorable or unfavorable. To make any general assessment of such risks, however, the risk-generating mechanism in terms of its major variables must be defined. These are summarized in Table 18.5.1 and define the variables to which the project financial outcome is sensitive and provide an estimate of the range of such variables together with their corresponding probabilities.

A major variable in the risk-generating mechanism is the range of capital costs in 1982 dollar terms. For purposes of this analysis the probability distribution of the range of capital costs as given in Section 18.2 has been reduced to the cumulative probability distribution shown in Table 18.5.1.

Another variable to which the risk-generating mechanism is highly sensitive is that of the rate of inflation and the related rate of interest on the revenue bonds and G.O. bonds financing the investment. Historically, inflation and interest rates have tended to be closely, although not precisely, related, as can be determined from Table 18.4.4. As was stressed in connection with that table, rates of inflation and interest are subject to a wide range of uncertainty. Furthermore, there exists no objective manner by which the probabilities of different inflation and interest rates occurring can be determined. As these are variables of fundamental importance in the risk-generating mechanism, however, probabilities have been estimated on a judgmental basis for a range of interest and inflation rates. These center on the Data Resources Incorporated, forecasts in Table 18.4.4 and result in the estimates given in Table 18.5.1.

The fourth variable to which the risk-generating mechanism is sensitive is that of the rate of escalation of thermal fuels, particularly coal. It is this which will primarily determine the cost savings Susitna energy will produce, and hence the wholesale rate which Susitna may charge. This determines the revenue earned by Susitna. The probabilities and range in this case are as given in Section 18.1.

While other variables also have an impact on the risk generating mechanism, it is the above four variables which are its primary determinants. In the analysis each combination of these four variables defines a particular financial outcome for the project.

The combination of probabilities entering into that scenario correspondingly defines the probability of this financial outcome occurring and hence the probability of any particular financial characteristic associated with it. This risk-generating mechanism is then used in the following sub-sections to analyze the specific and aggregate risks applying to the project.

(ii) Specific Risks

For a variety of reasons it may be important to focus on certain specific risks, such as the risk of financing requirements exceeding forecast, financial deficits in the early years, etc. The specific risks considered here are: firstly, those related to borrowing requirements, secondly, risk of inadequate debt service cover and thirdly, risks related to short-term economic viability.

- Specific Risk I: Risk of Bond Financing Overrun (Figure 18.5.1)

An area of risk which must be of substantive concern to the state is the risk that the project will not prove to be independently financially viable on the basis of the state appropriation and the bond financing authorized, but will require substantial supplementary state-supported funding. This outcome might arise from capital costs, interest rates, revenues, etc., being different from forecast and failing to "average" out so that project earnings were not sufficient to enable the project to secure the further revenue bond financing it requires for completion.

The risk-generating model described above enables us to assess this possibility in terms of the probability distribution given as Figure 18.5.1. This gives cumulative probability on the vertical axis and the magnitude of bond requirements for the $2.3 billion state appropriation scenario on the horizontal.

Because varying rates of inflation are allowed in the riskgenerating model, so that the financing overruns or underruns are all in dollars of differing purchasing powers, it is necessary to express the likely bond requirement in terms of 1982 dollars. This also facilitates evaluation of the relative importance of each risk.

The forecast requirement for bond financing on the central forecasts of the major variables is $1.7 billion. The probability of the overrun exceeding this forecast by more than 50 percent is only .12. The probability of any overrun at all is .29. Moreover, counter balancing these adverse possible outcomes is the .71 probability that the bond financing requirements will be less than the forecast amount of $1.7 billion.

- Specific Risk II: Inadequate Debt Service Cover (Figure 18.5.2)

An adverse impact on the state credit rating might occur if the project failed to earn adequate debt service and cover, and consequently, conversion into non-guaranteed revenue bonds was delayed. The analysis showed that in the $2.3 billion state appropriation case:

. The probability of forecast coverage being less than adequate (i.e., cover of less than 1.25) in 1994 (first normal year of Watana) is .22.

The probability of a shortfall in coverage also diminishes with time (due to increasing cost of alternative fuels). Reference to the 1997 line in Figure 18.5.2 shows that the probability of inadequate cover by that year is only .05.

- Specific Risk III: Early Year Non-viability (Figure 18.5.3)

The third specific risk that may be considered to be of importance is the risk that, although the project is fully completed and operational, it is not completely financially viable in its early years. A wide range of the factors detailed in Table 18.5.1 could lead to this result. For example, at the completion of Watana in 1993 the project might be unable to meet interest charges because capital costs had been higher than expected (due, for instance, to inflation or constant dollar overruns), or because interest rates had been higher than expected, or revenues lower.

The probabilities of this occurring are analyzed in Figure 18.5.3. This shows probability on the vertical axis, and on the horizontal, the Watana costs in 1996 as a percentage of the cost of the best thermal option.

Again, the reference financing scenario is that of the $2.3 billion state appropriation and the analysis is based on the central estimates of capital cost, interest rates, revenues, etc. This, as can be seen from Figure 18.4.4, should enable the Watana output in 1996 to be produced at a cost (excluding excess debt service cover) 51 percent of the cost of the best thermal option in that year. The 51 percent value is the reference point of the results summarized in Figure 18.5.2.

The result which may be of particular concern relates to the probability of the Watana costs exceeding the costs of the best thermal option so that the project either shows losses (i.e., is unable to meet its interest charges) or alternatively, insofar as it is able, it is forced to charge a higher energy price than the best thermal option. The probability of this occurrence is only .05. There is also a .71 probability that Watana costs will be less than the forecast level of 51 percent of the best thermal option (see previous paragraph).

(iii) Aggregate Risk (Figure 18.5.4)

While specific risks of the type considered above are of importance in evaluating particular aspects of the project, the basic concern in the financial risk analysis must relate to aggregate risk. It is inherent in the large number of independent variables and the very long time period involved in the Susitna project that, while many of these factors at any given point of time will be deviating from their forecast values, the deviations will, in total effect and over time, tend to cancel out so that the aggregate outcome will be close to forecast. There are, however, certain conditions under which this "averaging out" would not occur. This is where the outcome of the project depends critically upon relatively few major factors which are themselves very variable.

An essential purpose of the probability analysis is to evaluate this variability in a systematic manner so that we can ascertain the extent to which, long term, the averaging process will bring the aggregate outcome for the project close to forecast despite the inevitable variations from forecast of many of its component forecasts.

A number of measurements can be made to test the aggregate outcome for the project. The most obvious is that of the rate of return which it earns. This was considered in some detail in Section 18.1. The measure of aggregate outcome most appropriate for the financial analysis in this case is probably the cumulative net operating earnings at the end of the first nine years of operation of Watana (i.e., the year 2001, immediately before Devil Canyon comes into operation). These net operating earnings are after interest and include accumulated interest on any deficits which may arise over the period.

This statistic could not, however, reflect the impact of favorable outcomes which reduced the cost of the Watana output below its forecast level. This is because the requirements of Senate Bill 25 governing the wholesale electricity rate would oblige the APA to reduce the price of Watana energy in line with the lower cost so that no additional gains would show up in the net operating earnings. In order to make the statistic reflect the "upside" as well as "downside" possibilities, it has been reestimated for the present analysis on the assumption that the APA would have the freedom to set the wholesale price of the Watana energy at higher levels up to the full cost of output from the best thermal option. On this basis the resulting net operating earnings at the year 2001 fully reflect all favorable as well as unfavorable possibilities, picking up both the cost savings to consumers in the favorable outcomes and the excess costs arising from the adverse ones.

The results of this analysis for the $2.3 billion state appropriation scenario are shown in Figure 18.5.4. Again, probability is shown on the vertical axis. On the horizontal axis is shown the cumulative net operating deficit or surplus at the year 2001 (reexpressed in terms of 1982 dollars). The reference point of the figure is the forecast of $0.8 billion net operating surplus which would have occurred if the central estimates used in the financial analysis were realized. The $0.8 billion therefore represents the "forecast" against which the other outcomes can be assessed.

On the basis of this analysis, the probability of the net operating surplus being less than the forecast level is only .27. The probability of the surplus being less than $0.6 billion is only .2. Moreover, counter-balancing these adverse possibilities are the probabilities shown of very much larger surpluses arising. This would lead to very much larger cost savings being conferred upon Alaskan consumers than the forecast $0.8 billion. There is, for example, a .35 probability of the surplus exceeding $1.4 billion.

(c) Conclusions

The main conclusion of this analysis is that the project at the Watana stage has only limited exposure to adverse outcomes in terms of specific risks, particularly those of financing overruns, delayed revenue bond conversion or failure to realize early year cost savings once it is in operation. An important qualification attaching to the risk of financing overruns is that a point of reference is the forecast capital requirements in terms of 1982 dollars. It is inherent in the extreme unpredictability of the rate of inflation over the long term that forecasts of financing requirements in terms of then-current money (e.g., money of the purchasing power of the years 1985 to 1992 when the financing takes place) would prove to be substantially in error. It is, however, the risk of financial overrun in terms of today's purchasing power which represents the only meaningful assessment of this particular category of risk.

As regards the aggregate risk as measured by the net operating surplus or deficit over the first nine years of Watana's life, there is only a relatively low probability of this variable failing to achieve its forecast level. This low probability also extends to the chance that the project would not realize cost savings as large or even larger than those forecast in the central estimate.

The qualification attaching to all the foregoing analyses is that the estimates and probabilities used are free from any systematic biases which might render them unrealistically favorable. The approach to the study for Susitna and the analysis of its alternatives has been specifically designed to guard against this possibility. The Acres capital cost estimates have been subjected to independent verification by EBASCO and the economic estimates independently assessed by BATTELLE. Every practical precaution has been taken to exclude the possibility of any systmatic bias, and to base the analysis on consistently objective estimation.

BASIC PARAMETERS OF RISK GENERATION MODEL

	COAL PRICE ESCALATION (% REAL)		
	0	2.6 to 2000 1.2 thereafter	5.0 to 2000 2.2 thereafter
PROBABILITY	.25	.50	.25

	INTEREST RATES %			
	5 – 7	7 – 9	9 – 11	11 – 13
PROBABILITY	.10	.32	.43	.15

	INFLATION RATE DIFFERENCE FROM INTEREST RATE		
	–2%	–3%	–4%
PROBABILITY	.33	.34	.33

	CAPITAL COSTS (REAL 1982 $ billion)			
	Below 3.1	Below 3.6	Below 4.3	Below 5.1
PROBABILITY	.46	.73	.90	1.00

TABLE 18.5.1

ACRES

SPECIFIC RISK I: RISK OF BOND REQUIREMENT OVERRUN

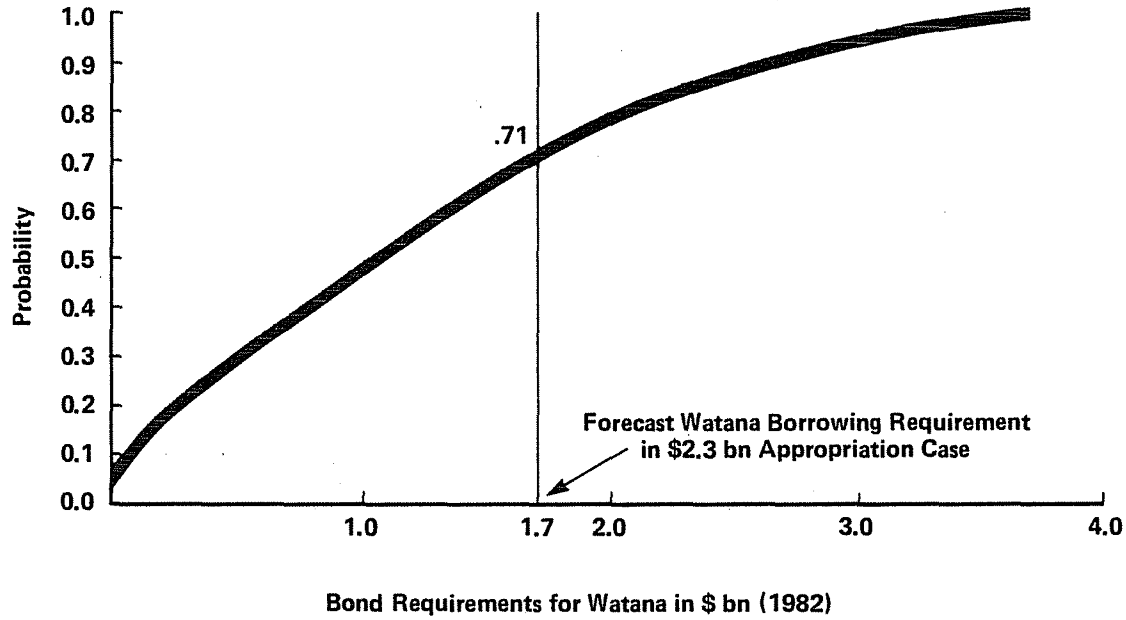


FIGURE 18.5.1 – BOND FINANCING REQUIREMENTS

SPECIFIC RISK II: IMPAIRMENT OF STATE CREDIT

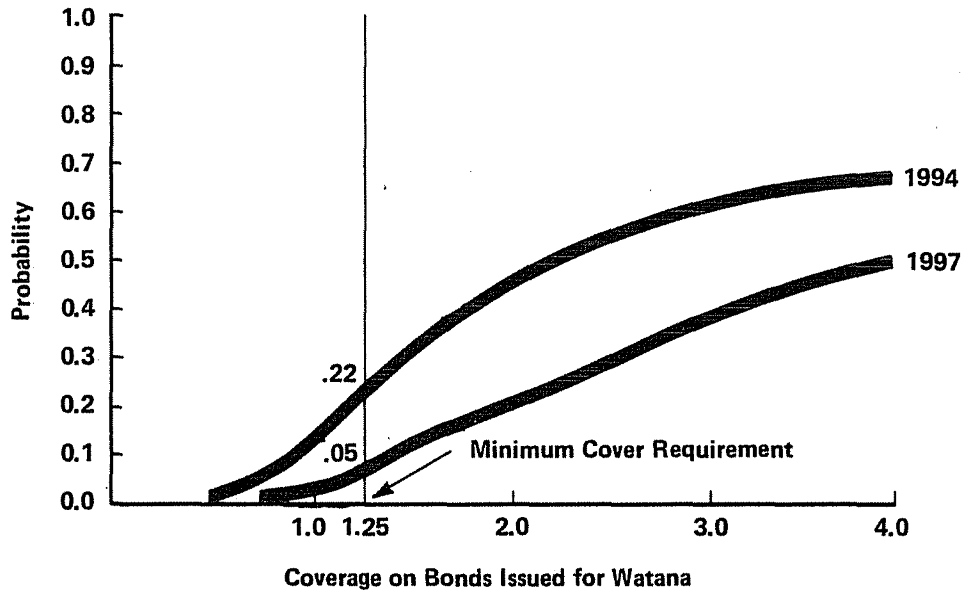


FIGURE 18.5.2 – DEBT SERVICE COVER

ACRES

SPECIFIC FINANCING RISK III: EARLY YEAR NONVIABILITY

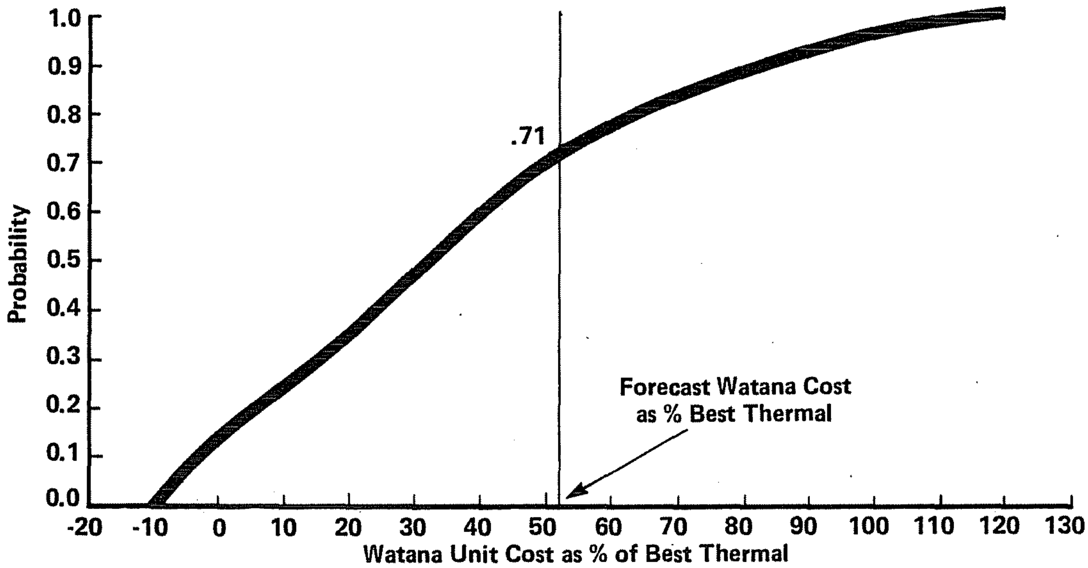


FIGURE 18.5.3 – WATANA UNIT COSTS AS PERCENT OF BEST THERMAL OPTION IN 1996

AGGREGATE RISK: POTENTIAL NET OPERATING EARNINGS

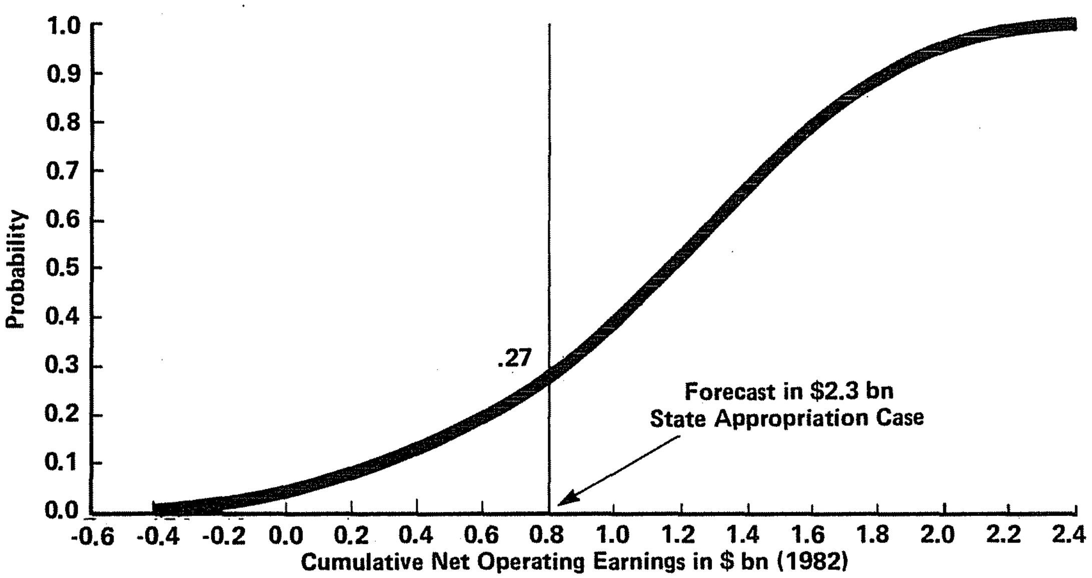


FIGURE 18.5.4 – CUMULATIVE NET OPERATING EARNINGS BY 2000

ACRES

LIST OF REFERENCES

(1) U.S. Department of Labor, Monthly Labor Review, various issues.

(2) Alaska Department of Commerce and Economic Development, The Alaska Economic Information and Reporting System, July 1980.

(3) Data Resources Inc., U.S. Long-Term Review, Fall 1980, Lexington, M.A., 1980.

(4) Wharton Econometric Forecasting Associates, Fall 1981, Philadelphia, P.A., (reported in Economic Council of Canada CANDIDE Model 2-0 Run, dated December 18, 1981.)

(5) Baumol, W.J., "On the Social Rate of Discount", American Economic Review, Vol. 58, September 1968.

(6) Mishan, E.J., Cost-Benefit Analysis, George Allen and Unwin, London, 1975.

(7) Prest, A.R. and R. Turvey, "Cost-Benefit Analysis: A Survey", Economic Journal, Vol. 75, 1965.

(8) U.S. Department of Commerce, Survey of Current Business, various issues.

(9) Data Resources, Inc., personal communication, November 1981.

(10) World Bank, personal communication, January 1981.

(11) U.S. Department of Energy, Energy Information Administration, Annual Report to Congress, Washington, D.C., 1980.

(12) National Energy Board of Canada, Ottawa, Canada, personal communication, October 1981.

(13) Noroil, "Natural Gas and International LNG Trade", Vol. 9, October 1981.

(14) Segal, J. "Slower Growth for the 1980's", Petroleum Economist, December 1980.

(15) Segal, J. and F. Niering, "Special Report on World Natural Gas Pricing", Petroleum Economist, September 1980.

(16) SRI International, personal communication, October 1981.

(17) World Bank, Commodity Trade and Price Trends, Washington 1980.

(18) Battelle Pacific Northwest Laboratories, Beluga Coal Market Study, Final Report, Richland, Washington, 1980.

(19) B.C. Business, August 1981.

(20) Coal Week International, various issues.

(21) Japanese Ministry of International Trade and Industry, personal communication, January 1982.

(22) Canadian Resourcecon Limited, Industrial Thermal Coal Use in Canada, 1980 to 2010, May 1980.

(23) Battelle Pacific Northwest Laboratories, Alaska Coal Future Availability and Price Forecast, May 1981.

(24) Roberts, J.O. et al, Treatment of Inflation in the Development of Discount Rates and Levelized Costs in NEPA Analyses for the Electric Utility Industry, U.S. Nuclear Regulatory Commission, Washington, D.C., January 1980.

(25) Acres American Incorporated. Report on "Economic, Marketing and Financial Evaluation" for Susitna Hydroelectric Project.