UNIVERSITY OF MINNESOTA

ST. ANTHONY FALLS HYDRAULIC LABORATORY

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Hydropower Feasibility and Uncertainty at Existing Minnesota Dams

by

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Abstract

This study details the development and application of a method for estimating economic feasibility of hydropower developments in the state of Minnesota, along with the associated uncertainty of the estimate. The uncertainty analysis is performed using input parameter probability distributions in combination with a Monte–Carlo–type simulation, while economic feasibility is calculated using an updated version of the hydropower survey program HYFEAS, developed in a previous study on site–feasibility in Minnesota. The result of the work is the computer program HYFEAS2, written to combine the routines of HYFEAS with the uncertainty analysis developed as part of this study. Additionally, equations have been derived to take the place of cost estimating techniques used in the previous program, based upon historical data which has since become available. HYFEAS2 is applied to 65 potential sites in the state of Minnesota, which were identified as having good or marginal feasibility by the authors of HYFEAS. Economic feasibility and the associated uncertainty is reported at four total energy values, in an effort to estimate the rate which most reasonably allows the majority of the sites to be developed.

Acknowledgements

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This research has also been reported in a Master of Science degree thesis submitted to the University of Minnesota, June 1991, by Robert U. Murdock.

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Finally, thanks to Dr. Efi Foufoula–Georgiou, for her helpful advice concerning the estimation of river flow at ungaged sites.

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I. Introduction

The generation of energy from hydropower is an industry which will always be capital–intensive. The major part of the total investment in a facility is spent in planning and construction of the plant, before there is any energy production. Therefore, there is a potential for major loss associated with hydropower ventures, should the income generated be less than expected due to unforeseen circumstances. This scenario does not compare favorably with energy produced from fossil fuels, where a greater portion of the costs are seen over the life of the project rather than in the initial phases. Such a facility may simply be shut down during times of excessive fuel costs, in order to reduce losses.

This lack of "economy of scale" for hydropower necessitates that extensive economic feasibility studies be performed before proceeding with projects. Developers and investors will continue with a project only in the event that favorable results are indicated by the study. Thus, the feasibility study is one of the most important tools in the hydropower industry. They are typically contracted to engineering consulting firms.

The two most frequently quoted results of a study are the feasibility indicators of benefit cost ratio and net discounted benefits. Unfortunately, these values are often obtained and reported without a measure of their associated uncertainty. This, in combination with the capital–intensive nature of such projects, tends to cause skepticism on the part of potential developers and investors. The skepticism is understandable, since upon first glance an estimate of a one million dollar net benefit from a project sounds favorable. However, if the probability of losing money on the venture is 45 percent, the same estimate would suddenly lose much of it's appeal. It is therefore valuable to provide an indication of uncertainty associated with feasibility indicators. This value reflects the variable nature of input parameters such as annual energy generation and discount rate, on which the feasibility indicators depend. In this manner, a degree of confidence in the quoted indicators is given to all parties concerned, better enabling them to make a prudent decision on whether to proceed with the venture.

A number of methods have previously been used for estimating economic uncertainty. The most simple of these is to perform a sensitivity analysis, in which input parameter values are varied according to user discretion so as to provide a range of possible values for the feasibility indicators. This method can be useful in some circumstances, but it does not give the probability of achieving a given result and thus cannot be considered to be an analysis of uncertainty. A first order, second moment analysis of uncertainty has been demonstrated for hydropower feasibility (Woods and Gulliver, 1990), in which a confidence interval is provided for estimated indicator along with the percent probability that the actual value will fall within the interval. Perhaps the most detailed type of analysis employs a Monte Carlo simulation to generate probability distributions of the independent parameters on which feasibility depends. The resulting output distributions are then used to identify the uncertainty associated with any desired result (Goidechea et al., 1982).

This thesis describes in detail a method for estimating the uncertainty associated with economic hydropower feasibility estimates. The method has been incorporated into the computer program HYFEAS2, written to run within the LOTUS 1–2–3 Software Package (Lotus Corporation, 1986). HYFEAS2 is an updated version of the hydropower survey program HYFEAS (Dotan and Gulliver, 1983), whose chief feature is the utilization of the LOTUS add–in software package @RISK (Palisade Corporation, 1989) to perform Monte Carlo uncertainty analyses on the estimated hydropower feasibility indicators. The program is applied to 65 sites in the state of Minnesota, which were identified as having either good or marginal feasibility in a previous study (Dotan and Gulliver, 1983).

The intent of this project is to update and improve the feasibility estimates for the 65 sites, made as part of this previous study. The sites were those remaining after an intensive 2–stage screening of all 853 dam sites in Minnesota. Seven of these sites have had some hydropower capacity installed since the conclusion of the previous study. The updated information includes this capacity. There are an additional four or five sties that are under intensive study at this time. The proposed capacity for these sites is not included as part of this study. Application of HYFEAS2 to the remaining sites will improve the previous estimates in the following ways:

1. The most obvious advantage of HYFEAS2 is that a complete range of possible outcomes is provided, along with their respective uncertainties. The user may know, for instance, what the uncertainty is of profiting from the installation or of seeing some level of benefit. In this particular study concerning the remaining sites, the risk of losing money is reported for each individual feasibility estimate.

2. The estimation of the indicators themselves will be more accurate, due to improved cost equations and the adjustment of previous site flow estimates (using a technique developed in this study).

3. The feasibility estimates will be made for a number of total energy values, in an attempt to identify the rate which will allow the majority of sites to be economically feasible.

Finally, the primary use of HYFEAS2 in this study was to estimate hydropower feasibility and uncertainty based on limited data. Project costs, as well as discount and escalation rates, are taken from equations developed using historical data. Such a study is known as a preliminary feasibility study (Dotan and Gulliver, 1983). However, HYFEAS2 has been written such that all historical equations can be adjusted or completely overridden. This allows HYFEAS2 to be used for estimating feasibility and uncertainty even when more complete data is available for the site. The program may be used for example, for a situation where estimates of some or all of the project costs are available. The same is true for discount and escalation rates. HYFEAS2 can even estimate uncertainties associated with user–selected capacities rather than those chosen by the program itself.

II. Estimation of Economic Hydropower Feasibility and Uncertainty

A. CALCULATION OF FEASIBILITY INDICATORS

Economic feasibility for hydropower projects is typically described by the feasibility indicators of benefit cost ratio and net discounted benefits. Both relate income generated by the plant to costs associated with construction and operation, as seen over the life of the project and discounted to present day value. The formulas describing the two are:

$$NDB = TDB - TDC \tag{1}$$

$$B/C = TDB/TDC \tag{2}$$

where NDB = net discounted benefits
B/C = benefit cost ratio
TDB = total discounted benefits
TDC = total discounted costs.

The benefits received in any year are dependent on the total energy generation and the total energy value (the rate at which the energy will be valued or purchased). Over the life of the project, inflation causes the value of energy to vary according to the average escalation rate. The total discounted benefits over the life of the project are given by equation 3 for a typical utility,

$$TDB = \sum_{n=1}^{N} \left\{ \frac{[(KWH\ \{(U + FOM)(1 + e)^n + ACV\}]}{(1 + d)^n} \right\} + \frac{SV}{(1 + d)^N} \tag{3}$$

where KWH= annual energy generation (KWH/year)
U = initial value at which energy is sold ($/KWH)
FOM = initial value of fixed operation and maintenance payment for the avoided energy generation ($/KWH)
ACV = avoided capacity value ($/KWH)
SV = salvage value of the plant in year N ($)
e = average annual escalation rate
d = interest and discount rate (assumed to be equal)
N = project economic life (years).

Equation 3 assumes that the same escalation rate applies to the initial energy value and fixed operation and maintenance payment.

Total discounted costs are the sum of those associated with the initial capital investment and with operation and maintenance. They are expressed as shown in equation 4,

$$TDC = \sum_{n=1}^{M} \frac{Cc \cdot d \cdot (1 + d)^M}{[(1 + d)^M - 1](1 + d)^n} + \sum_{n=1}^{N} \frac{OM\&R \ (1 + r)^n}{(1 + d)^n} \tag{4}$$

where
Cc = initial capital investment
OM&R = operation, maintenance, and replacement costs
M = amortization period of the capital investment loan.
r = escalation rate applied to operation, maintenance, and replacement costs.

Typically, the OM&R escalation rate (r) is set equal to (e) in equation 3.

B. THE MONTE CARLO METHOD OF ESTIMATING UNCERTAINTY FOR THE FEASIBILITY INDICATORS

Equations 1 thru 4 show that the feasibility indicators of net discounted benefits and benefit cost ratio depend on a number of input parameters. These functional relationships are

$$NDB = F_1(Cc,d,e,r,OM\&R,KWH,U,FOM,ACV,SV) \tag{5a}$$

$$B/C = F_2(Cc,d,e,r,OM\&R,KWH,U,FOM,ACV,SV) \tag{5b}$$

Uncertainty in the feasibility indicators (FI) is therefore related to the uncertainty of estimating each input parameter. As the estimates for each parameter become more certain, there will be less uncertainty associated with the indicators.

In developing the computer program HYFEAS2, a Monte Carlo method was chosen for analyzing uncertainty (Goidechea et al. 1984). The technique requires that a probability density function be developed for each input parameter, as displayed in figure 1. These density functions represent the probability of occurrence for a given value of the parameter. The values have a higher probability near the center of the distribution, where the function approaches it's maximum, and thus would occur more often in a random sampling. The most frequently occurring value of the distribution is defined as the median (Ψ). It identifies the point above and below which half of the sample distribution lies.

It can be seen from equation 5 that if the input parameters change in value, so too will the feasibility indicators. Herein lies the concept of the Monte Carlo approach to uncertainty analysis. The random selection of parameter values, according to their individual probability density functions, results in a number of output values for the indicators. The frequency with which the values occur can then be tabulated in order to generate frequency histograms for the indicators, as displayed in figure 2 (Steel and Torrie, 1980). The probability of achieving a given value of feasibility indicator is given by equation 6,

$$\text{Prob(FI>X)} = 1 - \left(\sum_{i=1}^{m} f_i \bigg/ \sum_{i=1}^{n} f_i \right) \tag{6}$$

where FI = the value of the feasibility indicator
X = the desired value of the feasibility indicator
f_i = frequency of occurrence for each histogram interval i
m = the number of histogram intervals where FI < X
n = the total number of histogram intervals.

Therefore, the uncertainty associated with any desired value of feasibility indicator may be calculated from the frequency histograms.

C. USE OF @RISK ADD–IN SOFTWARE FOR ESTIMATING UNCERTAINTY

HYFEAS2 was written to run on LOTUS 1–2–3 (Lotus Corporation, 1986) for the purposes of employing the add–in software package @RISK (Palisade Corporation, 1989). A cash flow chart of the type displayed in figure 3 is utilized for accepting input parameter values and calculating the corresponding feasibility indicator outputs. The functions $F_1(X)$ and $F_2(X)$ from equation 5 are used by the flow chart to calculate benefits and costs during each year of operation, which are then summed to give the net discounted benefits (net present value) and b/c ratio for the project. The indicators will take on new values for any given set of input parameters.

When an entire distribution of values is entered for each parameter, the cash flow chart will produce resulting distributions for the FI values. This task is performed by @RISK, which simultaneously varies all input parameters through successive iterations according to their probability density functions. The frequency with which each output FI value occurs is recorded, after which output frequency histograms are generated. The uncertainty for any desired level of economic benefit can then be calculated according to equation 6. The random sampling process is schematically represented in figure 4, showing both the input and resulting output density functions.

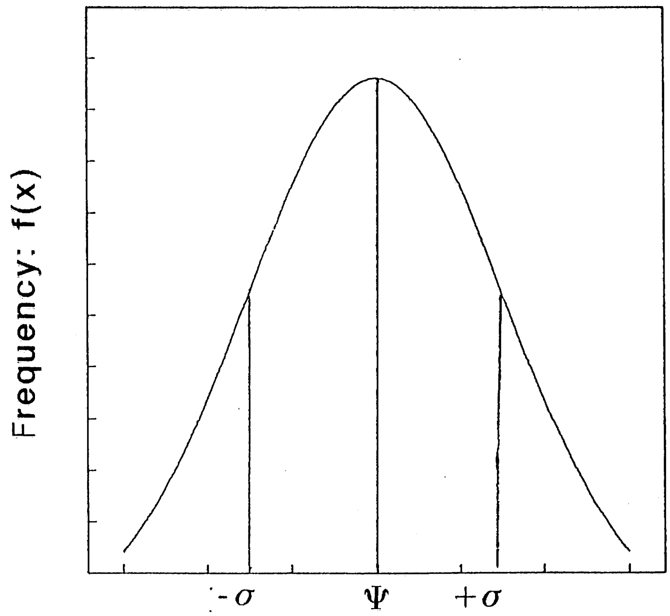

Figure 1 – Example of a Normal Probability Density Function.

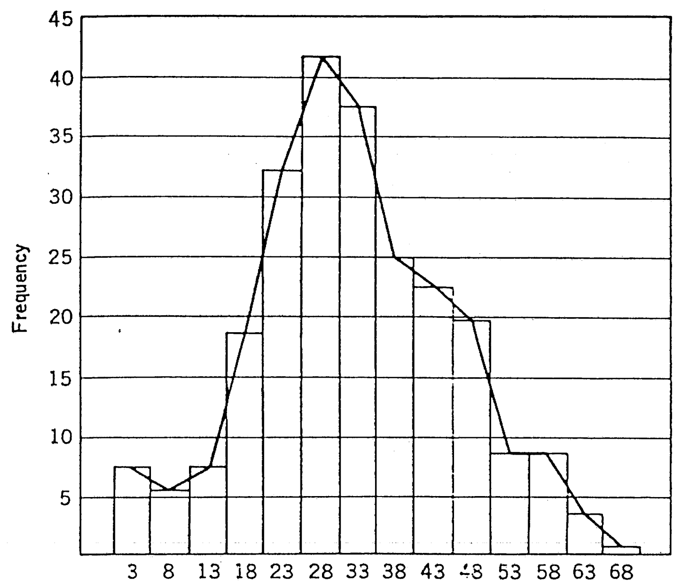

Figure 2 – Example of a Frequency Histogram.

FINANCIAL ASSUMPTIONS

Annual Energy Production (kWH)	1000000
Interest Rate, d	7.37%
Plant Capacity (kW)	125.7
Energy Buyback Rate ($/kWH)	0.0300
Avoided Capacity Value ($/kWH)	0.0100
Fixed O&M Capacity Payment ($/kWH)	0.0050
Energy escalation rate, e	5.55%
OM&R Yearly Uncertainty Factor	1
OM&R escalation rate, eom	5.55%
Res, Dam, Wtwy + Power House Costs	$118,180
Equipment Costs ($)	$73,636
Indirect Costs ($)	$50,000
Land Costs ($)	$0
Total Cost ($)	$241,816
Plant Life	10 years

F(X)

BENEFIT AND COST STREAMS

Year	Energy Buyback Rate ($/kWH)	Avoided Capacity Value ($/kWH)	Fixed O&M Capacity Payment ($/kWH)	O&M Costs ($)	Debt Service ($)	Revenues ($)	Present Worth (1990) Benefits	Present Worth (1990) Costs	Present Worth (1990) Cash Flow	Present Worth (1990) Net Pres. Value
							0	0	0	0
	0	0	0	0		0	0	0	0	0
1990	0	0	0	0	27,174	0	0	25,309	(25,309)	(25,309)
1991	0.0000	0.0000	0.0000	0	27,174	0	0	23,571	(23,571)	(48,880)
1992	0.0334	0.0100	0.0056	1,138	27,174	48,993	39,581	22,873	16,708	(32,172)
1993	0.0353	0.0100	0.0059	1,202	27,174	51,157	38,492	21,351	17,141	(15,031)
1994	0.0372	0.0100	0.0062	1,271	27,174	53,441	37,451	19,934	17,517	2,485
1995	0.0393	0.0100	0.0066	1,345	27,174	55,852	36,454	18,614	17,840	20,326
1996	0.0415	0.0100	0.0069	1,423	27,174	58,397	35,498	17,384	18,115	38,441
1997	0.0438	0.0100	0.0073	1,506	27,174	61,083	34,582	16,238	18,345	56,785
1998	0.0462	0.0100	0.0077	1,596						
1999	0.0488	0.0100	0.0081	1,691						
2000	0.0515	0.0100	0.0086	1,793						

ECONOMIC ANALYSIS

Net Present Value	$160,276
Benefit/Cost Ratio	1.84

F(X)

Figure 3 - Cash Flow Chart Used in Feasibility Analysis.

FINANCIAL ASSUMPTIONS

Annual Energy Production (kWH)	1000000
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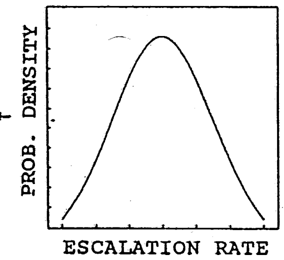

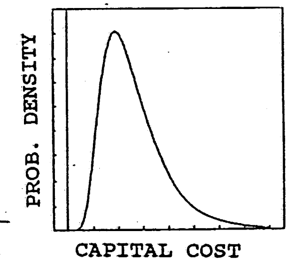

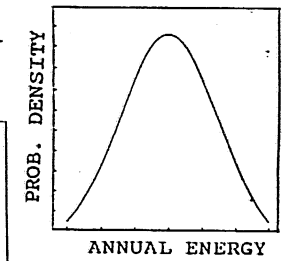

BENEFIT AND COST STREAMS

Year	Energy Buyback Rate ($/kWH)	Avoided Capacity Value ($/kWH)	Fixed O&M Capacity Payment ($/kWH)	O&M Costs ($)	Debt Service ($)	Revenues ($)	Present Worth (1990) Benefits	Costs	Cash Flow	Net Pres. Value
							0	0	0	0
	0	0	0	0		0	0	0	0	0
1990	0	0	0	0	27,174	0	0	25,309	(25,309)	(25,309)
1991	0.0000	0.0000	0.0000	0	27,174	0	0	23,571	(23,571)	(48,880)
1992	0.0334	0.0100	0.0056	1,138	27,174	48,993	39,581	22,873	16,708	(32,172)
1993	0.0353	0.0100	0.0059	1,202	27,174	51,157	38,492	21,351	17,141	(15,031)
1994	0.0372	0.0100	0.0062	1,271	27,174	53,441	37,451	19,934	17,517	2,485
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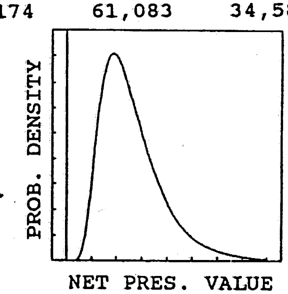
ECONOMIC ANALYSIS

Net Present Value	$160,276
Benefit/Cost Ratio	1.84



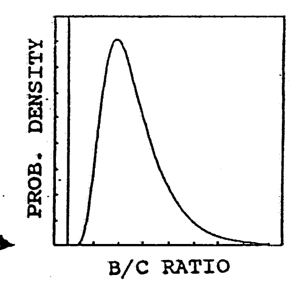


Figure 4 - Cash Flow Chart with @RISK Probability Density Functions.

It is important in using the Monte Carlo Method of uncertainty analysis that each of the input parameters behave independently, as this is an underlying assumption of the technique. If there is a strong relationship among the various costs or escalation rates, then a common density function must be used to describe their uncertainty. This matter will be addressed in the following chapter.

III. Development of Input Parameter equations and Probability Density Functions

Input probability density functions were developed for each of the parameters listed in equation 5. Variables describing the shape and magnitude of each function are accepted by HYFEAS2, which utilizes @RISK to generate the corresponding density functions. These are used in the Monte Carlo uncertainty analysis. A number of techniques were employed in developing the functions, which are described in the following sections.

A. ENERGY AND POWER PRODUCTION

1. Flow Estimation with Cumulative Probability Distribution Functions

Figure 5 displays a cumulative probability distribution function describing flow at a particular river site. The function gives the probability of exceedance for various flow rates on any given day of the year. Put differently, the function identifies the percentage of time that a given flow rate can be expected to be exceeded. It is commonly referred to as a daily flow duration curve in the hydropower industry, and is the key tool used for estimation of the annual energy available at a site.

The power generated by a hydropower plant is described by

$$P = \frac{Q\ H\ e}{11.81} \tag{7}$$

where
P = power (KW)
Q = flow rate through the turbine(s)
H = net head differential across the turbines (ft)
e = overall plant efficiency.

The annual energy delivered by the plant is obtained through the integration of equation 7 over a time period of one year. Although the head and efficiency are not constant with river flow, they may be assumed so in making a rough estimate of annual energy generation. In this case, the river flow is the only parameter which varies with time, according to the probability distribution function. Annual energy is then described by

$$AE = 7.417\ H\ e \left(\int_{P1}^{P2} Q(\%)\ d(\%) + \int_{P2}^{0\%} Q(p_2)\ d(\%) \right) \tag{8}$$

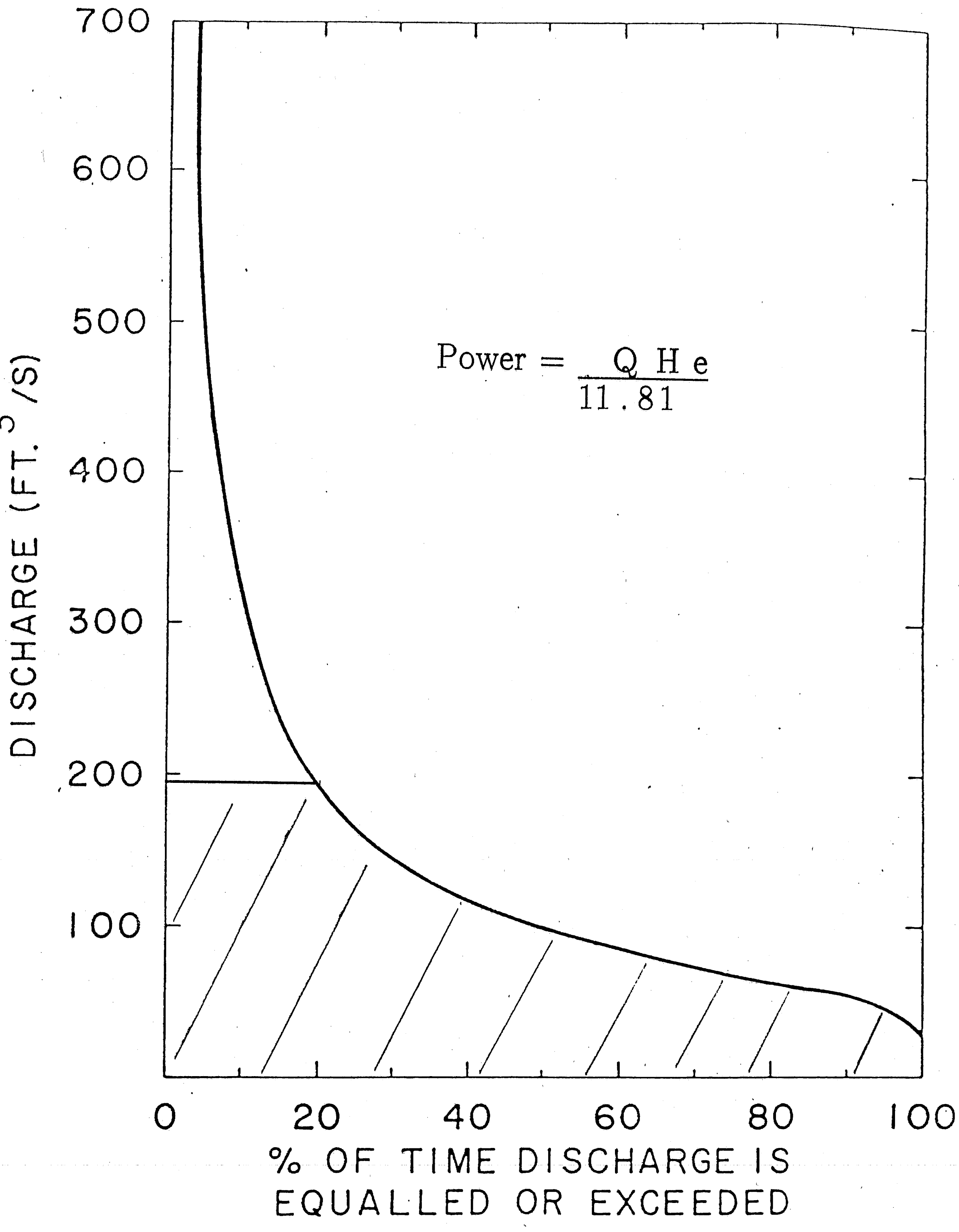


Figure 5 - Cumulative Probability Distribution Function for River Flow.

where AE = annual energy generation (KWH)
p_2 = the percentage exceedence level corresponding to the flow rate at which the turbine(s) are sized
p_1 = the percentage exceedence level corresponding to the minimum flow passed through the turbine.

The integral portion of equation 8 can be thought of as the annual flow volume passed through the turbines of a hydropower plant. It is schematically represented by the cross–sectioned area under the curve in figure 5, for the case where p_2 = 20% and p_1 = 100%. Multiplying this area by head and plant efficiency, as well as the appropriate conversion factor, yields the annual energy produced by the plant. Thus the area under a probability distribution function of discharge is a direct measure (assuming constant head and efficiency) of the annual energy available at a river site.

2. <u>Uncertainty Analysis for Annual Energy Generation</u>

Since annual energy generation has been shown to depend on the probability distribution function describing river flow, it follows that the uncertainty in such an estimate depends on that associated with constructing the function itself. The more accurate the function, the better the estimate of river flow and thus of energy generation.

a. Construction of Probability Distribution Functions

The work of constructing distribution functions is carried out by the United States Geological Survey (USGS), which maintains a large number of flow gages at various river sites within the country. Daily flow rate data is recorded at the gages, and afterwards is subdivided into intervals corresponding to different flow rate ranges. The result is a frequency histogram of the type displayed in figure 2, where equation 6 is again used to calculate the probability of exceedence, in this case for a flow rate rather than feasibility indicator:

$$\text{Prob}(Q>X) = 1 - \left(\sum_{i=1}^{m} f_i \bigg/ \sum_{i=1}^{n} f_i \right) \qquad (6a)$$

where Q = the river flow rate
X = the river flow value to be exceeded
f_i = frequency of occurrence of recorded values within flow rate interval i
m = the number of flow rate intervals where $Q < X$
n = the total number of flow rate intervals.

The largest single problem encountered in using USGS–constructed distribution functions is that the potential hydropower site typically does not coincide with a gaged location. It is common practice in these situations to use data from a gage located within the same watershed as that of the site, and extrapolate according to the equation (Gulliver and Arndt, 1991)

$$Qs_i = \left[\frac{As}{Ag}\right]^n Qg_i \tag{9}$$

where Qs_i = the flow rate at the site at percentage exceedence i
Qg_i = the flow rate at the gage at percentage exceedence i
As = the drainage area of the site
Ag = the drainage area of the gage
n = hydrologic exponent whose value depends on watershed characteristics and application.

The value of n is typically set to one within the hydropower industry, simply because there is normally insufficient information available to choose anything else. Figure 6 is a plot of n versus drainage area ratio for pairs of USGS gages which are located in common watersheds, as calculated from equation 9 using average annual flows (USGS, 1988). It shows that the assumption of n equal to 1 may be off by 50% or more. This can lead to large errors in estimating flow at an un–gaged site, particularly for cases where the drainage areas are significantly different. An actual value of n equal to 1.5 would result in a 5% error for an area ratio of 0.9, for example, compared to 30% if the area ratio were 0.5.

b. Use of Average Annual Flow Data for Estimating the Uncertainty of Cumulative Probability Distribution Functions for River Discharge

The previous section suggests that it is desirable to refine the assumption of n = 1 in using equation 9 to construct probability distribution functions of river discharge for un–gaged sites. Of course, there is also a need to assign an uncertainty to the method, whatever it may be. It is primarily time constraints that result in a chosen value of 1 for n, as engineering firms have deadlines and other considerations which preclude spending excessive time in constructing the distribution functions. With this in mind, average annual flow data from Minnesota and the surrounding states was used to estimate both an improved value of n, and the uncertainty associated with the new value. Such data is readily available from the USGS for numerous sites in the region. The hypothesis is that the new value of n may then be applied to the construction of entire probability distribution functions for river discharge, and that the associated uncertainty will conservatively be described by that derived from the average annual flow analysis.

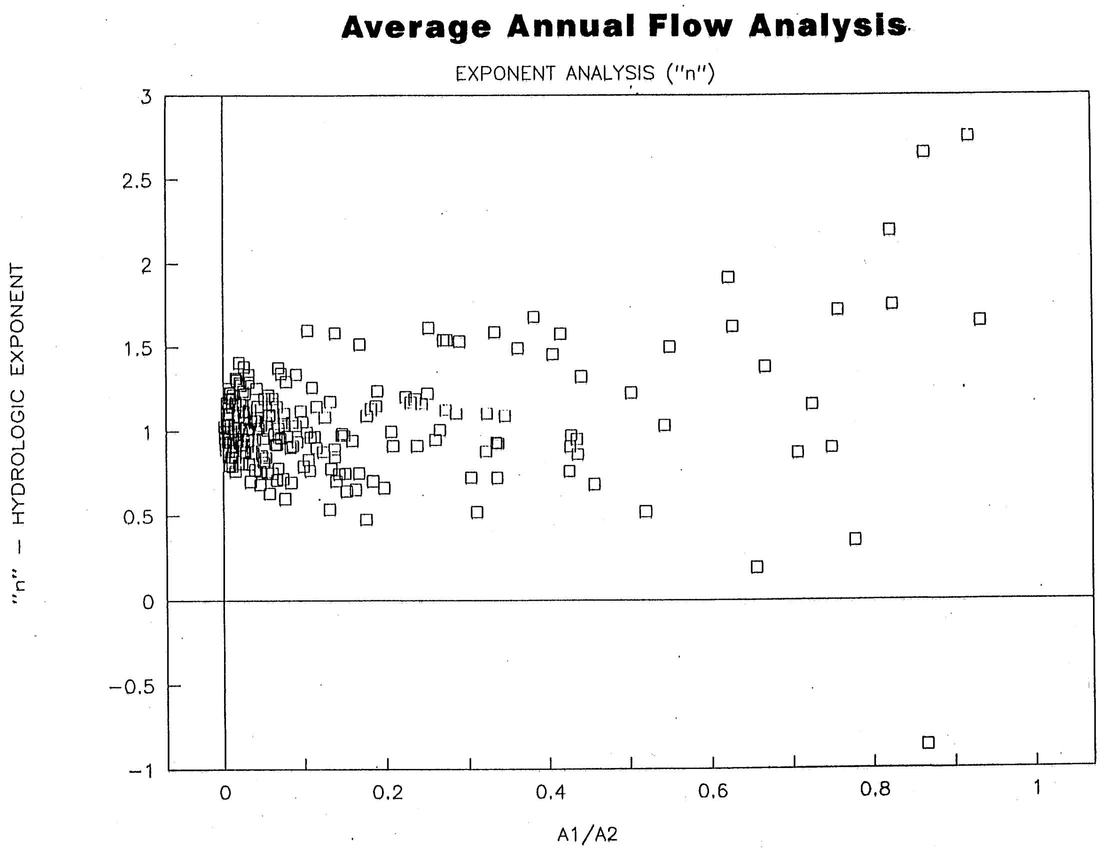


Figure 6 – Plot of "n" Versus Drainage Area Ratio per Equation 9.

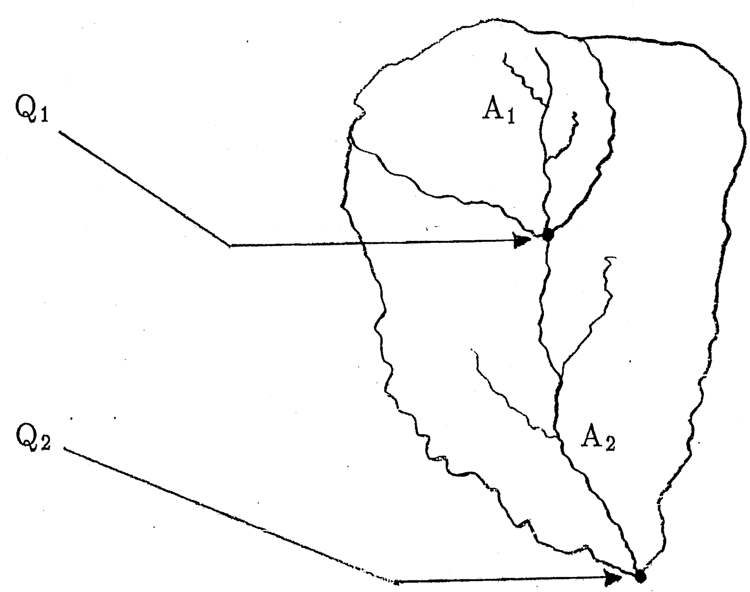


Figure 7 – Schematic of a Watershed.

Figure 7 displays a schematic of a watershed with upstream and downstream gages. Average annual flow data was obtained from the USGS, for 129 such pairs of gages located in Minnesota and the surrounding 5–state region (USGS, 1988). Equation 10 may be applied to the data,

$$\mathrm{Log}\left[\frac{Q_1}{Q_2}\right] = n\ \mathrm{Log}\left[\frac{A_1}{A_2}\right] \tag{10}$$

where Q_1 = the average annual flow rate at the upstream gage
Q_2 = the average annual flow rate at the downstream gage
A_1 = the drainage area for the upstream gage
A_2 = the drainage area for the downstream gage,

so as to develop 129 data points from which a revised value of n can be estimated. This data is plotted and fitted in figure 8. The slope of the fitted line is equal to the revised value of n, which on the average will yield the most accurate estimate of average annual flow ratio (Q_1/Q_2) when used in equation 10. The revised value of n was calculated to be $n = 1.126$. According to the hypothesis stated previously, this value will be used in equation 9, such that the revised equation is:

$$Qs_i = \left[\frac{As}{Ag}\right]^n Qg_i, \quad \text{where } n = 1.126 \tag{11}$$

It should be noted that the fitted line in figure 8 was forced through the origin, to satisfy the condition that $(Q_1/Q_2) = 1$ when $(A_1/A_2) = 1$.

The uncertainty of using the revised value of n to estimate average annual flow at ungaged sites is analyzed from a plot of the residual error between actual and predicted data points, $\mathrm{Log}(Q_1/Q_2)_a$ and $\mathrm{Log}(Q_1/Q_2)_p$, versus the independent variable, $\mathrm{Log}(A_1/A_2)$. The plot is presented in figure 9, and shows that the variance of the residuals decreases as $\mathrm{Log}(A_1/A_2)$ approaches 0. This suggests that there is less uncertainty in using equation 10 as the drainage area ratio approaches a value of one, which could be expected.

The non–constant variance of the residuals means that the data is heteroscedastic (Younger, 1979). There are many texts available which detail methods for working with such data, such as transformations and weighted least squares (Neter, et al, 1985). In lieu of these methods, it was decided that the uncertainty associated with the use of equation 10 could best be described by the construction of upper and lower confidence bands. A 68% confidence band was chosen because the ultimate result of this analysis is the uncertainty of feasibility indicators, where the 68% confidence band is all that can be predicted with accuracy. The bands describe the limits within which 68% of the residual values should fall, and are equal to the standard deviation of thirty or more residuals.

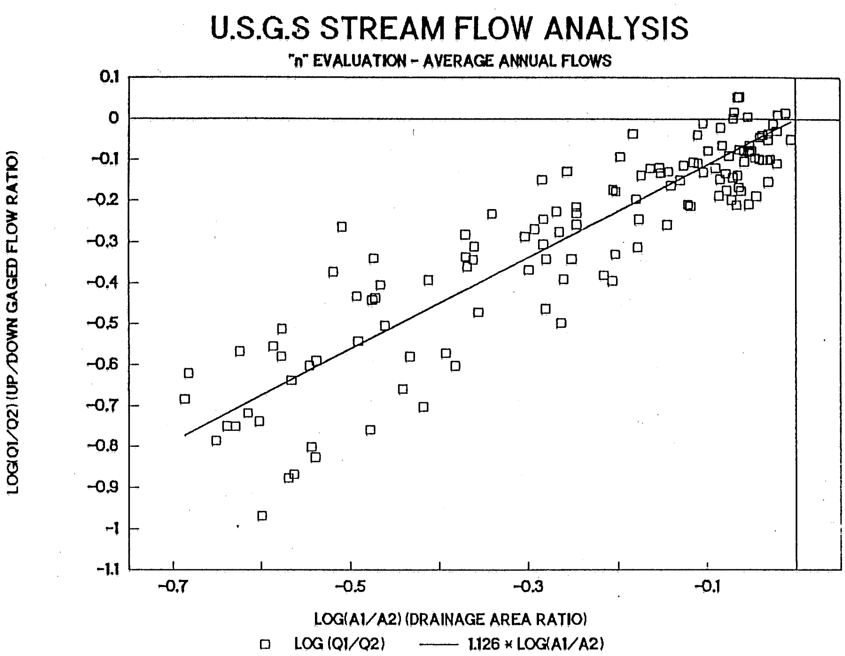


Figure 8 – Logarithmic Ratios of Average Annual Flow Versus Drainage Area.

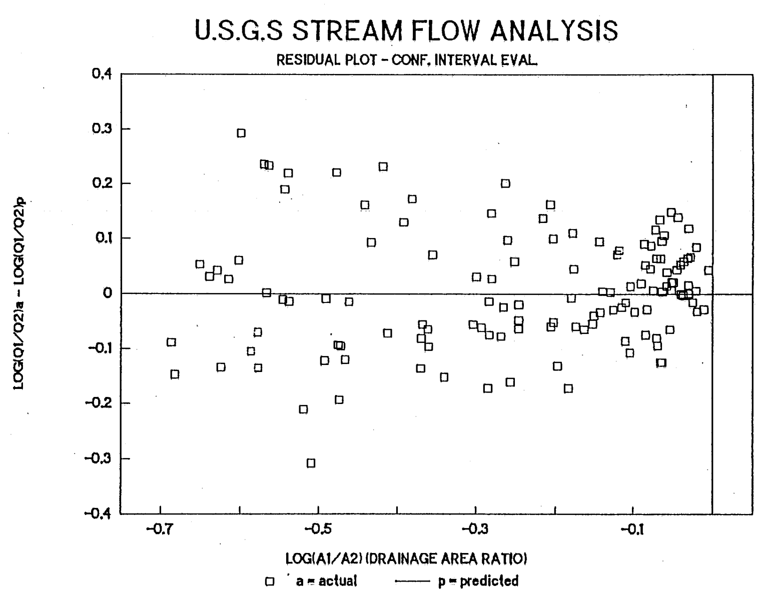


Figure 9 – Residuals Between Actual and Predicted Flow Ratios; Logarithmic Values.

The data was first divided into sub–intervals corresponding to different ranges of $\mathrm{Log}(A_1/A_2)$, identified by the vertical lines in figure 10. A standard deviation was calculated for the residual values within each sub–interval, in order to identify the 68% confidence range of the individual intervals. These deviations are plotted versus the interval midpoint in figure 11, where the squares represent the average residual value for each interval. The fact that the averages do not lie perfectly at 0 implies that the spread of residual values is not perfectly normal about 0 for any given value of $\mathrm{Log}(A_1/A_2)$. It is felt that this is primarily due to the finite (rather than infinite) number of data points used in the analysis. The averages do at least lie about 0, and therefore it was be assumed that the spread of residual values can be approximated as normal.

The result of imposing the confidence bands onto the residual plot is displayed in figure 12. Approximately 68% of the values fall inside of the bands. Once again, due to the finite number of data points and also because the data fit was forced to pass through the known condition at $\mathrm{Log}(A_1/A_2) = 0$, there is a discrepancy between the number of points above the bands as compared to below. Still adhering to the above–stated normal assumption, the equation for the confidence bands was determined from a log–linear regression to be:

$$\mathrm{Log}(Q_1/Q_2)_a - \mathrm{Log}(Q_1/Q_2)_p = \pm \left(0.066 + 0.3428\left\{[\mathrm{Log}(A_1/A_2)]^2\right\}^{0.9074}\right) \qquad (12)$$

These bands have been imposed on figure 8 as presented in figure 8a. As stated earlier, each residual is simply the error between an actual value of $\mathrm{Log}(Q_1/Q_2)_a$, calculated from average annual flow data, and $\mathrm{Log}(Q_1/Q_2)_p$, calculated from the fitted line in figure 8 according to equation 10, with $n = 1.126$. The confidence bands therefore describe the uncertainty in the use of equation 10. The anti–log of equation 12 yields confidence bands which describe the uncertainty in the absolute value of average annual flow ratio, according to the following equations:

$$\frac{(Q_1/Q_2)_a}{(Q_1/Q_2)_p} = 1.164 \cdot 10^{0.3428\left\{[\log(A_1/A_2)]^2\right\}^{0.9074}} \qquad (13a)$$

for the upper confidence band, and

$$\frac{(Q_1/Q_2)_a}{(Q_1/Q_2)_p} = 0.859 \cdot 10^{-0.3428\left\{[\log(A_1/A_2)]^2\right\}^{0.9074}} \qquad (13b)$$

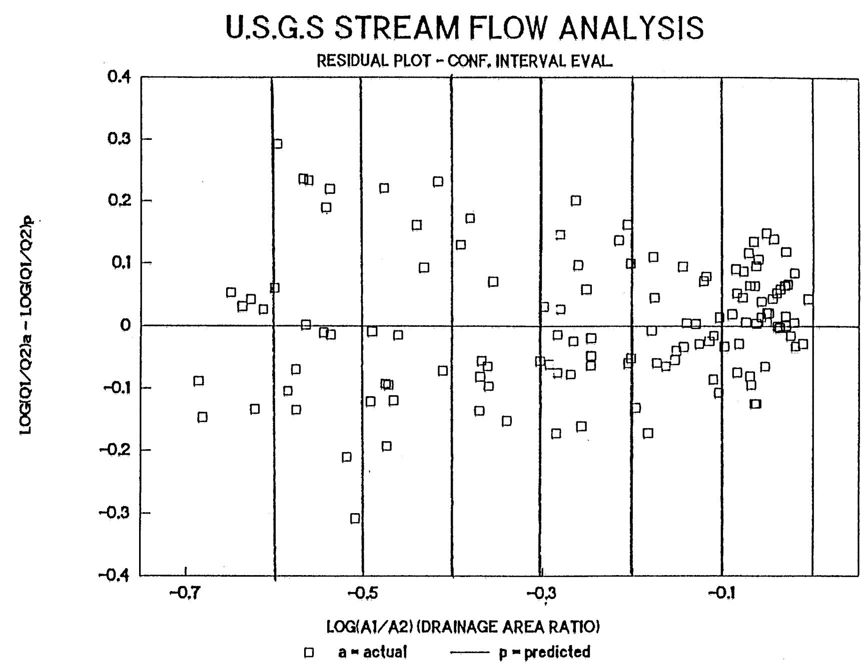


Figure 10 – Residuals Divided into Sub–Intervals of Drainage Area Ratio.

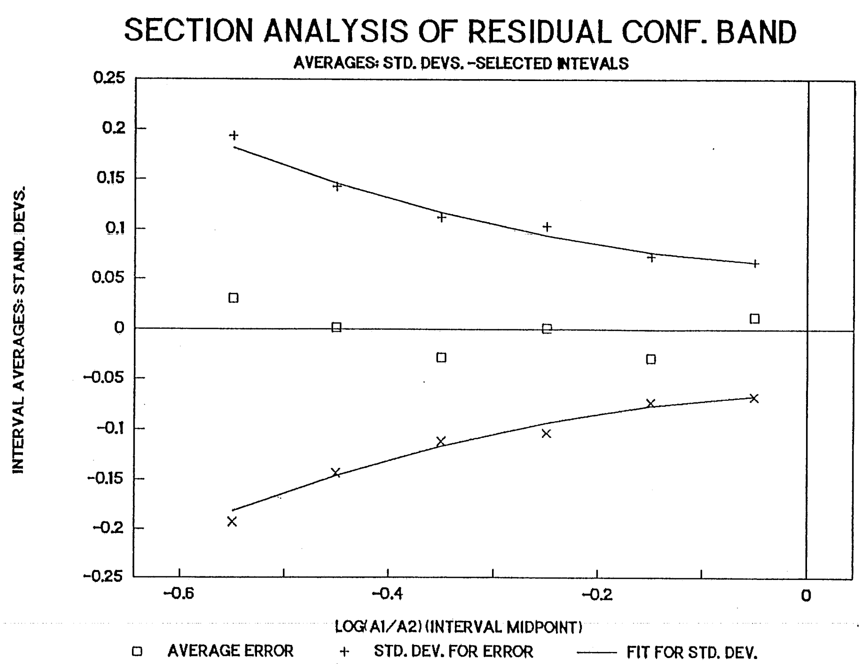


Figure 11 – Residual Deviations and Averages Versus Interval Midpoint.

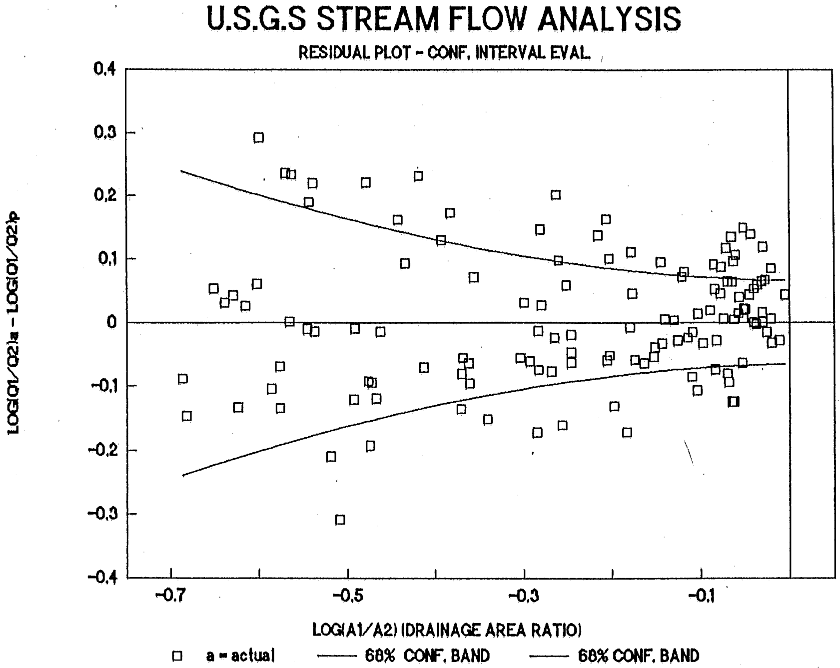


Figure 12 – Confidence Bands Imposed onto Flow Ratio Residuals

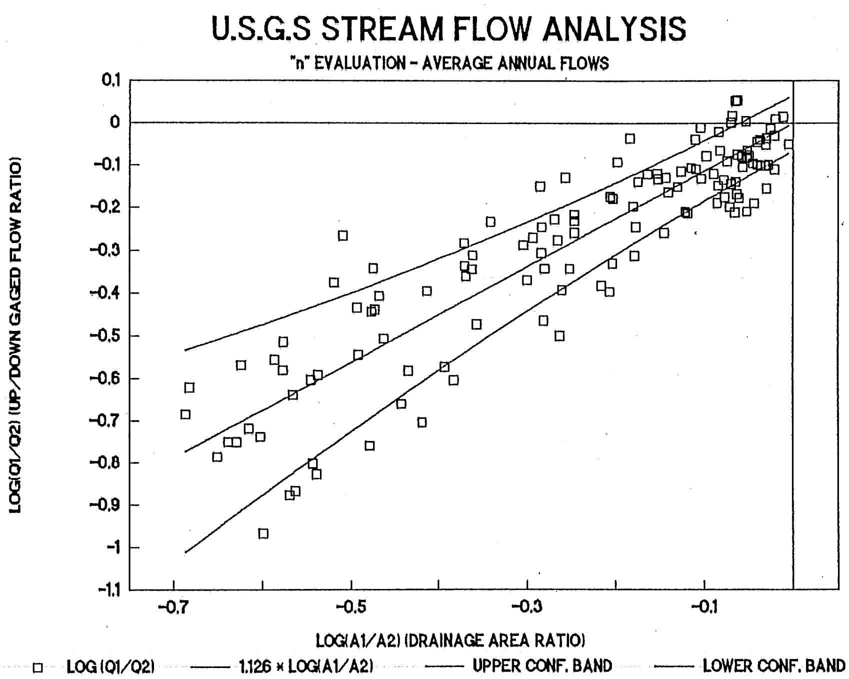


Figure 8a – Confidence Bands Imposed onto Flow Ratio Plot of Figure 8.

for the lower confidence band, where:

$(Q_1/Q_2)_a$ = the actual value of average annual flow ratio
$(Q_1/Q_2)_p$ = the predicted value of average annual flow ratio.

To this point, equations have been derived which describe uncertainty in predicting average annual flow ratios between upstream and downstream gages, using a revised value for n. In the case where the upstream site is ungaged, Q_1 may be set equal to Q_s, where Q_s is now the average annual flow at the ungaged site. Referring to equation 11, the predicted value of average annual flow ratio is described by the equation:

$$\left(\frac{Q_s}{Q_2}\right)_p = \left[\frac{As}{A_2}\right]^n, \qquad (14)$$

where n = 1.126
A_s = the drainage area of the ungaged site.

Equation 13 can then be re-expressed to yield the uncertainty associated with this prediction:

$$\left(\frac{Q_s}{Q_2}\right)_a = (A_s/A_2)^{1.126} \cdot 1.164 \cdot 10^{0.3428\left\{[\log(A_s/A_2)]^2\right\}^{0.9074}} \qquad (15a)$$

for the upper confidence band, and

$$\left(\frac{Q_s}{Q_2}\right)_a = (A_s/A_2)^{1.126} \cdot 0.859 \cdot 10^{-0.3428\left\{[\log(A_1/A_2)]^2\right\}^{0.9074}} \qquad (15b)$$

for the lower confidence band,

where $\left(\frac{Q_s}{Q_2}\right)_a$ = the actual value of average annual flow ratio.

Both the predicted value, and the confidence bands describing the upper and lower limits of uncertainty for the prediction, are presented in figure 13 for the case where the site drainage area is smaller than that of the gage. The distribution of data is log-normal on this absolute scale, since on the log scale of figure 8a it was assumed to be normally distributed.

This analysis may be extended to the case where the site drainage area, A_s, is larger than that of the gage, and therefore situated downstream rather than upstream. Each data point presented in figure 8 would take the inverse

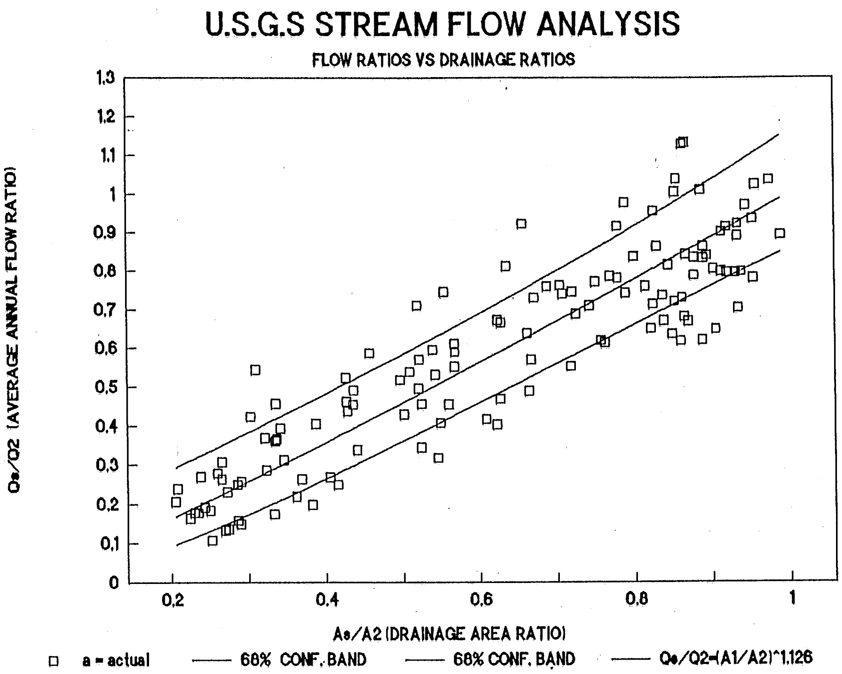


Figure 13 – Predicted Values of Average Annual Flow Ratio at un–gaged sites, with 68% Confidence Bands.

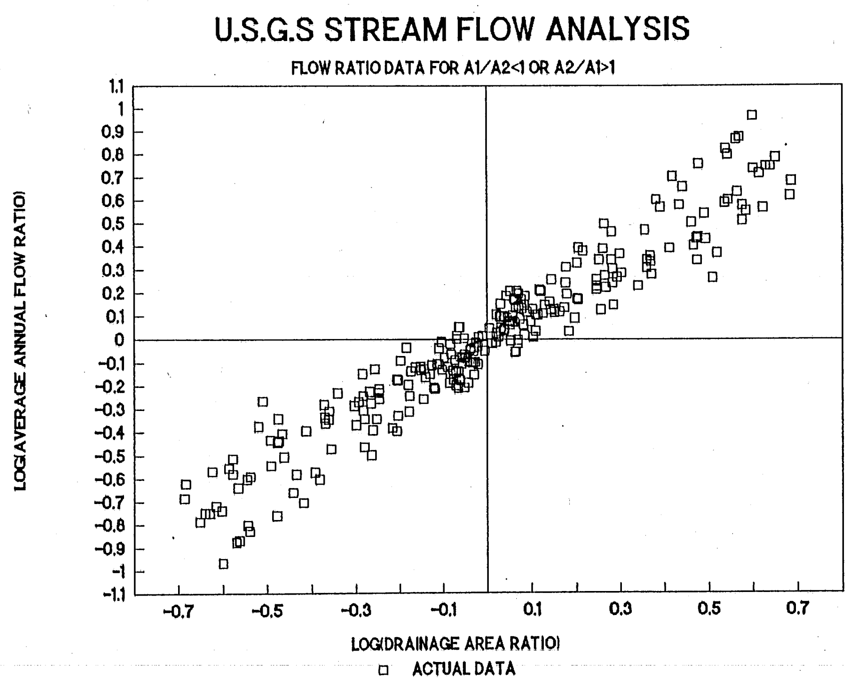


Figure 14 – Gaged Flow Ratios for Upstream and Downstream Cases.

of it's former value, since $(Q_2/Q_1) = (Q_1/Q_2)^{-1}$, and would be plotted at the inverse drainage area ratio, $(A_2/A_1) = (A_1/A_2)^{-1}$. Figure 14 demonstrates that the new plot becomes a mirror image of the old. The data fit and confidence intervals will remain the same on this log scale, and therefore equations 14 and 15 describe the data at *any* given value of drainage area ratio. The absolute prediction and confidence intervals presented in figure 13 are extended to include this entire range of drainage area ratios, as shown in figure 15. At first glance it appears that there is more uncertainty associated with large drainage areas ($A_s/A_2>1$), but this is not the case. The predicted value of Qs will in fact have the least uncertainty as a percentage of the median (defined by the fitted equation) at a drainage area ratio equal to 1 ($A_s/A_2=1$), with increasing uncertainty for area ratio values larger or smaller.

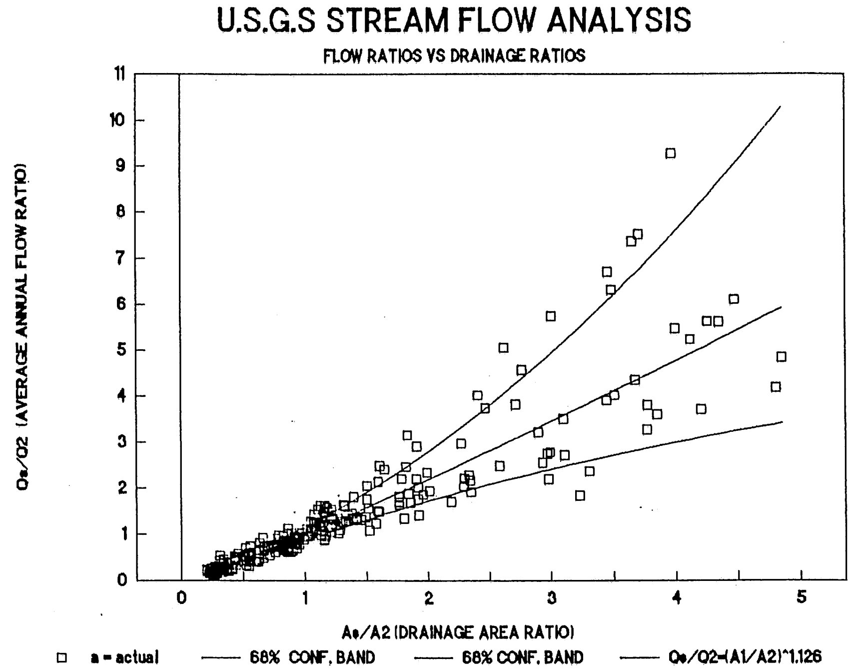


Figure 15 – Predicted Values of Average Annual Flow Ratio for Upstream and Downstream Cases, with 68% Confidence Intervals.

In summary, this average annual flow analysis has yielded an improved value of the exponent n, along with the uncertainty associated with it's use. The uncertainty has been shown to be described by the 68% confidence bands of figure 15, with a log–normal distribution of possible values. The entire analysis has been performed for estimation of average annual flows at ungaged sites. The task is now to verify that both the improved value of n, as well as the corresponding uncertainty limits, may be applied to the generation of entire probability distribution functions for river discharge at an ungaged sites per equations 9 and 11. This is the hypothesis originally stated at the start of this analysis.

c. Verification of the Average Annual Flow Technique

Figure 16 presents a comparison between two probability distribution functions, one of which was estimated through the use of equation 11 using the improved value of n, and the other based on actual USGS gage data for the site. The intent was to calculate the error in the application of equation 11 to this particular site. As stated in section a, the area under the probability distribution function is a direct measure of the annual energy available at the site. Therefore, the difference in area under the curves indicates the error in energy estimation which would occur in using equation 11 for the generation of the function. A 20% exceedence level was chosen as a typical turbine design capacity for hydroplants. Beyond this level, extra river flow is passed over the spillway, such that errors in river flow estimation have relatively little effect on energy estimates. Thus the functions have been terminated at this point.

The error is identified by the cross–sectioned area and is quantified by the indicated ratio. The uncertainty, as calculated from the upper 68% confidence band in figure 13, is also indicated. According to the hypothesis of section b, the error should be between this value, described by the upper confidence band of figure 13, and that of the lower band of the same figure, for two out of every three sites having this drainage area. Uncertainty taken from the confidence bands exceeded the actual error for this site.

Comparisons of actual versus predicted distribution functions were made for a total of 13 gaged sites in the state of Minnesota. Predictions were made using equation 11 in conjunction with distribution functions for upstream or downstream gaged sites. The error in areas beneath the curves and the 68% uncertainty limits are tabulated in table 1.

There are two major results of the the comparison. The first is that the confidence bands of figure 15 appear to slightly overestimate uncertainty in the generation of the probability distribution functions, when calculated from equation 11. In only 2 of the 13 comparisons did the actual error exceed the uncertainty limits. As the uncertainty limits are taken from 68% confidence bands, it was expected that there would be approximately four such occurrences. The reason for the overestimate of uncertainty is that the error is not accounted for when the river flow is larger than 20% exceedence, due to the turbine sizing assumption stated earlier. The average annual flow values do include these high flow periods, however, such that the confidence bands of figure 15 include a portion of the river flow which does not figure into energy generation.

Another result is that the error in predicted energy appears to be evenly distributed about one (for the actual/predicted area ratios), with 6 values above and seven below. This indicates that on the average, use of equation 11 should result in a median prediction of river flow at an ungaged site, and therefore of energy generation. There of course will always be an uncertainty associated with this estimate.

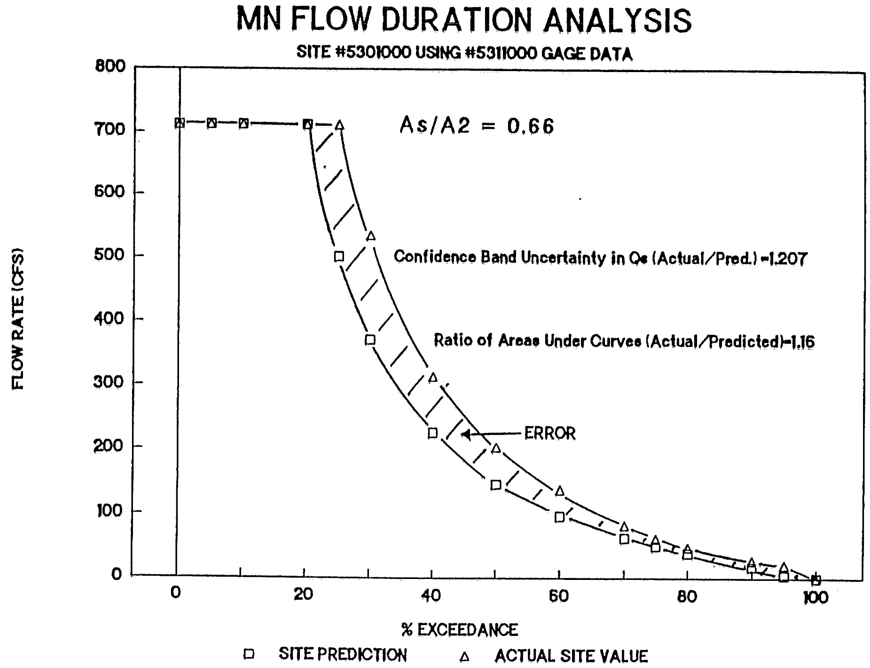


Figure 16 – Actual and Predicted Probability Distribution Functions.

TABLE 1 – Comparison of Predicted and Actual Distribution Functions

USGS Site #	Drainage Area Ratio	Uncertainty Limits (68%) (Actual/Pred.)	Actual Error (Actual/Pred.)
5079000	3.85	0.64 to 1.57	1.10
5082500	0.86	0.85 to 1.18	0.91
5301000	0.66	0.83 to 1.21	1.16
5315000	0.43	0.76 to 1.32	0.96
5330000	1.09	0.86 to 1.17	1.17
5330000*	0.44	0.76 to 1.32	0.79
5331000	0.82	0.85 to 1.18	0.96
5378500	1.32	0.84 to 1.18	1.35
5211000	2.34	0.76 to 1.32	0.95
5220500	1.50	0.83 to 1.20	0.95
5127000	0.71	0.84 to 1.19	1.02
5227500	1.21	0.85 to 1.17	1.00
4018750	0.21	0.58 to 1.73	1.17

* Two different distribution functions were calculated for this site based on upstream and downstream gages

d. Input Probability Density Function for HYFEAS2

In summary, the uncertainty in annual energy generation will be described by the confidence bands of figure 15. The input probability density function for the annual energy parameter of the HYFEAS2 risk analysis will be a log–normal distribution, with a log–standard deviation which depends on the drainage area ratio, per equation 12. For figure 16, the standard deviation of the logs would be:

$$\sigma[\log(Q_a)-\log(Q_p)] = \sigma\log(Q_a/Q_p) = \sigma\log(AE_a/AE_p) = 0.0817; \qquad (16)$$

with $A_s/A_2 = 0.66$ in equation 12 for the site of figure 16;

where:
- Q_a = actual flow volume passed through turbine
- Q_p = predicted flow volume passed through turbine
- AE_a = actual annual energy generated
- AE_p = predicted annual energy generated
- σ = symbol for standard deviation
- A_s/A_p = the drainage area ratio between the site and gage.

This deviation would be accepted by HYFEAS2, which would use a log–normal density function of the type displayed in figure 17, when performing the Monte Carlo uncertainty analysis.

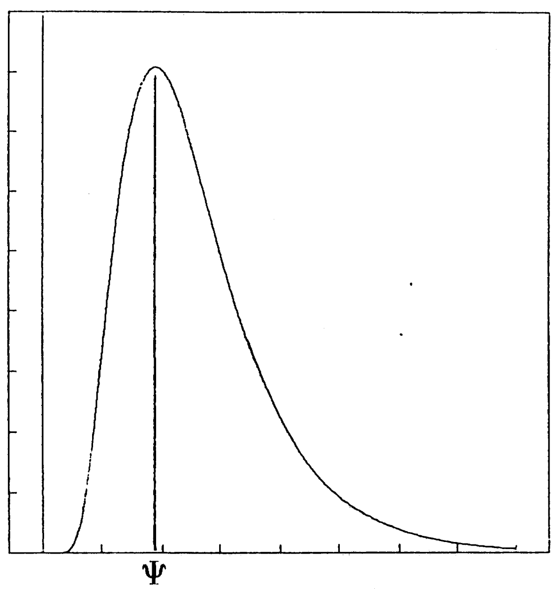


Figure 17 – Example of a Log–Normal Probability Density Function.

B. HYDROPLANT COSTS

Hydroplant costs include those associated with initial capital investment and those of operation, maintenance, and replacement. These were respectively defined as Cc and OM&R in equation 5. As with annual energy calculations, it was necessary to develop probability density functions for each of these parameters, in addition to the equations describing their best estimate. Capital investment costs were separated into the sub–categories of equipment, structures and waterways, and indirect costs. equations and uncertainties for each have been developed based on historical cost data. OM&R costs are calculated using a separate, previously published equation. A description of each analysis follows.

1. Structure and Waterway Costs

a. Development of the Cost equation

Two reports were used in developing cost equations. One (Energy Information Administration, 1987) includes historical plant cost data for numerous sites in the United States. The capacity typically ranges from 10 to 2000 MW for these facilities, and only those built in 1970 or later were used in developing the equations. The other report gives individual summaries of DOE Hydropower Demonstration Projects (DOE, 1986), where in this case the capacities of the facilities range from 700 KW to approximately 15 MW. Use of the two sources enabled equations to be developed which yield estimates for both small and large hydropower installations.

In the case of structure (C_s) and waterway (C_w) costs, the data was originally fitted as shown in figure 18, where the predicted formula describes the best fitting line for the data. The costs are seen to vary directly with plant capacity (KW), and inversely with head differential (H). Points which are labeled "EP" refer to installations where an existing powerhouse was used for housing the turbo–machinery. As demonstrated in the figure, the powerhouse is a major component of the total cost of construction, and therefore the cost is significantly reduced if an existing structure can be utilized. Since in the majority of cases this is not possible, the equation was revised to exclude these data points. Figure 19 presents the new fit, where three of the "EP" data points are shown for comparison purposes, representing situations in which entirely new turbines were installed in the existing powerhouses. The resulting equation used for describing structure and waterway costs in HYFEAS2 is:

$$(C_s + C_w) = 3608 \cdot KW^{0.937} \cdot H^{-0.223} \quad (17)$$

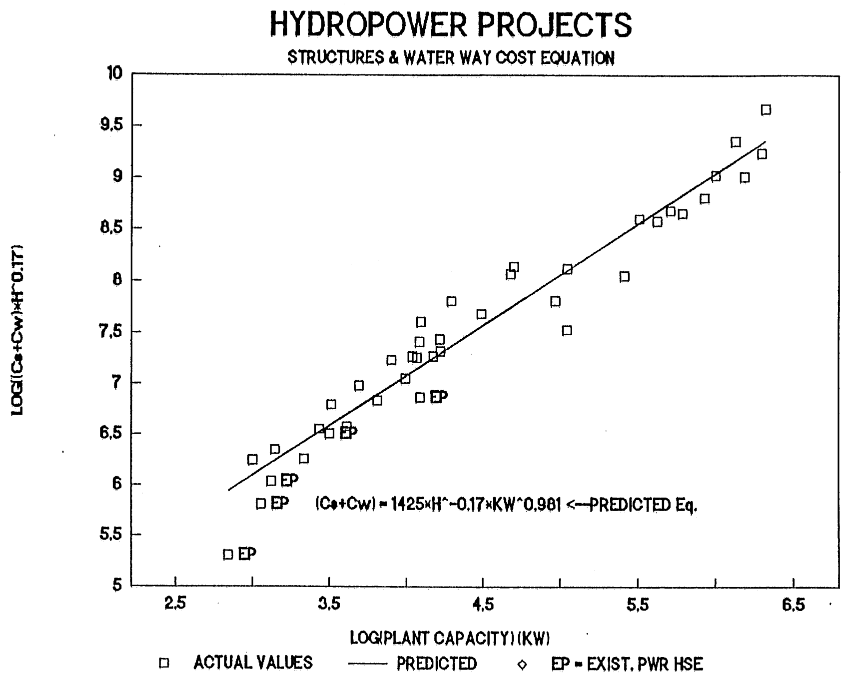


Figure 18 – Original Fit for Structure (C_S) and (C_W) Waterway Costs.

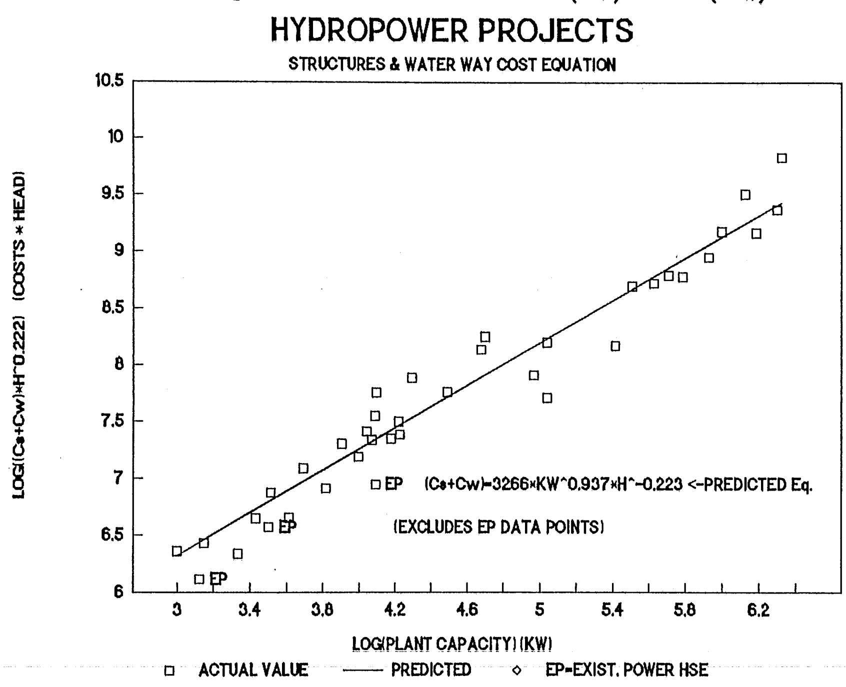


Figure 19 – Structure (C_S) and (C_W) Waterway Costs Revised to Exclude "EP" Points.

where:

$(C_s + C_w)$ = structure (C_s) and waterway (C_w) costs (1991 U.S. dollars)
KW = design plant capacity (KW)
H = gross head (ft).

The equation has been adjusted from that of the figure to give results in terms of 1991 dollars.

HYFEAS2 provides the user with various cost adjustment factors. These factors can be used to improve the equations when extra information is available about the proposed installation. In the event that an existing powerhouse will be used to house new turbo–machinery, it is recommended that the powerhouse cost factor be set to a value of 0.5. This will result in a 50% reduction in the predicted costs of equation 17. The factor was derived by calculating the average value of the actual costs of the three "EP" data points in figure 19, as compared to those predicted.

b. Development of the Probability Density Function

Figure 20 is a plot of the logarithms of actual costs versus those predicted by equation 17. The diagonal line represents a perfect fit situation where actual and predicted values are the same. The uncertainty in the equation was estimated by assuming that the data is normally distributed about the perfect–fit line, at any value of predicted cost. The standard deviation of the residuals may then be estimated per equation 18:

$$\sigma_{\log} = \left\{ \frac{\sum_{i=1}^{n} (\log Y_a - \log Y_p)^2}{(n-3)} \right\}^{\frac{1}{2}} \qquad (18)$$

where:
Y_a = the actual value
Y_p = the predicted value
n = the total number of data points used to develop the equation.

The denominator is (n – 3) in this equation since 3 degrees of freedom are lost, one for each exponent in equation 17 and one for the constant (Younger, 1979).

Since the logarithms of the data are assumed to be normally distributed, the distribution of the absolute values of actual cost data about the predicted will be log–normal. The application of equation 18 to the data results in a standard deviation of:

$$\sigma_{\log} = \sigma[\log(C_s + C_w)_a - \log(C_s + C_w)_p] = 0.222 \qquad (19)$$

or for the natural logarithm,

$$\sigma_{\ln} = 0.511 \qquad (19a)$$

The subscripts a and p refer to the actual and predicted values, respectively. This standard deviation is accepted as an input value by HYFEAS2, such that a log–normal density function is used for structure and waterway costs in performing the Monte Carlo uncertainty analysis. Figure 17 displays an example of this distribution.

2. <u>Equipment Costs</u>

a. Development of the Cost Equation

Equipment costs comprise those of turbines and generators, substations, transmission lines and accessory electrical equipment. These costs were correlated in the same manner as structure and waterways costs, as shown in figure 21. The resulting equation used for describing equipment costs in HYFEAS2 is:

$$C_e = 6430 \cdot KW^{0.836} \cdot H^{-0.207} \qquad (20)$$

where: C_e = equipment costs (1991 U.S. dollars)
KW = design plant capacity (KW)
H = gross head (ft).

The equation has been adjusted from that of the figure to give results in terms of 1991 dollars. It is similar to an equipment cost equation developed by Dotan and Gulliver (1983) in the original study on hydropower feasibility in Minnesota.

b. Development of the Probability Distribution Function

Uncertainty in the equation can also be estimated in an entirely analogous manner to that of structure and waterway costs. Equation 18 is once again applied to give the following standard deviations:

$$\sigma_{\log} = \sigma[\log(C_e)_a - \log(C_e)_p] = 0.286 \qquad (21)$$

or for the natural logarithm,

$$\sigma_{\ln} = 0.658 \qquad (21a)$$

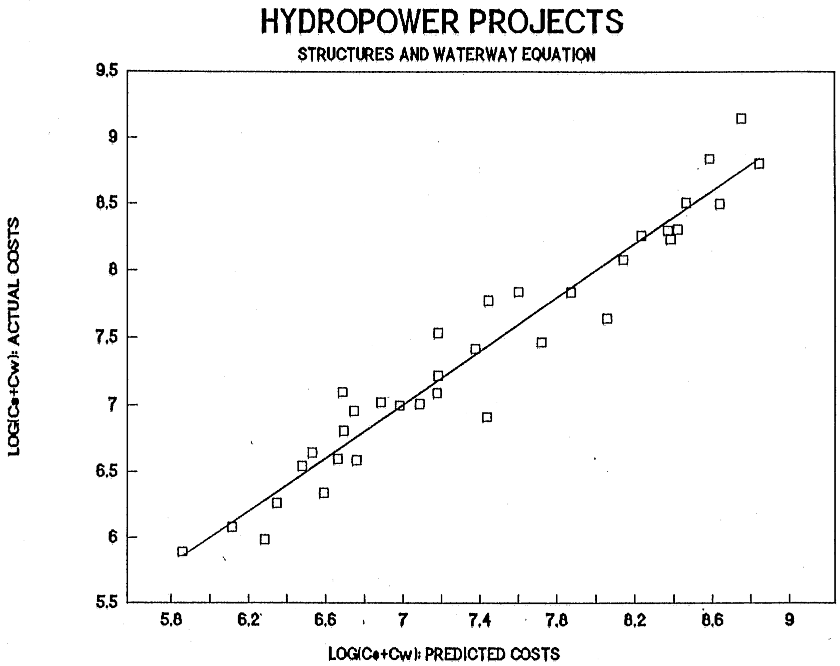


Figure 20 – Actual Versus Predicted Costs; Logarithmic Values.

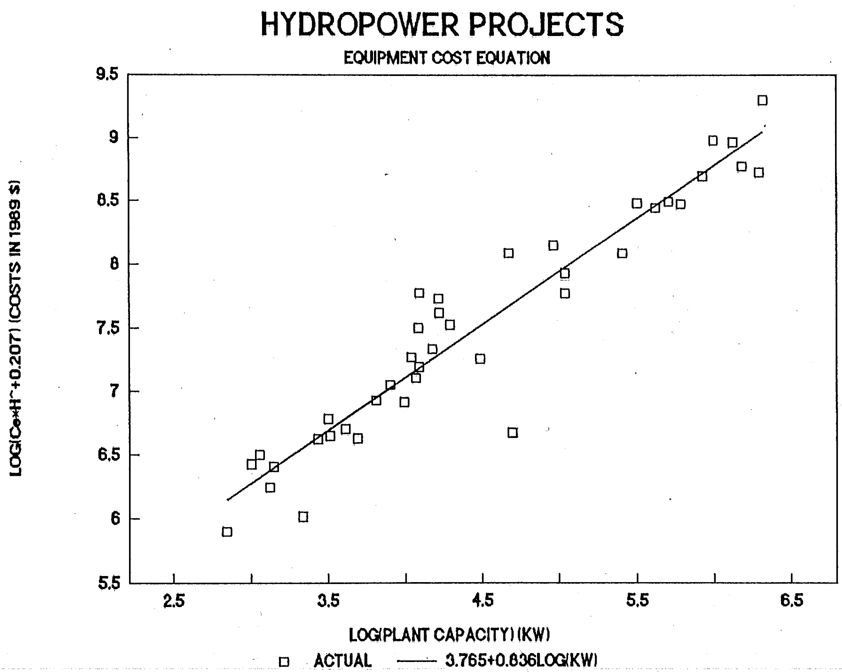


Figure 21 – Fit of Equipment Cost Data.

where the subscripts a and p refer to the actual and predicted values, respectively. This standard deviation is accepted as an input value by HYFEAS2, such that a log–normal density function is used for equipment costs in performing the Monte Carlo uncertainty analysis. Figure 17 once again displays the example of this distribution.

3. Indirect Costs

Indirect costs are those associated with planning and implementation of the project. Engineering, construction supervision, contingencies, administrative and legal are examples of costs which fall into this category. Such data was available only for the DOE Demonstration Projects (DOE, 1986), where costs were separated into those reported as construction per the Federal Energy Regulatory Commission Code of Cost Accounts, and those reported as indirect. Technically, therefore, the application of the following analyses should be limited to installations of less than 15 MW. The majority of potential sites in Minnesota fall into this category. However, HYFEAS2 does utilize the results of the analyses even for installations that are larger, since there is no better alternative. As with all cost equations, the user has the option of adjusting indirect cost estimates through use of a factor.

a. Development of the Cost Equation

Indirect costs were found to depend on the magnitude of the direct construction costs, defined as those of structure and waterway plus equipment. Figure 22 demonstrates the relationship, which is seen to be exponential in nature. The resulting equation describing indirect costs is:

$$IC = 1.18 \cdot DC^{0.901} \tag{22}$$

where: IC = indirect costs (1991 U.S. Dollars)
DC = direct costs = $C_s + C_w + C_e$ (1991 U.S. Dollars).

The exponent indicates that the proportion of indirect to direct costs decreases as the size of the project becomes larger.

b. Development of the Probability Distribution Function

The spread of data is once again assumed to be normal when the logarithms are plotted and fitted per figure 22. Therefore the data will be log–normally distributed about the predicted value on an absolute cost basis. The probability density function for the equation is that of figure 17, as it was previously for both direct cost parameters. Equation 18 (with 2 rather than 3 degrees of freedom) is applied to give the following standard deviations, where a students "t" value of 1.062 for 16 degrees of freedom has been included in the calculation (Lindgren et al, 1978):

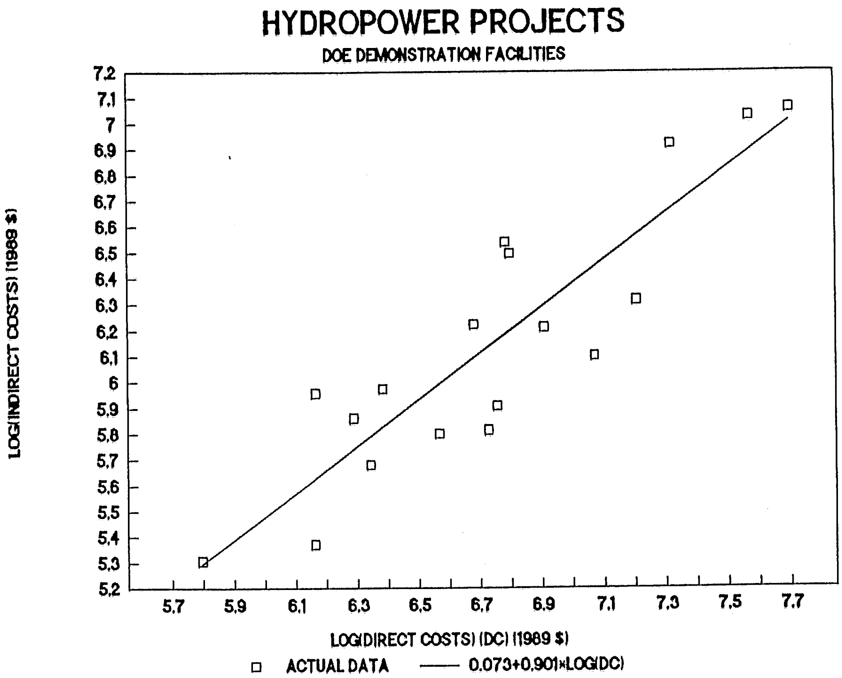


Figure 22 – Indirect Costs as a Function of Direct Costs.

$$\sigma_{\log} = \sigma[\log(IC)_a - \log(IC)_p] = 0.256 \tag{23}$$

or for the natural logarithm,

$$\sigma_{\ln} = 0.589 \tag{23a}$$

The subscripts a and p refer to the actual and predicted values, respectively.

Equation 23 gives the measure of uncertainty associated with use of the indirect cost equation. However, the indirect costs are dependent on the direct. Therefore, during the Monte Carlo uncertainty analysis, @RISK does not sample from a distribution that is independent of those of the direct cost components. Rather, the value of indirect cost is set to be dependent on that of the direct per equation 22. Upon calculation of this indirect cost, the value is allowed to vary according to it's log–normal density function. Thus, the ultimate value for indirect cost within each iteration is:

$$IC = 1.18 \cdot DC^{0.901} \cdot PDF_{ic} \tag{24}$$

where: PDF_{ic} = a factor describing uncertainty in equation 22.

The value of PDF_{ic} is independently sampled from the log–normal probability density function for equation 22. It's median value is one and the shape is that of figure 17.

4. Operation, Maintenance, and Replacement Costs

a. *Equation*

Operation, maintenance, and replacement (OM&R) costs were related to plant age in a study performed by Wong (1990). The equation was developed based upon historical production expense data reported by the Federal Energy Regulatory Commission. It is given as:

$$\ln(OM\&R) = 2.047 + 0.000235 \cdot AGE^2 \tag{25}$$

where:

OM&R = the OM&R costs for a particular year (1991 U.S. Dollars per KW of installed capacity)
AGE = the age of the plant in years.

The equation has been adjusted to reflect costs in terms of current U.S. Dollars. It has been incorporated into the HYFEAS2 Cash Flow Chart of figure 3, such that the OM&R costs are calculated for each year.

b. *Development of the Probability Density Function*

Figure 23 is a copy of that presented by Wong (1990), showing OM&R data fit by equation 25, along with it's associated 95% confidence intervals. The distribution is once again seen to be log–normal about the predicted

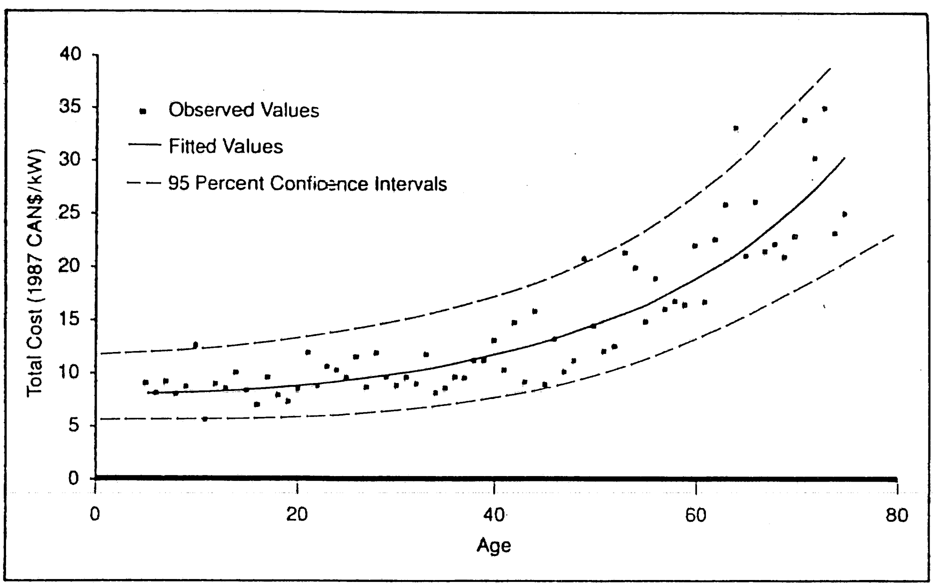


Figure 23 – Equation of OM&R Costs Versus Age (Wong, 1990).

value, such that the density function of figure 17 can be used to describe uncertainty in the equation. The confidence bands were adjusted to 68%, yielding the following natural log–standard deviation:

$$\sigma_{\ln} = \sigma[\ln(OM\&R)_a - \ln(OM\&R)_p] = 0.191 \qquad (26)$$

The subscripts a and p refer to the actual and predicted values, respectively.

During the Monte Carlo uncertainty analysis, the OM&R cost for each year will be determined by equation 25, multiplied by an uncertainty factor which is sampled by @RISK. Thus, for each iteration:

$$OM\&R(AGE) = e^{[2.047 + 0.000235 \cdot AGE^2]} \cdot PDF_{omr} \qquad (27)$$

where:

$OM\&R(AGE)$ = the OM&R costs in a particular year ($/KW)
AGE = the age of the plant in the same year
PDF_{omr} = an uncertainty factor for the OM&R cost equation.

PDF_{omr} has a median value of one, and varies as @RISK samples from a log–normal density function with shape of figure 17 and magnitude described by the anti–log of the deviation in equation 26.

5. Analysis of the Independence of Cost Parameters

It was stated previously that the input parameters must be independent if they are to be sampled from separate input probability density functions. Indirect costs have been shown to be dependent on direct costs, and OM&R costs behave independently by virtue of their dependence on age. Independence has been been assumed, however, between structure and waterway versus equipment costs. Each takes values from their individual density functions during @RISK random sampling, such that one may exceed and the other fall short of their median values within the same iteration.

The validity of the parameter independence has been analyzed from figure 24, which is a plot of the log–residuals of the fit for structure and waterway costs of figure 19, versus those for equipment costs as presented in figure 21. Both residuals correspond to the same plant. True independence implies that there be no trend in the spread of data, such that as many points lie in quadrants I and IV, where the respective costs are over and under predicted, as lie in quadrants II and III. Though a weak trend might be construed from the data, an analysis of the correlation coefficient (ρ) for the residual values (Haan, 1977) gave the result $\rho = 0.28$. A value of 1 indicates perfect correlation, while a value of 0 corresponds to no correlation. Using the procedure outlined in Haan (1977), it was determined that the hypothesis of correlation between the residuals could not be accepted at the 95% confidence level. Therefore, the scatter of figure 24 was considered to be large enough such that the cost parameters of structure and waterway versus equipment are taken to be independent in the Monte Carlo uncertainty analysis.

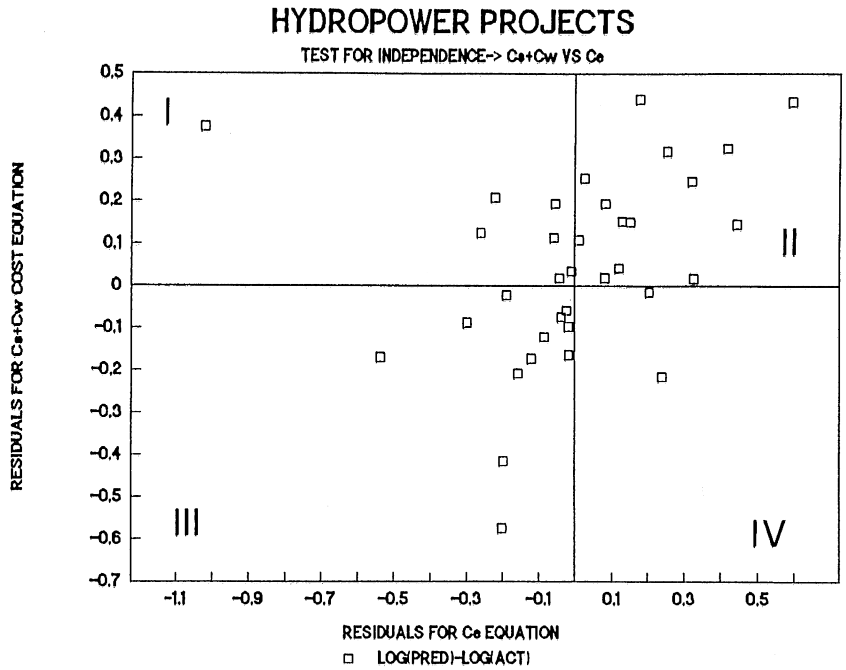


Figure 24 – Residuals of Structures and Waterways Versus Equipment.

C. ECONOMIC PARAMETERS

Economic parameters include the discount rate and escalation rates, the duration of economic and plant lives, and the total energy buy–back rate. Salvage value is also an economic parameter, and is calculated based on the others.

1. Discount Rate

The discount rate is used to discount future benefits and costs to present value. It may be thought of as the interest rate that could be earned on a sum of money had it not been invested in a project. For this analysis, it was assumed to be equal to the interest rate that would be paid on the capital investment loan.

a. Analysis of the Representative Value

The analysis used is that of Woods and Gulliver (1990). Figure 25 presents 10–year state Aaa bond yields as compiled by Moody's Investor Services (1990) from a small sampling of general market issues. These yields are thought to be typical of those for which a public utility or municipality would qualify. The prior analysis by Woods and Gulliver demonstrated interest rates to be lower and more stable prior to 1979. Therefore, only the most recent 11 available values were used in estimating the rate, due to the fact that it is typically fixed for the entire amortization period of the loan. Since the rate does not change, the lower values from pre–1979 will not likely be available to projects started in the near future. The average discount rate ($\bar{d}$) from the years 1979 thru 1989 was calculated as:

$$\bar{d} = 7.37\%. \tag{28}$$

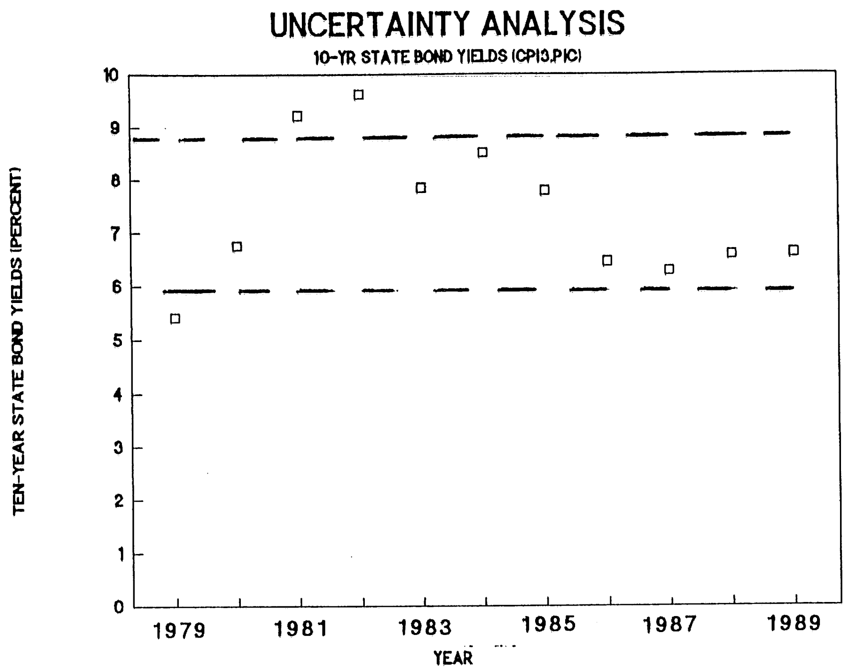


Figure 25 – 10–year State Aaa Bond Yields, 1979 – 1989.

b. Development of the Probability Density Function

The variation of discount rate about the average value is assumed to be normal. Calculation of the standard deviation (σ_d) for the eleven values, with (n – 1) degrees of freedom, yields:

$$\sigma_d = 1.44\ \% \tag{29}$$

A student's "t" value of 1.082 has been included to account for the limited number of data points.

The probability density function used by @RISK will therefore be normal, with a median value of 7.37% and a standard deviation as given in equation 29. A sample normal density function is presented in figure 1.

2. Escalation Rate for Energy Values and OM&R Costs

Over the life of a project, the value of energy and the costs of OM&R will typically increase, according to their respective escalation rates, defined in equation 5 as e and r. The rates are generally related, and frequently set to the same value in lieu of special data pertaining to one or the other, as in the case of the previous Dotan and Gulliver Study (1983). The escalation rates for energy and OM&R were set to the same value in this analysis, as well.

a. Analysis of the Representative Value

Figure 26 presents one–year percentage changes in the consumer price index dating to 1950. If these values are considered representative of those of escalation, then the plot shows the last decade to be one of low, relatively stable rates. Since the escalation rate is particularly critical to economic feasibility during a project's first years, a recent 10–year average of these values is used, from 1980 thru 1989:

$$e = r = 5.55\% \qquad (30)$$

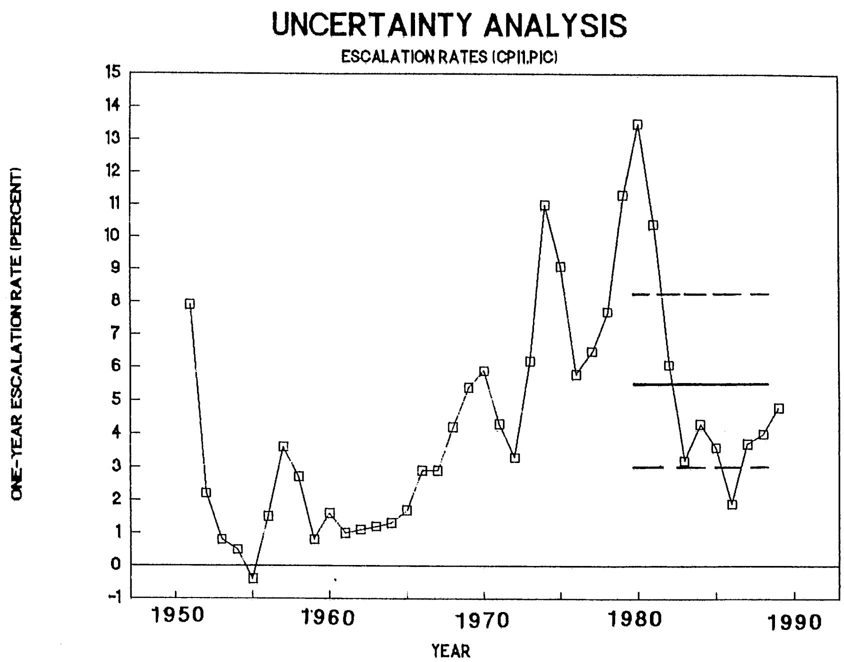


Figure 26 – One–year Percentage Changes in the Consumer Price Index.

This is deemed to be the escalation rate most likely to occur during the first years of projects initiated in the near future.

b. Development of the Probability Density Function

Unlike the discount rate, that of escalation does change throughout the project life. Therefore, even though an average value based on the first years of operation is employed, the uncertainty in escalation rate over the life of the project is estimated based on a longer period. In this case, a standard deviation in escalation rates was estimated from 10–year averages of the consumer price index ranging back to 1960:

$$\sigma_e = 2.59\% \qquad (31)$$

The uncertainty in escalation rate averaged over 10 years is greater than it would be if the average was taken over the 30–year project life. There is no historical record, however, that is appropriate for such a long–term average escalation rate. Once again, a normal density function like that of figure 1 is used by @RISK for sampling.

3. Periods of Project Economic Life, Plant Life, and Amortization

The economic life of a project is the period of time in which the project generates benefits for, and costs to, the initial investors, after which the plant is sold. Plant life is the expected life of the plant, to the point in time where it has no salvage value. Amortization is the period of time within which the project loan is repaid. HYFEAS2 accepts these values as user inputs, with no assigned uncertainty.

For this study, the economic project life was chosen to be 32 years, with a 2 year construction period followed by 30 years of operation. This value is typical of that used in the industry. Benefits received in the last years of plant operation are severely discounted, such that longer economic lives generally have little advantage. The typical operating life of a plant ranges from 60 years on the low end to more than a 100 years on the upper. The long operating life is one of the advantages of hydropower plants. A conservative value of 60 years was chosen for the sites studied in this report. Finally, the amortization period, defining the number of years for which equal installments are made towards repayment of the loan, was set at 30 years.

4. Estimation of the Salvage Value of the Plant

The plant is salvaged at the end of the economic project life. After 30 years of operation, the plant should still be in good operating condition and thus can typically be sold. For this study, the salvage value of the plant was assumed to decrease linearly with age according to equation 32:

$$SVU = Cc \left\{ 1 - \frac{(EPL-CP)}{PL} \right\} \qquad (32)$$

where:

SVU = the unadjusted salvage value of the plant ($)
Cc = the initial capital investment ($)
EPL = the economic project life (years)
PL = the plant life (years)
CP = the construction period for the plant.

The investor will not receive this benefit until the sale of the plant at termination of the economic life. At this time, it's value has increased according to the escalation rate, such that the final benefit due to salvage value is described by

$$SV = SVU\,(1 + e)^{EPL} \qquad (33)$$

where: SV = the salvage value adjusted for escalation
e = the escalation rate as given previously.

This value is discounted to present value as previously shown in equation 3. The choice of 32 years for economic life and 60 years for that of the plant yields an unadjusted salvage value (SVU) which is half that of the initial capital investment (Cc). It is assumed that there is no deterioration in the plant value during the construction period (CP) of 2 years.

5. Total Energy Value

This parameter determines the amount of benefits which will be generated by a hydropower plant. It is the total value received from the purchaser, typically a utility, for each KWH of energy generated. In equation 3, this rate was separated into the initial value received for energy (U), the avoided capacity value (ACV), reflecting the savings to the utility in avoiding new plant construction costs, and a fixed operation and maintenance payment (FOM).

Standard contract offers, detailing the above payments, are required to be submitted to the Minnesota Public Utilities Commission (MPUC) annually by utility companies. An attempt was made to obtain copies of these offers with limited success, resulting in data for 1987, 1989 and 1990 (MPUC, 1987–1990). The overall average values, escalated to 1991 value, are presented in table 2 for the Northern States Power Company, where the value of fixed operation and maintenance is included in that of avoided capacity:

Table 2 – Annual energy values from standard contract offers

Year	Initial Energy Value (cents/KWH)	Avoided Capacity Value (cents/KWH)
1987	1.70	0.95
1989	1.45	0.46
1990	1.58	0.56

All values are adjusted to 1991 value; the offers were those of Northern States Power Co.

The table demonstrates that the initial energy value has been relatively constant in recent years, while that offered for avoided capacity has been erratic. These energy values are down substantially from what they were in the period 1980 – 1985, when the contracts for most of the approximately 25 MW developed since 1980 were written. Most of these contracts had an average utility buy–back rate of between 4 and 6 cents/KWH, compared to between 1.9 and 2.7 cents/KWH given above. It is believed that sometime in the future, energy buy–back values will return to the early 1980's figures. The primary difference is that the avoided capacity value fluctuates greatly with future demand projections by the utility.

The total value of energy is very difficult to predict for the coming years, depending greatly on the utility's supply/demand projections. It is also the single most important parameter for determining hydropower project feasibility. Unfortunately, the concept of uncertainty is not directly applicable to the energy value because it is set once the power purchase contract is signed, before construction has begun. Minimal expenditures and other commitments have occurred before this contract is signed, and thus there is minimal risk at this point. Therefore, multiple runs were made with HYFEAS2 for different total energy buy–back rates. Based on table 2, the initial value of energy was set to the most recent value of 1.6 cents/KWH for all cases, reflecting it's relative consistency. The avoided capacity value was then varied such that total energy buy–back rates (U + ACV) of 1.6, 2, 4 and 6 cents/KWH were analyzed. Usually, only the fixed operation and maintenance portion of avoided capacity is escalated, in addition to the value of energy. In a recent contract offer to Saint Anthony Falls Hydraulic Laboratory for a proposed facility, the operation and maintenance portion of the total avoided capacity value was approximately a fifth. Therefore, 20% of the avoided capacity value was escalated during the economic analysis of HYFEAS2, along with the entire value of energy.

There is no uncertainty assigned to the values. Uncertainty over time however, is accounted for due to that of the energy escalation rate. Providing the total energy buy–back rate as an input variable allows the user to determine what rate the project must have to be feasible. For the sites in this study, use of multiple rates should provide the required value specific to each site for achieving economic feasibility.

IV. Description of HYFEAS2

HYFEAS2 has been written to run on LOTUS 1–2–3 (Lotus Corporation, 1986), and utilizes the LOTUS add–in software package @RISK (Palisade Corporation, 1989) to perform the Monte Carlo uncertainty analysis. The program is an updated version of the hydropower survey program HYFEAS (Dotan and Gulliver, 1983), developed as part of a previous study on Minnesota hydropower potential. HYFEAS2 is user interactive and menu–driven, such that users need not be familiar with LOTUS in order to use the program. A user's manual is included in Appendix A–4.

A. REQUIRED INPUT PARAMETERS

Figure 27 displays the required input field for HYFEAS2. Most values are self explanatory. The energy value parameters discussed earlier are included, as are factors for adjustment of the individual cost equations. Also, the program will adjust the flow duration curve to reflect the preferred value of the exponent "n", as previously derived, through use of items #12 and #13. An escalation factor may be entered in item #1, allowing the program to perform the economic analysis for base years other than 1991.

A flow duration table (describing the probability distribution function) is presented in figure 3 of Appendix A–4. Flow rates, along with head and tail water levels are required at 21 percentage exceedence levels. These values were taken from curves developed for the sites by Dotan and Gulliver in their original study. A column has been added to the table which may be used to enter a head loss curve, used to describe head losses not accounted for in the overall plant efficiency, such as those in the head and tail races or those of a penstock. HYFEAS2 will include the loss within the annual energy calculations, choosing values from the curve based on the flow passing through the plant.

Other relevant parameters include those of overall plant efficiency and minimum stream flow. The former was chosen to be 85% for proposed and 75% for existing plants, per previous study recommendations. Minimum stream flow, below which plant operation ceases so as to maintain required downstream oxygen levels, was set to be the lesser of either 100 cfs or the 80% river flow exceedence level.

EXISTING POWERPLANT (IF NONE WRITE ZEROS)

1.	EXISTING CAPACITY(KW):	13400
2.	DESIGN DISCHARGE(FT^3/S):	4960
3.	OVERALL EFFICIENCY(FRACTION):	0.75

PROPOSED POWERPLANT (1=DEFAULT VALUE FOR ALL FACTORS)

1.	ESCALATION FACTOR FOR PLANT COSTS:	1
2.	INITIAL ENERGY VALUE (CENT/KWH-1990)	1.6000
3.	AVOIDED CAPACITY VALUE (CENT/KWH)	0.3200
4.	FIXED O&M PAYMENT (CENT/KWH)	0.0800
5.	SPILLWAY CREST ELEVATION (FT):	1081.7
6.	MINIMUM STREAM FLOW(FT^3/S):	100
7.	OVERALL EFFICIENCY(FRACTION):	0.85
8.	POWER HSE. COST ADJUSTMENT FACTOR	0.5
9.	OM&R COST ADJUSTMENT FACTOR (>0 REQ)	1
10.	EQUIPMENT COST FACTOR	1
11.	INDIRECT COST FACTOR	1
12.	RATIO OF DRAINAGE AREAS	0.99
13.	ADJUST CURVE TO "n" = 1.126	YES

Figure 27 – Input Field for HYFEAS2.

USER INPUTS TO OVERIDE DEFAULT ECONOMIC PARAMETERS

		MEAN VALUE	STD. DEV.
1.	ANNUAL ENERGY PRODUCTION	PROGRAM OUTPUT	0
2.	DISCOUNT RATE	0.00%	0.00%
3.	ENERGY ESCALATION RATE	0.00%	0.00%
4.	OPERATION & MAINTENANCE RATE	0.00%	0.00%
5.	RES,DAM,WTWY + POWER HSE COST	PROGRAM OUTPUT	0.000
6.	EQUIPMENT COST	PROGRAM OUTPUT	0.000
7.	INDIRECT COST	PROGRAM OUTPUT	0.000
8.	OTHER COST ($)	0	NO UNCERTAINTY
9.	OM&R COST UNCERTAINTY	PROGRAM OUTPUT	0.000
10.	ECONOMIC LIFE (YRS) (LOAN TO SALE)	0	NO UNCERTAINTY
11.	PLANT LIFE (YRS) (START TO SHUTDOWN)	0	NO UNCERTAINTY
12.	LOAN AMORTIZATION PERIOD (YRS)	0	NO UNCERTAINTY

DEFAULT ECONOMIC PARAMETERS

		MEAN VALUE	STD. DEV.
1.	ANNUAL ENERGY PRODUCTION	PROGRAM OUTPUT	0.152
2.	DISCOUNT RATE	7.37%	1.44%
3.	ENERGY ESCALATION RATE	5.55%	2.59%
4.	OPERATION & MAINTENANCE RATE	5.55%	2.59%
5.	RES,DAM,WTWY + POWER HSE COST	PROGRAM OUTPUT	0.511
6.	EQUIPMENT COST	PROGRAM OUTPUT	0.658
7.	INDIRECT COST	PROGRAM OUTPUT	0.589
8.	OTHER COST ($)	0	NONE
9.	OPERATION & MAINTENANCE COST	PROGRAM OUTPUT	0.191
10.	ECONOMIC LIFE (YRS) (LOAN TO SALE)	32	NONE
11.	PLANT LIFE (YRS) (START TO SHUTDOWN)	60	NONE
12.	LOAN AMORTIZATION PERIOD (YRS)	30	NONE

Figure 28 – Default and Override Fields for Economic Parameters.

B. DEFAULT ECONOMIC PARAMETERS

Figure 28 displays the default and override fields for the economic parameters. The user may change many of the default values, including the standard deviations which describe uncertainty for the Monte Carlo analysis of @RISK. In the absence of changes, the economic parameters as outlined in this report are used.

C. FORMAT, PROCEDURE, AND ASSUMPTIONS OF HYFEAS2

HYFEAS2 begins by prompting the user for all necessary data, which is entered in the input fields using the ⟨arrow⟩ keys on the keyboard. Upon initiation, the program first estimates the economic feasibility parameters of net discounted benefits and benefit–cost ratio, for 21 plant design capacities corresponding to the flow duration values. The two capacities which maximize the respective feasibility indicators are stored. The user may then choose to perform the Monte Carlo uncertainty analysis for these two capacities, which is the default option, or those of other hydroplant sizings. Alternatively, the economic feasibility analysis may be performed again for different energy values or interest rates. A general flow chart of program operation is presented in figure 29.

The method for calculating annual energy at each design capacity, including the case where a plant expansion is considered, was outlined in the previous Dotan and Gulliver Study (1983). Costs at each design capacity are estimated from the cost equations derived in chapter 3 of this report. The economic analysis is performed for the incremental energy generated, which is the increase in generation when there is an existing plant, or the total energy generation in cases of a new development. Finally, the Monte Carlo uncertainty analysis is performed as was described in chapter 2.

D. A CASE STUDY USING HYFEAS2 WITH @RISK ANALYSIS

The use of HYFEAS2 can best be presented from a case study on hydropower feasibility at a potential site. Blanchard, with existing capacity of 13,400 KW and a design head of approximately 42 feet, was chosen. It was desired to analyze the economic feasibility of a capacity expansion at various levels of total energy buy–back rate.

Runs were made for total rates of 2, 4, and 6 cents per KWH. Figures 30 and 31 presents standard output fields for the runs, followed by frequency histograms of net discounted benefits in figure 32. The histograms reflect the uncertainty in the final outcome. For the two–cent case, the majority of the results fall below 0, indicating a high risk of losing money. After increasing the total energy value to 4 cents per KWH, the distribution moves to the right, such that more than half of the possible values lie above 0. Cumulative probability distribution functions are constructed from the

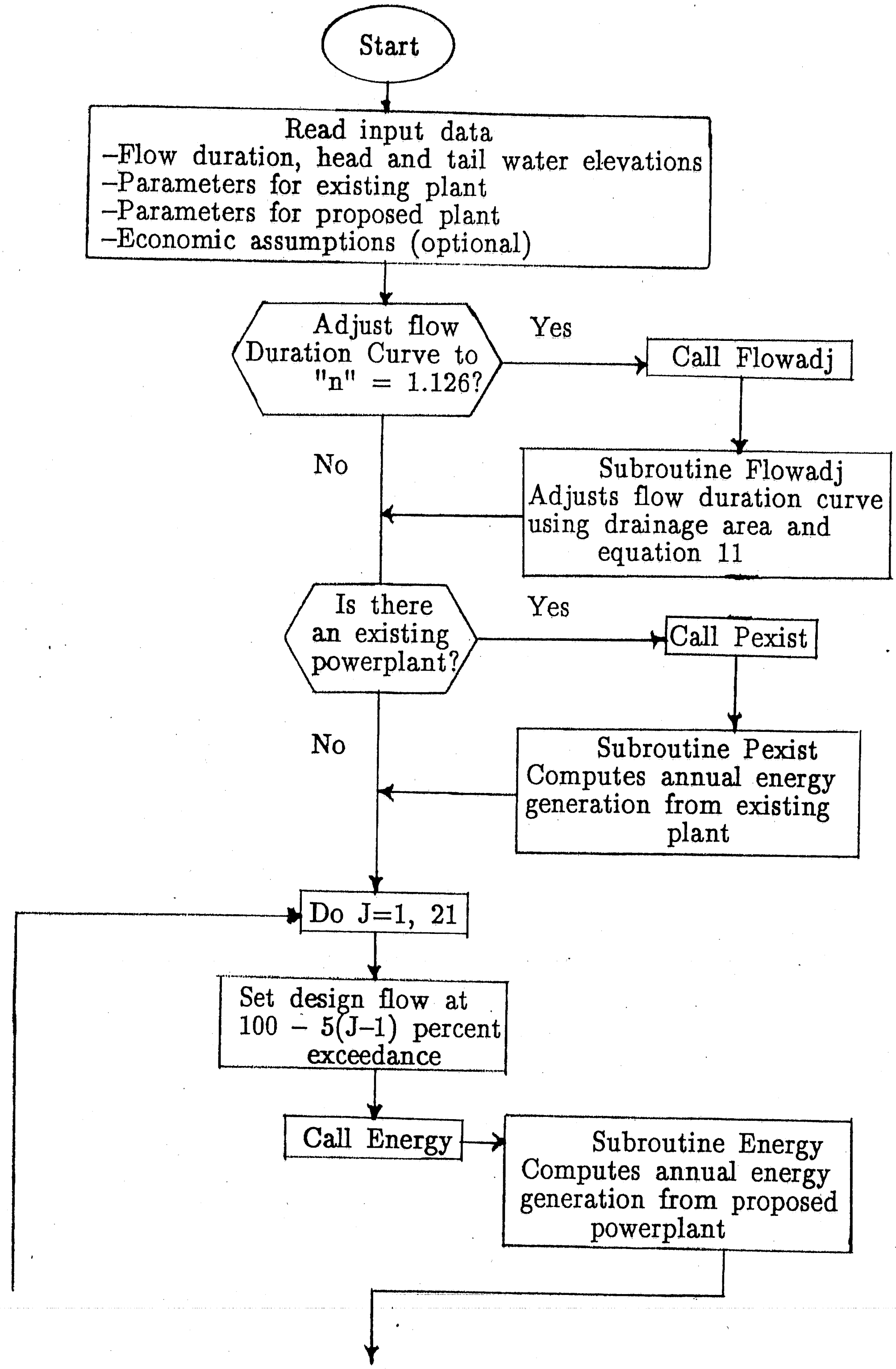


Figure 29 – General Flow Chart for HYFEAS2.

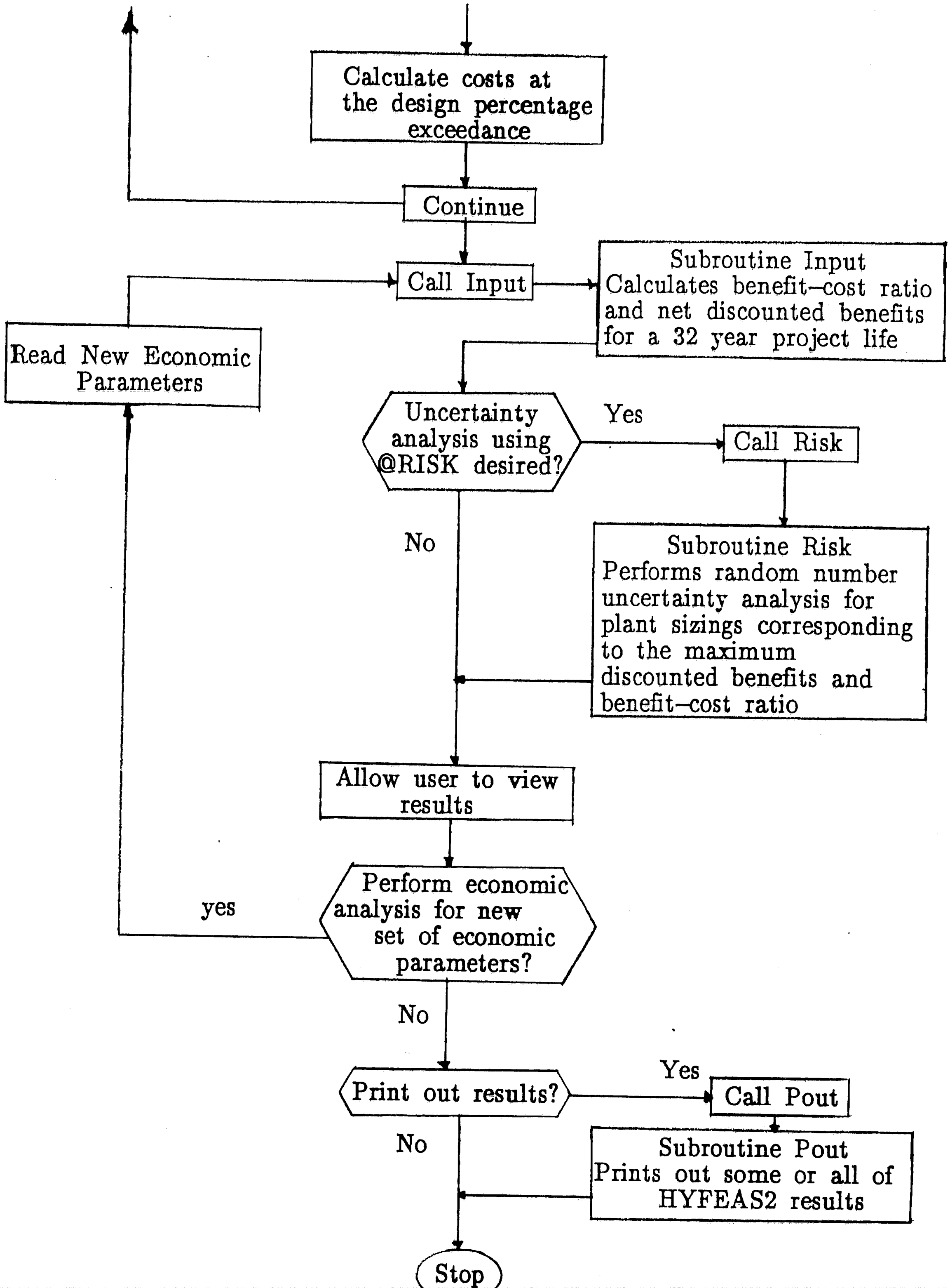


Figure 29 continued – General Flow Chart for HYFEAS2

SITE: BLANCHARD

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	0.32 CENTS/KWH
	FIXED O&M VALUE =	0.08 CENTS/KWH
	TOTAL ENERGY VALUE =	2.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	13400.0 KW
	DESIGN DISCHARGE =	4960.0 FT^3/S
	OVERALL EFFICIENCY =	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	42.30	FT
DESIGN DISCHARGE:	408.21	FT^3/S
DESIGN CAPACITY:	1241.82	KW
TOTAL DESIGN EXCEEDENCE:	20.00	%
EQUIPMENT COST ($1000):	1143.33	
TOTAL COST ($1000):	2266.02	
NET BENEFIT ($1000):	-509.53	
32 YR. B/C RATIO:	0.80	
RISK OF LOSING MONEY:	67.14285%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	41.
DESIGN DISCHARGE:	1571.
DESIGN CAPACITY:	4702.
TOTAL DESIGN EXCEEDENCE:	15.
EQUIPMENT COST ($1000):	3492.
TOTAL COST ($1000):	7096.
NET BENEFIT ($1000):	-1423.
32 YR. B/C RATIO:	0.
RISK OF LOSING MONEY:	63.428

Figure 30 – Standard Output Field for 2–cent Run.

SITE: BLANCHARD
SITE NO.: MN00599

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	13400.0 KW
	DESIGN DISCHARGE =	4960.0 FT^3/S
	OVERALL EFFICIENCY =	0.75

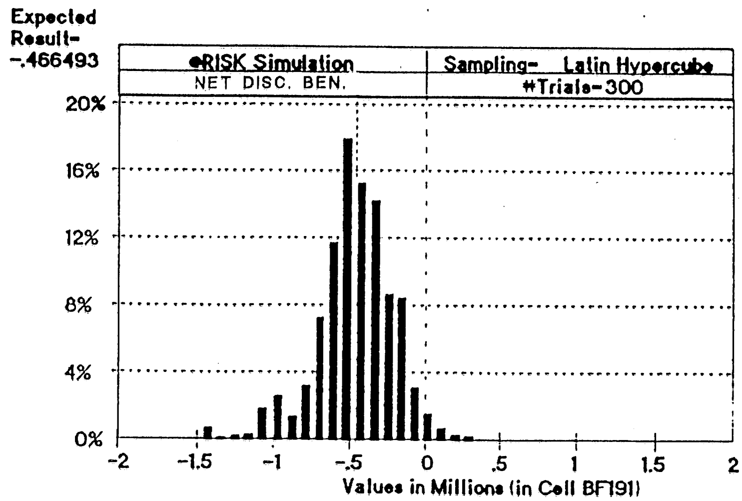
FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	41.61	FT
DESIGN DISCHARGE:	1563.50	FT^3/S
DESIGN CAPACITY:	4678.38	KW
TOTAL DESIGN EXCEEDENCE:	15.00	%
EQUIPMENT COST ($1000):	3477.15	
TOTAL COST ($1000):	7065.39	
NET BENEFIT ($1000):	1425.35	
32 YR. B/C RATIO:	1.18	
RISK OF LOSING MONEY:	40.8%	

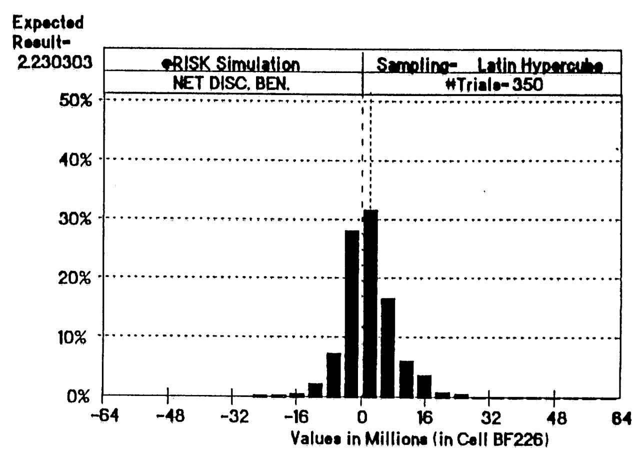
FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	41.
DESIGN DISCHARGE:	1563.
DESIGN CAPACITY:	4678.
TOTAL DESIGN EXCEEDENCE:	15.
EQUIPMENT COST ($1000):	3477.
TOTAL COST ($1000):	7065.
NET BENEFIT ($1000):	1425.
32 YR. B/C RATIO:	1.
RISK OF LOSING MONEY:	40.

Figure 31 – Standard Output Field for 4–cent Run.



2-Cent Case



4-Cent Case

Figure 32 – Output Frequency Histograms for Net Discounted Benefits

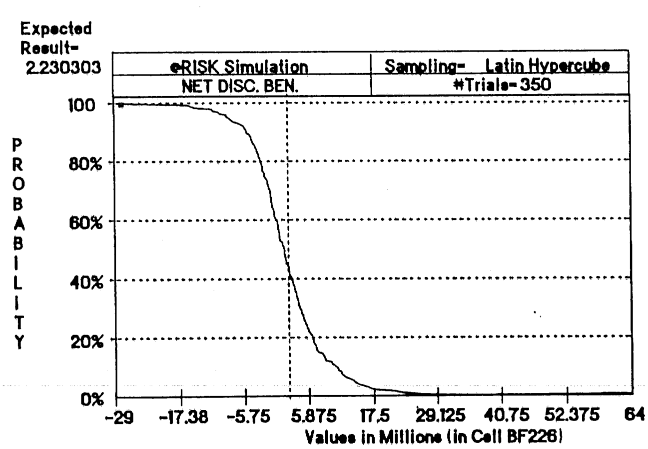


Figure 33 - Cumulative Probability Distribution for 4-Cent Case.

frequency histograms according to equation 6, as displayed in figure 33 for the 4–cent case. The probability of achieving any desired result may be read from this plot. All of the above plots are easily obtained from @RISK using the LOTUS Print_Graph option. For those users who do not wish to become familiar with this option, the cumulative probabilities are also presented in tabular form as one of the standard outputs of HYFEAS2.

The trend in results is as expected, showing a much higher risk associated with the expansion at a 2–cent energy value as compared to 4 cents. In all cases, the program recommends the appropriate capacity for the alternatives of maximizing net discounted benefits and benefit–cost ratio. The risk of losing money for either of the alternatives is reported as a standard output, allowing the user to evaluate the desirability of proceeding with the project for the currently entered value of energy. The energy value may be adjusted until the risk is reduced to the desired level. This would be the minimum desired energy buy–back rate for the development to proceed.

V. Feasibility Analysis Results

Dotan and Gulliver (1983) identified 853 existing Minnesota dam sites in the previously mentioned 1983 study. Application of a two stage screening process resulted in 65 of the sites being deemed as having good or marginal hydropower potential, as presented in appendix A–1. These sites were then analyzed for economic feasibility using the hydropower survey program HYFEAS, developed as part of the study. The results were presented as shown in appendix A–2. Sites with an estimated benefit–cost ratio greater than 1.8 were categorized as having very good feasibility, while those greater than 1.2 and 1.0 were labeled respectively as good and marginal. The comments include important information such as the availability of an existing powerhouse or assumptions made in the analysis.

It was the intent of this study to improve the original feasibility estimates for these remaining sites, through the addition of an uncertainty analysis and use of historical cost data which has become available since the previous study. Thus, the sites were re–analyzed with HYFEAS2, the results of which are now presented in this chapter. The seven hydroelectric plants that have come on line or have been expanded since the original study have been updated in this analysis.

A. Comparison of HYFEAS2 Estimates to Recent Installations.

HYFEAS2 was verified to give reasonable results through comparison to data on recent hydropower developments. Economic data for current private developments, such as projected benefits and project costs, are generally not made available to the public. It can only be assumed that these projects were projected to be economically feasible. Therefore, selected sites which HYFEAS2 found to be sufficiently feasible were chosen, and a comparison was made between HYFEAS2–recommended plant capacity versus that actually installed. The results are presented in table 3, where all recommended capacities correspond to a total energy value of 4 cents/KWH.

The plant capacities recommended by HYFEAS2 correspond well to those installed or proposed for the majority of comparisons. Both the Rapidan and Granite Falls Projects employ peaking, which accounts for the under–prediction by HYFEAS2. Peaking employs reservoir storage to maximize power generation when it is most valuable, and was not considered in this study. Other discrepancies are likely due to economic parameters which are different than assumed by the program. On an overall basis, it appears that HYFEAS2 estimates site feasibility and corresponding plant sizings in a realistic manner.

Table 3 – Plant Capacity Comparison; Recommended vs. Actual

Site Name	Recommended Capacity (KW)	Actual Installed Capacity (KW)
Byllesby	2,000	2,500
Rapidan	4,000	6,200
Lanesboro	285	250
Lock & Dam #2	8,070	4,000***
Upper St. Anthony Falls	31,000	30,000*
Lower St. Anthony Falls	21,600	9,500 – 17,800**
Coon Rapids	15,000	12,000*
St. Cloud	7,288	8,400
Granite Falls	291	800

* Proposed for installation in a site–specific feasibility study
** Values for a currently planned installation and future proposed expansion
*** Capacity at this facility was limited by the developer's bonding authority

B. HYFEAS2 FEASIBILITY ESTIMATES

Results of the analysis using HYFEAS2 are given in table 4. Feasibility for each site, measured by the parameters of net discounted benefits and benefit–cost ratio, was estimated for the four different total energy values discussed in chapter 3. Typically, a public utility or municipality will size the hydropower plant to maximize net discounted benefits rather than benefit–cost ratio, and therefore the results have been presented for this criteria. The uncertainty in the estimate is quoted in terms of the risk of losing money on the project, that is, of receiving negative benefits. It is the percentage of outcomes which fall below zero during the Monte Carlo analysis, and is graphically depicted in figure 34. Here the range of possible results spans both positive and negative values, with those to the left of zero indicating risk. The probability of achieving positive benefits is simply 100 percent minus the risk, representing the portion of the results to the right of zero.

The purpose of making multiple runs was to identify the value of total energy required for each site to yield positive discounted benefits. A program output summary at this value is included for each of the sites in table A–3 of the appendix. The dependence of hydropower feasibility on energy value is further demonstrated in the feasibility histograms of figures 35 and 36. Figure 35 summarizes the project risks as estimated by HYFEAS2 at the four energy values. The risk of loss is high at the majority of sites for the lower

Table 4 - Results of HYFEAS2 Feasibility Analysis.

SITE ID	SITE NAME	TOTAL ENERGY VALUE (CENTS/KWH)	NET DISCOUNTED BENEFITS ($1000, 1991)	32-YEAR BENEFIT COST RATIO	RISK OF NEGATIVE BENEFIT (%)	DESIGN CAPACITY (KW)	INCREMENTAL ENERGY (MWH/Yr)	TOTAL PROJECT COST ($1000, 1991)	COMMENTS
MN00591	ST. ANTHONY	1.60	$9,332	1.47	28	12,054	70,292	$17,577	EXISTING POWER HOUSE ASSUMED.
	FALLS LOWER	2.00	$12,925	1.59	21	13,445	74,312	$19,357	STRUCTURES AND WATERWAY COST FACTOR
	LOCK & DAM	4.00	$33,537	2.00	11	21,643	90,935	$29,604	= 0.5.
		6.00	$56,638	2.41	5	26,495	96,900	$35,538	
MN00507	COON RAPIDS	1.60	$5,760	1.43	29	7,222	45,703	$12,016	EXISTING POWER HOUSE ASSUMED.
		2.00	$8,268	1.48	27	9,548	53,546	$15,410	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$22,352	1.87	11	14,997	64,530	$23,136	= 0.5.
		6.00	$38,566	2.49	4	14,997	64,530	$23,136	
MN00 93	KETTLE FALLS	1.60	$3,322	1.22	41	5,419	42,516	$14,368	NO EXISTING POWERHOUSE ASSUMED
		2.00	$5,506	1.34	31	5,739	44,124	$15,107	CONSTANT HEAD IS MAINTAINED AT SITE.
		4.00	$17,788	1.80	15	8,284	53,035	$20,843	
		6.00	$31,646	2.12	7	10,830	58,532	$26,371	
MN00513	KETTLE RIVER	1.60	$167	1.19	38	313	2,348	$814	EXISTING POWER HOUSE ASSUMED.
		2.00	$297	1.28	36	400	2,765	$1,004	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$1,199	1.51	23	975	4,525	$2,160	= 0.5.
		6.00	$2,400	1.83	13	1,254	5,068	$2,682	
MN00590	ST. ANTHONY	1.60	$4,360	1.19	39	16,079	62,298	$19,732	EXISTING POWER HOUSE ASSUMED.
	FALLS UPPER	2.00	$7,491	1.33	30	16,079	62,298	$19,732	STRUCTURES AND WATERWAY COST FACTOR
	LOCK & DAM	4.00	$27,596	1.70	13	30,090	88,689	$33,821	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$52,278	1.97	10	43,249	103,830	$46,199	OF 12.5 MW.
MN00589	LOCK & DAM #5	1.60	$1,120	1.06	49	6,320	43,924	$17,916	NO EXISTING POWERHOUSE ASSUMED
		2.00	$3,945	1.16	43	8,408	56,168	$23,265	
		4.00	$18,870	1.61	17	10,738	64,423	$29,003	
		6.00	$35,924	1.95	10	13,447	71,140	$35,553	
MN00604	THOMSON	1.60	$628	1.04	45	14,750	34,741	$12,094	EXISTING POWER HOUSE ASSUMED.
		2.00	$2,374	1.16	40	14,750	34,741	$12,094	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$24,251	1.53	20	53,233	92,922	$36,569	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$55,109	1.53	19	131,480	151,431	$80,016	OF 68.6 MW.
MN00587	LOCK & DAM #7	1.60	$692	1.04	51	5,982	40,925	$17,165	NO EXISTING POWERHOUSE ASSUMED
		2.00	$2,958	1.13	43	7,939	51,245	$22,061	
		4.00	$16,662	1.60	20	9,568	57,409	$26,062	
		6.00	$35,154	1.79	15	15,114	75,430	$41,615	
MN00505	SARTELL	1.60	$3	1.00	48	1,542	7,461	$3,189	EXISTING POWER HOUSE ASSUMED.
		2.00	$459	1.09	44	2,421	10,828	$4,710	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$4,126	1.45	26	4,627	16,879	$8,297	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$8,875	1.78	14	5,910	19,308	$10,316	OF 3200 KW.
MN00152	MINNESOTA ONE	1.60	($21)	0.96	53	166	1,035	$484	EXISTING POWER HOUSE ASSUMED.
		2.00	$40	1.05	49	248	1,500	$680	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$661	1.31	33	868	3,484	$2,003	= 0.5.
		6.00	$1,836	1.43	25	1,842	5,570	$3,960	

Table 4 - continued.

SITE ID	SITE NAME	TOTAL ENERGY VALUE (CENTS/KWH)	NET DISCOUNTED BENEFITS ($1000, 1991)	32-YEAR BENEFIT COST RATIO	RISK OF NEGATIVE BENEFIT (%)	DESIGN CAPACITY (KW)	INCREMENTAL ENERGY (MWH/Yr)	TOTAL PROJECT COST ($1000, 1991)	COMMENTS
MN00234	FISH HOOK	1.60	($25)	0.83	63	37	238	$139	EXISTING POWER HOUSE ASSUMED.
	RIVER DAM	2.00	$6	1.02	52	87	578	$288	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$169	1.43	29	117	705	$371	= 0.5.
		6.00	$352	1.77	16	139	765	$431	
MN00600	LITTLE FALLS	1.60	($113)	0.83	62	237	1,089	$622	EXISTING POWER HOUSE ASSUMED.
		2.00	($14)	0.99	53	1,144	4,804	$2,379	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$2,404	1.31	33	4,129	12,734	$7,097	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$6,433	1.43	21	8,450	19,470	$13,321	OF 4600 KW.
MN00612	ISLAND LAKE	1.60	($22)	0.81	65	27	187	$114	NO EXISTING POWERHOUSE ASSUMED
		2.00	$101	1.09	48	359	2,362	$1,068	CONSTANT HEAD IS MAINTAINED AT SITE.
		4.00	$1,060	1.35	33	1,104	5,082	$2,826	
		6.00	$2,471	1.55	23	1,716	6,405	$4,148	
MN00549	RUM RIVER	1.60	($35)	0.78	66	29	227	$151	NO EXISTING POWERHOUSE ASSUMED
		2.00	($18)	0.97	53	124	972	$529	
		4.00	$410	1.30	33	347	2,163	$1,292	
		6.00	$1,023	1.54	21	507	2,679	$1,802	
MN00365	SHADY LAKE	1.60	($46)	0.77	69	43	296	$196	NO EXISTING POWERHOUSE ASSUMED
		2.00	($31)	0.85	64	43	296	$196	
		4.00	$143	1.26	37	139	853	$535	
		6.00	$379	1.49	23	201	1,049	$736	
MN00 8	RED LAKE TWO	1.60	($35)	0.75	65	31	189	$132	EXISTING POWER HOUSE ASSUMED.
	(CROOKSTON)	2.00	($19)	0.96	53	142	894	$483	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$361	1.30	35	380	1,925	$1,137	= 0.5.
		6.00	$867	1.57	20	488	2,197	$1,421	
MN0094	ST. LOUIS RIVER	1.60	($45)	0.76	65	38	263	$181	NO EXISTING POWERHOUSE ASSUMED
		2.00	($32)	0.83	63	38	263	$181	
		4.00	$380	1.29	35	360	2,094	$1,268	
		6.00	$1,026	1.50	25	581	2,806	$1,940	
MN 0011	MAZEPPA	1.60	($17)	0.76	64	15	104	$70	EXISTING POWER HOUSE ASSUMED.
		2.00	($12)	0.84	54	15	104	$70	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$41	1.24	39	42	262	$168	= 0.5.
		6.00	$114	1.48	29	60	321	$228	
MN00 92	PIKE RIVER	1.60	($10)	0.75	67	9	56	$39	EXISTING POWER HOUSE ASSUMED.
		2.00	($7)	0.82	62	9	56	$39	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$48	1.20	38	71	344	$227	= 0.5.
		6.00	$160	1.38	28	138	525	$401	
MN00610	WHITE FACE LAKE	1.60	($15)	0.75	69	12	86	$60	NO EXISTING POWERHOUSE ASSUMED
		2.00	($11)	0.82	62	12	86	$60	CONSTANT HEAD ASSUMED.
		4.00	$128	1.27	33	130	733	$451	
		6.00	$329	1.53	23	178	876	$594	

Table 4 - continued.

SITE ID	SITE NAME	TOTAL ENERGY VALUE (CENTS/KWH)	NET DISCOUNTED BENEFITS ($1000, 1991)	32-YEAR BENEFIT COST RATIO	RISK OF NEGATIVE BENEFIT (%)	DESIGN CAPACITY (KW)	INCREMENTAL ENERGY (MWH/Yr)	TOTAL PROJECT COST ($1000, 1991)	COMMENTS
MN00574	POKEGAMA LAKE	1.60	($24)	0.72	71	14	115	$86	NO EXISTING POWERHOUSE ASSUMED
		2.00	$77	1.03	54	594	4,446	$2,191	CONSTANT HEAD ASSUMED.
		4.00	$1,561	1.40	28	1,087	6,830	$3,706	
		6.00	$3,346	1.77	14	1,232	7,274	$4,132	
MN00586	WINNIBIGOSHISH	1.60	($73)	0.72	70	56	342	$252	NO EXISTING POWERHOUSE ASSUMED
		2.00	($56)	0.79	65	56	342	$252	
		4.00	$630	1.24	36	721	3,885	$2,446	
		6.00	$1,642	1.58	19	805	4,142	$2,698	
MN00607	WINTON	1.60	($321)	0.70	73	528	1,396	$990	EXISTING POWER HOUSE ASSUMED.
		2.00	($251)	0.77	68	528	1,396	$990	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$501	1.12	41	2,615	5,783	$3,870	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$2,422	1.28	29	5,864	10,029	$7,739	OF 5000 KW.
MN00602	BLANDIN	1.60	($153)	0.69	71	160	599	$463	EXISTING POWER HOUSE ASSUMED.
		2.00	($123)	0.75	66	160	599	$463	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$149	1.10	46	567	1,896	$1,362	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$760	1.32	33	980	2,781	$2,183	OF 2100 KW.
MN00599	BLANCHARD	1.60	($973)	0.68	75	1,566	3,740	$2,772	12 MW ORIGINALLY INSTALLED AT THIS
		2.00	($785)	0.74	72	1,566	3,740	$2,772	SITE. SITE WAS RECENTLY EXPANDED
		4.00	$762	1.07	45	6,998	14,200	$10,016	WITH A 6.0 MW INSTALLATION, WHICH WAS
		6.00	$4,329	1.38	26	6,998	14,200	$10,016	INCLUDED IN THIS ANALYSIS.
MN00574	ORWELL DAM	1.60	($17)	0.68	71	9	61	$50	NO EXISTING POWERHOUSE ASSUMED
		2.00	($13)	0.74	69	9	61	$50	
		4.00	$564	1.35	32	490	2,694	$1,520	
		6.00	$1,367	1.59	20	738	3,401	$2,170	
MN00190	PELICAN RAPIDS	1.60	($4)	0.68	74	2.2	16	$13	EXISTING POWER HOUSE ASSUMED.
		2.00	($4)	0.74	67	2.2	16	$13	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$63	1.26	34	2.2	369	$229	= 0.5.
		6.00	$164	1.56	20	82.0	422	$279	
MN00593	LOCK & DAM #1	1.60	($912)	0.68	71	1,008	3,445	$2,684	NO EXISTING POWER HOUSE ASSUMED.
		2.00	($739)	0.74	69	1,008	3,445	$2,684	SITE HAS EXISTING CAPACITY OF 14.4 MW.
		4.00	$1,112	1.07	48	7,474	20,873	$15,437	
		6.00	$7,280	1.27	31	12,947	30,599	$25,001	
MN00356	CANNON RIVER II	1.60	($33)	0.67	74	17	112	$96	NO EXISTING POWERHOUSE ASSUMED
		2.00	($27)	0.72	70	17	112	$96	
		4.00	$77	1.17	41	99	640	$445	
		6.00	$271	1.39	35	156	860	$662	
MN00598	CLOQUET	1.60	($669)	0.67	71	958	2,431	$1,868	EXISTING POWER HOUSE ASSUMED.
		2.00	($546)	0.73	69	958	2,431	$1,868	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$187	1.03	49	3,184	6,967	$5,238	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$1,938	1.33	33	3,184	6,967	$5,238	OF 5.5 MW.

Table 4 - continued.

SITE ID	SITE NAME	TOTAL ENERGY VALUE (CENTS/KWH)	NET DISCOUNTED BENEFITS ($1000, 1991)	32-YEAR BENEFIT COST RATIO	RISK OF NEGATIVE BENEFIT (%)	DESIGN CAPACITY (KW)	INCREMENTAL ENERGY (MWH/Yr)	TOTAL PROJECT COST ($1000, 1991)	COMMENTS
MN00653	RAINY LAKE	1.60	($99)	0.65	70	93	316	$268	EXISTING POWER HOUSE ASSUMED.
		2.00	($83)	0.71	70	93	316	$268	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$2,213	1.23	34	5,528	14,629	$8,729	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$7,127	1.45	24	9,597	21,058	$14,055	OF 10 MW.
MN00605	SCANLON	1.60	($138)	0.65	80	115	423	$368	EXISTING POWER HOUSE ASSUMED.
		2.00	($117)	0.70	70	115	423	$368	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$100	1.05	46	700	2,239	$1,709	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$940	1.30	35	1,287	3,591	$2,871	OF 1500 KW.
MN00606	KNIFE FALLS	1.60	($197)	0.65	76	184	629	$533	EXISTING POWER HOUSE ASSUMED.
		2.00	($166)	0.71	70	184	629	$533	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$120	1.04	49	1,361	3,793	$2,920	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$1,171	1.22	38	2,499	5,714	$4,914	OF 1900 KW.
MN00515	SOUTH BRANCH ZUMBRO RIVER	1.60	($30)	0.64	76	14	86	$80	NO EXISTING POWER HOUSE.
		2.00	($26)	0.69	73	14	86	$80	
		4.00	$9	1.05	47	33	212	$171	
		6.00	$69	1.30	33	45	265	$225	
MN00502	RED LAKE ONE (THIEF RIVER)	1.60	($143)	0.65	73	119	441	$383	EXISTING POWER HOUSE ASSUMED.
		2.00	($121)	0.70	70	119	441	$383	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$18	1.02	48	400	1,328	$1,075	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$473	1.24	34	729	2,111	$1,807	OF 550 KW.
MN00508	SAUK RIVER I	1.60	($29)	0.63	72	11	80	$76	NO EXISTING POWERHOUSE ASSUMED
		2.00	($25)	0.68	71	11	80	$76	
		4.00	$4	1.02	49	34	231	$194	
		6.00	$83	1.21	39	74	407	$377	
MN00364	MAYWOOD LAKE	1.60	($18)	0.62	76	8	49	$47	EXISTING POWER HOUSE ASSUMED.
		2.00	($16)	0.68	74	8	49	$47	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$1	1.01	53	16	108	$92	= 0.5.
		6.00	$33	1.24	37	25	147	$133	
MN00 17	BRONSON LAKE	1.60	($5)	0.62	75	2	14	$14	NO EXISTING POWERHOUSE.
		2.00	($5)	0.67	72	2	14	$14	
		4.00	$3	1.05	47	13	79	$63	
		6.00	$27	1.30	36	19	105	$89	
MN00512	RAPIDAN	1.60	($498)	0.61	79	608	1,309	$1,178	STRUCTURES AND WATERWAY COST FACTOR
		2.00	($433)	0.66	73	608	1,309	$1,178	= 0.5. SITE WAS RECENTLY DEVELOPED
		4.00	($104)	0.92	57	608	1,309	$1,178	WITH A 6.2 MW INSTALLATION, WHICH WAS
		6.00	$564	1.13	43	2,571	4,353	$4,037	INCLUDED IN THIS ANALYSIS.
MN00516	ELK RIVER	1.60	($27)	0.61	77	12	66	$67	NO EXISTING POWERHOUSE.
		2.00	($24)	0.66	75	12	66	$67	
		4.00	$130	1.19	41	164	980	$662	
		6.00	$413	1.47	23	216	1,174	$842	

Table 4 - continued.

SITE ID	SITE NAME	TOTAL ENERGY VALUE (CENTS/KWH)	NET DISCOUNTED BENEFITS ($1000, 1991)	32-YEAR BENEFIT COST RATIO	RISK OF NEGATIVE BENEFIT (%)	DESIGN CAPACITY (KW)	INCREMENTAL ENERGY (MWH/Yr)	TOTAL PROJECT COST ($1000, 1991)	COMMENTS
MN00614	FISH LAKE	1.60	($7)	0.60	74	3	18	$18	NO EXISTING POWERHOUSE.
		2.00	($7)	0.65	73	3	18	$18	
		4.00	($0)	1.00	52	10	68	$59	
		6.00	$28	1.22	34	25	134	$124	
MN00561	SAUK RIVER III	1.60	($10)	0.60	78	3	23	$24	NO EXISTING POWERHOUSE.
		2.00	($9)	0.65	72	3	23	$24	
		4.00	($1)	0.98	52	10	68	$61	
		6.00	$20	1.19	39	18	107	$102	
MN00120	BRAWNER LAKE	1.60	($5)	0.60	74	2	12	$12	NO EXISTING POWERHOUSE.
		2.00	($4)	0.65	74	2	12	$12	
		4.00	($1)	0.99	52	5	35	$31	
		6.00	$13	1.18	40	14	74	$70	
MN00582	PINE RIVER	1.60	($25)	0.59	77	10	55	$59	NO EXISTING POWERHOUSE.
		2.00	($22)	0.63	76	10	55	$59	
		4.00	$103	1.14	42	164	965	$687	
		6.00	$383	1.40	29	227	1,198	$911	
MN00601	SYLVAN	1.60	($357)	0.59	78	317	811	$813	EXISTING POWER HOUSE ASSUMED.
		2.00	($317)	0.64	76	317	811	$813	STRUCTURES AND WATERWAY COST FACTOR
		4.00	($113)	0.87	58	317	811	$813	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$91	1.10	44	317	811	$813	OF 1900 KW.
MN00597	BRAINERD	1.60	($39)	0.59	79	23	88	$92	EXISTING POWER HOUSE ASSUMED.
		2.00	($34)	0.64	75	23	88	$92	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$745	1.16	41	2,111	6,483	$4,286	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$2,794	1.43	24	3,091	8,495	$5,978	OF 3700 KW.
MN00191	PELICAN RIVER DAM	1.60	($9)	0.58	80	3	19	$22	NO EXISTING POWERHOUSE.
		2.00	($8)	0.63	74	3	19	$22	
		4.00	$11	1.06	45	38	237	$190	
		6.00	$92	1.25	37	75	393	$346	
MN00585	LEECH LAKE DAM	1.60	($87)	0.57	79	38	176	$198	NO EXISTING POWERHOUSE.
		2.00	($78)	0.62	78	38	176	$198	
		4.00	$45	1.03	48	347	1,802	$1,479	
		6.00	$510	1.31	33	366	1,887	$1,563	
MN00117	JACKSON DAM	1.60	($5)	0.57	78	2	9	$10	EXISTING POWER HOUSE ASSUMED.
		2.00	($4)	0.61	77	2	9	$10	STRUCTURES AND WATERWAY COST FACTOR
		4.00	$6	1.04	49	32	170	$138	= 0.5.
		6.00	$77	1.21	37	96	384	$351	
MN00603	FON DU LAC	1.60	($938)	0.57	82	881	2,074	$2,164	EXISTING POWER HOUSE ASSUMED.
		2.00	($883)	0.62	77	881	2,074	$2,164	STRUCTURES AND WATERWAY COST FACTOR
		4.00	($362)	0.84	63	881	2,074	$2,164	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$513	1.05	47	4,417	8,475	$8,833	OF 11.8 MW.

Table 4 - continued.

SITE ID	SITE NAME	TOTAL ENERGY VALUE (CENTS/KWH)	NET DISCOUNTED BENEFITS ($1000, 1991)	32-YEAR BENEFIT COST RATIO	RISK OF NEGATIVE BENEFIT (%)	DESIGN CAPACITY (KW)	INCREMENTAL ENERGY (MWH/Yr)	TOTAL PROJECT COST ($1000, 1991)	COMMENTS
MN00608	CROW WING	1.60	($94)	0.57	79	62	184	$205	EXISTING POWER HOUSE ASSUMED.
		2.00	($84)	0.61	75	62	184	$205	STRUCTURES AND WATERWAY COST FACTOR
		4.00	($38)	0.82	65	62	184	$205	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	$270	1.14	41	797	1,887	$1,793	OF 1500 KW.
MN00062	NEW LONDON	1.60	($4)	0.56	79	1	8	$10	NO EXISTING POWERHOUSE.
		2.00	($4)	0.60	77	1	8	$10	
		4.00	($2)	0.80	63	1	8	$10	
		6.00	$11	1.08	44	29	133	$144	
MN00580	LAC QUI PARLE	1.60	($55)	0.55	82	20	93	$116	NO EXISTING POWERHOUSE.
		2.00	($50)	0.58	79	20	93	$116	
		4.00	($27)	0.78	66	20	93	$116	
		6.00	$35	1.08	46	95	413	$445	
MN00535	SAND CREEK	1.60	($4)	0.55	80	1	7	$8	NO EXISTING POWERHOUSE.
		2.00	($3)	0.59	76	1	7	$8	
		4.00	($2)	0.79	63	1	7	$8	
		6.00	$3	1.06	47	1	7	$8	
MN00550	GRAND FORKS EAST	1.60	($15)	0.54	83	5	25	$32	NO EXISTING POWERHOUSE ASSUMED
		2.00	($14)	0.58	79	5	25	$32	
		4.00	$418	1.17	42	646	3,446	$2,366	
		6.00	$1,382	1.42	23	855	4,188	$3,108	
MN00581	HWY 75 DAM	1.60	($4)	0.54	77	1	6	$8	NO EXISTING POWERHOUSE ASSUMED
		2.00	($4)	0.58	77	1	6	$8	
		4.00	($2)	0.77	69	1	6	$8	
		6.00	$21	1.11	44	34	171	$177	
MN00506	ST. CLOUD	1.60	($450)	0.54	82	338	784	$924	STRUCTURES AND WATERWAY COST FACTOR
		2.00	($410)	0.58	78	338	784	$924	= 0.5. SITE WAS RECENTLY DEVELOPED
		4.00	($213)	0.78	68	338	784	$924	WITH A 8.4 MW INSTALLATION, WHICH WAS
		6.00	$296	1.05	46	2,567	4,996	$5,224	INCLUDED IN THIS ANALYSIS.
MN00594	LOCK & DAM #2	1.60	($15)	0.53	80	5	23	$30	STRUCTURES AND WATERWAY COST FACTOR
		2.00	($13)	0.57	74	5	23	$30	= 0.5. SITE WAS RECENTLY DEVELOPED
		4.00	$1,791	1.18	38	4,382	14,060	$9,095	WITH A 4.0 MW INSTALLATION, WHICH WAS
		6.00	$5,341	1.34	31	7,368	18,980	$14,512	INCLUDED IN THIS ANALYSIS.
MN00517	LANESBORO	1.60	($20)	0.53	82	10	31	$41	STRUCTURES AND WATERWAY COST FACTOR
		2.00	($19)	0.56	82	10	31	$41	= 0.5. SITE WAS RECENTLY DEVELOPED
		4.00	($11)	0.74	69	10	31	$41	WITH A 250 KW INSTALLATION, WHICH WAS
		6.00	$22	1.04	46	185	458	$498	INCLUDED IN THIS ANALYSIS.
MN00358	ZUMBRO LAKE	1.60	($233)	0.52	84	202	361	$451	EXISTING POWER HOUSE ASSUMED.
		2.00	($215)	0.56	81	202	361	$451	STRUCTURES AND WATERWAY COST FACTOR
		4.00	($125)	0.74	67	202	361	$451	= 0.5. SITE HAS EXISTING CAPACITY
		6.00	($34)	0.93	53	202	361	$451	OF 2200 KW.

Table 4 - continued.

SITE ID	SITE NAME	TOTAL ENERGY VALUE (CENTS/KWH)	NET DISCOUNTED BENEFITS ($1000, 1991)	32-YEAR BENEFIT COST RATIO	RISK OF NEGATIVE BENEFIT (%)	DESIGN CAPACITY (KW)	INCREMENTAL ENERGY (MWH/Yr)	TOTAL PROJECT COST ($1000, 1991)	COMMENTS
MN00544	WILLOW RIVER	1.60	($15)	0.49	86	5	18	$28	NO EXISTING POWERHOUSE ASSUMED
		2.00	($14)	0.53	81	5	18	$28	
		4.00	($9)	0.68	72	5	18	$28	
		6.00	$24	1.08	45	66	264	$281	
MN00514	BYLLESBY	1.60	($310)	0.48	86	251	363	$548	STRUCTURES AND WATERWAY COST FACTOR = 0.5. SITE WAS RECENTLY DEVELOPED WITH A 2.5 MW INSTALLATION, WHICH WAS INCLUDED IN THIS ANALYSIS.
		2.00	($292)	0.51	84	251	363	$548	
		4.00	($201)	0.66	77	251	363	$548	
		6.00	($109)	0.82	66	251	363	$548	
MN00510	MINNESOTA TWO (GRANITE FALLS)	1.60	($479)	0.52	81	352	728	$935	580 KW ORIGINALLY INSTALLED AT THIS SITE. SITE RECENTLY EXPANDED WITH 710 KW, WHICH WAS INCLUDED IN THIS ANALYSIS
		2.00	($442)	0.56	82	352	728	$935	
		4.00	($259)	0.74	70	352	728	$935	
		6.00	($76)	0.92	56	352	728	$935	
MN00583	SANDY LOCK AND DAM	1.60	($17)	0.42	89	4	12	$29	NO EXISTING POWERHOUSE ASSUMED
		2.00	($17)	0.44	87	4	12	$29	
		4.00	($14)	0.54	81	4	12	$29	
		6.00	($11)	0.64	77	4	12	$29	
MN00 26	MUSTINKA RIVER	1.60	($4)	0.42	86	1	3	$7	NO EXISTING POWERHOUSE ASSUMED
		2.00	($4)	0.44	85	1	3	$7	
		4.00	($3)	0.54	80	1	3	$7	
		6.00	($3)	0.65	70	1	3	$7	

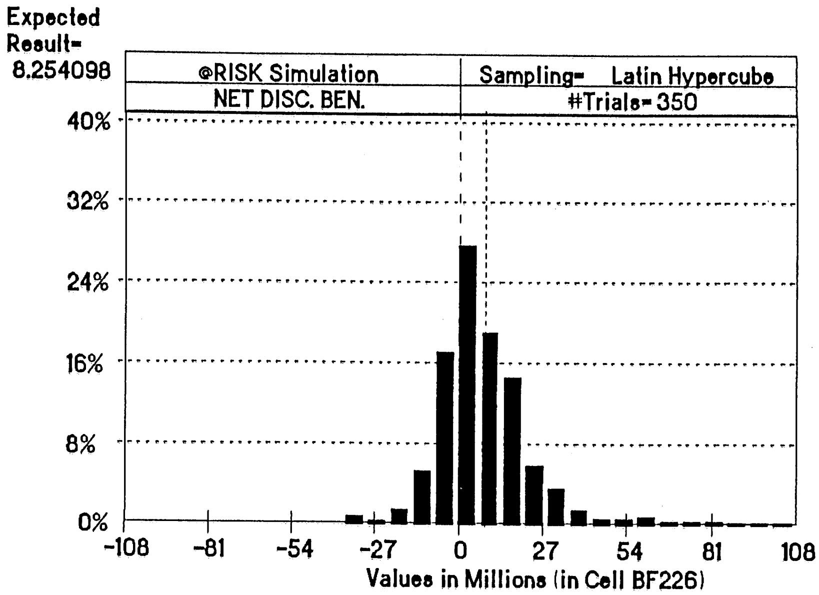
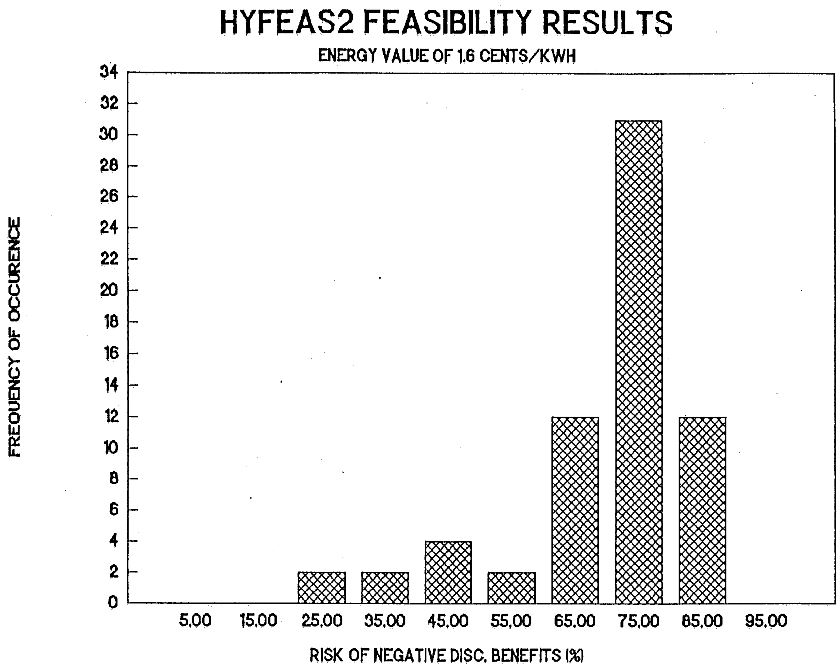


Figure 34 – Histogram of Possible Outcomers; Used for Predicting Risk

values of 1.6 and 2 cents/KWH, indicating poor feasibility. Greatly improved results are seen for 4 cents/KWH, and the vast majority of sites have low risk when the value is raised to 6 cents/KWH. Figure 36 presents similar distributions for site benefit–cost ratios, showing a similar dependence on total energy value.

The sites may also be categorized into those having very good, good or marginal feasibility. Sites having very good feasibility were considered to be those with less than a 20% risk, while 35% and 50% described those which were good and marginal. Table 5 gives the percentage of sites in each category for each total energy value, along with the corresponding total capacity and energy generation. As expected, the higher energy values allow more of the sites to be developed. Furthermore, the plants can be economically sized at larger capacities, such that potential energy generation increases rapidly with the value of energy.

It should be noted that a site with marginal feasibility does not indicate that it should not be developed. Site–specific information may render invalid the more generalized assumptions used in HYFEAS2, and economic conditions may be more favorable than those assumed in this study. Furthermore, daily and seasonal peaking have not been accounted for, primarily because they are currently not permitted for new installations in the state of Minnesota. Should changes in policy occur, such operation may significantly improve the economic feasibility of many installations. Therefore, these results are a first estimate of feasibility, and can be improved through a more detailed studies specific to the given sites.



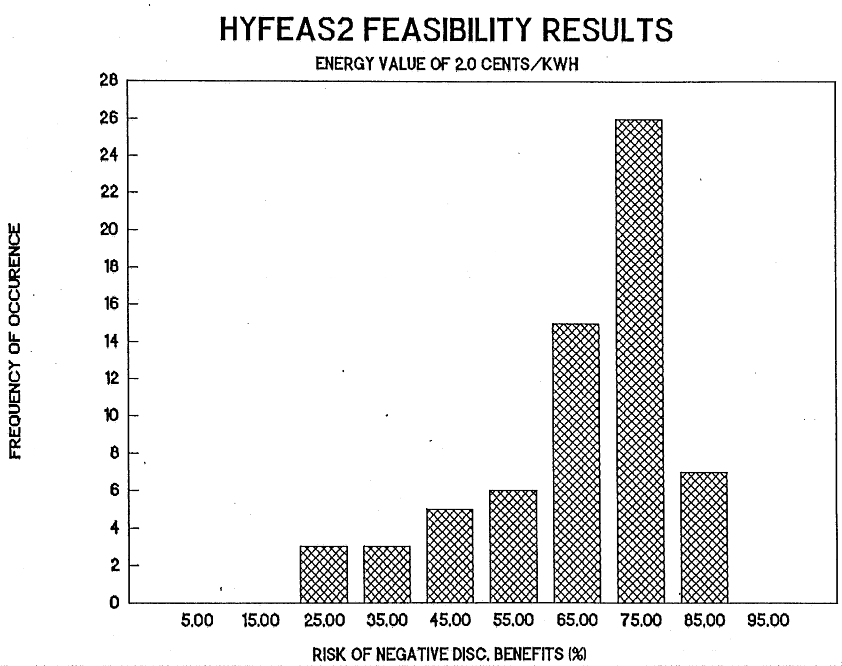
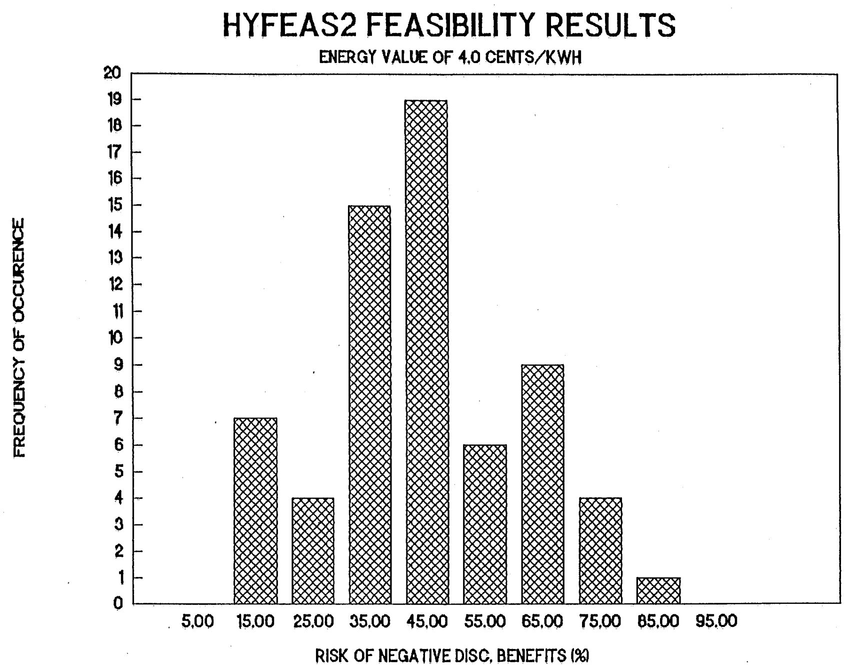


Figure 35 – Frequency Histograms of Project Risks, as Estimated by HYFEAS2 for 65 Sites.



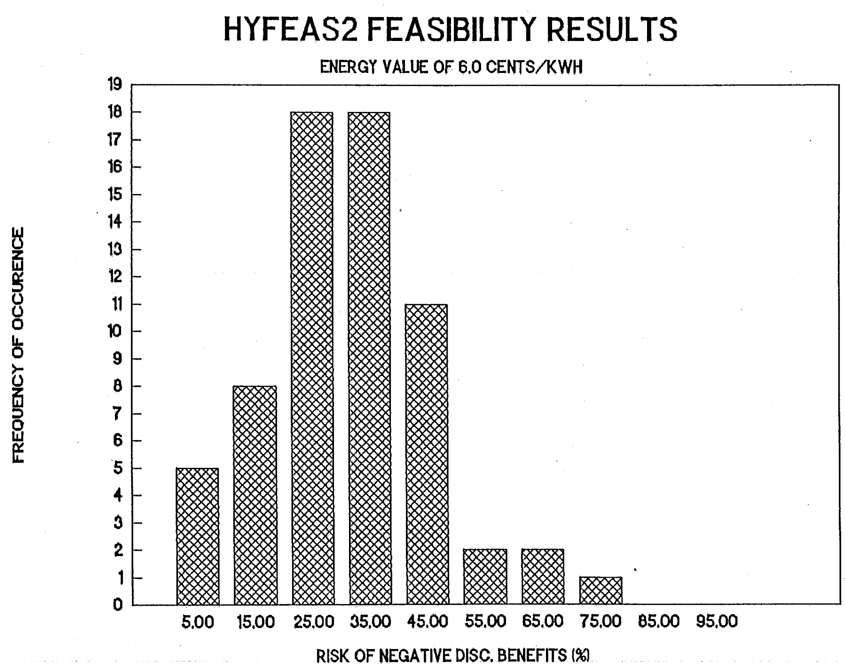
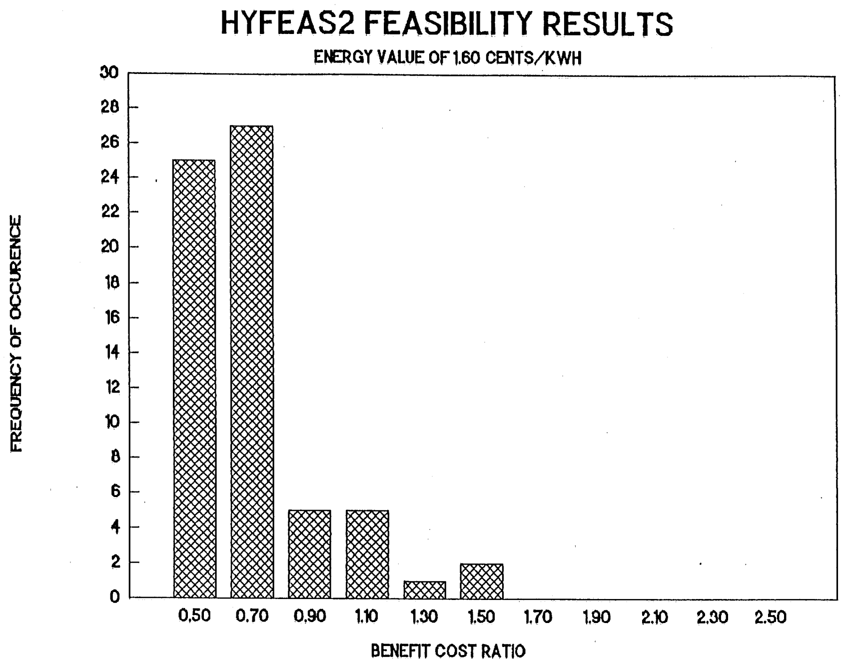


Figure 35 – continued.



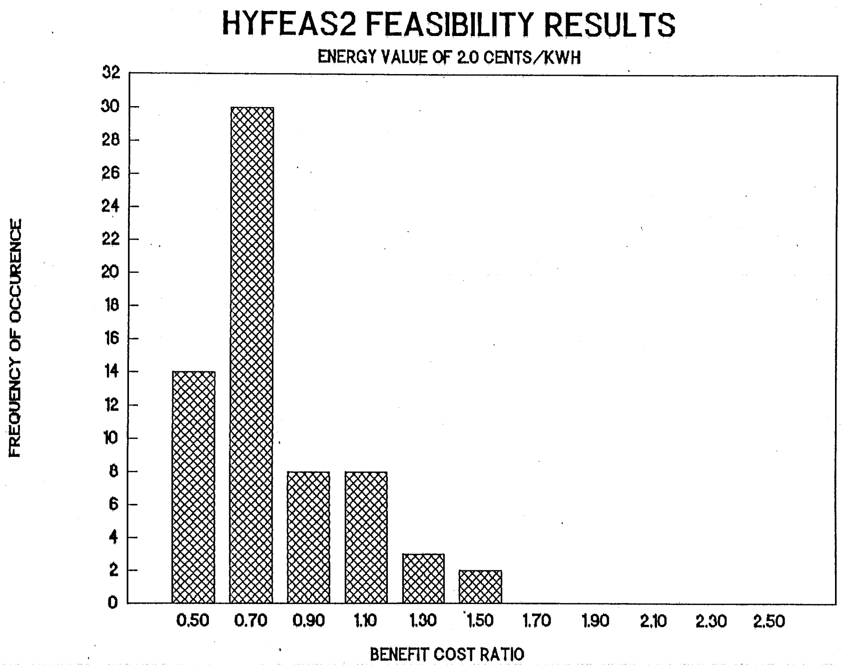
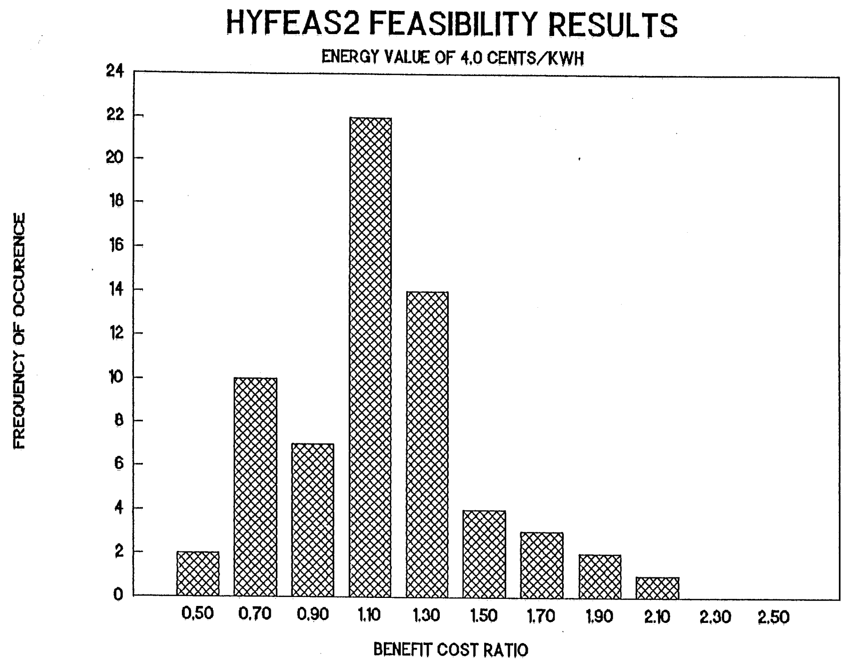


Figure 36 – Frequency Histograms of Benefit–Cost Ratios Values, as Estimated by HYFEAS2 for 65 Sites.



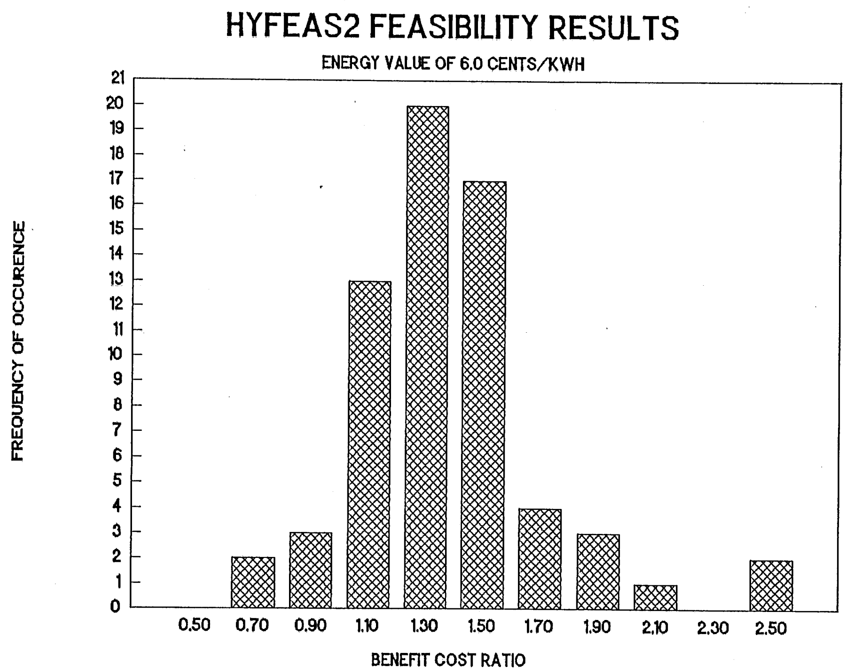


Figure 36 – continued.

Table 5 – Study Results Separated into Three Feasibility Categories

Total Energy Value (cent/KWH)	Very Good			Good			Marginal			Total: All Categories		
	Number of Sites Feasible	Total Capacity (MW)	Total Energy (GWH)	Number of Sites Feasible	Total Capacity (MW)	Total Energy (GWH)	Number of Sites Feasible	Total Capacity (MW)	Total Energy (GWH)	Number of Sites Feasible	Total Capacity (MW)	Total Energy (GWH)
1.6	0	0.0	0.0	2	19.3	116.0	6	44.4	193.3	8	63.7	309.3
2.0	0	0.0	0.0	4	44.8	234.3	7	34.5	159.6	11	79.3	393.9
4.0	7	148.6	511.9	14	20.1	74.8	24	32.3	91.7	45	201.0	678.4
6.0	13	265.7	661.8	28	68.2	170.8	19	13.9	29.3	60	347.8	861.9

VI. Summary and Conclusions

1. A previous report on hydropower potential at existing dams in the state of Minnesota was used to identify 65 potentially feasible hydropower sites (Dotan and Gulliver, 1983).

2. The original hydropower survey program, HYFEAS, was updated to incorporate risk analysis and to run on LOTUS 1–2–3 software, under the name HYFEAS2. Risk analysis was performed using the add–in software package @RISK.

3. Cost equations for HYFEAS2 were developed using historical data from DOE demonstration projects and an Energy Information Administration Report.

4. The economic climate in Minnesota was analyzed using historical data on consumer price indices and average state Aaa bond yields. The final estimates were incorporated into HYFEAS2.

5. A Monte Carlo Method of uncertainty analysis was applied in assigning uncertainty to the economic estimates of hydropower feasibility.

6. The uncertainty in each of the equations used by HYFEAS2 was analyzed. Probability density functions were then developed for use by @RISK in performing the Monte Carlo uncertainty analysis.

7. Average annual flow data was used to to improve an industry–wide equation typically applied in estimating flow conditions at un–gaged river sites. Flow duration curves for the 65 sites, previously developed in the original Dotan and Gulliver Study, were adjusted accordingly. The analysis was then incorporated into HYFEAS2 for the purposes of improving estimates of annual energy generation. A probability density function, describing uncertainty in the estimate, was developed for use by @RISK in the Monte Carlo analysis.

8. The economic criteria used in this study is similar to that of a municipally owned or public utility, in that plant capacity was sized to maximize projected net discounted benefits seen during a 32 year project life. The loan interest rate (discount rate) chosen was typical of that for which a public development of this kind might qualify.

9. Projections of hydropower feasibility were made for total energy values of 1.6, 2, 4 and 6 cents/KWH, for the 65 sites identified in the previous study. This allowed the value enabling feasible operation for each site to be determined. Although the required value varied depending on the project, the most marked change in positive compared to negative feasibility was observed to occur at a value of 4 cents/KWH. At this value the results were:

   Very good: seven (7) sites
   Good: fourteen (14) sites
   Marginal: twenty-four (24) sites
   Total additional hydropower capacity (MW): 201.0
   Total additional energy generation (GWH/year): 678.4
   Total project costs (millions – 1991 base year): 304.9

10. A site with very good feasibility is one which should yield positive net discounted benefits under most conditions. In terms of uncertainty, there is less than a one-in-five chance of losing money on the project. Typically, this risk corresponded to a benefit-cost ratio of 1.6 or better.

11. Sites with good feasibility are those projected as having substantially favorable economic feasibility, but with a higher risk of less than approximately one chance in three. These projects typically have benefit-cost ratios which are greater than 1.3.

12. Marginal feasibility implies that the project could be economically justifiable depending on specific site characteristics and economics. There is less than a one-in-two chance of losing money on these projects under the assumptions of this study, corresponding to benefit-cost ratios of one or higher.

13. This analysis was performed under the assumptions of an existing, run-of-the-river reservoir, typical of hydropower installations in Minnesota. Civil costs associated with bringing the dam up to current safety criteria were not included in the analysis. Differences in actual site conditions may affect the actual feasibility of a site. Furthermore, the equation developed for estimating river flow at ungaged sites utilized data strictly from Minnesota and the surrounding 5-state region, such that HYFEAS2 may not be valid for use in other regions of the country.

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APPENDICES

Appendix A-1: 65 Sites with Good or Marginal Hydropower Potential (Dotan and Gulliver, 1983).

ID Number	Site Name	County	Source of Site Information	hydraulic height, ft	Average Annual discharge, cfs	Potential Power Capacity, MW	Present Capacity (former capacity)	Reliability of Data Used in Energy Calculation	Second Screening Feasiblity Region
MN00365	Shady Lake	Olmsted	SV, SIR	18	210	0.27		M-G	B
MN00364	Mayowood	Olmsted	SV	13	55	0.05		M	B
MN00515	South Branch Zumbro R	Olmsted	SV	11	110	0.09		G	B
MN00190	Pelican Rapids	Ottertail	SIR	15	64	0.07		G	B
MN00191	Pelican River	Ottertail	SIR	16	77	0.09		G	B
MN00574	Orwell Dam	Ottertail	OC, SV	33	305	0.59		VG	A
MN00502	Red Lake I (Thief R)	Pennington	SV, SAFHL	15	816	0.88	0.55	VG	B
MN00544	Willow River	Pine	SIR	13	65	0.06		G	B
MN00513	Kettle River	Pine	SV, SAFHL	19	692	0.95	(0.47)	VG	A
MN00008	Red Lake II (Crockstone)	Polk	SV, OC	10	1120	0.81	(0.175)	VG	B
MN00550	Grand Fork East	Polk	SV, OC	10	2550	1.6		VG	A
MN00356	Cannon River II	Rice	SV, OC	11	300	0.24		G	B
MN00535	Sand Creek	Scott	SV	13	46	0.04		M	B
MN00516	Elk River	Sherburn	SIR, OC	16	269	0.31		M-G	B
MN00614	Fish Lake	St. Louis	OC	18	52	0.07		M	B
MN00092	Pike River	St. Louis	SV	21	85	0.13		M	B
MN00093	Kettle Falls	St. Louis	DNR (Inv. File)	10+17	9600	6.9+11.7		P	A
MN00094	St. Louis River	St. Louis	SV, OC	15	550	0.59		VG	B
MN00610	White Face Lake (Skunk Creek)	St. Louis	OC	34	82	0.70		M	A
MN00612	Island Lake	St. Louis	OC	37	230	0.61		M	A
MN00505	Mississippi (Sartell)	Stearns	SIR	23	4765	7.9	3.2	VG	A
MN00506	St. Cloud	Stearns	SV, SAFHL	18	5100	7.4	(2.2)	VG	A
MN00508	Sauk R. I (cold spring)	Stearns	DNR	8	270	0.16		M	B
MN00561	Sauk River III	Stearns	SIR	12	170	0.15		G	B
MN00011	Zumbro R (Mazeppa)	Wabasha	SV, DNR	12	115	0.10		M	B
MN00358	Zumbro Lake	Wabasha	SV, SIR	55	388	1.5	2.2	VG	A
MN00587	Lock & Dam #7	Winona	OC	7	27800	14.0		VG	A
MN00589	Lock & Dam #5	Winona	OC	8	26250	15.1		VG	A
MN00152	Minnesota River I	Yellow Medicine	SV, SAFHL	17	705	0.86	(0.78)	VG	A
MN00510	Minnesota River II (Grante Falls)	Yellow Medicino	SV, SAFHL	18	705	0.91	(0.58)	VG	A

SV = Site visit
OC = Owner contact
SIR = Safety Inspection Report
DNR = General Information obtained from the DNR
SAFHL = St. Anthony Falls Hydraulic Laboratory feasibility studies

ID Number	Site Name	County	Source of Site Information	hydraulic height, ft	Average Annual discharge, cfs	Potential Power Capacity, MW	Present Capacity (former capacity)	Reliability of Data Used in Energy Calculation	Second Screening Feasibility Region
MN00583	Sandy Lake Lock & Dam	Aitkin	OC	9.5	215	0.15		G	B
MN00549	Rum River	Anoka	SV, SAFHL	12	637	0.55		VG	B
MN00512	Rapidan	Blue Earth	OC	62	835	3.7	(1.5)	VG	A
MN00598	Cloquet	Carlton	SV, OC	39	2290	6.4	5.5	VG	A
MN00603	Fon Du Lac	Carlton	SV, OC	81	2405	14.0	11.8	VG	A
MN00604	Thomson	Carlton	SV, OC	363	2375	62.1	68.6	VG	A
MN00605	Scanlon	Carlton	SV, OC	16	2290	2.6	1.5	G	A
MN00606	Knife Falls	Carlton	SV, OC	18	2290	3.0	1.9	G	A
MN00601	Sylvan	Cass	OC	22	2470	2.3	1.9	M	A
MN00585	Leech Lake Dam (federal)	Cass	OC	7	360	0.18		VG	B
MN00586	Winnibigoshish Dam	Cass	SV, OC	12	515	0.46		VG	B
MN00582	Pine River Dam	Crow Wing	OC	13	217	0.20		M	B
MN00597	Brainerd	Crow Wing	OC	20	3465	5.0	3.7	VG	A
MN00594	Lock & Dam #2	Dakota	OC	12	10700	9.0		VG	A
MN00514	Byllesby	Dakota, Goodhue	SIR	57	414	1.7		VG	A
MN00517	Lanesboro	Fillmore	SV, SAFHL	27	140	0.34		VG	A
MN00026	Mustinka R	Grant	DNR	13	50	0.05		P	B
MN00507	Coon Rapids	Hennepin	SV, SIR	20	7560	10.9	(6.5)	VG	A
MN00590	St. Anthony Upper Lock & Dam	Hennepin	SV, OC	49	7790	27.5	12.5	VG	A
MN00591	St. Anthony Lower Lock & Dam	Hennepin	SV, OC	24	7790	13.5	8.0	VG	A
MN00593	Lock & Dam #1	Hennepin	OC	38	7795	21.3	14.4	VG	A
MN00234	Fish Hook	Hubbard	SV, SAFHL	15	100	0.10		VG	B
MN00584	Pokegma Lake & Dam	Itasca	OC	10	1135	0.78		M	B
MN00602	Blandin	Itasca	OC	21	1170	1.8	2.1	VG	A
MN00117	Jackson Dam	Jackson	SIR	11	283	0.22		G	B
MN00607	Winton	Kake	OC	65	1000	4.7	5.0	VG	A
MN00062	New London	Kandiyohi	SIR	16	50	0.06		G	B
MN00017	Bronson Lake	Kittson	SIR	26	89	0.17		VG	B
MN00653	Rainy Lake	Koochiching	SIR	28	10035/2*	10.1	10	G	A
MN00580	Lac Qui Parle	Lac Qui Parle	OC, SV	13	632	0.57		VG	B
MN00581	Highway 75 Dam	Lac Qui Parle	SV, OC	13	127	0.12		G	B
MN00120	Brawner Lake	Lyon	SIR	21	39	0.06		G	B
MN00599	Blanchard	Morrison	OC	45	4375	14.2	13.4	VG	A
MN00600	Little Falls	Morrison	OC	24	4380	7.6	4.6	VG	A
MN00608	Crow Wing R. (Pillager)	Morrison	OC	22	1470	2.3	1.5	VG	A

(Cont'd)

Appendix A-2: - Results of Feasibility Study by Dotan and Gulliver (1983).

Sites with VERY GOOD Hydropower Feasibility

Site ID	Site Name	Design Capacity (KW)	Incremental Energy (MWH/Yr)	Total Project Cost ($1000, 1982)	35-Year Benefit-Cost Ratio	Comments
MN00506	St. Cloud	5135	33169	8790	2.43	A feasibility study by SAFHL recommended between 5500 and 8000 KW with benefit-cost ratio of 1.9 to 2.2.
MN00514	Byllesby	1159	6779	1504	2.31	Rehabilitation of the existing powerhouse is assumed. Dakota-Goodhue counties have licensing exemption.
MN00507	Coon Rapids	8600	50543	16118	2.11	Assuming that entirely new powerhouse is built. Preliminary permit issued to City of Anoka.
MN00513	Kettle River	403	2818	737	1.95	A feasibility study by SAFHL recommended 1100 Kw with benefit-cost ratio of 1.7.
MN00590	St. Anthony Falls Upper Lock & Dam	21630	72588	20271	1.84	Location of powerhouse is at wasteway No. 2
MN00512	Rapidan Dam	2440	11036	3017	1.82	Utilizing the existing substructure of the old powerhouse. 5000 KW currently being installed.
	Total:	39367	176933	50437		

Sites with GOOD Hydropower Feasibility

Site ID	Site Name	Design Capacity (KW)	Incremental Energy (MWH/Yr)	Total Project Cost ($1000, 1982)	35-Year Benefit-Cost Ratio	Comments
MN00517	Lanesboro	233	1515	397	1.73	Installing new turbines at existing powerhouse. SAFHL recommended rehabilitating existing turbines.
MN00612	Island Lake	506	3223	1177	1.59	Assumed avg. head of 37'. Bulb turbine installed at existing draft tube.
MN00591	St. Anthony Falls Lower Lock & Dam	10250	30708	12133	1.39	Installing horizontal tubular turbine units in the auxiliary lock.
MN00093	Kettle Falls	6060	45630	25104	1.36	Excellent flow duration curve; constant head of 12' assumed. Cost of transmission line included. Constant in equip. cost equation No. 11 changed from 9600 to 18000.
MN00234	Fish Hook	97	689	244	1.29	A feasibility study by SAFHL recommended 97 Kw with 1.7 benefit-cost ratio.
MN00152	Minnesota I	447	2351	958	1.29	SAFHL has developed cost estimates but no detailed feasibility analysis for this site.
MN00589	Lock & Dam #5	8040	54101	31084	1.24	Installing turbines in tainter gate bays on east side of dam. Constant in equip. cost equation was changed from 9600 to 20500.
MN00505	Sartell	3735	14250	6805	1.24	Assuming that an entirely new powerhouse is built.
MN00599	Blanchard	10380	20053	7719	1.22	Installing turbine in existing powerhouse.
	Total:	39748	172100	86521		

Sites with MARGINAL Hydropower Feasibility

Site ID	Site Name	Design Capacity (KW)	Incremental Energy (MWH/Yr)	Total Project Cost ($1000, 1982)	35-Year Benefit-Cost Ratio	Comments
MN00594	Lock & Dam #2	3040	20936	12667	1.19	Installing turbines in spillway dam and river lock. Constant in equip. cost Eq. No. 12 changed from 9600 to 20500
MN00604	Thomson	52680	89948	39452	1.17	Cost includes penstock, bifurcation, by-pass facilities and surge tanks.
MN00549	Rum River	272	1874	966	1.15	Feasibility study by SAFHL found site not quite feasible for development by City of Anoka.
MN00094	St. Louis River	311	1943	984	1.14	Crest elevation is maintained at design elevation.
MN00516	Elk River	148	987	454	1.13	Substructure of old powerhouse is used.
MN00586	Winnibigoshish Dam	495	2925	1642	1.10	Powerhouse location adjacent to the right abutment wall.
MN00587	Lock & Dam #7	5960	40834	28622	1.06	Placing units under existing storage yard. Constant in equip. cost Eq. No. 11 was change from 9600 to 20500.
MN00597	Brainerd	2120	6131	2825	1.05	Installing turbine units in abandoned turbine bays of existing powerhouse.
MN00368	Shady Lake	108	775	410	1.02	Powerhouse location is at the left abutment of the dam.
MN00607	Winton	2660	5732	2365	1.01	Turbine installed in existing bay; cost of penstock is included.
MN00008	Red Lake II	227	1406	556	1.29	Low WF estimate. Reconstruction of old powerhouse.
MN00550	Grand Fork East	517	2905	1284	1.27	Low WF estimate.
MN00610	White Face Lake	98	644	240	1.23	Low WF estimate. Constant head of 34' is assumed.
MN00653	Rainy Lake	6270	16211	6836	1.20	Low WF estimate. Utilizing only half of flow at river. Other half assumed utilized by Canadian Powerhouse.
MN00600	Little Falls	2860	9574	4272	1.18	Low WF estimate.
MN00356	Cannon River II	96	682	287	1.16	Low WF estimate.
MN00584	Pokegama Lake	847	5866	3507	1.15	Low WF estimate. Constant in equip. cost Eq. No. 12 was changed from 9600 to 20500. Constant head of 9.6' is assumed.
MN00593	Lock & Dam #1	7440	20205	9362	1.13	Low WF estimate. Powerhouse located downstream to the existing PH; the water would be transported by tunnel.
MN00574	Orwell Dam	430	2523	1394	1.09	Low WF estimate. Avg. headwater elevation was derived from 10 yrs of reservoir operation.
	Total	86579	232101	118125		

Sites with POOR Hydropower Feasibility

Site ID	Site Name	Design Capacity (KW)	Incremental Energy (MWH/Yr)	Total Project Cost ($1000, 1982)	35-Year Benefit-Cost Ratio	Comments
MN00598	Cloquet	3290	6937	4351	0.98	Installing turbine unit in abandoned turbine bay of existing powerhouse.
MN00011	Mazeppa Dam	47	326	271	0.96	Rehabilitating existing powerhouse.
MN00603	Fon-du-Lac	4308	7992	6768	0.76	Includes new penstock and a structure for new units.
MN00190	Pelican Rapids	50	328	343	0.75	Rehabilitating abandoned powerhouse.
MN00608	Crow Wing	810	1878	1776	0.64	Installing turbines in existing turbine bay.
MN00602	Blandin	597	1931	2139	0.63	Building entirely new powerhouse for new units.
MN00585	Leech Lake Dam	348	1836	2237	0.62	Proposed to locate powerhouse at north side of dam.
MN00605	Scanlon	1301	3512	3558	0.62	Installing turbine at tainter gate bay adjacent to existing powerhouse.
MN00191	Pelican River	60	349	441	0.62	Powerhouse assumed to replace one spillway gate.
MN00606	Knife Falls	1371	3697	3551	0.61	Installing turbine at gate bay adjacent to existing powerhouse.
MN00117	Jackson Dam	56	767	308	0.61	Rehabilitating old powerhouse.
MN00582	Pine River	164	1016	1355	0.58	Powerhouse construction involves large amount of civil works.
MN00092	Pike River	57	306	404	0.56	Poor flow duration curve. Possible to use substructure of old powerhouse
MN00508	Sauk River I	52	338	492	0.55	Building entirely new powerhouse (Impossible to use the substructure of old plant).
MN00515	South Branch Zumbro River	52	312	444	0.53	Installing turbine in tainter gate bay.
MN00510	Granite Falls	677	1845	1329	0.53	Feasibility study by SAFHL found site marginal for capacity addition.
MN00358	Zumbro Lake	299	555	697	0.51	Installing turbine in existing turbine bay of powerhouse.
MN00544	Willow River	47	265	410	0.49	Powerhouse is proposed to be located adjacent to right abutment wall.
MN00580	Lac-Qui-Parle	58	297	492	0.45	Building the powerhouse in one of the gate bays.
MN00601	Sylvan	887	1708	2445	0.44	Assuming constant head of 22 ft.
MN00561	Sauk River III	49	210	318	0.43	Installing turbine in gate section.
MN00364	Moyowood Lake	47	776	383	0.42	Utilizing the existing headrace channel.
MN00502	Thief River	515	1545	2696	0.36	Study conducted by SAFHL indicated poor feasibility.
MN00017	Bronson Lake	52	194	388	0.32	Powerhouse is proposed to be located adjacent to right abutment wall.
MN00583	Sandy Lock & Dam	73	266	583	0.30	When the stage at the Mississippi River is high, it backs up the Sandy River and the head at the dam is almost zero.
MN00062	New London	55	210	528	0.25	Impossible to use penstock openings because of safety hazard.
MN00581	Hwy 75 Dam	61	263	690	0.24	Powerhouse is proposed to be located at low flow outlet.
MN00614	Fish Lake	65	243	767	0.20	Including cost of transmission lines.
MN00120	Brawner Lake	59	188	575	0.19	Very poor flow duration curve.
MN00535	Sand Creek	49	175	529	0.19	Very poor flow duration curve.
MN00026	Mustinka River	47	50	610	0.04	Including cost of transmission lines.

Appendix A–3 – Site Feasibility Output Summaries for the Minimum Total Energy Value to First Yield Positive Net Discounted Benefits.

SITE: ST. ANTHONY FALLS LOWER LOCK & DAM
SITE NO.: MN00591

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	0.00	CENTS/KWH
	FIXED O&M VALUE =	0.00	CENTS/KWH
	TOTAL ENERGY VALUE =	1.60	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	0.5	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	25.99	FT
DESIGN DISCHARGE:	6448.92	FT^3/S
DESIGN CAPACITY:	12053.59	KW
TOTAL DESIGN EXCEEDENCE:	35.00	%
EQUIPMENT COST ($1000):	8455.54	
TOTAL COST ($1000):	17577.30	
NET BENEFIT ($1000):	9332.09	
32 YR. B/C RATIO:	1.47	
RISK OF LOSING MONEY:	28%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	25.00
DESIGN DISCHARGE:	2609.68
DESIGN CAPACITY:	4691.68
TOTAL DESIGN EXCEEDENCE:	80.00
EQUIPMENT COST ($1000):	3873.06
TOTAL COST ($1000):	7877.91
NET BENEFIT ($1000):	6721.68
32 YR. B/C RATIO:	1.77
RISK OF LOSING MONEY:	19.42857%

SITE: COON RAPIDS
MN00507

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	0.00	CENTS/KWH
	FIXED O&M VALUE =	0.00	CENTS/KWH
	TOTAL ENERGY VALUE =	1.60	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	0.5	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	19.50	FT
DESIGN DISCHARGE:	5150.00	FT^3/S
DESIGN CAPACITY:	7221.76	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	5847.71	
TOTAL COST ($1000):	12015.81	
NET BENEFIT ($1000):	5759.55	
32 YR. B/C RATIO:	1.43	
RISK OF LOSING MONEY:	28.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	20.40
DESIGN DISCHARGE:	2800.00
DESIGN CAPACITY:	4107.61
TOTAL DESIGN EXCEEDENCE:	75.00
EQUIPMENT COST ($1000):	3614.64
TOTAL COST ($1000):	7334.28
NET BENEFIT ($1000):	4174.32
32 YR. B/C RATIO:	1.52
RISK OF LOSING MONEY:	28%

SITE: KETTLE FALLS
SITE NO.: MNOO 93

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	0.00 CENTS/KWH
	FIXED O&M VALUE	=	0.00 CENTS/KWH
	TOTAL ENERGY VALUE	=	1.60 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.00	FT
DESIGN DISCHARGE:	6280.00	FT^3/S
DESIGN CAPACITY:	5419.29	KW
TOTAL DESIGN EXCEEDENCE:	60.00	%
EQUIPMENT COST ($1000):	5086.07	
TOTAL COST ($1000):	14367.66	
NET BENEFIT ($1000):	3322.14	
32 YR. B/C RATIO:	1.22	
RISK OF LOSING MONEY:	40.57143%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	12.00
DESIGN DISCHARGE:	4550.00
DESIGN CAPACITY:	3926.40
TOTAL DESIGN EXCEEDENCE:	85.00
EQUIPMENT COST ($1000):	3884.96
TOTAL COST ($1000):	10836.48
NET BENEFIT ($1000):	2854.57
32 YR. B/C RATIO:	1.25
RISK OF LOSING MONEY:	37.14286%

SITE: KETTLE RIVER
SITE NO.: MN00513

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	0.00 CENTS/KWH
	FIXED O&M VALUE =	0.00 CENTS/KWH
	TOTAL ENERGY VALUE =	1.60 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	20.70	FT
DESIGN DISCHARGE:	210.00	FT^3/S
DESIGN CAPACITY:	312.60	KW
TOTAL DESIGN EXCEEDENCE:	60.00	%
EQUIPMENT COST ($1000):	418.41	
TOTAL COST ($1000):	813.51	
NET BENEFIT ($1000):	166.99	
32 YR. B/C RATIO:	1.19	
RISK OF LOSING MONEY:	38.28571%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	20.80
DESIGN DISCHARGE:	160.00
DESIGN CAPACITY:	239.32
TOTAL DESIGN EXCEEDENCE:	75.00
EQUIPMENT COST ($1000):	334.34
TOTAL COST ($1000):	648.06
NET BENEFIT ($1000):	149.58
32 YR. B/C RATIO:	1.22
RISK OF LOSING MONEY:	39.42857%

SITE: ST. ANTHONY FALLS UPPER LOCK & DAM
SITE NO.: MN00590

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	0.00 CENTS/KWH
	FIXED O&M VALUE	=	0.00 CENTS/KWH
	TOTAL ENERGY VALUE	=	1.60 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	12500.0 KW
	DESIGN DISCHARGE	=	4060.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	48.90	FT
DESIGN DISCHARGE:	4572.01	FT^3/S
DESIGN CAPACITY:	16078.79	KW
TOTAL DESIGN EXCEEDENCE:	25.00	%
EQUIPMENT COST ($1000):	9439.11	
TOTAL COST ($1000):	19732.12	
NET BENEFIT ($1000):	4359.91	
32 YR. B/C RATIO:	1.19	
RISK OF LOSING MONEY:	39.14286%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	48.60
DESIGN DISCHARGE:	1284.82
DESIGN CAPACITY:	4490.36
TOTAL DESIGN EXCEEDENCE:	45.00
EQUIPMENT COST ($1000):	3253.65
TOTAL COST ($1000):	6603.67
NET BENEFIT ($1000):	2431.74
32 YR. B/C RATIO:	1.33
RISK OF LOSING MONEY:	31.71428%

SITE: LOCK & DAM #5
SITE NO.: MN00589

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	0.00 CENTS/KWH
	FIXED O&M VALUE	=	0.00 CENTS/KWH
	TOTAL ENERGY VALUE	=	1.60 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	8.00	FT
DESIGN DISCHARGE:	10986.11	FT^3/S
DESIGN CAPACITY:	6320.27	KW
TOTAL DESIGN EXCEEDENCE:	80.00	%
EQUIPMENT COST ($1000):	6290.32	
TOTAL COST ($1000):	17916.27	
NET BENEFIT ($1000):	1120.45	
32 YR. B/C RATIO:	1.06	
RISK OF LOSING MONEY:	48.57143%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	8.00
DESIGN DISCHARGE:	9088.51
DESIGN CAPACITY:	5228.58
TOTAL DESIGN EXCEEDENCE:	90.00
EQUIPMENT COST ($1000):	5368.18
TOTAL COST ($1000):	15173.14
NET BENEFIT ($1000):	1038.22
32 YR. B/C RATIO:	1.06
RISK OF LOSING MONEY:	48.85714%

SITE: [illegible] THOMSON
SITE NO.: [illegible] MN00604

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	0.00 CENTS/KWH
	FIXED O&M VALUE	=	0.00 CENTS/KWH
	TOTAL ENERGY VALUE	=	1.60 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	68600.0 KW
	DESIGN DISCHARGE	=	3040.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	355.00	FT
DESIGN DISCHARGE:	577.79	FT^3/S
DESIGN CAPACITY:	14750.32	KW
TOTAL DESIGN EXCEEDENCE:	15.00	%
EQUIPMENT COST ($1000):	5826.64	
TOTAL COST ($1000):	12094.47	
NET BENEFIT ($1000):	628.33	
32 YR. B/C RATIO:	1.04	
RISK OF LOSING MONEY:	44.57143%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	355.00
DESIGN DISCHARGE:	577.79
DESIGN CAPACITY:	14750.32
TOTAL DESIGN EXCEEDENCE:	15.00
EQUIPMENT COST ($1000):	5826.64
TOTAL COST ($1000):	12094.47
NET BENEFIT ($1000):	628.33
32 YR. B/C RATIO:	1.04
RISK OF LOSING MONEY:	44.57143%

SITE: LOCK & DAM #7
SITE NO.: MN00587

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	0.32	CENTS/KWH
	FIXED O&M VALUE =	0.08	CENTS/KWH
	TOTAL ENERGY VALUE =	2.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	7.70	FT
DESIGN DISCHARGE:	14337.66	FT^3/S
DESIGN CAPACITY:	7939.09	KW
TOTAL DESIGN EXCEEDENCE:	65.00	%
EQUIPMENT COST ($1000):	7671.88	
TOTAL COST ($1000):	22061.73	
NET BENEFIT ($1000):	2958.11	
32 YR. B/C RATIO:	1.13	
RISK OF LOSING MONEY:	42.85714%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	7.80
DESIGN DISCHARGE:	9809.98
DESIGN CAPACITY:	5502.55
TOTAL DESIGN EXCEEDENCE:	90.00
EQUIPMENT COST ($1000):	5631.78
TOTAL COST ($1000):	15952.88
NET BENEFIT ($1000):	2572.49
32 YR. B/C RATIO:	1.15
RISK OF LOSING MONEY:	43.14286%

SITE: SARTELL
SITE NO.: MN00505

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	0.32 CENTS/KWH
	FIXED O&M VALUE	=	0.08 CENTS/KWH
	TOTAL ENERGY VALUE	=	2.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	3200.0 KW
	DESIGN DISCHARGE	=	2440.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	19.45	FT
DESIGN DISCHARGE:	1730.33	FT^3/S
DESIGN CAPACITY:	2420.56	KW
TOTAL DESIGN EXCEEDENCE:	35.00	%
EQUIPMENT COST ($1000):	2346.02	
TOTAL COST ($1000):	4709.93	
NET BENEFIT ($1000):	458.59	
32 YR. B/C RATIO:	1.09	
RISK OF LOSING MONEY:	43.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	19.86
DESIGN DISCHARGE:	1079.36
DESIGN CAPACITY:	1541.65
TOTAL DESIGN EXCEEDENCE:	45.00
EQUIPMENT COST ($1000):	1602.00
TOTAL COST ($1000):	3189.42
NET BENEFIT ($1000):	378.29
32 YR. B/C RATIO:	1.11
RISK OF LOSING MONEY:	44.85714%

SITE: MINNESOTA ONE
SITE NO.: MN00152

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	17.69	FT
DESIGN DISCHARGE:	682.53	FT^3/S
DESIGN CAPACITY:	868.40	KW
TOTAL DESIGN EXCEEDENCE:	30.00	%
EQUIPMENT COST ($1000):	1015.48	
TOTAL COST ($1000):	2002.68	
NET BENEFIT ($1000):	660.93	
32 YR. B/C RATIO:	1.31	
RISK OF LOSING MONEY:	33.42857%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	19.20
DESIGN DISCHARGE:	120.45
DESIGN CAPACITY:	166.30
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	250.74
TOTAL COST ($1000):	484.16
NET BENEFIT ($1000):	291.11
32 YR. B/C RATIO:	1.57
RISK OF LOSING MONEY:	26.57143%

SITE: FISH HOOK RIVER DAM
SITE NO.: MN00234

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	16.20	FT
DESIGN DISCHARGE:	100.00	FT^3/S
DESIGN CAPACITY:	116.50	KW
TOTAL DESIGN EXCEEDENCE:	35.00	%
EQUIPMENT COST ($1000):	192.87	
TOTAL COST ($1000):	371.17	
NET BENEFIT ($1000):	168.63	
32 YR. B/C RATIO:	1.43	
RISK OF LOSING MONEY:	28.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	16.50
DESIGN DISCHARGE:	73.00
DESIGN CAPACITY:	86.62
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	149.97
TOTAL COST ($1000):	287.93
NET BENEFIT ($1000):	151.20
32 YR. B/C RATIO:	1.50
RISK OF LOSING MONEY:	25.14286%

SITE: LITTLE FALLS
SITE NO.: MN00600

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	4600.0 KW
	DESIGN DISCHARGE	=	2990.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	24.40	FT
DESIGN DISCHARGE:	2353.25	FT^3/S
DESIGN CAPACITY:	4129.44	KW
TOTAL DESIGN EXCEEDENCE:	20.00	%
EQUIPMENT COST ($1000):	3498.54	
TOTAL COST ($1000):	7097.15	
NET BENEFIT ($1000):	2403.67	
32 YR. B/C RATIO:	1.31	
RISK OF LOSING MONEY:	32.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	23.90
DESIGN DISCHARGE:	665.38
DESIGN CAPACITY:	1143.75
TOTAL DESIGN EXCEEDENCE:	35.00
EQUIPMENT COST ($1000):	1201.21
TOTAL COST ($1000):	2378.84
NET BENEFIT ($1000):	1192.89
32 YR. B/C RATIO:	1.46
RISK OF LOSING MONEY:	27.42857%

SITE: ISLAND LAKE
SITE NO.: MN00612

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	37.00	FT
DESIGN DISCHARGE:	415.00	FT^3/S
DESIGN CAPACITY:	1104.21	KW
TOTAL DESIGN EXCEEDENCE:	30.00	%
EQUIPMENT COST ($1000):	1065.54	
TOTAL COST ($1000):	2826.36	
NET BENEFIT ($1000):	1060.10	
32 YR. B/C RATIO:	1.35	
RISK OF LOSING MONEY:	32.57143%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	37.00
DESIGN DISCHARGE:	99.00
DESIGN CAPACITY:	263.41
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	321.54
TOTAL COST ($1000):	816.51
NET BENEFIT ($1000):	541.33
32 YR. B/C RATIO:	1.63
RISK OF LOSING MONEY:	18.57143%

SITE: RUM RIVER
SITE NO.: MN00549

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92	CENTS/KWH
	FIXED O&M VALUE =	0.48	CENTS/KWH
	TOTAL ENERGY VALUE =	4.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.89	FT
DESIGN DISCHARGE:	374.03	FT^3/S
DESIGN CAPACITY:	346.76	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	503.30	
TOTAL COST ($1000):	1291.92	
NET BENEFIT ($1000):	409.61	
32 YR. B/C RATIO:	1.30	
RISK OF LOSING MONEY:	32.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	13.10
DESIGN DISCHARGE:	146.58
DESIGN CAPACITY:	138.08
TOTAL DESIGN EXCEEDENCE:	80.00
EQUIPMENT COST ($1000):	232.32
TOTAL COST ($1000):	581.31
NET BENEFIT ($1000):	251.34
32 YR. B/C RATIO:	1.41
RISK OF LOSING MONEY:	27.14286%

SITE: SHADY LAKE
SITE NO.: MN00365

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	19.90	FT
DESIGN DISCHARGE:	97.00	FT^3/S
DESIGN CAPACITY:	138.81	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	213.99	
TOTAL COST ($1000):	535.03	
NET BENEFIT ($1000):	143.38	
32 YR. B/C RATIO:	1.26	
RISK OF LOSING MONEY:	36.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	20.00
DESIGN DISCHARGE:	65.00
DESIGN CAPACITY:	93.49
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	153.61
TOTAL COST ($1000):	380.31
NET BENEFIT ($1000):	120.61
32 YR. B/C RATIO:	1.30
RISK OF LOSING MONEY:	34.85714%

SITE: RED LAKE TWO(CROOKSTON)
SITE NO.: MN00 8

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	9.10	FT
DESIGN DISCHARGE:	580.00	FT^3/S
DESIGN CAPACITY:	379.55	KW
TOTAL DESIGN EXCEEDENCE:	35.00	%
EQUIPMENT COST ($1000):	583.37	
TOTAL COST ($1000):	1137.25	
NET BENEFIT ($1000):	361.31	
32 YR. B/C RATIO:	1.30	
RISK OF LOSING MONEY:	34.57143%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	9.80
DESIGN DISCHARGE:	275.00
DESIGN CAPACITY:	193.80
TOTAL DESIGN EXCEEDENCE:	60.00
EQUIPMENT COST ($1000):	327.53
TOTAL COST ($1000):	633.35
NET BENEFIT ($1000):	278.37
32 YR. B/C RATIO:	1.42
RISK OF LOSING MONEY:	29.42857%

SITE: ST. LOUIS RIVER
SITE NO.: MNOO 94

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	16.40	FT
DESIGN DISCHARGE:	305.00	FT^3/S
DESIGN CAPACITY:	359.70	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	493.74	
TOTAL COST ($1000):	1267.85	
NET BENEFIT ($1000):	380.31	
32 YR. B/C RATIO:	1.29	
RISK OF LOSING MONEY:	34.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	17.10
DESIGN DISCHARGE:	145.00
DESIGN CAPACITY:	178.31
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	272.23
TOTAL COST ($1000):	685.35
NET BENEFIT ($1000):	269.50
32 YR. B/C RATIO:	1.38
RISK OF LOSING MONEY:	30%

SITE: MAZEPPA DAM (ZUMBRO RIVER)
SITE NO.: MNOO 11

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	11.50	FT
DESIGN DISCHARGE:	50.64	FT^3/S
DESIGN CAPACITY:	41.88	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	88.03	
TOTAL COST ($1000):	168.16	
NET BENEFIT ($1000):	41.29	
32 YR. B/C RATIO:	1.24	
RISK OF LOSING MONEY:	39.42857%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	11.50
DESIGN DISCHARGE:	35.94
DESIGN CAPACITY:	29.72
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	66.09
TOTAL COST ($1000):	126.04
NET BENEFIT ($1000):	36.13
32 YR. B/C RATIO:	1.28
RISK OF LOSING MONEY:	32.85714%

SITE: PIKE RIVER
SITE NO.: MN00 92

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	23.08	FT
DESIGN DISCHARGE:	42.65	FT^3/S
DESIGN CAPACITY:	70.79	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	118.20	
TOTAL COST ($1000):	226.65	
NET BENEFIT ($1000):	47.64	
32 YR. B/C RATIO:	1.20	
RISK OF LOSING MONEY:	38.28571%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	23.79
DESIGN DISCHARGE:	15.23
DESIGN CAPACITY:	26.06
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	50.93
TOTAL COST ($1000):	97.19
NET BENEFIT ($1000):	29.49
32 YR. B/C RATIO:	1.29
RISK OF LOSING MONEY:	30.85714%

SITE: WHITE FACE LAKE
SITE NO.: MN00610

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	1.0
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	34.00	FT
DESIGN DISCHARGE:	53.00	FT^3/S
DESIGN CAPACITY:	129.59	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	180.83	
TOTAL COST ($1000):	450.81	
NET BENEFIT ($1000):	127.56	
32 YR. B/C RATIO:	1.27	
RISK OF LOSING MONEY:	32.85714%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	34.00
DESIGN DISCHARGE:	24.00
DESIGN CAPACITY:	58.68
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	93.25
TOTAL COST ($1000):	228.20
NET BENEFIT ($1000):	87.48
32 YR. B/C RATIO:	1.37
RISK OF LOSING MONEY:	32.28571%

SITE: POKEGAMA LAKE
SITE NO.: MN00584

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	9.60	FT
DESIGN DISCHARGE:	1575.00	FT^3/S
DESIGN CAPACITY:	1087.31	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	1390.78	
TOTAL COST ($1000):	3705.76	
NET BENEFIT ($1000):	1561.29	
32 YR. B/C RATIO:	1.40	
RISK OF LOSING MONEY:	28%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	9.60
DESIGN DISCHARGE:	740.00
DESIGN CAPACITY:	510.86
TOTAL DESIGN EXCEEDENCE:	75.00
EQUIPMENT COST ($1000):	739.62
TOTAL COST ($1000):	1922.77
NET BENEFIT ($1000):	1061.47
32 YR. B/C RATIO:	1.53
RISK OF LOSING MONEY:	21.42857%

SITE: WINNIBIGOSHISH DAM
SITE NO.: MN00586

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.70	FT
DESIGN DISCHARGE:	790.00	FT^3/S
DESIGN CAPACITY:	721.49	KW
TOTAL DESIGN EXCEEDENCE:	35.00	%
EQUIPMENT COST ($1000):	931.52	
TOTAL COST ($1000):	2446.00	
NET BENEFIT ($1000):	629.74	
32 YR. B/C RATIO:	1.24	
RISK OF LOSING MONEY:	35.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	13.70
DESIGN DISCHARGE:	435.00
DESIGN CAPACITY:	428.56
TOTAL DESIGN EXCEEDENCE:	55.00
EQUIPMENT COST ($1000):	593.28
TOTAL COST ($1000):	1532.28
NET BENEFIT ($1000):	501.57
32 YR. B/C RATIO:	1.31
RISK OF LOSING MONEY:	32.28571%

SITE: WINTON
SITE NO.: MN00607

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	5000.0 KW
	DESIGN DISCHARGE	=	1140.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	68.50	FT
DESIGN DISCHARGE:	530.75	FT^3/S
DESIGN CAPACITY:	2614.55	KW
TOTAL DESIGN EXCEEDENCE:	15.00	%
EQUIPMENT COST ($1000):	1928.19	
TOTAL COST ($1000):	3869.66	
NET BENEFIT ($1000):	501.01	
32 YR. B/C RATIO:	1.12	
RISK OF LOSING MONEY:	41.42857%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	68.50
DESIGN DISCHARGE:	530.75
DESIGN CAPACITY:	2614.55
TOTAL DESIGN EXCEEDENCE:	15.00
EQUIPMENT COST ($1000):	1928.19
TOTAL COST ($1000):	3869.66
NET BENEFIT ($1000):	501.01
32 YR. B/C RATIO:	1.12
RISK OF LOSING MONEY:	41.42857%

SITE: BLANDIN
SITE NO.: MN00602

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	2100.0 KW
	DESIGN DISCHARGE	=	1630.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	19.70	FT
DESIGN DISCHARGE:	400.00	FT^3/S
DESIGN CAPACITY:	566.67	KW
TOTAL DESIGN EXCEEDENC	20.00	%
EQUIPMENT COST ($1000)	695.06	
TOTAL COST ($1000):	1361.96	
NET BENEFIT ($1000):	149.22	
32 YR. B/C RATIO:	1.10	
RISK OF LOSING MONEY:	45.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	19.80
DESIGN DISCHARGE:	315.00
DESIGN CAPACITY:	448.52
TOTAL DESIGN EXCEEDENCE:	25.00
EQUIPMENT COST ($1000):	571.05
TOTAL COST ($1000):	1115.37
NET BENEFIT ($1000):	134.11
32 YR. B/C RATIO:	1.11
RISK OF LOSING MONEY:	45.14286%

SITE: BLANCHARD
SITE NO.: MN00599

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	18000.0 KW
	DESIGN DISCHARGE	=	6000.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	40.91	FT
DESIGN DISCHARGE:	2378.80	FT^3/S
DESIGN CAPACITY:	6997.90	KW
TOTAL DESIGN EXCEEDENCE:	10.00	%
EQUIPMENT COST ($1000):	4885.92	
TOTAL COST ($1000):	10016.07	
NET BENEFIT ($1000):	761.59	
32 YR. B/C RATIO:	1.07	
RISK OF LOSING MONEY:	44.8%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	40.91
DESIGN DISCHARGE:	2378.80
DESIGN CAPACITY:	6997.90
TOTAL DESIGN EXCEEDENCE:	10.00
EQUIPMENT COST ($1000):	4885.92
TOTAL COST ($1000):	10016.07
NET BENEFIT ($1000):	761.59
32 YR. B/C RATIO:	1.07
RISK OF LOSING MONEY:	44.8%

SITE: ORWELL DAM
SITE NO.: MN00574

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92	CENTS/KWH
	FIXED O&M VALUE =	0.48	CENTS/KWH
	TOTAL ENERGY VALUE =	4.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	24.80	FT
DESIGN DISCHARGE:	275.00	FT^3/S
DESIGN CAPACITY:	490.44	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	587.32	
TOTAL COST ($1000):	1520.30	
NET BENEFIT ($1000):	563.50	
32 YR. B/C RATIO:	1.35	
RISK OF LOSING MONEY:	32.28571%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	25.10
DESIGN DISCHARGE:	160.00
DESIGN CAPACITY:	288.80
TOTAL DESIGN EXCEEDENCE:	60.00
EQUIPMENT COST ($1000):	376.29
TOTAL COST ($1000):	959.00
NET BENEFIT ($1000):	433.47
32 YR. B/C RATIO:	1.43
RISK OF LOSING MONEY:	25.71429%

SITE: PELICAN RAPIDS
SITE NO.: MN00190

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	15.12	FT
DESIGN DISCHARGE:	59.41	FT^3/S
DESIGN CAPACITY:	64.59	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	119.49	
TOTAL COST ($1000):	228.91	
NET BENEFIT ($1000):	63.13	
32 YR. B/C RATIO:	1.26	
RISK OF LOSING MONEY:	34%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	15.40
DESIGN DISCHARGE:	28.24
DESIGN CAPACITY:	31.28
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	64.92
TOTAL COST ($1000):	123.88
NET BENEFIT ($1000):	45.92
32 YR. B/C RATIO:	1.35
RISK OF LOSING MONEY:	31.42857%

SITE: LOCK & DAM #1
SITE NO.: MN00593

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	14400.0 KW
	DESIGN DISCHARGE	=	6970.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	32.30	FT
DESIGN DISCHARGE:	3217.78	FT^3/S
DESIGN CAPACITY:	7474.13	KW
TOTAL DESIGN EXCEEDENCE:	20.00	%
EQUIPMENT COST ($1000):	5421.12	
TOTAL COST ($1000):	15437.19	
NET BENEFIT ($1000):	1111.68	
32 YR. B/C RATIO:	1.07	
RISK OF LOSING MONEY:	47.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	32.40
DESIGN DISCHARGE:	1662.01
DESIGN CAPACITY:	3872.16
TOTAL DESIGN EXCEEDENCE:	25.00
EQUIPMENT COST ($1000):	3126.43
TOTAL COST ($1000):	8676.17
NET BENEFIT ($1000):	876.54
32 YR. B/C RATIO:	1.09
RISK OF LOSING MONEY:	46%

SITE: CANNON RIVER II
SITE NO.: MN00356

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	1.0
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	11.80	FT
DESIGN DISCHARGE:	116.24	FT^3/S
DESIGN CAPACITY:	98.64	KW
TOTAL DESIGN EXCEEDENCE:	55.00	%
EQUIPMENT COST ($1000):	179.20	
TOTAL COST ($1000):	444.70	
NET BENEFIT ($1000):	77.48	
32 YR. B/C RATIO:	1.17	
RISK OF LOSING MONEY:	41.42857%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	11.90
DESIGN DISCHARGE:	86.24
DESIGN CAPACITY:	73.80
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	140.37
TOTAL COST ($1000):	345.90
NET BENEFIT ($1000):	65.87
32 YR. B/C RATIO:	1.18
RISK OF LOSING MONEY:	41.71429%

SITE: CLOQUET
SITE NO.: MN00598

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	5510.0 KW
	DESIGN DISCHARGE	=	2320.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	36.00	FT
DESIGN DISCHARGE:	1230.00	FT^3/S
DESIGN CAPACITY:	3184.26	KW
TOTAL DESIGN EXCEEDENCE:	15.00	%
EQUIPMENT COST ($1000):	2597.52	
TOTAL COST ($1000):	5237.87	
NET BENEFIT ($1000):	1938.28	
32 YR. B/C RATIO:	1.33	
RISK OF LOSING MONEY:	32.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	36.00
DESIGN DISCHARGE:	1230.00
DESIGN CAPACITY:	3184.26
TOTAL DESIGN EXCEEDENCE:	15.00
EQUIPMENT COST ($1000):	2597.52
TOTAL COST ($1000):	5237.87
NET BENEFIT ($1000):	1938.28
32 YR. B/C RATIO:	1.33
RISK OF LOSING MONEY:	29.71429%

SITE: RAINY LAKE
SITE NO.: MN00653

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	0.5
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	10000.0 KW
	DESIGN DISCHARGE =	5000.0 FT^3/S
	OVERALL EFFICIENCY =	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	29.99	FT
DESIGN DISCHARGE:	2562.59	FT^3/S
DESIGN CAPACITY:	5527.51	KW
TOTAL DESIGN EXCEEDENCE:	15.00	%
EQUIPMENT COST ($1000):	4277.63	
TOTAL COST ($1000):	8728.73	
NET BENEFIT ($1000):	2213.37	
32 YR. B/C RATIO:	1.23	
RISK OF LOSING MONEY:	34.28572%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	30.45
DESIGN DISCHARGE:	1350.64
DESIGN CAPACITY:	2957.69
TOTAL DESIGN EXCEEDENCE:	20.00
EQUIPMENT COST ($1000):	2528.17
TOTAL COST ($1000):	5091.96
NET BENEFIT ($1000):	1381.27
32 YR. B/C RATIO:	1.25
RISK OF LOSING MONEY:	34.57143%

SITE: SCANLON
SITE NO.: MN00605

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	1500.0 KW
	DESIGN DISCHARGE	=	1480.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	15.70	FT
DESIGN DISCHARGE:	1140.00	FT^3/S
DESIGN CAPACITY:	1287.08	KW
TOTAL DESIGN EXCEEDENC	20.00	%
EQUIPMENT COST ($1000)	1446.36	
TOTAL COST ($1000):	2871.29	
NET BENEFIT ($1000):	939.93	
32 YR. B/C RATIO:	1.30	
RISK OF LOSING MONEY:	34.57143%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	15.70
DESIGN DISCHARGE:	620.00
DESIGN CAPACITY:	699.99
TOTAL DESIGN EXCEEDENCE:	25.00
EQUIPMENT COST ($1000):	869.25
TOTAL COST ($1000):	1708.77
NET BENEFIT ($1000):	662.89
32 YR. B/C RATIO:	1.36
RISK OF LOSING MONEY:	28%

SITE: KNIFE FALLS
SITE NO.: MN00606

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	3.52 CENTS/KWH
	FIXED O&M VALUE	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	7.37%
	ESCALATION RATE	5.55%
	OM&R ESCALATION RATE	5.55%
	OTHER COSTS ($1000)	0.0
	AMORTIZATION PERIOD	30.0 YEARS
	ECONOMIC LIFE	32.0 YEARS
	PLANT LIFE	60.0 YEARS
	EQUIPMENT COST FACT.	1.0
	POWER HSE. COST FACT	0.5
	OM&R COST FACTOR	1.0
	INDIRECT COST FACTOR	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	1900.0 KW
	DESIGN DISCHARGE	1630.0 FT^3/S
	OVERALL EFFICIENCY	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	18.10	FT
DESIGN DISCHARGE:	1920.00	FT^3/S
DESIGN CAPACITY:	2499.09	KW
TOTAL DESIGN EXCEEDENCE:	15.00	%
EQUIPMENT COST ($1000):	2445.70	
TOTAL COST ($1000):	4913.63	
NET BENEFIT ($1000):	1170.54	
32 YR. B/C RATIO:	1.22	
RISK OF LOSING MONEY:	38%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	18.20
DESIGN DISCHARGE:	500.00
DESIGN CAPACITY:	654.40
TOTAL DESIGN EXCEEDENCE:	25.00
EQUIPMENT COST ($1000):	796.91
TOTAL COST ($1000):	1564.83
NET BENEFIT ($1000):	609.41
32 YR. B/C RATIO:	1.36
RISK OF LOSING MONEY:	28%

SITE: SOUTH BRANCH ZUMBRO RIVER
SITE NO.: MN00515

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.13	FT
DESIGN DISCHARGE:	51.45	FT^3/S
DESIGN CAPACITY:	44.89	KW
TOTAL DESIGN EXCEED.:	40.00	%
EQUIPMENT COST ($1000):	92.26	
TOTAL COST ($1000):	224.80	
NET BENEFIT ($1000):	68.96	
32 YR. B/C RATIO:	1.30	
RISK OF LOSING MONEY:	33.42857%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	12.4
DESIGN DISCHARGE:	33.9
DESIGN CAPACITY:	30.4
TOTAL DESIGN EXCEEDENCE:	65.0
EQUIPMENT COST ($1000):	66.2
TOTAL COST ($1000):	160.2
NET BENEFIT ($1000):	58.5
32 YR. B/C RATIO:	1.3
RISK OF LOSING MONEY:	30.2857

SITE: MINNESOTA TWO (GRANITE FALLS)
SITE NO.: MN00510

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	580.0 KW
	DESIGN DISCHARGE	=	435.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	17.19	FT
DESIGN DISCHARGE:	869.84	FT^3/S
DESIGN CAPACITY:	1075.52	KW
TOTAL DESIGN EXCEEDENCE:	20.00	%
EQUIPMENT COST ($1000):	1221.54	
TOTAL COST ($1000):	2417.43	
NET BENEFIT ($1000):	530.04	
32 YR. B/C RATIO:	1.20	
RISK OF LOSING MONEY:	36%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	18.20
DESIGN DISCHARGE:	222.44
DESIGN CAPACITY:	291.06
TOTAL DESIGN EXCEEDENCE:	30.00
EQUIPMENT COST ($1000):	404.83
TOTAL COST ($1000):	786.44
NET BENEFIT ($1000):	226.29
32 YR. B/C RATIO:	1.27
RISK OF LOSING MONEY:	33.71429%

SITE: RED LAKE ONE(THIEF RIVER)
SITE NO.: MN00502

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	0.5	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	550.0	KW
	DESIGN DISCHARGE =	570.0	FT^3/S
	OVERALL EFFICIENCY =	0.75	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	14.21	FT
DESIGN DISCHARGE:	713.79	FT^3/S
DESIGN CAPACITY:	729.34	KW
TOTAL DESIGN EXCEED.:	20.00	%
EQUIPMENT COST ($1000):	918.39	
TOTAL COST ($1000):	1806.63	
NET BENEFIT ($1000):	473.37	
32 YR. B/C RATIO:	1.24	
RISK OF LOSING MONEY:	34.28572%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	14.7
DESIGN DISCHARGE:	377.0
DESIGN CAPACITY:	399.6
TOTAL DESIGN EXCEEDENCE:	30.0
EQUIPMENT COST ($1000):	551.1
TOTAL COST ($1000):	1075.0
NET BENEFIT ($1000):	351.5
32 YR. B/C RATIO:	1.3
RISK OF LOSING MONEY:	29.7142

SITE: SAUK RIVER 1
SITE NO.: MN00508

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	8.00	FT
DESIGN DISCHARGE:	128.82	FT^3/S
DESIGN CAPACITY:	74.11	KW
TOTAL DESIGN EXCEED.:	40.00	%
EQUIPMENT COST ($1000):	152.92	
TOTAL COST ($1000):	377.16	
NET BENEFIT ($1000):	82.56	
32 YR. B/C RATIO:	1.21	
RISK OF LOSING MONEY:	38.857143%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	8.0
DESIGN DISCHARGE:	59.4
DESIGN CAPACITY:	34.2
TOTAL DESIGN EXCEEDENCE:	65.0
EQUIPMENT COST ($1000):	80.1
TOTAL COST ($1000):	194.2
NET BENEFIT ($1000):	62.3
32 YR. B/C RATIO:	1.3
RISK OF LOSING MONEY:	32.2857

SITE: MAYOWOOD LAKE
SITE NO.: MN00364

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	13.90	FT
DESIGN DISCHARGE:	25.11	FT^3/S
DESIGN CAPACITY:	25.10	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	55.17	
TOTAL COST ($1000):	132.82	
NET BENEFIT ($1000):	32.93	
32 YR. B/C RATIO:	1.24	
RISK OF LOSING MONEY:	36.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	14.20
DESIGN DISCHARGE:	16.14
DESIGN CAPACITY:	16.48
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	38.64
TOTAL COST ($1000):	92.33
NET BENEFIT ($1000):	28.31
32 YR. B/C RATIO:	1.30
RISK OF LOSING MONEY:	34.85714%

SITE: BRONSON LAKE
SITE NO.: MN00 17

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	29.00	FT
DESIGN DISCHARGE:	9.00	FT^3/S
DESIGN CAPACITY:	18.77	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	37.16	
TOTAL COST ($1000):	88.94	
NET BENEFIT ($1000):	27.26	
32 YR. B/C RATIO:	1.30	
RISK OF LOSING MONEY:	35.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	29.00
DESIGN DISCHARGE:	5.00
DESIGN CAPACITY:	10.43
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	22.73
TOTAL COST ($1000):	53.89
NET BENEFIT ($1000):	19.94
32 YR. B/C RATIO:	1.36
RISK OF LOSING MONEY:	30.28571%

SITE: RAPIDAN
SITE NO.: MN00512

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	6200.0 KW
	DESIGN DISCHARGE	=	1240.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	52.20	FT
DESIGN DISCHARGE:	685.00	FT^3/S
DESIGN CAPACITY:	2571.36	KW
TOTAL DESIGN EXCEEDENCE:	10.00	%
EQUIPMENT COST ($1000):	2011.57	
TOTAL COST ($1000):	4037.28	
NET BENEFIT ($1000):	564.33	
32 YR. B/C RATIO:	1.13	
RISK OF LOSING MONEY:	42.8%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	52.80
DESIGN DISCHARGE:	160.00
DESIGN CAPACITY:	607.51
TOTAL DESIGN EXCEEDENCE:	15.00
EQUIPMENT COST ($1000):	600.71
TOTAL COST ($1000):	1177.65
NET BENEFIT ($1000):	225.22
32 YR. B/C RATIO:	1.18
RISK OF LOSING MONEY:	40.8%

SITE: ELK RIVER
SITE NO.: MN00516

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92 CENTS/KWH
	FIXED O&M VALUE =	0.48 CENTS/KWH
	TOTAL ENERGY VALUE =	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	1.0
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	14.50	FT
DESIGN DISCHARGE:	157.78	FT^3/S
DESIGN CAPACITY:	164.46	KW
TOTAL DESIGN EXCEEDENCE:	50.00	%
EQUIPMENT COST ($1000):	263.30	
TOTAL COST ($1000):	661.71	
NET BENEFIT ($1000):	129.93	
32 YR. B/C RATIO:	1.19	
RISK OF LOSING MONEY:	40.85714%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	14.59
DESIGN DISCHARGE:	130.64
DESIGN CAPACITY:	137.11
TOTAL DESIGN EXCEEDENCE:	60.00
EQUIPMENT COST ($1000):	225.84
TOTAL COST ($1000):	564.87
NET BENEFIT ($1000):	123.72
32 YR. B/C RATIO:	1.21
RISK OF LOSING MONEY:	37.42857%

SITE: FISH LAKE
SITE NO.: MN00614

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	18.00	FT
DESIGN DISCHARGE:	19.00	FT^3/S
DESIGN CAPACITY:	24.59	KW
TOTAL DESIGN EXCEED.:	40.00	%
EQUIPMENT COST ($1000):	51.41	
TOTAL COST ($1000):	123.71	
NET BENEFIT ($1000):	27.55	
32 YR. B/C RATIO:	1.22	
RISK OF LOSING MONEY:	34.28572%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	18.0
DESIGN DISCHARGE:	8.0
DESIGN CAPACITY:	10.3
TOTAL DESIGN EXCEEDENCE:	65.0
EQUIPMENT COST ($1000):	24.9
TOTAL COST ($1000):	59.1
NET BENEFIT ($1000):	16.9
32 YR. B/C RATIO:	1.2
RISK OF LOSING MONEY:	33.1428

SITE: SAUK RIVER THREE
SITE NO.: MN00561

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52	CENTS/KWH
	FIXED O&M VALUE	=	0.88	CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%	
	ESCALATION RATE	=	5.55%	
	OM&R ESCALATION RATE	=	5.55%	
	OTHER COSTS ($1000)	=	0.0	
	AMORTIZATION PERIOD	=	30.0	YEARS
	ECONOMIC LIFE	=	32.0	YEARS
	PLANT LIFE	=	60.0	YEARS
	EQUIPMENT COST FACT.	=	1.0	
	POWER HSE. COST FACT	=	1.0	
	OM&R COST FACTOR	=	1.0	
	INDIRECT COST FACTOR	=	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE	KW
	DESIGN DISCHARGE	=	NONE	FT^3/S
	OVERALL EFFICIENCY	=	NONE	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.90	FT
DESIGN DISCHARGE:	19.54	FT^3/S
DESIGN CAPACITY:	18.13	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	42.69	
TOTAL COST ($1000):	102.18	
NET BENEFIT ($1000):	19.69	
32 YR. B/C RATIO:	1.19	
RISK OF LOSING MONEY:	39.42857%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	12.90
DESIGN DISCHARGE:	11.55
DESIGN CAPACITY:	10.71
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	27.50
TOTAL COST ($1000):	65.23
NET BENEFIT ($1000):	16.71
32 YR. B/C RATIO:	1.25
RISK OF LOSING MONEY:	33.42857%

SITE: BRAWNER LAKE
SITE NO.: MN00120

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	24.31	FT
DESIGN DISCHARGE:	7.81	FT^3/S
DESIGN CAPACITY:	13.66	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	29.55	
TOTAL COST ($1000):	70.36	
NET BENEFIT ($1000):	13.38	
32 YR. B/C RATIO:	1.18	
RISK OF LOSING MONEY:	39.71429%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	24.50
DESIGN DISCHARGE:	3.91
DESIGN CAPACITY:	6.88
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	16.64
TOTAL COST ($1000):	39.21
NET BENEFIT ($1000):	10.57
32 YR. B/C RATIO:	1.26
RISK OF LOSING MONEY:	34%

SITE: PINE RIVER
SITE NO.: MN00582

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	1.92	CENTS/KWH
	FIXED O&M VALUE =	0.48	CENTS/KWH
	TOTAL ENERGY VALUE =	4.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.00	FT
DESIGN DISCHARGE:	190.00	FT^3/S
DESIGN CAPACITY:	163.96	KW
TOTAL DESIGN EXCEEDENCE:	50.00	%
EQUIPMENT COST ($1000):	273.10	
TOTAL COST ($1000):	686.59	
NET BENEFIT ($1000):	103.16	
32 YR. B/C RATIO:	1.14	
RISK OF LOSING MONEY:	42.28571%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	12.30
DESIGN DISCHARGE:	110.00
DESIGN CAPACITY:	97.30
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	175.65
TOTAL COST ($1000):	435.70
NET BENEFIT ($1000):	71.89
32 YR. B/C RATIO:	1.16
RISK OF LOSING MONEY:	41.14286%

SITE: SYLVAN
SITE NO.: MN00601

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	1900.0 KW
	DESIGN DISCHARGE	=	1360.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	22.00	FT
DESIGN DISCHARGE:	200.33	FT^3/S
DESIGN CAPACITY:	316.94	KW
TOTAL DESIGN EXCEED.:	15.00	%
EQUIPMENT COST ($1000):	417.96	
TOTAL COST ($1000):	812.76	
NET BENEFIT ($1000):	90.77	
32 YR. B/C RATIO:	1.10	
RISK OF LOSING MONEY:	44.28571%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	22.0
DESIGN DISCHARGE:	200.3
DESIGN CAPACITY:	316.9
TOTAL DESIGN EXCEEDENCE:	15.0
EQUIPMENT COST ($1000):	417.9
TOTAL COST ($1000):	812.7
NET BENEFIT ($1000):	90.7
32 YR. B/C RATIO:	1.1
RISK OF LOSING MONEY:	44.2857

SITE: BRAINERD
SITE NO.: MN00597

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	3700.0 KW
	DESIGN DISCHARGE	=	3080.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	17.44	FT
DESIGN DISCHARGE:	1683.02	FT^3/S
DESIGN CAPACITY:	2110.59	KW
TOTAL DESIGN EXCEEDENCE:	20.00	%
EQUIPMENT COST ($1000):	2139.96	
TOTAL COST ($1000):	4285.70	
NET BENEFIT ($1000):	744.65	
32 YR. B/C RATIO:	1.16	
RISK OF LOSING MONEY:	41.14286%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	17.92
DESIGN DISCHARGE:	1120.86
DESIGN CAPACITY:	1444.20
TOTAL DESIGN EXCEEDENCE:	25.00
EQUIPMENT COST ($1000):	1549.59
TOTAL COST ($1000):	3081.91
NET BENEFIT ($1000):	593.09
32 YR. B/C RATIO:	1.18
RISK OF LOSING MONEY:	38.28571%

SITE: PELICAN RIVER DAM
SITE NO.: MN00191

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH	
	AVOIDED CAPAC. VALUE =	3.52 CENTS/KWH	
	FIXED O&M VALUE =	0.88 CENTS/KWH	
	TOTAL ENERGY VALUE =	6.00 CENTS/KWH	
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.63	FT
DESIGN DISCHARGE:	82.54	FT^3/S
DESIGN CAPACITY:	74.96	KW
TOTAL DESIGN EXCEEDENC	35.00	%
EQUIPMENT COST ($1000)	140.47	
TOTAL COST ($1000):	346.25	
NET BENEFIT ($1000):	91.66	
32 YR. B/C RATIO:	1.25	
RISK OF LOSING MONEY:	36.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	13.41
DESIGN DISCHARGE:	33.41
DESIGN CAPACITY:	32.22
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	68.48
TOTAL COST ($1000):	165.71
NET BENEFIT ($1000):	62.41
32 YR. B/C RATIO:	1.36
RISK OF LOSING MONEY:	30.85714%

SITE: JACKSON DAM
SITE NO.: MN00117

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	0.5	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	9.50	FT
DESIGN DISCHARGE:	140.18	FT^3/S
DESIGN CAPACITY:	95.76	KW
TOTAL DESIGN EXCEEDENCE:	35.00	%
EQUIPMENT COST ($1000):	182.84	
TOTAL COST ($1000):	351.19	
NET BENEFIT ($1000):	76.80	
32 YR. B/C RATIO:	1.21	
RISK OF LOSING MONEY:	36.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	9.90
DESIGN DISCHARGE:	30.04
DESIGN CAPACITY:	21.38
TOTAL DESIGN EXCEEDENCE:	60.00
EQUIPMENT COST ($1000):	51.77
TOTAL COST ($1000):	98.58
NET BENEFIT ($1000):	36.07
32 YR. B/C RATIO:	1.35
RISK OF LOSING MONEY:	30.57143%

SITE: FON DU LAC
SITE NO.: MN00603

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	11800.0 KW
	DESIGN DISCHARGE	=	3560.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	51.27	FT
DESIGN DISCHARGE:	1198.00	FT^3/S
DESIGN CAPACITY:	4416.60	KW
TOTAL DESIGN EXCEEDENC	10.00	%
EQUIPMENT COST ($1000)	3173.63	
TOTAL COST ($1000):	8832.85	
NET BENEFIT ($1000):	512.56	
32 YR. B/C RATIO:	1.05	
RISK OF LOSING MONEY:	46.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	51.87
DESIGN DISCHARGE:	236.28
DESIGN CAPACITY:	881.36
TOTAL DESIGN EXCEEDENCE:	15.00
EQUIPMENT COST ($1000):	822.92
TOTAL COST ($1000):	2164.21
NET BENEFIT ($1000):	159.22
32 YR. B/C RATIO:	1.07
RISK OF LOSING MONEY:	47.14286

SITE: CROW WING
SITE NO.: MN00608

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	1500.0 KW
	DESIGN DISCHARGE	=	1100.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	21.10	FT
DESIGN DISCHARGE:	525.00	FT^3/S
DESIGN CAPACITY:	796.61	KW
TOTAL DESIGN EXCEEDENC	15.00	%
EQUIPMENT COST ($1000)	910.98	
TOTAL COST ($1000):	1793.93	
NET BENEFIT ($1000):	270.16	
32 YR. B/C RATIO:	1.14	
RISK OF LOSING MONEY:	41.42857%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	21.30
DESIGN DISCHARGE:	250.00
DESIGN CAPACITY:	382.93
TOTAL DESIGN EXCEEDENCE:	20.00
EQUIPMENT COST ($1000):	492.85
TOTAL COST ($1000):	960.63
NET BENEFIT ($1000):	166.92
32 YR. B/C RATIO:	1.16
RISK OF LOSING MONEY:	36.85714%

SITE: NEW LONDON
SITE NO.: MNOO 62

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	17.26	FT
DESIGN DISCHARGE:	23.35	FT^3/S
DESIGN CAPACITY:	28.97	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	59.47	
TOTAL COST ($1000):	143.56	
NET BENEFIT ($1000):	11.48	
32 YR. B/C RATIO:	1.08	
RISK OF LOSING MONEY:	44%	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	17.82
DESIGN DISCHARGE:	6.54
DESIGN CAPACITY:	8.38
TOTAL DESIGN EXCEEDENCE:	60.00
EQUIPMENT COST ($1000):	20.94
TOTAL COST ($1000):	49.49
NET BENEFIT ($1000):	6.18
32 YR. B/C RATIO:	1.12
RISK OF LOSING MONEY:	41.42857%

SITE: LAC QUI PARLE
SITE NO.: MN00580

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	10.20	FT
DESIGN DISCHARGE:	130.00	FT^3/S
DESIGN CAPACITY:	95.36	KW
TOTAL DESIGN EXCEEDENCE:	55.00	%
EQUIPMENT COST ($1000):	179.54	
TOTAL COST ($1000):	445.29	
NET BENEFIT ($1000):	35.26	
32 YR. B/C RATIO:	1.08	
RISK OF LOSING MONEY:	45.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	10.80
DESIGN DISCHARGE:	60.00
DESIGN CAPACITY:	46.60
TOTAL DESIGN EXCEEDENCE:	70.00
EQUIPMENT COST ($1000):	97.51
TOTAL COST ($1000):	237.84
NET BENEFIT ($1000):	22.41
32 YR. B/C RATIO:	1.09
RISK OF LOSING MONEY:	46%

SITE: LEECH LAKE DAM
SITE NO.: MN00585

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	6.50	FT
DESIGN DISCHARGE:	783.00	FT^3/S
DESIGN CAPACITY:	366.00	KW
TOTAL DESIGN EXCEED.:	20.00	%
EQUIPMENT COST ($1000):	606.72	
TOTAL COST ($1000):	1563.16	
NET BENEFIT ($1000):	510.40	
32 YR. B/C RATIO:	1.31	
RISK OF LOSING MONEY:	33.428571%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	6.8
DESIGN DISCHARGE:	710.0
DESIGN CAPACITY:	347.1
TOTAL DESIGN EXCEEDENCE:	30.0
EQUIPMENT COST ($1000):	575.1
TOTAL COST ($1000):	1479.2
NET BENEFIT ($1000):	497.2
32 YR. B/C RATIO:	1.3
RISK OF LOSING MONEY:	31.7142

SITE: SAND CREEK
SITE NO.: MN00535

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	13.20	FT
DESIGN DISCHARGE:	9.00	FT^3/S
DESIGN CAPACITY:	8.54	KW
TOTAL DESIGN EXCEED.:	50.00	%
EQUIPMENT COST ($1000):	22.65	
TOTAL COST ($1000):	53.54	
NET BENEFIT ($1000):	3.35	
32 YR. B/C RATIO:	1.06	
RISK OF LOSING MONEY:	46.85714%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	13.2
DESIGN DISCHARGE:	4.0
DESIGN CAPACITY:	3.8
TOTAL DESIGN EXCEEDENCE:	60.0
EQUIPMENT COST ($1000):	11.5
TOTAL COST ($1000):	26.8
NET BENEFIT ($1000):	2.8
32 YR. B/C RATIO:	1.1
RISK OF LOSING MONEY:	43.7142

SITE: GRAND FORKS EAST
SITE NO.: MN00550

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	1.0
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	NONE KW
	DESIGN DISCHARGE	=	NONE FT^3/S
	OVERALL EFFICIENCY	=	NONE

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA			FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA	
DESIGN HEAD:	9.40	FT	DESIGN HEAD:	10.80
DESIGN DISCHARGE:	955.00	FT^3/S	DESIGN DISCHARGE:	500.00
DESIGN CAPACITY:	645.55	KW	DESIGN CAPACITY:	388.32
TOTAL DESIGN EXCEEDENCE:	55.00	%	TOTAL DESIGN EXCEEDENCE:	75.00
EQUIPMENT COST ($1000):	903.37		EQUIPMENT COST ($1000):	573.91
TOTAL COST ($1000):	2366.06		TOTAL COST ($1000):	1478.95
NET BENEFIT ($1000):	417.66		NET BENEFIT ($1000):	301.87
32 YR. B/C RATIO:	1.17		32 YR. B/C RATIO:	1.20
RISK OF LOSING MONEY:	42%		RISK OF LOSING MONEY:	42.85714%

SITE: HIGHWAY 75 DAM
SITE NO. MN00581

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH	
	AVOIDED CAPAC. VALUE =	3.52 CENTS/KWH	
	FIXED O&M VALUE =	0.88 CENTS/KWH	
	TOTAL ENERGY VALUE =	6.00 CENTS/KWH	
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	12.70	FT
DESIGN DISCHARGE:	37.70	FT^3/S
DESIGN CAPACITY:	34.43	KW
TOTAL DESIGN EXCEEDENCE:	45.00	%
EQUIPMENT COST ($1000):	73.21	
TOTAL COST ($1000):	177.39	
NET BENEFIT ($1000):	20.92	
32 YR. B/C RATIO:	1.11	
RISK OF LOSING MONEY:	43.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	12.70
DESIGN DISCHARGE:	9.17
DESIGN CAPACITY:	8.37
TOTAL DESIGN EXCEEDENCE:	65.00
EQUIPMENT COST ($1000):	22.45
TOTAL COST ($1000):	53.06
NET BENEFIT ($1000):	9.17
32 YR. B/C RATIO:	1.17
RISK OF LOSING MONEY:	40.85714%

SITE: SAINT CLOUD
SITE NO.: MN00506

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	8400.0 KW
	DESIGN DISCHARGE	=	7400.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	15.06	FT
DESIGN DISCHARGE:	2370.14	FT^3/S
DESIGN CAPACITY:	2567.15	KW
TOTAL DESIGN EXCEEDENCE:	10.00	%
EQUIPMENT COST ($1000):	2598.23	
TOTAL COST ($1000):	5224.33	
NET BENEFIT ($1000):	296.42	
32 YR. B/C RATIO:	1.05	
RISK OF LOSING MONEY:	46.4%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	15.06
DESIGN DISCHARGE:	2370.14
DESIGN CAPACITY:	2567.15
TOTAL DESIGN EXCEEDENCE:	10.00
EQUIPMENT COST ($1000):	2598.23
TOTAL COST ($1000):	5224.33
NET BENEFIT ($1000):	296.42
32 YR. B/C RATIO:	1.05
RISK OF LOSING MONEY:	46.4%

SITE: LOCK & DAM #2
SITE NO.: MN00594

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	1.92 CENTS/KWH
	FIXED O&M VALUE	=	0.48 CENTS/KWH
	TOTAL ENERGY VALUE	=	4.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	4000.0 KW
	DESIGN DISCHARGE	=	5400.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	9.50	FT
DESIGN DISCHARGE:	6414.77	FT^3/S
DESIGN CAPACITY:	4382.34	KW
TOTAL DESIGN EXCEEDENCE:	25.00	%
EQUIPMENT COST ($1000):	4469.66	
TOTAL COST ($1000):	9095.24	
NET BENEFIT ($1000):	1790.54	
32 YR. B/C RATIO:	1.18	
RISK OF LOSING MONEY:	37.6%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	10.80
DESIGN DISCHARGE:	2209.51
DESIGN CAPACITY:	1715.89
TOTAL DESIGN EXCEEDENCE:	40.00
EQUIPMENT COST ($1000):	1987.55
TOTAL COST ($1000):	3967.77
NET BENEFIT ($1000):	959.86
32 YR. B/C RATIO:	1.22
RISK OF LOSING MONEY:	35.6%

SITE: LANESBORO
SITE NO.: MN00517

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	250.0 KW
	DESIGN DISCHARGE	=	145.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	25.70	FT
DESIGN DISCHARGE:	100.00	FT^3/S
DESIGN CAPACITY:	184.81	KW
TOTAL DESIGN EXCEEDENCE:	15.00	%
EQUIPMENT COST ($1000):	257.83	
TOTAL COST ($1000):	498.41	
NET BENEFIT ($1000):	22.23	
32 YR. B/C RATIO:	1.04	
RISK OF LOSING MONEY:	46.4%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	26.00
DESIGN DISCHARGE:	57.00
DESIGN CAPACITY:	106.57
TOTAL DESIGN EXCEEDENCE:	20.00
EQUIPMENT COST ($1000):	162.34
TOTAL COST ($1000):	312.26
NET BENEFIT ($1000):	21.77
32 YR. B/C RATIO:	1.07
RISK OF LOSING MONEY:	46.8%

SITE: ZUMBRO LAKE
SITE NO.: MN00358

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	2200.0 KW
	DESIGN DISCHARGE	=	580.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	59.82	FT
DESIGN DISCHARGE:	46.91	FT^3/S
DESIGN CAPACITY:	201.80	KW
TOTAL DESIGN EXCEEDENCE:	10.00	%
EQUIPMENT COST ($1000):	232.98	
TOTAL COST ($1000):	450.87	
NET BENEFIT ($1000):	-33.99	
32 YR. B/C RATIO:	0.93	
RISK OF LOSING MONEY:	53.14286%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	59.82
DESIGN DISCHARGE:	46.91
DESIGN CAPACITY:	201.80
TOTAL DESIGN EXCEEDENCE:	10.00
EQUIPMENT COST ($1000):	232.98
TOTAL COST ($1000):	450.87
NET BENEFIT ($1000):	-33.99
32 YR. B/C RATIO:	0.93
RISK OF LOSING MONEY:	53.14286%

SITE: WILLOW RIVER
SITE NO.: MN00544

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60	CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52	CENTS/KWH
	FIXED O&M VALUE =	0.88	CENTS/KWH
	TOTAL ENERGY VALUE =	6.00	CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA			FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA	
DESIGN HEAD:	20.40	FT	DESIGN HEAD:	20.5
DESIGN DISCHARGE:	45.00	FT^3/S	DESIGN DISCHARGE:	29.0
DESIGN CAPACITY:	66.02	KW	DESIGN CAPACITY:	42.7
TOTAL DESIGN EXCEED.:	45.00	%	TOTAL DESIGN EXCEEDENCE:	55.0
EQUIPMENT COST ($1000):	114.37		EQUIPMENT COST ($1000):	79.4
TOTAL COST ($1000):	280.86		TOTAL COST ($1000):	193.2
NET BENEFIT ($1000):	24.37		NET BENEFIT ($1000):	21.2
32 YR. B/C RATIO:	1.08		32 YR. B/C RATIO:	1.1
RISK OF LOSING MONEY:	44.57143%		RISK OF LOSING MONEY:	42.2857

SITE: BYLLESBY
SITE NO.: MN00514

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	2500.0 KW
	DESIGN DISCHARGE	=	800.0 FT^3/S
	OVERALL EFFICIENCY	=	0.75

FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM NET BENEFIT CRITERIA			FEASBILITY PARAMETERS FOR THE PROPOSED POWERPLANT USING MAXIMUM B/C RATIO CRITERIA	
DESIGN HEAD:	56.65	FT	DESIGN HEAD:	56.65
DESIGN DISCHARGE:	61.57	FT^3/S	DESIGN DISCHARGE:	61.57
DESIGN CAPACITY:	250.80	KW	DESIGN CAPACITY:	250.80
TOTAL DESIGN EXCEEDENCE:	10.00	%	TOTAL DESIGN EXCEEDENCE:	10.00
EQUIPMENT COST ($1000):	282.57		EQUIPMENT COST ($1000):	282.57
TOTAL COST ($1000):	548.04		TOTAL COST ($1000):	548.04
NET BENEFIT ($1000):	-109.45		NET BENEFIT ($1000):	-109.45
32 YR. B/C RATIO:	0.82		32 YR. B/C RATIO:	0.82
RISK OF LOSING MONEY:	66%		RISK OF LOSING MONEY:	66%

SITE: MINNESOTA TWO (GRANITE FALLS)
SITE NO.: MN00510

ENERGY VALUE DATA:	INITIAL ENERGY VALUE	=	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE	=	3.52 CENTS/KWH
	FIXED O&M VALUE	=	0.88 CENTS/KWH
	TOTAL ENERGY VALUE	=	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE	=	7.37%
	ESCALATION RATE	=	5.55%
	OM&R ESCALATION RATE	=	5.55%
	OTHER COSTS ($1000)	=	0.0
	AMORTIZATION PERIOD	=	30.0 YEARS
	ECONOMIC LIFE	=	32.0 YEARS
	PLANT LIFE	=	60.0 YEARS
	EQUIPMENT COST FACT.	=	1.0
	POWER HSE. COST FACT	=	0.5
	OM&R COST FACTOR	=	1.0
	INDIRECT COST FACTOR	=	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY	=	1290.0 KW
	DESIGN DISCHARGE	=	1020.0 FT^3/S
	OVERALL EFFICIENCY	=	0.80

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	17.19	FT
DESIGN DISCHARGE:	284.84	FT^3/S
DESIGN CAPACITY:	352.19	KW
TOTAL DESIGN EXCEEDENCE:	20.00	%
EQUIPMENT COST ($1000):	480.38	
TOTAL COST ($1000):	935.39	
NET BENEFIT ($1000):	-76.46	
32 YR. B/C RATIO:	0.92	
RISK OF LOSING MONEY:	55.6%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	17.19
DESIGN DISCHARGE:	284.84
DESIGN CAPACITY:	352.19
TOTAL DESIGN EXCEEDENCE:	20.00
EQUIPMENT COST ($1000):	480.38
TOTAL COST ($1000):	935.39
NET BENEFIT ($1000):	-76.46
32 YR. B/C RATIO:	0.92
RISK OF LOSING MONEY:	55.6%

SITE: SANDY LOCK & DAM
SITE NO.: MN00583

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH
	AVOIDED CAPAC. VALUE =	3.52 CENTS/KWH
	FIXED O&M VALUE =	0.88 CENTS/KWH
	TOTAL ENERGY VALUE =	6.00 CENTS/KWH
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%
	ESCALATION RATE =	5.55%
	OM&R ESCALATION RATE =	5.55%
	OTHER COSTS ($1000) =	0.0
	AMORTIZATION PERIOD =	30.0 YEARS
	ECONOMIC LIFE =	32.0 YEARS
	PLANT LIFE =	60.0 YEARS
	EQUIPMENT COST FACT. =	1.0
	POWER HSE. COST FACT =	1.0
	OM&R COST FACTOR =	1.0
	INDIRECT COST FACTOR =	1.0
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE KW
	DESIGN DISCHARGE =	NONE FT^3/S
	OVERALL EFFICIENCY =	NONE

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	11.20	FT
DESIGN DISCHARGE:	5.00	FT^3/S
DESIGN CAPACITY:	4.03	KW
TOTAL DESIGN EXCEED.:	95.00	%
EQUIPMENT COST ($1000):	12.50	
TOTAL COST ($1000):	29.24	
NET BENEFIT ($1000):	-10.71	
32 YR. B/C RATIO:	0.64	
RISK OF LOSING MONEY:	77.14286%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	7.4
DESIGN DISCHARGE:	137.0
DESIGN CAPACITY:	72.9
TOTAL DESIGN EXCEEDENCE:	45.0
EQUIPMENT COST ($1000):	153.3
TOTAL COST ($1000):	377.9
NET BENEFIT ($1000):	-53.6
32 YR. B/C RATIO:	0.8
RISK OF LOSING MONEY:	58.2857

SITE: MUSTINKA RIVER
SITE NO.: MN00 26

ENERGY VALUE DATA:	INITIAL ENERGY VALUE =	1.60 CENTS/KWH	
	AVOIDED CAPAC. VALUE =	3.52 CENTS/KWH	
	FIXED O&M VALUE =	0.88 CENTS/KWH	
	TOTAL ENERGY VALUE =	6.00 CENTS/KWH	
ECONOMIC ASSUMPTIONS:	DISCOUNT RATE =	7.37%	
	ESCALATION RATE =	5.55%	
	OM&R ESCALATION RATE =	5.55%	
	OTHER COSTS ($1000) =	0.0	
	AMORTIZATION PERIOD =	30.0	YEARS
	ECONOMIC LIFE =	32.0	YEARS
	PLANT LIFE =	60.0	YEARS
	EQUIPMENT COST FACT. =	1.0	
	POWER HSE. COST FACT =	1.0	
	OM&R COST FACTOR =	1.0	
	INDIRECT COST FACTOR =	1.0	
EXISTING PLANT DATA:	EXISTING CAPACITY =	NONE	KW
	DESIGN DISCHARGE =	NONE	FT^3/S
	OVERALL EFFICIENCY =	NONE	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM NET BENEFIT CRITERIA

DESIGN HEAD:	13.10	FT
DESIGN DISCHARGE:	0.85	FT^3/S
DESIGN CAPACITY:	0.80	KW
TOTAL DESIGN EXCEEDENCE:	40.00	%
EQUIPMENT COST ($1000):	3.15	
TOTAL COST ($1000):	7.26	
NET BENEFIT ($1000):	-2.63	
32 YR. B/C RATIO:	0.65	
RISK OF LOSING MONEY:	69.71429%	

FEASBILITY PARAMETERS FOR
THE PROPOSED POWERPLANT
USING MAXIMUM B/C RATIO CRITERIA

DESIGN HEAD:	13.10
DESIGN DISCHARGE:	0.86
DESIGN CAPACITY:	0.81
TOTAL DESIGN EXCEEDENCE:	35.00
EQUIPMENT COST ($1000):	3.15
TOTAL COST ($1000):	7.27
NET BENEFIT ($1000):	-2.63
32 YR. B/C RATIO:	0.65
RISK OF LOSING MONEY:	72.85714%

Appendix A–4 – User's Manual for HYFEAS2

USER'S GUIDE FOR HYFEAS2

(386 Version)

by

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INTRODUCTION

HYFEAS2 is a computer program which analyses the economic feasibility of hydropower developments. The program returns estimates for the economic feasibility indicators of net discounted benefits and benefit–cost ratio. It is an updated version of the original hydropower survey program HYFEAS (Dotan and Gulliver, 1983), and is written to run on the LOTUS 1–2–3 software package (Lotus Corporation, 1986). The chief additional feature of HYFEAS2 is the utilization of @RISK add–in software (Palisade Corporation, 1989) to perform a random number uncertainty analysis on the results. Thus, in addition to the best estimates for the feasibility indicators, the user is provided with a complete range of possible outcomes and their associated probabilities. The user may know, for instance, what the probability is of losing money on the development, or of receiving a certain level of benefits. HYFEAS2 also uses improved cost correlations developed from historical data which has become available since the development of the previous program. An optional technique for improving site flow estimates of Mid–western locations is available as well.

The program may be used to estimate feasibility at an undeveloped site, where only the dam exists, or for capacity expansions at existing facilities. The program is "user–friendly" and menu–driven, such that the user need not be familiar with LOTUS in order to run the program. Initial installation of the program is somewhat more involved, but the installer should have little problem when directions in this manual are followed.

REQUIRED INPUT DATA

Figure 1 presents the required input field for HYFEAS2. The user enters the data using the ⟨arrow⟩ and ⟨enter⟩ keys of the keyboard. The parameters were described in detail by the authors in a report written for the Legislative Commission on Minnesota Resources (LCMR), in which HYFEAS2 was used to analyze economic feasibility for sites in Minnesota (Murdock and Gulliver, 1991). A short description of each input parameter follows.

Existing Power Plant Parameters

1. Existing Capacity – The installed capacity of the existing facility.
2. Design Discharge – The total design discharge of existing turbines.
3. Overall Efficiency – The overall existing plant efficiency.

Proposed Power Plant Parameters

1. Escalation Factor for Plant Costs – This factor may be used to escalate HYFEAS2 cost estimates to a year other than 1991.
2. Initial Energy Value – The rate to be paid by the utility for purchased energy. This value is escalated to account for inflation.
3. Avoided Capacity Value – This is the rate payed to the supplier reflecting the utility's avoided costs in building a new facility to meet demand. The value is not escalated.
4. Fixed O&M Payment – The rate payed to reflect the utility's avoidance of operation and maintenance costs. This value is escalated.
5. Spillway Crest Elevation – The height of the spillway or the level of water in the reservoir if kept constant.

6. Minimum Stream Flow – The minimum stream flow passed over the spillway at all times to meet downstream dissolved oxygen requirements.

7. Overall Efficiency – The overall efficiency of the proposed plant.

8. Powerhouse Cost Adjustment Factor – A factor for adjusting structures and waterway costs calculated by HYFEAS2. For sites where new turbines are installed in existing powerhouses, it is recommended that this factor be set to 0.5.

9. OM&R Cost Factor – A factor used for adjusting operation, maintenance, and replacement cost estimates.

10. Equipment Cost Factor – A factor for adjusting estimates of equipment costs.

11. Indirect Cost Factor – Used for adjusting indirect cost estimates (engineering costs, etc.).

12. Ratio of Drainage Areas – Often times, flow duration curves for sites are estimated using data from a gage located within the same watershed as that of the site, extrapolating according to the equation (Gulliver and Arndt, 1991):

$$Qs_i = \left[\frac{As}{Ag}\right]^n Qg_i \tag{9}$$

where
Qs_i = the flow rate at the site at percentage exceedance i
Qg_i = the flow rate at the gage at percentage exceedance i
As = the drainage area of the site
Ag = the drainage area of the gage
n = hydrologic exponent whose value depends on watershed characteristics and application.

The value of n is typically set to one within the hydropower industry. An analysis by the authors on this exponent indicated a more accurate value to be n=1.126, for sites located in Minnesota and the surrounding 5–state area. HYFEAS2 will adjust user–entered flow duration curves according to the improved value if the user so requests in parameter number 13. The ratio of drainage areas (Qs/Qg, parameter #12) is used in this case. Uncertainty in annual energy generation is also estimated from the ratio, such that a value should be entered regardless. If the flow duration curve was derived using another method, a value of one should be entered for parameter #12.

OPTIONAL PARAMETERS – ECONOMIC DATA AND UNCERTAINTIES

Figure 2 presents the input field for economic data and uncertainties. Default values for all parameters, along with their uncertainties, have been derived by the authors and are given in the default field. Therefore, it is not required that values be entered by the user. A value of 0 in the user–override field indicates that the default value will be used. The standard deviation column defines uncertainties in the input parameters, as explained by Murdock & Gulliver in the previously stated LCMR report. The uncertainties are used in the random number analysis performed by @RISK. A description of each parameter follows.

1. <u>Annual Energy Production</u> – The median value is calculated by the program. The user may not change this value. Uncertainty in the value is described with a standard deviation for a log–normal probability density function. HYFEAS2 chooses a default standard deviation based on the user entered drainage area ratio value of figure 1.

2. <u>Discount Rate</u> – The rate at which all yearly costs and benefits are discounted back to present value. Typically the interest rate of the loan is used. Uncertainty is described with a standard deviation for a normal probability density function.

3. <u>Energy Escalation Rate</u> – The rate at which the energy values are escalated over time. A normal probability density function is used to describe uncertainty.

4. <u>Operation & Maintenance Rate</u> – The rate at which OM&R costs are escalated over time. A normal probability density function is used to describe uncertainty.

5. <u>Reservoirs, Dams, Waterway, and Powerhouse Costs</u> – The median value is estimated by the program. The user can adjust the value using the previously described cost adjustment factors of figure 1. A log–normal

probability density function is used to describe uncertainty.

6. Equipment Costs – Above description holds for this parameter.

7. Indirect Costs – Above description holds for this parameter.

8. Other Costs – This parameter may be used to enter extra costs associated with the project, such as those of land or finance. No uncertainty is assigned to this value.

9. OM&R Cost Uncertainty – OM&R costs are estimated by HYFEAS2. A log–normal probability density function is used to describe uncertainty.

10. Economic Life – The period of time from the taking of the loan until the plant is to be sold. The feasibility indicators are estimated for this period of time.

11. Plant Life – The expected life of the plant, after which the facility would have no resale value. HYFEAS2 estimates a sale (or salvage) value for the plant at the end of the economic life based on this value and that of parameters #10. The sale value is incorporated into the estimates for the feasibility indicators.

12. Loan Amortization Period – The time within which the initial loan taken for construction costs must be payed.

FLOW DURATION TABLE

Figure 3 presents the input field for the flow duration table. The user is required to enter river flow rates and head and tail water elevations at 21 percentage exceedance levels. Head losses not included in the overall plant efficiency may be included as a function of exceedance flow rates in the final column, where in this case the flow rate is assumed to refer to that which is passing through the facility.

PROGRAM FLOW

HYFEAS2 begins by prompting the user for all necessary data, which is entered in the input fields using the ⟨arrow⟩ keys on the keyboard. Upon initiation, the program first estimates the economic feasibility parameters of net discounted benefits and benefit–cost ratio, for 21 plant design capacities corresponding to the flow duration values. The two capacities which maximize the respective feasibility indicators are stored. The user may then choose to perform the random number uncertainty analysis on the maximum values or those of other sizings. Alternatively, the economic feasibility analysis may be performed again for different energy values or interest rates, until an acceptable outcome is achieved. A general flow chart of program operation is presented in figure 4.

INSTRUCTIONS FOR USE OF HYFEAS2

There are a few simple steps which must be followed to initiate LOTUS and call up HYFEAS2. They are simple enough so that the user should not require any prior knowledge of LOTUS 1–2–3.

1. Initialize LOTUS 1–2–3:

   From the DOS operating system, enter the LOTUS 1–2–3 directory. Type:

   RISK (initializes LOTUS 1–2–3)

   You will have to wait for a few seconds until the yellow borders and a "ready" prompt appear.

2. Removing the "Undo" feature:

   The installer should have removed this feature of LOTUS to free up memory for HYFEAS2. However, if the yellow "Undo" indicator appears at the bottom of the screen, remove it with the following key sequences:

   /WGDOUDQ

   /WGDUQ

3. Attaching LOTUS to DOS directory containing HYFEAS2 files:

   HYFEAS2 must be read into LOTUS. This requires that the directory path to the HYFEAS2 file be defined. Use the following key sequence:

/FD...(you must enter the DOS directory path to the directory containing HYFEAS2, ie. C:\SAMPLE\DIRECT)

4. Reading HYFEAS2 into LOTUS:

   Type the following key sequence:

   /FRHYFEAS2⟨enter⟩

   The menu of figure 5 should appear. If it does not, it is because the autoexec option of LOTUS has been altered. To reset it, type the following key sequences:

   /WGDAYQ

   /WGDUQ

   ⟨Alt⟩⟨M⟩

You have now read in HYFEAS2 and are ready to use the program. The ⟨arrow⟩ keys can be used to move the highlighter among the menu options. A description of the function for each appears underneath the option when it is highlighted. Options may be selected by hitting either the ⟨enter⟩ key when the option is highlighted or by hitting the key corresponding to the option's first letter.

MENU DESCRIPTION

The menu presented to the user is given in figure 5. It may be brought up at any time during the session with the key sequence ⟨Alt⟩⟨M⟩. Be sure to pay particular attention to option #1, which must be used to define the HYFEAS2 file–directory path name. A description of each option follows.

1. INPUT_PATH – The user must define the DOS path to the directory containing the HYFEAS2 files.

2. FLOW_DATA – This option is used to enter the flow duration table. Upon completion, the user may choose to save the flow duration table in a LOTUS work file in the directory containing the other HYFEAS2

files, such that the file may be read in for future runs. HYFEAS2 writes the name and ID number included here as a title to the output data

3. PLANT_DATA – This option brings up the input field of figure 1. Data is entered using the ⟨arrow⟩ keys.

4. DFLT_DATA – The economic and uncertainty field of figure 2 is brought up.

5. HYFEAS2 – This option is used to run HYFEAS2 after all necessary data has been entered. HYFEAS2 need only be run once for each site in order to estimate annual energy production and costs. The economic analysis is automatically performed after HYFEAS2 calculations. Afterwards, this option may then be used to perform either the economic or risk analysis (or both) for new parameter values. Various energy values, discount rates, etc., may be tested for acceptance without the need to estimate cost and energy data a second time.

6. VIEW_OUTPUT – The results may be viewed, printed, or saved into a DOS print file using this option.

7. QUIT – HYFEAS2, with the current results and input parameters, is saved into the directory containing the HYFEAS2 files, and the program exits LOTUS into DOS.

It is important to keep the original HYFEAS2 files backed up on floppy disk. If a problem is ever encountered in using the HYFEAS2 files loaded on the hard–disk directory, they should be erased and the original versions copied into the empty directory.

INSTALLATION INSTRUCTIONS

HYFEAS2 runs on LOTUS 1–2–3, version 2.2 or higher, and uses the LOTUS add–in software package @RISK, version 1.5 or higher. The program is best suited to an IBM compatible 386 computer, or faster models. Use of slower computers will result in excessive run times. The installer of @RISK and HYFEAS2 should follow these instructions.

1. Installation of the @RISK Add_in Software.

Installation of @RISK involves loading the contents of two floppy disks into the LOTUS directory of the hard disk, which is well explained in the accompanying @RISK documentation. Upon completion of the process, the installer will be notified of a "hot key", used to initiate @RISK within LOTUS. This key should be recorded.

2. Installation of the HYFEAS2 Files.

A DOS directory should be created on the hard disk for the files. All files should then be copied into this directory from the floppy. Within the newly created HYFEAS2 file directory, with the floppy installed in the floppy drive, type either:

Copy a:*.*   or   Copy b:*.*

depending on whether the floppy is installed in the "a" or "b" drive. Next, copy the files "riskmac.rgm" and "rgraph.cnf" into the LOTUS hard–disk directory. From within the LOTUS directory, type:

Copy a:riskmac.rgm   and   Copy a:rgraph.cnf

Substitute the letter "b" for "a" if the floppy disk is in drive "b".

3. Initializing HYFEAS2.

Within the LOTUS directory, the command "Risk" (rather than "123") must be typed whenever HYFEAS2 is to be used. Type:

RISK

and hit return. Next, follow steps two through four of the previous instructions for use of HYFEAS2, in order to read in the HYFEAS2 program into LOTUS. Answer the question regarding the previously mentioned @RISK "hot key". Pick the appropriate response depending on which key was indicated upon installation of the @RISK disks. This is a one–time question, the answer to which enables HYFEAS2 to initiate the @RISK package. It will not be asked during subsequent HYFEAS2 sessions.

HYFEAS2 has now been installed and is ready for use by anyone. The user need only follow the 4 previously given steps for use of HYFEAS2 in order to start the program.

GRAPH PRINTING OPTION FOR USERS WITH LOTUS ABILITY

HYFEAS2 creates graphs of frequency histograms and cumulative probability distribution functions for both feasibility indicators (benefit–cost ratio and net discounted benefits). They are written to the directory containing the HYFEAS2 files (defined with menu option number 1) during each @RISK analysis, under the following names.

bc.pic	Histogram of possible outcomes for benefit–cost ratio
bcc.pic	Cumulative probability distribution function for benefit–cost ratio
npv.pic	Histogram of possible outcomes for net discounted benefits
npvc.pic	Cumulative probability distribution function for net discounted benefits

These "pic" files can be printed out using the LOTUS Print_Graph Option. Users with prior LOTUS knowledge will have no difficulty. For those with no LOTUS familiarity, it will be necessary to read the LOTUS software documentation in order to print the files.

Samples of these graphs are presented in figure 6 for the feasibility indicator of net discounted benefits. The files give a graphic display of the uncertainty in feasibility indicator outcomes. However, an entire range of these possible outcomes, along with their associated probabilities, are included in tabular form as a standard output of HYFEAS2. They may be viewed or printed using option number 6 of the menu. Thus, it is not necessary to be able to print out the "pic" files in order to know the complete range of uncertainty associated with the indicators.

EXISTING POWERPLANT (IF NONE WRITE ZEROS)

1.	EXISTING CAPACITY(KW):	0
2.	DESIGN DISCHARGE(FT^3/S):	0
3.	OVERALL EFFICIENCY(FRACTION):	0

PROPOSED POWERPLANT (1=DEFAULT VALUE FOR ALL FACTORS

1.	ESCALATION FACTOR FOR PLANT COSTS:	1
2.	INITIAL ENERGY VALUE (CENT/KWH-1991)	1.6000
3.	AVOIDED CAPACITY VALUE (CENT/KWH)	0.0000
4.	FIXED O&M PAYMENT (CENT/KWH)	0.0000
5.	SPILLWAY CREST ELEVATION (FT):	100
6.	MINIMUM STREAM FLOW(FT^3/S):	100
7.	OVERALL EFFICIENCY(FRACTION):	0.85
8.	POWER HSE. COST ADJUSTMENT FACTOR	0.5
9.	OM&R COST ADJUSTMENT FACTOR (>0 REQ)	1
10.	EQUIPMENT COST FACTOR	1
11.	INDIRECT COST FACTOR	1
12.	RATIO OF DRAINAGE AREAS	1.03
13.	ADJUST CURVE TO "n" = 1.126	YES

Figure 1 - Required Input Field for HYFEAS2

USER INPUTS TO OVERIDE DEFAULT ECONOMIC PARAMETERS

	MEDIAN VALUE	STD. DEV.
1. ANNUAL ENERGY PRODUCTION	PROGRAM OUTPUT	0
2. DISCOUNT RATE	0.00%	0.00%
3. ENERGY ESCALATION RATE	0.00%	0.00%
4. OPERATION & MAINTENANCE RATE	0.00%	0.00%
5. RES,DAM,WTWY + POWER HSE COST	PROGRAM OUTPUT	0.000
6. EQUIPMENT COST	PROGRAM OUTPUT	0.000
7. INDIRECT COST	PROGRAM OUTPUT	0.000
8. OTHER COST ($)	0	NO UNCERT
9. OM&R COST UNCERTAINTY	PROGRAM OUTPUT	0.000
10. ECONOMIC LIFE (YRS) (LOAN TO SALE)	0	NO UNCERT
11. PLANT LIFE (YRS) (START TO SHUTDOWN)	0	NO UNCERT
12. LOAN AMORTIZATION PERIOD (YRS)	0	NO UNCERT

DEFAULT ECONOMIC PARAMETERS

	MEDIAN VALUE	STD. DEV.
1. ANNUAL ENERGY PRODUCTION	PROGRAM OUTPUT	0.152
2. DISCOUNT RATE	7.37%	1.44%
3. ENERGY ESCALATION RATE	5.55%	2.59%
4. OPERATION & MAINTENANCE RATE	5.55%	2.59%
5. RES,DAM,WTWY + POWER HSE COST	PROGRAM OUTPUT	0.511
6. EQUIPMENT COST	PROGRAM OUTPUT	0.658
7. INDIRECT COST	PROGRAM OUTPUT	0.589
8. OTHER COST ($)	0	NONE
9. OPERATION & MAINTENANCE COST	PROGRAM OUTPUT	0.191
10. ECONOMIC LIFE (YRS) (LOAN TO SALE)	32	NONE
11. PLANT LIFE (YRS) (START TO SHUTDOWN)	60	NONE
12. LOAN AMORTIZATION PERIOD (YRS)	30	NONE

Figure 2 - Default and Override Fields for Economic Parameters

PERCENT EXCEEDANCE	DISCHARGE FT3/S	HEADWATER ELEV. (FT)	TAILWATER ELEV. (FT)	SYSTEM HEAD LOSS (FT)
100	602.23	100.00	75.00	0
95	1355.03	100.00	75.00	0
90	1806.70	100.00	75.00	0
85	2208.19	100.00	75.00	0
80	2609.68	100.00	75.00	0
75	2986.07	100.00	74.97	0
70	3337.38	100.00	74.19	0
65	3688.68	100.00	73.79	0
60	4065.08	100.00	73.59	0
55	4466.56	100.00	73.40	0
50	4918.24	100.00	73.50	0
45	5395.01	100.00	73.60	0
40	5896.87	100.00	73.71	0
35	6448.92	100.00	74.01	0
30	7276.99	100.00	74.31	0
25	8581.83	100.00	74.71	0
20	10388.53	100.00	75.21	0
15	12546.53	100.00	76.01	0
10	15959.19	100.00	76.91	0
5	22282.64	100.00	78.42	0
0	38141.45	100.00	82.03	0

SITE:
ST. ANTHONY

SITE NUMBER:
MN00591

Figure 3 - Flow Duration Table

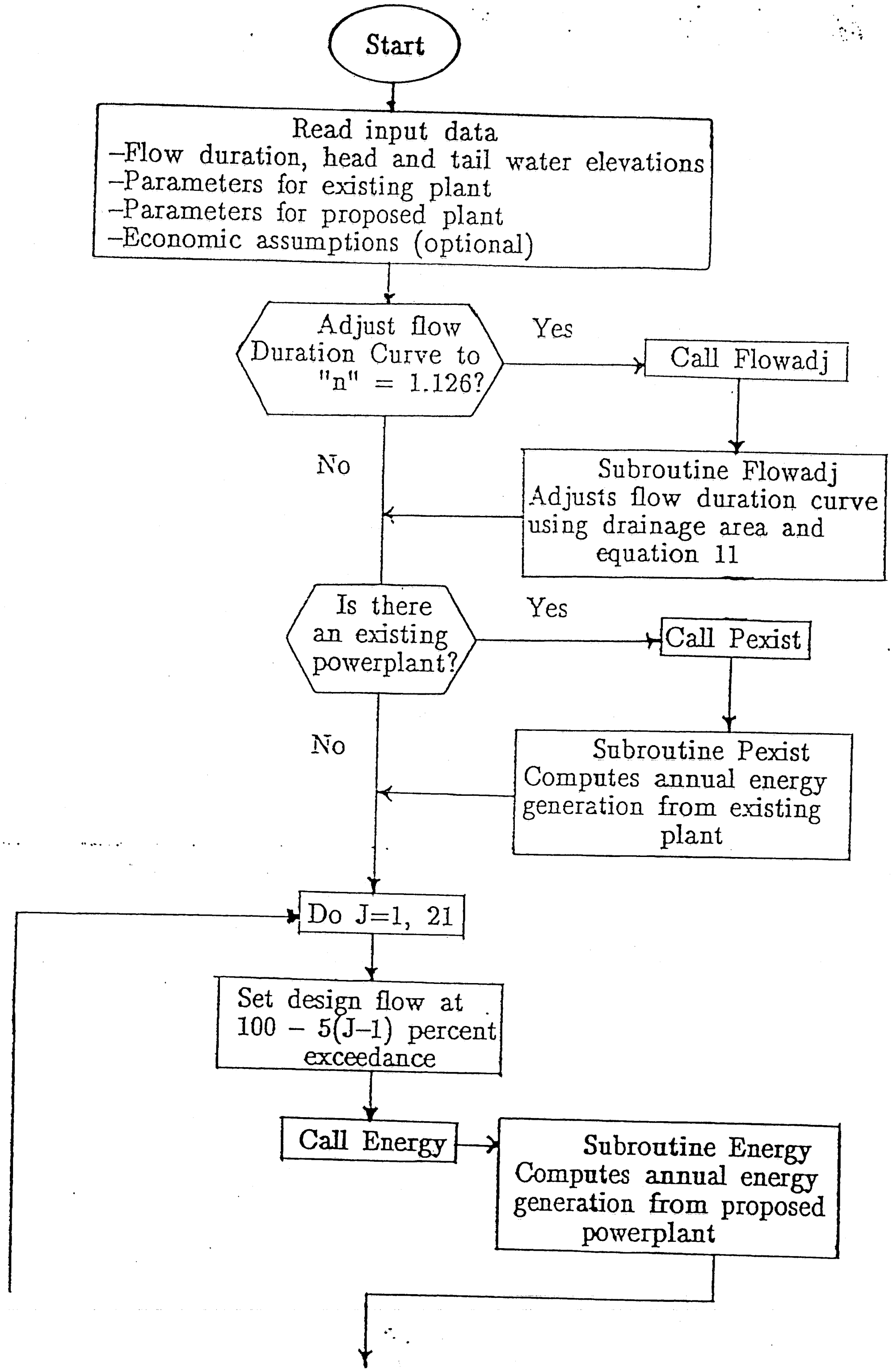

Figure 4 - General Flowchart for HYFEAS2

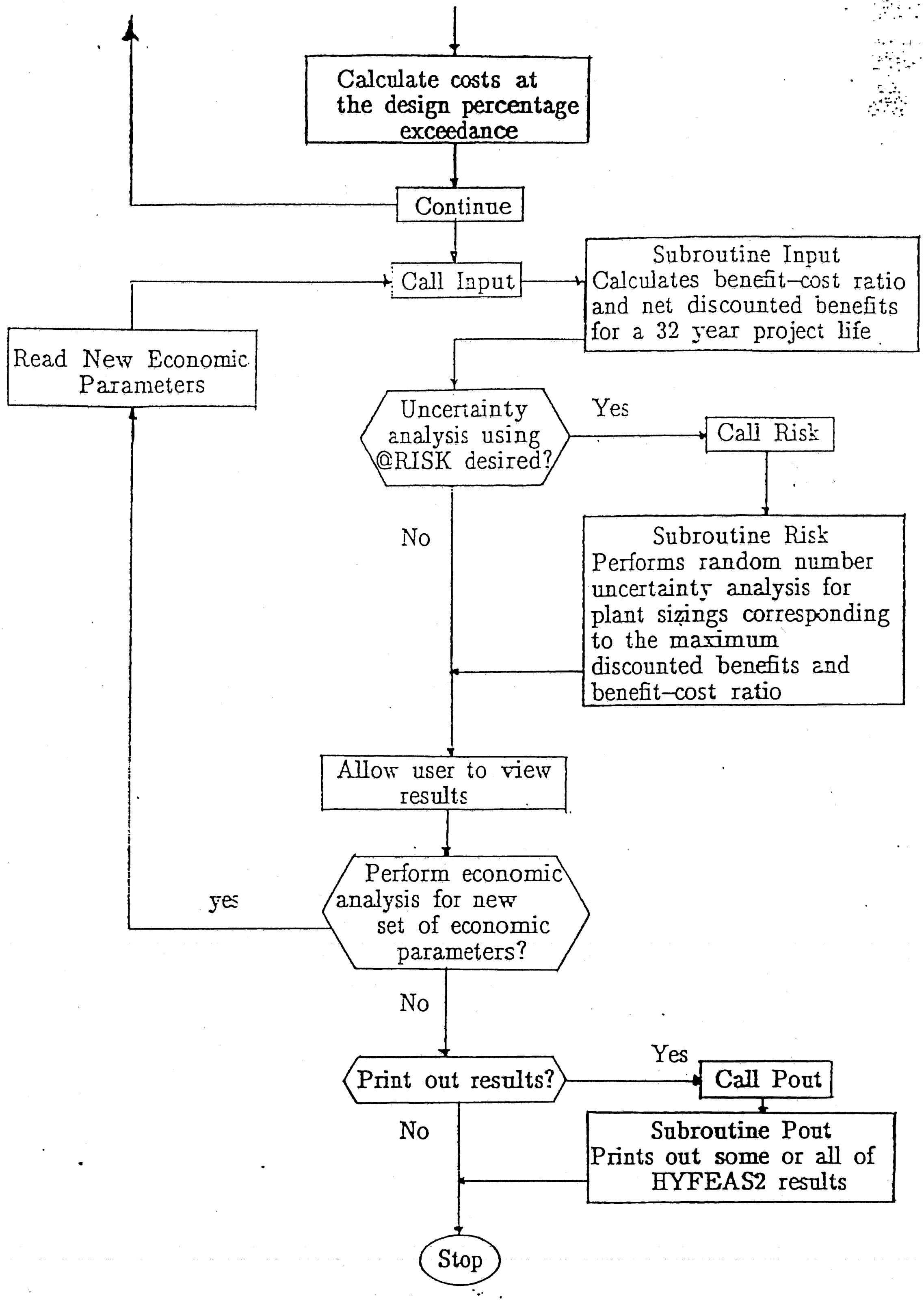

Figure 4 - General Flow Chart for HYFEAS2

```
INPUT_PATH  FLOW_DATA  PLANT_DATA  DFLT_DATA  HYFEAS2  VIEW_OUTPUT  QUIT
DEFINE DEFAULT DIRECTORY WHERE ALL FILES RESIDE

  WELCOME TO HYFEAS2.  HYFEAS2 ESTIMATES ECONOMIC FEASIBILITY PARAMETERS
  FOR A HYDROPOWER INSTALLATION, BASED ON USER-ENTERED VALUES REGARDING
  THE SITE.  RISK ASSOCIATED WITH THE FEASIBILITY PARAMETERS IS ALSO
  EVALUATED.  THE PROGRAM MAY BE APPLIED TO NEW SITES (WITH ONLY THE DAM
  EXISTING) OR TO EXPANSIONS OF CAPACITY AT EXISTING PLANTS.
  THE PROGRAM IS MENU DRIVEN AND THEREFORE USER FRIENDLY.  THE KEY
  SEQUENCE <Alt><M> WILL BRING UP THE MENU AT ANY TIME WHEN IT IS NOT
  ALREADY DISPLAYED.  SHOULD THERE EVER BE A RUN ERROR, IT MAY BE
  NECESSARY TO PRESS THE <Esc> KEY BEFORE <Alt><M>, IF THE MENU DOES NOT
  REAPPEAR AUTOMATICALLY (IN MOST CASES IT WILL).

  THE PROGRAM REQUIRES INPUT DATA REGARDING PLANT PARAMETERS AND ENERGY
  BUY-BACK RATES, AS WELL AS A FLOW DURATION CURVE.  DEFAULT ECONOMIC
  AND UNCERTAINTY PARAMETERS MAY BE CHANGED IF DESIRED.  ALL DATA MAY
  BE ENTERED VIA THE MENU.

  IT IS NECESSARY TO RUN HYFEAS2 AT LEAST ONCE BEFORE EMPLOYING THE
  ECONOMIC AND RISK ANALYSIS OPTIONS.  SUBSEQUENTLY, ECONOMIC AND/OR
  RISK ANALYSIES MAY BE RUN SEPERATELY TO EVALUATE THE EFFECT OF CHANGING
  BUY-BACK RATES, DISCOUNT RATES, ETC.
```

Figure 5 - Top Level Menu for HYFEAS2

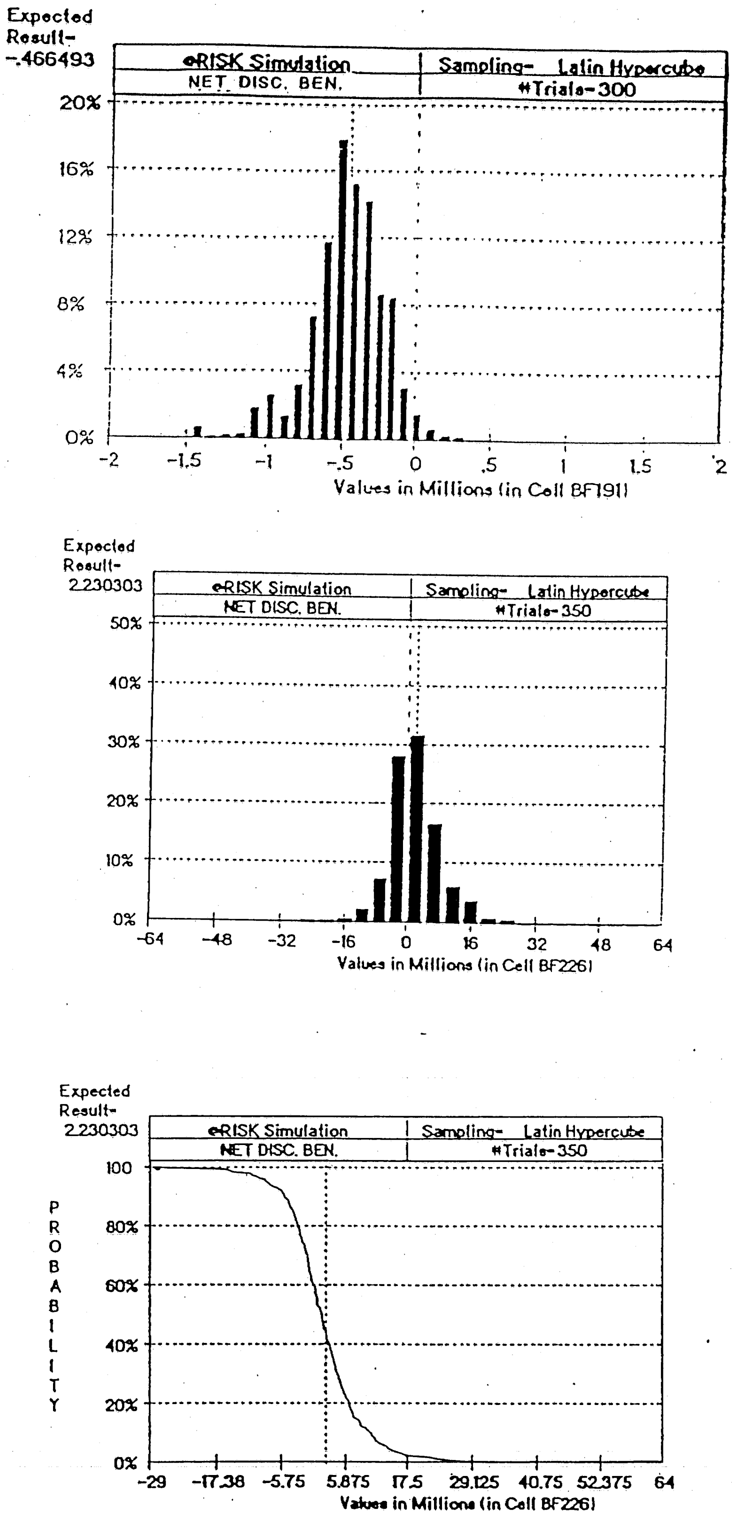

Figure 6 - Cumulative Distribution Function and Histogram "pic" Files