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PREFACE

This document is Appendix F of DYNATREND INCORPORATED’s report, “Development Of a Risk Analysis Model, Final Report,” October 1979, prepared for the Department of Energy’s Office of Buildings and Community Systems under Contract DE-AC03-77CS20158. Three case studies were conducted in the process of the contract effort. Appendix D, “Gas Fired Heat Pump Case Study”; and Appendix E, “1000 Ton Per Day Anaerobic Digestion Plant Case Study,” were prepared by DYNATREND INCORPORATED. Appendix F, “District Heating and Cooling System Case Study” was prepared by Econ, Incorporated. Appendix C, “Risk Analysis Methodology”, provides general information concerning the model used in the three case studies, its input data requirements, and its output reports.

This appendix presents the findings of studies related to district energy systems using thermal energy cogenerated at electric power plants performed for DYNATREND INCORPORATED by ECON, Incorporated. Mr. Joel S. Greenberg served as the Principal Investigator. In carrying out related efforts, ECON, Incorporated provided DYNATREND with additional reports (References 1, 2 and 3).

The district heating and cooling case study performed in Minneapolis/St. Paul was made possible through the enthusiastic efforts of Mr. Michael Karnitz of Oak Ridge National Laboratory and Mr. Herb Jaehne and Mr. Conrad Aas of the Northern States Power Company.
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1. INTRODUCTION
Public sector funded research, development and demonstration (RD&D) and incentive projects should yield societal benefits which exceed project costs. The societal benefits, in many cases, can only be achieved if the RD&D and incentive project results are transformed into goods and/or services which are adopted and find widespread utilization in the public sector and/or private sectors. This transmission process is usually referred to as “technology transfer”.

When technology transfer requires private sector participation, it follows that the achievement of the indicated societal benefits also depends upon private sector participation. Thus, from the public sector’s point of view, the estimation of the societal benefits which may result from a public sector funded RD&D or incentive project must take into account the likelihood of private sector participation. The likelihood of private sector participation depends upon many factors, foremost among which are perceived uncertainty, resulting risk and exposure (i.e., magnitude of investment). The public sector benefits from an RD&D or incentive project are thus inextricably tied to the impact of the project upon the likelihood of private sector participation through its effect on perceived uncertainty, risk, and exposure.

The Office of Buildings and Community Systems of the Department of Energy has established an RD&D project evaluation and selection methodology aimed at increasing the likelihood that the best federally-supported research opportunities receive funding. The DOE has been investigating the utilization of risk analysis techniques to determine if and how such techniques may improve the project evaluation and selection methodology.

DYNATREND efforts and the efforts of its subcontractor, ECON, Incorporated, in support of this investigation included analysis of the risk in commercial ventures which could result from the DOE RD&D projects. The risk analysis reported in this appendix was concerned with a business venture in the area of district energy systems using thermal energy cogenerated at existing electric power plants. A case study of a cogeneration system in Washington, D.C. was considered. Data provided by Dr. Dan Santini at Argonne National Laboratory served as the basis of the cogeneration risk analysis. This study is summarized in Section 4 of the report. It should be noted that the Potomac Electric Power Company did not play a role in the study except for providing some data on their existing financial structure. Because of the site-specific nature of cogeneration business ventures, the results of the Washington case study cannot be extrapolated to other geographic locations. The Washington case study illustrated the use of risk analysis and demonstrated the Risk Model capabilities and limitations.

As a result of the initial investigations, a decision was made to proceed with an analysis of the regulated utility industry investment decision process from the points of view of accounting procedures, regulatory constraints, and public utility company objectives. This was to be followed by refinement of the district heating and cooling system case study to better reflect the regulated utility.
The resulting efforts included a review of utility industry investment decisions. Discussions were held with a number of utility companies including Northern States Power Company, Philadelphia Electric Company, Potomac Electric Power Company, and Public Service Electric and Gas Company of New Jersey. Most utility companies evaluate regulated investment opportunities from the point of view of "minimization of revenue requirements" (this is discussed in Section 3). However, when non-regulated investment opportunities are considered, payback period, return-on-investment, and net present value techniques are also utilized. Institutional issues concerning district heating and cooling systems (DHCS) were also discussed with these power companies and also with the Federal Regulatory Agency. It was the general feeling that district heating and cooling systems, operated and owned by either public utility companies or private ownership, would be regulated as soon as the customer base becomes reasonably large (see Section 2). On the other hand, municipally owned systems would not be regulated. The prevailing attitude is that revenue from electrical customers should not and would not be used to subsidize customers purchasing thermal products.

A major difference was found to exist between a public utility providing electric energy and one providing thermal energy (in the form of hot water) for heating and cooling applications. The pricing of electric energy products must be such that an allowed (by the public utility commission) maximum annual rate of return on investment is not exceeded. The pricing of thermal products for heating and cooling applications, if current regulatory attitudes continue, will also be such that an allowed maximum annual rate of return on investment is not exceeded. However, whereas there is little competition for electricity, there are alternative energy sources (i.e., oil and gas) for heating and cooling applications. The availability of alternatives implies that a market developed price constraint will also be imposed upon the thermal products. Within the current regulatory climate the multiple constraints on thermal product pricing can have a significant impact upon the economic viability of regulated district heating and cooling business ventures.

As part of the efforts under this task, a risk analysis case study was performed of a district heating and cooling business venture in Minneapolis/St. Paul. Minneapolis/St. Paul was selected primarily because of the availability of a data base resulting from recent studies funded by both DOE and the Northern States Power Company. Serious consideration is currently being given to the implementation of a DHCS in Minneapolis/St. Paul. Thus the risk analysis was based upon a solid foundation of detailed technical and financial analyses. The uncertainty assessments were made by individuals directly involved in these studies. A number of different scenarios ranging from private ownership to programs such as mandatory hookups, reduced depreciation life and government cost sharing for consumer equipment. The Minneapolis/St. Paul DHCS risk analysis is summarized in Section 5.

The DHCS risk analysis indicated that a viable, though risky and very capital intensive, district heating business is possible in Minneapolis/St. Paul. Municipal ownership has the advantage of being unregulated and exempt from taxation. In the long term, municipal ownership offers the possibility of higher returns on investment than a privately owned venture.
This task was also concerned with recommending a risk analysis methodology that will allow DOE to evaluate public utility investment decisions in terms of DOE RD&D and incentive projects. This is discussed in Section 6. The existing RISK Model limitations are identified and specific recommended modifications are also described in Section 6. Since public utility investment decisions concern both regulated and non-regulated business ventures, the risk analysis methodology should be capable of analyzing both types of investments. The existing RISK Model, with several recommended modifications, is capable of analyzing a very large class of non-regulated business ventures. It can also be used, to a limited extent, to evaluate regulated business ventures. Its two major limitations when used to evaluate regulated business ventures are: (1) it does not directly establish the price that will yield an allowed (constraint) return on investment and (2) it does not perform the analysis using the "minimization of revenue requirements" accounting procedures which are used by utilities (see Section 3). The former limitation may be circumvented, to a certain extent, by considering different price scenarios. The latter limitation is important when it is necessary to obtain public utility endorsement of results.

The results of the analyses are summarized in the following pages. This report is organized as follows: Section 2, Institutional Issues, presents an introduction to investment decisions and thence considers regulatory constraints and issues. The regulatory dilemma facing DHCS is also discussed. Section 3 reviews public utility company objectives and investment analysis approach (i.e., the minimum revenue requirement approach). Section 4 reviews the case study of DHCS in Washington, D.C. Section 5 presents the results of the Minneapolis/St. Paul DHCS case study. Section 6 summarizes the desired risk analysis methodology for evaluating regulated utility investment decisions. Limitations of, and recommendations for modifications to, the RISK Model are also discussed. Section 7 presents overall conclusions and recommendations.
2. INSTITUTIONAL ISSUES
District heating is a process in which thermal energy from a central source (either a heat-only unit or a cogeneration plant that produces both electricity and useful thermal energy) is distributed to commercial, industrial and residential consumers for space heating and domestic hot water needs. District heating technology is currently being considered for use [4, 5] because of rapidly escalating energy prices and the increasing dependence on imported oil. Large hot water district heating systems have the potential of providing consumers with space heating at competitive prices while substituting more plentiful domestic fuels, such as coal and uranium, for heating needs currently supplied by oil and natural gas. Hot water district heating technology is available and has been widely utilized in many European countries with a great deal of success.

Implementation of cogenerated district heating is currently under consideration by many power companies and municipalities. Both technical and institutional factors will effect their implementation decisions. The objective of the following paragraphs is to indicate and summarize some of the more important institutional issues which are of concern to organizations considering district heating. Institutional issues are nontechnical business-related issues effecting the creation, ownership or operation of new cogenrating hot water district heating systems. These may be grouped under the general headings of ownership and operation, financing, marketing, taxation and regulation. It should be noted that although given separate headings these issues are very much interrelated—for example, the form of ownership (i.e., municipal ownership) will limit the form of financing (i.e., municipal bonds). These issues may be termed traditional institutional issues concerned with the development, ownership and operation of businesses. There are also issues which may be referred to as "perceived" or those generally arising from public perception of the purpose and effects of cogenerated hot water district heating.

Many perceived issues have been raised by the general public [7]. It is anticipated that many of the perceived issues will become nonissues with an active education program. A number of issues, such as the effect of DHCS on community growth (will development lead or follow community growth?), safety and reliability of the system and the magnitude of construction disruption appear to require special attention. Improper interaction with, and education of, the general public on these issues may lead to long and expensive time delays.

The perceived issues, while important, are not addressed further. The following paragraphs consider the traditional issues with major emphasis placed upon regulation—the issue felt to be of most import and one that effects all of the other issues.

*The comments are based upon discussions with DOE, Federal Energy Regulatory Commission, and a number of utility companies including Northern States Power Company, Philadelphia Electric Company, Public Service Electric and Gas Company of New Jersey and Potomac Electric Company. Many references are available and have been reviewed including references 6, 7 and 8.
INSTITUTIONAL ISSUES

- Non-technical business related issues affecting the creation, ownership or operation of new cogenerating hot water district heating systems

- Issues considered
  -- Traditional issues
    + Form of ownership and operation
    + Financing
    + Marketing
    + Taxation
    + Regulation
  -- Perceived issues
    + Effect of DHCS on community growth
    + Safety and reliability
    + Magnitude of construction disruption
There are at least the following two basic forms of owner/operator options (there are a number of variants within each basic form) that appear to be compatible with the desired development program, existing public service institutions, financial and management requirements and long-term stability. The first option is that of the private owner/operator. In this scenario the existing utility company would continue to own and operate the base-load cogenerating power plants. An existing or new privately-owned utility would build, own, operate and maintain the hot water transmission and distribution system and peaking equipment. The retrofit cost of the electric generating capacity and incremental thermal product-related expenses will ultimately be borne by the thermal system owner/operator. The specific mechanism to accomplish this and its effects upon the utility company and the private owner/operator (which may or may not be the utility company or its subsidiary) have not been investigated. Individual customers (buildings) would own and operate their own heat exchangers and heating systems. The private owner/operator could be responsible for all hookup costs which could then be passed on to the customer in the price of the hot water. The second basic option is that of the public owner/operator. This scenario is the same as the private owner/operator scenario with the exception that an existing or new government entity would be created to build, own, operate and maintain the hot water transmission and distribution system and peaking equipment.

Both of these scenarios have similarities yet major differences. Both are concerned with financing a very capital intensive business venture. The private owner/operator has alternatives in the form of combinations of debt and equity. The public owner/operator is concerned with debt financing and in particular with tax exempt bonds in order to reduce interest expense. The private owner/operator is faced with federal, state and local taxes, investment tax credits, allowance for funds used during construction, etc. The public owner/operator is not faced with the issue of taxation and the peripheral issues that impact taxes. Both of the forms of ownership are concerned with pricing policies that will achieve return-on-investment goals and yet stimulate conversion from oil/gas to hot water. The public owner/operator is also faced with the profit motivation issue; i.e., the choice between a "for-profit" and "not-for-profit" enterprise. Both are faced with issues concerning hookup policy. Who should assume the costs for customer hookup? Business enterprise assumption will increase funding requirements but probably lead to increased rate of conversion since presumably the customer will receive a simple monthly bill which, if comparable to or less than the cost of oil/gas, will encourage conversion. Consumer assumption of hookup costs will probably lead to reduced conversion rates but will also reduce funding requirements of the business enterprise. Consumers will also want a high degree of assurance of long-term continuity of service. A third party hookup financing arrangement may solve the dilemma if it does not place a burden on, or inconvenience the consumer. Both of the forms of ownership will be effected by legislation that mandates hookup to the local network. Mandating hookup will considerably reduce the risk associated with the venture and will ensure a large early inflow of needed revenues.

A privately owned/operated district heating system will be regulated when its customer base expands from a small number of industrial/commercial clients. This is the opinion of all parties with whom discussions have been held. The publicly owned/operated DHCS faces little or no regulation. It appears that the regulatory agencies will not allow the thermal product customers to be subsidized by the electrical customers. This implies cost allocation between thermal and electrical products with all of its accompanying problems. Note that subsidization will be allowed in the case of public ownership/operation. The subsidization results from the use of tax exempt bonds which implies that all taxpayers are subsidizing the hot water customers.
OWNER/OPERATOR OPTIONS AND INSTITUTIONAL ISSUES

PRIVATE OWNER/OPERATOR

FINANCING
- DEBT
- EQUITY

TAXATION
- FEDERAL
- STATE
- LOCAL

MARKETING
- PRICING POLICY
- HOOKUP POLICY
  - ASSUMPTION OF COSTS
  - MANDATED VS. NON-MANDATED HOOKUP

REGULATION
- REGULATE/DO NOT REGULATE
  - RATE OF RETURN
  - SERVICE AREA

PUBLIC OWNER/OPERATOR

OWNER/OPERATOR OPTIONS

FORM & STRUCTURE
- RESPONSIBLE LEVEL OF GOVERNMENT
- OPERATING STRUCTURE
  - FOR-PROFIT OR NOT-FOR-PROFIT

FINANCING
- DEBT (TAX EXEMPT BONDS)

TAXATION
- NONE

MARKETING
- PRICING POLICY
- HOOKUP POLICY
  - ASSUMPTION OF COSTS
  - MANDATED VS. NON-MANDATED HOOKUP

REGULATION
- NONE

*NOTE THAT THIS IS A FORM OF SUBSIDIZATION WHEREIN ALL TAXPAYERS SUBSIDIZE THE THERMAL PRODUCT CUSTOMERS.*
Regulated utilities are unique among American business for many reasons. The main reason is the regulated environment within which they must operate. Utilities are granted franchised areas and are regulated for a number of reasons, including the need to avoid inefficient duplication of invested resources, and to permit the realization of economies of scale. Regulation permits these factors to be operative, and at the same time, provides a means for insuring that fair and reasonable prices are charged for an acceptable level and quality of service. In return for the monopoly power granted utilities, they are restricted by regulation to recover only costs prudently incurred, including the opportunity to earn a fair and reasonable return on the investment committed to the supply of service. In essence, regulation attempts to insure (1) that total costs are covered, (2) that adequate and reliable service is available to all within the monopoly franchise area, (3) that the prices charged for these services reflect the lowest reasonable costs of providing service, and (4) that the prices charged for these services are not unduly discriminatory.

Because of the far-reaching consequences of regulation, regulators influence both the decisions of the firm and the cost and availability of investment capital. Thus, the institutional issues of financing, taxation, marketing and regulation are interrelated. The objective of the regulator is to balance the interests of customers and investors. Regulators attempt to set rates that allow the utility an opportunity to earn a fair and reasonable return on capital. Therefore, the regulated firm, unlike the nonregulated firm, is not free to maximize the value of its stockholders' equity. Instead, the firm is faced with the problem of maximizing the value of stockholders' equity subject to the constraints imposed by the regulator.
REGULATION, THE FIRM AND CAPITAL MARKETS

REGULATORY AGENCY
- DETERMINE TOTAL REVENUE REQUIREMENTS
- APPROVE RATE STRUCTURES
- APPROVE NEW FINANCING
- DETERMINE ACCOUNTING POLICIES
- APPROVE CAPACITY EXPANSION PLANS

FIRM DECISION AREAS
- CAPITAL BUDGETING
- CAPITAL STRUCTURE
- DIVIDEND POLICY

DEMAND FOR FUNDS

CAPITAL MARKETS EVALUATION
- RISK
- EXPECTED RETURN

SUPPLY OF FUNDS

The consensus of opinion is that private owner/operator district heating systems will be regulated in a manner similar to electric utility enterprises. Since this seems to be the general perception of the electric utilities it is important to understand the significance of regulation. This perception coupled with the perception that electric customers will not be allowed to subsidize thermal customers, will have a significant impact upon DHCS investment decisions. The reasoning is as follows.

Electric utilities and thermal product business enterprises have certain basic differences. Electric utilities exist. They have large rate (asset) bases and large customer bases. They operate in an area of limited competition (from oil/gas). They are regulated in many ways, perhaps the most important is the setting (by the regulatory commission) of limits on allowable return on investment. The electric utilities must establish a pricing policy such that the allowable return on investment is not exceeded. The pricing policy is based on a simple constraint—the allowable rate of return. If the allowed rate of return is not achieved in year N it cannot be made up by exceeding the constraint in year N+1.

The facing page illustrates (top), in a simplified form, the impact of an additional investment to the electric utility. When the investment becomes part of the rate base the electric utility may request rate relief so that, with the increased rate base, the allowed rate of return may be achieved. If the rate adjustment is approved, a new price may be established so that the allowed rate of return is maintained. There is no constraint upon the price other than that established in accordance with the allowed rate of return.

Consider now the situation of the regulated district heating business enterprise. The business enterprise must be considered as a startup situation with no existing customer base and no existing assets. It is assumed (perceived) that the same regulation (i.e., allowable return on investment) will apply to the district heating enterprise. The district heating system requires an investment which establishes the rate base. In order to achieve the allowed rate of return, because of the small initial customer base, a relatively high price must be established for the hot water. This is illustrated by the dashed lines in the lower figure on the facing page. However, because of market constraints in the form of prices of competitive products (i.e., oil/gas), the price required to achieve the allowed rate of return is not possible. There are now two constraints, namely the allowed rate of return and the price of competitive products as established in the marketplace. When the hot water price is set by the dual constraints it is not likely that the allowed rate of return can be achieved in the early years of the district heating enterprise. Since, within the perceived regulation, these early lost returns cannot be made up in future years, the perceived regulations act as a deterrent to the establishment of private owned/operated cogeneration district heating systems. It should be noted that the average (over a number of years) return on investment for hot water systems will be less than the average for electrical systems.
THE DHCS REGULATORY DILEMMA

NO COMPETITION: (THE CASE OF ELECTRICITY--LARGE EXISTING CUSTOMER BASE)

CONSTRAINT:
- SET PRICE SO AS TO ACHIEVE UP TO AN ALLOWED (BY REGULATION) RATE OF RETURN ON INVESTMENT

COMPETITION: (THE CASE OF DHCS HOT WATER--LIMITED INITIAL CUSTOMER BASE)

CONSTRAINT:
- SET PRICE SO AS TO ACHIEVE UP TO AN ALLOWED (BY REGULATION) RATE OF RETURN ON INVESTMENT
- SET PRICE SO AS TO BE COMPETITIVE (MARKETPLACE) WITH ALTERNATIVE PRODUCTS (GAS AND OIL)
It appears that there are at least two incentive programs that may have a major impact upon decisions pertaining to the investment in district heating systems. These pertain to (a) a strong incentive program ranging from tax and other incentives aimed at encouraging conversion to hot water use to legislation of mandatory hookup to the local hot water distribution network and (b) regulation regarding allowed return on investment. Legislation of mandatory hookup will have two effects on the district heating enterprise. First, it will reduce the uncertainty associated with the rate and magnitude of market development (sales versus time) thus reducing the risk associated with the business venture. Second, it will ensure higher levels of sales earlier thus tending to make the enterprise more profitable in the early years and more likely to achieve allowed rates of return in the early years. Regulation changes are necessary in order to eliminate the return on investment deterrent discussed above. The changes may take the form of (a) allowing adjustments to be made to allowed rate of return based upon inadequate returns during the early startup years or (b) establishing rate of return based upon proforma income, cash flow and net present value computations. The rate of return would thus be equivalent to the internal rate of return or that rate which makes the present value of annual (net) cash flow equal to zero.

More will be said with respect to institutional issues in Section 6 with respect to the Minneapolis/St. Paul case study.
3. REGULATED UTILITY INVESTMENT ANALYSIS
Nonregulated business ventures are normally faced with a large number of investment opportunities. Decisions must be made with respect to which opportunities should be selected for investment and within each opportunity which is the best alternative. The goal is normally to maximize the stockholders' equity. Usually it is necessary to compare two or more alternatives that are structured so as to achieve the same level of capability. These alternatives usually have different cash flow patterns both in magnitude and timing. The methods used to analyze these alternatives must be sensitive to the differences in these cash flow patterns. Various methods have been devised and are in widespread use. Several of these are summarized in the facing page and are used with different levels of sophistication.

The "minimum revenue requirements" method is in common use for evaluating utility company investment alternatives. This method is discussed in the following paragraphs. The preference by utilities for the revenue requirements method results from a number of conditions peculiar to the utility industry that either do not exist in general industry or are not considered by them to be compelling. General industry, by design and by financial conditions, has a limited pool of capital that it can invest in new projects. Thus, tests are made of various projects to determine their relative profitability and to disqualify the less promising projects (see facing page). With utilities, on the other hand there are no constraints on the size of capital pool from which the utilities can draw. Utilities are expected to perform their basic job, at almost any cost, without primary regard for capital limitations or even for the profitability of the required projects. Therefore, utilities instead of examining the profitability of a given project examine all possible alternative means of accomplishing a given project and then select the alternative that is least costly in terms of the amount of revenue required from consumers. Hence, the emphasis in utilities is on minimizing the revenue requirements rather than determining and rating the profitability of various alternatives. The principal objective is to minimize the cost to the consumer.

The revenues attributable to any particular alternative are difficult to trace in a complex revenue-producing system such as a utility. Therefore, when alternatives are being compared, the use of a method that assumes revenue to be the same in each alternative and dwells on a minimum cost determination becomes a necessity.

For the utility, regardless of the profit or lack of profit on a given project, minimization of the revenue requirements insures all concerned, both stockholders and consumers, of selection of the best alternative. For the stockholders, the lowest revenue requirement (1) yields a profit if the revenues actually received from customers after the project goes into service are greater than the revenue requirements of the project or (2) minimize the loss if the revenues actually received are less than the revenue requirements. For the consumers, the continuous selection by the utility of alternatives with the lowest revenue requirements (1) results in rate decreases if the aggregate revenue being paid by the consumers is greater than the revenue requirements or (2) minimizes the rate increases if the revenue being paid is less than the revenue requirements.
PAYBACK PERIOD METHOD: DETERMINATION OF THE NUMBER OF YEARS REQUIRED FOR THE CUMULATIVE CASH INFLOWS TO EQUAL THE CUMULATIVE CASH OUTFLOWS. IN A SIMPLIFIED SITUATION

PAYBACK PERIOD = \frac{\text{CAPITAL EXPENDITURE}}{\text{AVERAGE ANNUAL CASH FLOW}}

RETURN ON INVESTMENT METHOD: DETERMINATION OF THE RATE OF RETURN ON INVESTMENT. RETURN IS THE AFTER-TAX PROFIT AND INVESTMENT IS THE BOOK VALUE OF TOTAL ASSETS. IN A SIMPLIFIED SITUATION

RETURN ON INVESTMENT = \frac{\text{AVERAGE AFTER-TAX PROFIT}}{\text{REQUIRED INVESTMENT}}

NET PRESENT VALUE METHOD: DETERMINATION OF THE PRESENT VALUE OF THE CASH FLOW STREAM. THIS IS OBTAINED BY DISCOUNTING ALL FUTURE CASH FLOWS TO THE PRESENT AT THE FIRM'S COST OF CAPITAL

\text{NET PRESENT VALUE} = \sum_{n=1}^{\infty} \frac{(\text{CASH FLOW}(n))/(1 + R)^{n-1}}{N-1}

DISCOUNTED CASH FLOW (INTERNAL RATE OF RETURN) METHOD: DETERMINATION OF THE RATE OF RETURN THAT MAKES THE PRESENT VALUE OF THE STREAM OF CASH FLOWS EQUAL TO ZERO. THIS IS ALSO REFERED TO AS THE DISCOUNTED RETURN ON INVESTMENT.

\sum_{n=1}^{\infty} \frac{(\text{CASH FLOW}(n))/(1 + IR)^{n-1}}{N-1} = 0

IR IS THE RATE OF RETURN THAT MAKES THE ABOVE RELATIONSHIP TRUE.

SEE REFERENCE 12.
Alternative investments are compared by utilities on the basis of the present worth of the revenue required by each alternative during the period of the analysis. Revenue requirements include fixed costs, such as return on investment, depreciation, taxes, etc., which result from having made an investment, and operating costs such as fuel costs, operation and maintenance (O&M) costs, etc., which result from the use of the investment. The minimum acceptable return is the lowest amount that investors will accept (or the utility commission will approve) to provide funds needed to make an investment.

Many factors must be taken into account when making a decision between investment alternatives. Among the alternatives, there will be one which results in the lowest overall revenue requirements. That alternative having the minimum revenue requirement is the proper choice among alternatives. The revenue requirements are the amounts that must be covered in order to compensate the utility for all expenditures made as a result of implementing an investment decision. Actual revenues must be equal to the revenue requirements, plus a profit incentive which is needed to attract investors, plus the tax on the profit incentive.

Revenue requirements for an investment will normally be different during each year. In order to develop a single overall revenue requirement for each alternative, the revenue requirement stream is discounted to a particular point in time. This present value amount is then, for convenience of comparison of alternatives, converted to an annuity (constant) value which if received over a period of time equal to the life of the investment would yield the same revenue requirement present value. The resulting value is referred to as the "levelized" value.

In economic studies, it is important to be able to distinguish between expenditures which are capitalized and those which are considered expenses. Capital expenditures are generally characterized by (a) use for purchase of long lived equipment and (b) not lending themselves to financing from current revenue. Expenses are generally for payment of day-to-day operating and maintenance items such as fuel, payroll, supplies, rents and insurance. Funds for expenses generally come from current revenue.

Another difference between capital items and expense items is that only a portion of the annual carry charges (depreciation, return and income taxes) that result from a capital expenditure are deductible for income tax purposes and such deductions are spread over the life of the facility; while an expense is completely deductible for income tax purposes and has its total impact at the time it is incurred. Capital items generally involve additions or improvements which have an anticipated service life of at least several years. Expenses are expenditures made for day-to-day operations.
REVENUE REQUIREMENT METHOD

Source: Reference 10.
The burden to the company caused by capital expenditures is the annual revenue required by the utility to cover the costs of depreciation, return and income taxes. These three elements when added together constitute what is known as annual carrying charges resulting from capital expenditures. The following discussion is based on Reference 11.

Book Depreciation, or return of capital, represents the amount of money which must be set aside annually to recover the capital cost over the anticipated life of the facility. Accelerated or straight line methods may be used. It should be noted that when straight line depreciation is used, the annual depreciation is constant each year and does not require levelizing.

Return, or return on capital, represents the money required annually to compensate security holders for the funds provided as invested capital for the plant facilities. It consists of interest on debt, dividends on preferred stock and earnings on common equity. The return element is variable, being greatest initially and then declining over the years because a fixed cost of money, or rate of return, is applied annually to the net plant (total plant less accumulated depreciation). To adjust for the variability of this component, present worth techniques are employed to obtain an equivalent levelized or constant, annual return.

Basic Income Taxes consist of the annual income taxes levied upon the utility by federal, state and local governments. Revenue received for payment of operating and maintenance expenses is not subject to income tax since, in computing taxable income, they are recognized as deductions. Depreciation is also a recognized deduction. The portion of the return element attributable to interest on debt also is deductible. The portion of the return element attributable to earnings on preferred and common stock is not deductible and therefore is subject to income tax. Since the income tax element is a function of the return element, it is a variable—being greatest initially and then declining over the years as the return element declines. The tax element, like the return element, is reexpressed in terms of an equivalent levelized annual amount.

The total of the level annual amounts for depreciation, return and income taxes are known as "level annual carrying charges." When these level annual carrying charges are expressed in terms of the initial capital investment a level annual carrying charge rate is obtained.

There are several other less significant components of annual carrying charges and annual carrying charge rates other than the above. Typical other components are:

Accelerated Depreciation Component—For purposes of recovering invested capital either "straight line" or accelerated depreciation may be used. Straight line recovers the capital in equal annual increments over the service life of the facility. These revenues, collected for capital recovery through depreciation, are tax deductible. Accelerated depreciation permits the claiming of more of the depreciation early in the service life than does the use
of straight line depreciation. The earlier claiming of depreciation acts to reduce income taxes during the early years of service life. Conversely, it acts to increase income taxes during the later years of service life. The important aspect of accelerated depreciation is that a temporary fund is provided by the use of the accelerated depreciation that is of value to the utility. Hence, this component when computed appears as a negative cost, acting to reduce the carrying charges.

Mortality Dispersion Component—Retirements of plant facilities do not occur at their average life. Rather they are dispersed, such that some elements in a given category die before average life while other elements in the same category die after average life. This dispersion about average life acts to increase the level annual carrying charges. This is because the time value of money discounts, by unequal amounts, the seemingly offsetting early and late failures. The early failures are discounted less than late failures and the net result is an added revenue requirement to cover the cost of mortality dispersion.

Funds Used During Construction Component—Projects which require lengthy construction periods incur appreciable financing costs prior to their service dates. These financing costs are considered to be one of the costs of putting the project into service. Hence, they are treated the same as the costs of equipment, material and labor. For capital recovery purposes, the costs of financing during construction are depreciated as part of the total initial capital cost. However, for tax depreciation purposes, the federal tax authorities do not recognize the costs of funds used during construction as a component of initial capital cost; and this portion of initial capital cost is not allowed as a depreciation deduction. When the calculation of income taxes presumes full deductibility of the initial capital cost, a correction must be made to the revenue requirements for income taxes to recognize the extent to which the initial capital cost is not deductible. This component acts to increase the carrying charges.

Realty Tax Component—Annual state taxes on land and structure must be included in the carrying charge rate.

Capital Stock Tax Component—States usually levy a tax on the estimated value of the company's capital stock. Since new facilities are partially financed with capital stock, the addition of new facilities increases the total value of the company's capital stock. In recognition of this, a cost component is normally added to carrying charges.

Investment Tax Credit Component—The federal government allows a tax savings (credit) related to the capital cost of certain new plant. The tax credit amounts to 10 percent of the capital expenditure for long depreciation lives (greater than seven years) and somewhat less for shorter depreciation lives. The credit is applicable in the year of the expenditure but can be carried forward under certain conditions. The credit reduces income taxes and therefore acts to decrease carrying charges.
The revenue received must be sufficient to provide for the payment of annual operating expenses and the needs for capital recovery. These latter needs are comprised of the setting aside of depreciation funds for recovery of the invested capital plus payment of the return obligations to the security holders, plus payment of associated income taxes.

The income statement on the facing page shows for a typical one-year period the revenues received, the expenses incurred, the depreciation accrued, the income taxes paid, and the income available to provide for the return requirements which are necessitated by the capital cost of plant facilities. The figures shown illustrate the general magnitude of dollars occurring in each of the categories of revenue and operating expense. Income available for return on capital amounts to 8.3 percent of the depreciated plant. The income statement shows that the revenue received during the year amounted to $544,800,000. Also shown are the operating expenses and other expenses which act as revenue deductions. The expense items are fuel, other production expenses, transmission and distribution expenses, sales expenses and customer billing expenses; plus administrative and general expenses which are overhead expenses and are not sufficiently defined to permit classification directly to the categories of production, transmission, distribution, etc. The listed expenses from fuel through administrative and general expenses are called operating and maintenance expenses. These are the annual expenses needed to operate the business. They consist primarily of payroll payments to the labor force plus expenditures for material and supplies. Following these operating expenses in the income statement are the annual depreciation accruals, the income taxes and other taxes.

The depreciation expense and the income taxes are recognizable as capital related expenses. They act as substantial annual expenses to be provided for out of annual revenue received from the customers.

The total revenue deductions amount to $419,600,000. Out of the total of $544,800,000 received in the form of revenue, $419,600,000 is used to pay operating expenses, income taxes, other taxes and an annual payment into a depreciation reserve. The remainder constitutes income available for return on capital and amounts to $125,200,000.

Before examining the dispensation of the $125,200,000, consider briefly the rate base (shown below the income statement) and the way in which the Public Utility Commission examines the adequacy of the income available for return. The rate base is comprised of the capital cost of production facilities, transmission and distribution facilities, general plant used in electric operations, plus a share of common plant used jointly in providing electric, gas and steam services. The total plant in service, including the share of common plant, amounts to $1,993,300,000 in this illustration. The depreciation reserve funds accumulated over the years must be deducted from the total capital cost of plant in service. These funds are deducted from the plant in service because they represent funds which have been provided by the customers rather than by security holders through the sale of stocks and bonds. Since a portion of the revenue has provided the depreciation funds, the customer is considered to be the source of funds used to build the $490,800,000 depreciation reserve. Therefore, the company is not entitled to earn a return on plant purchased with depreciation funds. In this illustration the depreciated plant or rate base, amounts to $1,502,500,000. It is to this amount that the income available for return is related to determine the rate of return. The $125,200,000 represents a 8.3 percent return on the rate base.
# ILLUSTRATIVE INCOME STATEMENT, RATE BASE & RATE OF RETURN

## A. INCOME STATEMENT

**REVENUE** $544,800,000

**OPERATING EXPENSES**

- **FUEL** $145,100,000
- **OTHER PRODUCTION** 62,800,000
- **TRANSMISSION** 8,300,000
- **DISTRIBUTION**
  - **HIGH TENSION** 5,500,000
  - **PRIMARY** 10,000,000
  - **SECONDARY** 15,400,000
- **SALES PROMOTION** 7,100,000
- **CUSTOMER BILLING** 13,400,000
- **ADMINISTRATIVE AND GENERAL** 24,600,000
- **DEPRECIATION** 50,400,000
- **INCOME TAXES** 35,700,000
- **OTHER TAXES** 41,300,000

**TOTAL REVENUE DEDUCTIONS** $419,600,000

**INCOME AVAILABLE FOR RETURN** $125,200,000

## B. RATE BASE

**PLANT IN SERVICE**

- **PRODUCTION** $763,900,000
- **TRANSMISSION** 303,800,000
- **DISTRIBUTION**
  - **HIGH TENSION** 265,500,000
  - **PRIMARY** 343,600,000
  - **SECONDARY** 220,700,000
- **GENERAL AND INTANGIBLES** 9,900,000
- **SHARE OF COMMON PLANT** 85,900,000

**TOTAL PLANT IN SERVICE** $1,993,300,000

**LESS: DEPRECIATION RESERVE** 490,800,000

**DEPRECIATED PLANT (RATE BASE)** $1,502,500,000

## C. RATE OF RETURN

**INCOME AVAILABLE FOR RETURN** $125,200,000

**DEPRECIATED PLANT** $1,502,500,000

**RATE OF RETURN** 8.3 PERCENT

**SOURCE:** REFERENCE 11
The facing page illustrates the manner in which the income available for return is disbursed. The total income available for return is $123,200,000. Of this $54,700,000 is used to pay the interest on the bonds that financed some 52 percent of the plant in service not provided for by the depreciation reserve funds. That which remains after payment of the interest are the earnings available for payment of dividends to preferred stockholders and earnings on common stock. After payment of $10,500,000 in dividends to preferred stock, the balance remaining for common stock is $60,000,000. This is divided in two ways: a portion is retained for reinvestment in the business and a portion is paid out in dividends to common stockholders.

The calculations at the bottom of the illustration show the steps used to determine the quantities of payments required for each method of financing. This illustration has reflected a 7.0 percent interest rate on debt, a 7.0 percent interest rate on preferred stock and a 10.5 percent earnings rate on common stock. Further, it has assumed a 75 percent payout of common stock earnings with 25 percent of the earnings retained in the company for capital expansion.
ILLUSTRATIVE DISPOSITION OF INCOME AVAILABLE FOR RETURN

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>TOTAL INCOME AVAILABLE FOR RETURN</td>
<td>$125,200,000</td>
</tr>
<tr>
<td>LESS: INCOME DEDUCTIONS (INTEREST ON DEBT)</td>
<td>$54,700,000 (1)</td>
</tr>
<tr>
<td>NET INCOME = EARNINGS AVAILABLE FOR</td>
<td>$70,500,000</td>
</tr>
<tr>
<td>PREFERRED AND COMMON STOCK</td>
<td></td>
</tr>
<tr>
<td>LESS: DIVIDENDS ON PREFERRED STOCK</td>
<td>$10,500,000 (2)</td>
</tr>
<tr>
<td>BALANCE FOR COMMON STOCK</td>
<td>$60,000,000</td>
</tr>
<tr>
<td>LESS: DIVIDENDS ON COMMON STOCK</td>
<td></td>
</tr>
<tr>
<td>LESS: EARNINGS RETAINED IN THE BUSINESS</td>
<td></td>
</tr>
<tr>
<td>BALANCE</td>
<td>$0</td>
</tr>
<tr>
<td>RESTATEMENT</td>
<td></td>
</tr>
<tr>
<td>INTEREST ON DEBT</td>
<td>$54,700,000 (1)</td>
</tr>
<tr>
<td>DIVIDENDS ON PREFERRED STOCK</td>
<td>$10,500,000 (2)</td>
</tr>
<tr>
<td>EARNINGS ON COMMON STOCK</td>
<td>$60,000,000 (3)(4)</td>
</tr>
<tr>
<td>TOTAL RETURN</td>
<td>$125,200,000</td>
</tr>
<tr>
<td>RETURN IN % OF $1,502,500,000 RATE BASE</td>
<td>8.3%</td>
</tr>
</tbody>
</table>

(1) INTEREST ON DEBT
\[
\frac{1,502,500,000 \times 52\% \text{ DEBT FINANCED} \times 7.0\% \text{ INTEREST RATE}}{1} = 54,700,000
\]

(2) DIVIDENDS TO PREFERRED STOCK
\[
\frac{1,502,500,000 \times 10\% \text{ PREFERRED FINANCED} \times 7.0\% \text{ INTEREST RATE}}{1} = 10,500,000
\]

(3) DIVIDENDS TO COMMON STOCK
\[
\frac{1,502,500,000 \times 38\% \text{ COMMON FINANCED} \times 10.5\% \text{ EARNINGS RATE} \times 75\% \text{ PAYOUT}}{1} = 45,000,000
\]

(4) EARNINGS RETAINED IN BUSINESS
\[
\frac{1,502,500,000 \times 38\% \text{ COMMON FINANCED} \times 10.5\% \text{ EARNINGS RATE} \times 25\% \text{ RETAINED}}{1} = 15,000,000
\]

SOURCE: REFERENCE 11
The illustration on the facing page shows a simple determination of revenue requirements on a project which has operating and maintenance expenses of $80 per year. It assumes carrying charges or investment-related costs, amounting to $270 per year (the depreciation expense amounts to $100 per year; the return component amounts to another $100; and, the income taxes on the equity portion of return amount to $70). The carrying charges are annual in nature so they may be added to the annual operating expenses to obtain total annual revenue requirements. The total revenue requirements in this simplified example amount to $350 and are comprised of $80 operating and maintenance expenses and $270 in annual carrying charges.

On the bottom half of the illustration, the revenue requirements have been repressed into the more familiar income statement form. The revenue which the company would have to collect from the customers to cover the cost of this project would be $350. The operating expenses which must be paid for out of these revenue dollars are production expenses, transmission and distribution expenses, sales, accounting and administrative and general expenses amounting to $80. Further revenue reductions consist of the depreciation accrual of $100 per year and the income taxes of $70 per year. The total operating expenses or revenue deductions amount to $250. When these deductions are subtracted from the revenue, $100 remains as income available for the return requirements associated with the capital cost of the project being studied. This return is sufficient to provide for the $37 of added interest incurred because of new capital, plus $9 for payment of dividends to the preferred stockholders and $54 to common stockholders.

Revenue requirements for a new project generally are determined only if several alternative methods of achieving the same objective must be considered. The alternative with the lowest revenue requirement should be selected. For example, a project with revenue requirements of $350 has just been examined and the assumption made that $350 of revenue will be collected from the customers to cover all the operating expenses and investment-related costs. If an alternative method of accomplishing the same objective has lower revenue requirements, say of $300, that alternative should be selected rather than the alternative originally examined. This is because the receipt of the same $350 revenue would allow an additional $50 (before deduction of additional income taxes) to flow through to earnings available to common stockholders. Further, no matter what revenue is assumed in the income statement, it can be seen that the alternative with the lowest revenue requirements will act to increase the benefits to the common stockholder when the revenue to be received is more than sufficient to cover the revenue requirements (or to minimize the "hurt" when the revenue to be received is less than sufficient to cover the revenue requirements).
### AN EXAMPLE OF REVENUE REQUIREMENTS

<table>
<thead>
<tr>
<th>OPERATING AND MAINTENANCE EXPENSES</th>
<th>$80</th>
</tr>
</thead>
<tbody>
<tr>
<td>CARRYING CHARGES (INVESTMENT-RELATED COSTS)</td>
<td></td>
</tr>
<tr>
<td>DEPRECIATION</td>
<td>$100</td>
</tr>
<tr>
<td>RETURN</td>
<td>100</td>
</tr>
<tr>
<td>INCOME TAXES ON EQUITY EARNINGS</td>
<td>70</td>
</tr>
<tr>
<td>TOTAL CARRYING CHARGES</td>
<td>$270</td>
</tr>
<tr>
<td>TOTAL REVENUE REQUIREMENTS</td>
<td>$350</td>
</tr>
</tbody>
</table>

**HOW THESE REVENUE REQUIREMENTS APPEAR IN THE INCOME STATEMENT**

<table>
<thead>
<tr>
<th>REVENUE</th>
<th>$350</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPERATING EXPENSES</td>
<td></td>
</tr>
<tr>
<td>PRODUCTION</td>
<td>$50</td>
</tr>
<tr>
<td>TRANSMISSION</td>
<td>-</td>
</tr>
<tr>
<td>DISTRIBUTION</td>
<td>30</td>
</tr>
<tr>
<td>SALES PROMOTION</td>
<td>-</td>
</tr>
<tr>
<td>CUSTOMER BILLING</td>
<td>-</td>
</tr>
<tr>
<td>ADMINISTRATIVE &amp; GENERAL</td>
<td>-</td>
</tr>
<tr>
<td>SUB-TOTAL OPERATING &amp; MAINTENANCE EXPENSES</td>
<td>$80</td>
</tr>
<tr>
<td>DEPRECIATION</td>
<td>100</td>
</tr>
<tr>
<td>INCOME TAXES</td>
<td>70</td>
</tr>
<tr>
<td>OTHER TAXES</td>
<td></td>
</tr>
<tr>
<td>TOTAL REVENUE DEDUCTIONS</td>
<td>$250</td>
</tr>
<tr>
<td>INCOME AVAILABLE FOR RETURN</td>
<td>$100</td>
</tr>
</tbody>
</table>

**DISPOSITION OF INCOME AVAILABLE FOR RETURN**

| INTEREST ON DEBT | $37  |
| DIVIDENDS TO PREFERRED STOCK | 9    |
| EARNINGS ON COMMON STOCK | 54   |
| REMAINDER | $0   |

**SOURCE:** REFERENCE 11
4. CASE STUDY OF DHCS—WASHINGTON D.C.
INTRODUCTION TO THE CASE STUDY OF DHCS IN WASHINGTON, DC.

A risk analysis was performed to evaluate the financial merits of the application of district energy systems using thermal energy cogenerated at existing electric power plants. The results of the Task 2 risk analysis, based upon the use of the previously described RISK Model, are reported in this section. The primary objective was to demonstrate and evaluate the use of risk analysis techniques with respect to the development of improved project selection methods and procedures and to provide better insights into the financial merits of business ventures based upon the use of cogeneration techniques. Because of the strong relationships between retrofit costs (for providing thermal energy products) and existing power plant characteristics, and thermal energy distribution and maintenance costs and spatial and temporal demand distributions, the financial merits of the application of district energy systems using thermal energy cogenerated at existing electric power plants can only be developed on a site specific (case study) basis.

Since Dr. J. Santini at Argonne National Laboratory (ANL) had recently completed an analysis of district energy systems using thermal energy cogenerated at existing electric power plants in Washington, DC, it was agreed to use this study and associated data base as the basis for a site specific case study risk analysis. The basic analysis performed by Dr. Santini considered early retrofitting of all applicable existing power plants and the consequent distribution of thermal products to satisfy the commercial, industrial and residential heating and cooling demand within the entirety of Washington, DC.

The risk analysis assumed that during the ten-year detailed planning horizon, only a portion of the existing power plants would be retrofit to produce the thermal energy product (hot water). It was also assumed that the thermal energy distribution would only be accomplished for the highest demand area within Washington. Thus, Dr. Santini's basic data was used to structure a business venture around the retrofit of two power plants (Buzzard Point and Potomac River) which would thence provide hot water to the highest density demand area in Washington. It should be cautioned that, because of level of effort constraints, no attempt was made to optimize the business venture (for example, reducing distribution costs by selecting an area having a somewhat lower thermal demand). It is felt, however, that the slow growth with respect to retrofit and distribution is realistic and would probably be followed by a prudent investor who would like to "test the water before jumping in."

The primary input data source for the analysis was Dr. Santini at ANL. The Potomac Electric Power Company was not a party to this analysis although PEP Co. did provide some financial data. No active consideration was being given to DHCS in Washington by PEP Co. The data collection was performed jointly by Dynatrend and ECON with Dynatrend having the overall responsibility for providing the data as per ECON's needs. A report currently in preparation by Dynatrend will describe the details of the input data and associated assumptions. This data is summarized in the following pages.
The basic objective of this risk analysis was to establish insights into the likelihood of private sector investment in cogeneration facilities. More specifically, it was desired to establish the economic merits of a business venture concerned with the retrofit of existing power plants so as to produce thermal products for district heating and cooling applications. This requires capital expenditures for the retrofitting with additional expenditures for the thermal products transmission and local distribution system. One of the dominant economic characteristics of a district energy system are the large capital expenditures which must be made for the thermal transmission and distribution system. Thermal energy in the form of hot water or steam is much more costly per unit distance to transport than competing forms of energy (i.e., electrical, gas, oil). As a result of this characteristic, the financial merit of a district energy system is extremely sensitive to the density of demand characteristics and to the geographic distance between demand and supply points. The greater the proximity of these points, the lower the cost of distributing energy between them. Thus, the question facing the decision maker (investor) is whether the long-term increase in cash flow resulting from the sale of thermal energy products will compensate for the large short-term cash outflow (i.e., investment) required to achieve cogeneration. The answer to this question is confounded by uncertainty and risk. The major areas of uncertainty are the magnitude of capital expenditures (retrofit and distribution), future energy prices (electrical and thermal), fuel costs, O&M expenses and the demand (and its rate of development) for thermal products. The demand uncertainty is further confounded by the energy price uncertainty and the end user decisions pertaining to investments which would result in energy savings of sufficient magnitude to pay back their investments in a reasonable time. (It was assumed that end user retrofit costs would not be considered as part of the venture under investigation.)

The business venture of concern considers the retrofit of Buzzard Point (combustion) and Potomac River power plants. The general characteristics of these and other Washington power plants are summarized on the facing page. The market for the resulting thermal products results from the heating and cooling requirements of the residential, commercial and industrial sectors in the peak demand central area of Washington.

### Washington, DC Area Power Plant Characteristics Before and After Retrofit for Cogeneration

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Buzzard Point</th>
<th>Benning</th>
<th>Potomac River</th>
<th>Dickerson Existing</th>
<th>Dickerson New</th>
<th>Dickerson Existing</th>
<th>Morgantown</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turbine Type</td>
<td>Steam</td>
<td>Combustion</td>
<td>Steam</td>
<td>Steam</td>
<td>Steam</td>
<td>Steam</td>
<td>Combustion</td>
</tr>
<tr>
<td>Nominal Power (MW)</td>
<td>230</td>
<td>320</td>
<td>685</td>
<td>455</td>
<td>183</td>
<td>800</td>
<td>367</td>
</tr>
<tr>
<td>Type of Fuel</td>
<td>Oil #6</td>
<td>Oil #2</td>
<td>Oil #6</td>
<td>Coal</td>
<td>Coal</td>
<td>Coal</td>
<td>Coal</td>
</tr>
<tr>
<td>Cogeneration Capacity (MW)</td>
<td>Electric</td>
<td>Thermal</td>
<td>Electric</td>
<td>Thermal</td>
<td>Electric</td>
<td>Thermal</td>
<td>Electric</td>
</tr>
<tr>
<td></td>
<td>130</td>
<td>640</td>
<td>845</td>
<td>325</td>
<td>125</td>
<td>560</td>
<td>750</td>
</tr>
<tr>
<td>Electrical Drawing Factor</td>
<td>0.565</td>
<td>0.906</td>
<td>0.664</td>
<td>0.714</td>
<td>0.682</td>
<td>0.700</td>
<td>0.682</td>
</tr>
<tr>
<td>Heat Rate (MBTU/KWH)</td>
<td>Electric</td>
<td>Thermal</td>
<td>Electric</td>
<td>Thermal</td>
<td>Electric</td>
<td>Thermal</td>
<td>Electric</td>
</tr>
<tr>
<td></td>
<td>9.33</td>
<td>2.39</td>
<td>8.31</td>
<td>2.26</td>
<td>8.45</td>
<td>1.83</td>
<td>8.00</td>
</tr>
<tr>
<td>Cogenerating Efficiency</td>
<td>0.365</td>
<td>0.285</td>
<td>0.410</td>
<td>0.440</td>
<td>0.426</td>
<td>0.434</td>
<td>0.426</td>
</tr>
<tr>
<td>Original Nominal Efficiency</td>
<td>0.827</td>
<td>0.828</td>
<td>0.778</td>
<td>0.821</td>
<td>0.800</td>
<td>0.800</td>
<td>0.800</td>
</tr>
<tr>
<td>Number of Generating Units</td>
<td>5</td>
<td>2</td>
<td>6</td>
<td>5</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Capability for Terminating Cogeneration and Returning to Original Electrical Capacity</td>
<td>NO</td>
<td>YES</td>
<td>NO</td>
<td>YES</td>
<td>YES</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>1975 Load Factor</td>
<td>0.139</td>
<td>0.313</td>
<td>0.492</td>
<td>0.689</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
</tbody>
</table>

The basic structure of the cogeneration risk analysis is illustrated in the facing page. It should be noted that this structure is imposed to a considerable extent by the form and availability of data which characterizes the business venture. The structure is also imposed to a certain extent by the use of the RISK Model which, though extremely flexible, was not designed with this type of application in mind. Specifically, the RISK Model was designed to simulate unregulated manufacturing and sales-type of ventures. Since the power industry is a regulated industry with constraints imposed on return on investment, it is not possible to accurately simulate the utility investment analysis. Since modifying the existing RISK Model was beyond the scope of this effort and since a major objective was to demonstrate the use of risk analysis techniques, it was decided to perform the analysis assuming no regulation.

The analysis considered two products which were assumed to be independent from the demand side. This implies that little or no product substitution (electrical to thermal) will take place. Since gas and oil are the principal forms of energy used for heating applications in Washington, significant electrical to thermal product substitution is not anticipated. For cooling applications, there will be electrical to thermal product substitution. The specific consequences of this substitution have not been considered in the financial analysis of the business venture. It was assumed that the demand for electrical products would remain constant over the time frame of the analysis.

The revenue from each product is the product of plant capacity, load factor (percent utilization) and unit selling price. Cost of sales is considered to be primarily fuel cost, considered separately for each product. All other expenses (except depreciation) are considered as operation and maintenance (O&M) expenses. These are considered separately for the Potomac River and Buzzard Point power plants and for the transmission and local distribution systems. Total operating cost is the sum of all of these.

Depreciation is considered separately for the retrofit of the Buzzard Point and Potomac River power plants and for the transmission and local distribution expenditures. Note that the user retrofit costs are not considered. Interest expense based upon the previous year's indebtedness is added to the sum of depreciation and operating costs and subtracted from revenue to yield before-tax profit. Consideration of the tax structure and before-tax profit leads to after-tax profit. After-tax profit is combined with annual capital expenditures, depreciation and changes in balance sheet items to produce annual cash flow, indebtedness and present value of cash flow.

As will be described in the following pages, much of the input data is characterized by uncertainty profiles which are sampled using Monte Carlo techniques to produce risk profiles of pertinent financial performance measures.
Simplified Cogeneration Risk Analysis Structure

- Thermal Capacity (I)
- Unit Selling Price (I)
- Utilization (I)
- Electric Capacity (I)
- Unit Selling Price (I)
- Utilization (I)

1. Revenue (I)

2. Electric Fuel Cost (I)
   - Thermal Fuel Cost (I)
   - O&M-Trans. and Local Dist. (I)
   - O&M-Potomac (I)
   - O&M-Ruzzard Point (I)

3. Depreciation (I)
   - Ruzzard Point Retrofit
   - Potomac Retrofit
   - Transmission Expenditure
   - Local Dist. Expenditure

4. Total Capital Expenditures (I)

5. Total Operating Cost (I)

6. Indebtedness (I-1)

7. Interest Expense (I)

8. Total Expenses (I)

9. Before Tax Profit (I)

10. Carry Forward Loss (I-1)

11. After Tax Profit (I)

12. Present Value

13. Payback

14. Receivables (I), (I-1)

15. Change in Balance Sheet Item (I)

16. Payables (I), (I-1)
The assumed supply and demand situation is illustrated on the facing page. The supply of energy products is in terms of plant capacity. The electric energy capacity during the first four years is \(6789 \times 10^9\) W-HR per year based upon the combustion capacity at Buzzard Point and steam capacity at Potomac River. Only these plants are considered since these are assumed to be retrofitted during a four-year period starting in 1981 and being completed by the end of 1984. Upon completion of the retrofit, the electric energy capacity is reduced as indicated and a large thermal capacity \((26690 \times 10^9\) BTU per year) becomes available.

The electric energy sales are indicated as \(2350 \times 10^9\) W-HR per year based upon the 1975 average load factor of 35 percent. It is assumed that this will nominally continue during the ten-year time frame examined in detail in the analysis. It is assumed that to achieve this the load factor will increase to approximately 44 percent when the thermal products become available (start of the fifth year of the analysis). It is further assumed that the electric energy sales are known with certainty so as not to mask the thermal product sales uncertainty. Electric energy sales will, however, vary depending upon the price selected (in the Monte Carlo sampling) for the electric energy product.

Thermal energy products (hot water) will be offered at the start of the fifth year of the analysis. The range of uncertainty of sales is illustrated as the dotted region in the figure. It is assumed that the demand grows steadily during the indicated six-year period. It is assumed that an initial demand exists such that the thermal product load factor will be in the range of 14 to 17.4 percent. By the end of the tenth year, this has increased to 28 to 35 percent. Normal distributions have been assumed for these ranges of uncertainty. The high initial load factor is the result of the fact that the power company would probably not invest large sums of money in retrofitting the existing power plants without a guaranteed demand. As will be seen, the assumed initial demand may not be adequate to make investment attractive. Thus, a more attractive business situation would result from a higher initial demand.

A number of capital expenditures are required to bring about the thermal products. These are summarized below in terms of ranges of the expenditures and the probability of achieving different values. All expenditures are made during the initial four-year period. Depreciation expenses are computed based upon twenty-year life and straight-line depreciation.

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<thead>
<tr>
<th>Type of Expenditure</th>
<th>Range of Uncertainty (and Probability)</th>
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<td>Retrofit at Potomac River</td>
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<tr>
<td>Local Distribution</td>
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PLANT CAPACITY AND UTILIZATION

ANNUAL CAPACITY AND UTILIZATION ($10^9$)

- 26690 x $10^9$ BTU(T)
- 9288 x $10^9$ BTU(T)
- 5525 x $10^9$ BTU(T)
- 6789 x $10^9$ W-HR(e)
- 5387 x $10^9$ W-HR(e)
- 2350 x $10^9$ W-HR(e)

TIME (YEARS)

0 1 2 3 4 5 6 7 8 9 10
The price, fuel cost and O&M expense data used in the analysis are summarized on the facing page and are based upon current year dollars. The O&M expenses are considered separately for the Buzzard Point and Potomac River power plants and for transmission and local distribution. It is anticipated that the costs will increase at the rate of 2.8 percent per year as per the increase in fuel costs between 1977 and 1978 at Potomac Electric Power Company. This then establishes the expected future cost pattern. It was assumed that the same variability in cost would exist on the high side as on the low side (i.e., a symmetric uncertainty profile centered on the expected value). Since costs are not expected to decrease below their 1977/1978 values, the range of uncertainty is thus established (the lower bound being the 1977 cost and the upper bound being the expected value plus the difference between the expected value and lower bound). The lower cost bound corresponds to 2 mills per kilowatt hour for coal-fired plants (Potomac River) and 3 mills per kilowatt hour for combustion plants (Buzzard Point). In the fifth year, it is anticipated that these O&M costs will increase significantly due to the introduction of the thermal products. It is estimated that these costs will approximately double.

The O&M costs associated with transmission and local distribution were related to capital costs. The maximum was estimated to be .0406 times capital costs and the minimum as .0067 times capital cost. The capital costs used were the expected values.

Electrical energy price is based upon current pricing in Washington and projected in the same manner as were the O&M expenses (i.e., 2.8 percent per year and with the same procedure followed for establishing the range of uncertainty). In this case, the 2.8 percent per year increase is based upon eight-year trend data. The price of thermal energy products was established by determining the price which would yield sufficient savings to an average user to pay back the user capital investments (for utilizing the thermal energy products) in four years. Therefore,

\[
\text{Allowed Thermal Energy Price} = \text{Current Energy Charge} - \frac{\text{Capital Investment}}{4}
\]

Since this is based upon the end user energy, an adjustment was made to establish the price per unit of energy produced at the power plant in order to take into account an estimated 28 percent transmission loss. Current end-user energy costs were based on fuel oil which is the dominant fuel for heating and cooling applications in Washington.

Fuel costs are assumed to be synonymous with cost of sales (all other costs are included as O&M, depreciation or interest). The fuel costs are based upon the current costs of generating electrical and thermal energy. These costs are projected in the same manner as previously described (2.8 percent per year).
INPUT DATA -- PRICE, FUEL COST, O&M EXPENSES

- Electric Energy Price (Mills/kWh)
- Electric Energy Fuel Cost (Mills/kWh)
- Thermal Energy Price (Mills/10^3 BTU)
- Thermal Energy Fuel Cost (Mills/10^3 BTU)

Graphs showing annual expenses from 1971 to 1981 in 80's dollars for:
- Potomac River
- Buzzard Point
- Transmission and Local Distribution

Yearly data for input data analysis.
The question to be answered from the point of view of the power company is: Should business continue as usual (i.e., electrical products) or should the existing power plants be modified so as to provide both electrical and thermal products? Normally, to answer this question, an incremental analysis is sufficient; that is, the incremental cash flows are developed. This form of analysis is adequate when the incremental cash flows resulting from the new venture are small compared to corporate cash flows. In other words, the risk of the venture does not materially affect the risk of the overall or parent organization. When the cash flows of the new venture become an appreciable part of the overall cash flows, the risk of the overall or parent organization is affected and the risk analysis must be performed as "with" and "without" analyses and the results compared.

For the cogeneration risk analyses, two business ventures were analyzed. The first was the business as usual venture—the "without" investment in cogeneration situation. The second was the business with the investment made for cogeneration—the "with" situation. The results of these two analyses are summarized on the facing page. Expected or average values are represented by \( m \) and standard deviation by \( \sigma \).

The financial analyses were performed for each year of the planning horizon (ten years). It was assumed that the cash flow in future (greater than ten) years would be similar to that of the last year of the planning horizon. It was assumed that the venture was part of a larger corporation with losses used to offset other profits. Four weeks of outstanding receivables and two weeks of outstanding payables were assumed. Since the cogeneration business venture will make use of existing facilities and other assets, it was necessary to consider these. Current receivables were estimated as the product of capacity, utilization factor, price and percent of outstanding receivables.* Payables were estimated in a similar fashion, but based upon expenses. Book value of current plant (Buzzard Point combustion and Potomac River) was estimated, based upon PEPCO data, as $390,870,000. Depreciation expenses were based upon straight-line depreciation and 20-year depreciation life. Normal corporate income tax rates were used.

A summary of the financial results is presented on the facing page. Detailed results are given in Appendix B. The increase in revenue with time is the result of the estimated 2.8 percent per year increase in price plus, in the cogeneration case, the revenue from thermal products. After-tax profits increase with time as does return on assets. The increase in return on assets is due to the combined effect of increased profit and reduced asset value (due to accumulated depreciation). Indebtedness is negative indicating that cumulative cash inflows exceed cumulative cash outflows. Particular note should be made that in the cogeneration case, the cash flow is negative in the third and fourth years due to the large capital expenditures.

---

* Four weeks of outstanding receivables corresponds to 7.7 percent.
FINANCIAL SUMMARY (MILLIONS OF DOLLARS)

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### ELECTRIC AND THERMAL ENERGY PRODUCTS

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F-41
The present worth risk profile data is indicated in the facing page in terms of discount rate. The results are based upon an infinite horizon discounting with the cash flow in the $10^{th}$ year assumed to continue for all future time periods. The data is presented for both the business as usual venture (electrical energy products) and the cogeneration business venture (electrical and thermal products). The present worth (or value) is given by

$$\text{NPV} = \sum \frac{CF_I}{(1 + R)^{I-1}}$$

where $CF_I$ is the cash flow in the $I^{th}$ year. Since $CF_I$ is a random variable, it follows that the present worth is also a random variable. The accompanying table indicates the probability that the indicated present worth or value will be exceeded (i.e., in the business as usual situation with a 10 percent discount rate, there is a 60 percent chance that present worth will exceed $635$ million).

Also indicated are the expected or average values and associated standard deviations.
## Present Worth Risk Profile Data (Thousands of Dollars)

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**Thermal and Electric Energy Products**

**Economic Data**

- **Initial End User Thermal Demand**: High Level of Initial End User Thermal Demand
- **Thermal and Electric Energy Products**: Present Worth Risk Profile Data (Thousands of Dollars)

**Discount Rate (Percent)**

- 2.0
- 5.0
- 10.0
- 15.0
- 20.0

**Average ($1000)**

- Electric Energy Product
  - 4253841
  - 1484236
  - 613860
  - 352331
  - 235079

**Std. Dev. ($1000)**

- 356687
- 43576
- 2686
- 16221

**Economic Data**

- **Initial End User Thermal Demand**: High Level of Initial End User Thermal Demand
- **Thermal and Electric Energy Products**: Present Worth Risk Profile Data (Thousands of Dollars)

**Discount Rate (Percent)**

- 2.0
- 5.0
- 10.0
- 15.0
- 20.0

**Average ($1000)**

- Electric Energy Product
  - 3705337
  - 1385426
  - 641283
  - 407675
  - 296955

**Std. Dev. ($1000)**

- 309277
- 100215
- 32756
- 18088
- 12639

**F-43**
The present worth risk profile data presented in the previous chart are displayed graphically on the facing page. The present worth risk profiles indicate the probability of exceeding different levels of present worth.

The risk profiles, both for business as usual venture (electrical energy products) and the cogeneration business venture (thermal and electrical energy products) are illustrated. Several observations should be made. First, both risk profiles are approximately Normal and have the well-known "S" shape. Second, the risk profiles are approximately parallel indicating the same level of risk (as measured by the standard deviation). Third, the expected present worth of the business as usual situation, $NPV_e$, exceeds that of the cogeneration business venture, $NPV_c$. This situation, as can be seen from the previous chart, is a function of discount rate; therefore, conclusions cannot be drawn without considering the applicable cost of capital. The following pages develop a comparison of the business venture alternatives in terms of the risk profile of return on investment.
PRESENT WORTH RISK PROFILES (10% DISCOUNT RATE)

ELECTRIC ENERGY PRODUCTS

THERMAL AND ELECTRIC ENERGY PRODUCTS (HIGH LEVEL OF INITIAL END USER THERMAL DEMAND)

PROBABILITY OF EXCEEDING INDICATED NPV

NPV (MILLIONS OF DOLLARS)
It is necessary to establish the probability of being better off by making the investment in cogeneration than continuing the business as usual (electrical energy only). To accomplish this and at the same time develop insights into the return on investment in cogeneration, it is necessary to establish the risk profile of return on investment (ROI). This can be accomplished by evaluating the cogeneration business venture relative to the business as usual situation.

Return on investment (ROI) is defined as the discount rate that reduces the present worth to zero. This is also commonly referred to as the internal rate of return. The internal rate of return is therefore the cost of capital which would make the investor indifferent to the investment opportunity. Since the present worth is a random variable, it follows that the internal rate of return is also a random variable.

The comparison of the "with" and "without" situations is accomplished as follows. It is necessary to establish the probability distribution of the present worth (as a function of discount rate) of the cogeneration business venture relative to the business as usual situation. Since the present worth probability distributions of each of the ventures is near Normal, the resulting probability distribution will be Normal with an expected value, \( m \), obtained as \( m = m_2 - m_1 \), and a standard deviation, \( \sigma \), obtained as \( \sqrt{\sigma_1^2 + \sigma_2^2} \), \( m_1 \) and \( \sigma_1 \) are the expected value and standard deviation, respectively, of the business as usual situation and \( m_2 \) and \( \sigma_2 \) are for the cogeneration business venture. This data is summarized below.

<table>
<thead>
<tr>
<th>Business Situation</th>
<th>2%</th>
<th>5%</th>
<th>10%</th>
<th>15%</th>
<th>20%</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Business As Usual (Electric Energy)</td>
<td>$3705M</td>
<td>$1593M</td>
<td>$641M</td>
<td>$407M</td>
<td>$297M</td>
</tr>
<tr>
<td></td>
<td>309M</td>
<td>100M</td>
<td>37M</td>
<td>20M</td>
<td>13M</td>
</tr>
<tr>
<td>(2) Cogeneration (Thermal &amp; Electric Energy)</td>
<td>$6294M</td>
<td>$1480M</td>
<td>$614M</td>
<td>$352M</td>
<td>$235M</td>
</tr>
<tr>
<td></td>
<td>357M</td>
<td>115M</td>
<td>44M</td>
<td>24M</td>
<td>16M</td>
</tr>
<tr>
<td>(3) Cogeneration Relative to Business as Usual</td>
<td>$549M</td>
<td>$99M</td>
<td>$27M</td>
<td>$55M</td>
<td>$62M</td>
</tr>
<tr>
<td></td>
<td>472M</td>
<td>152M</td>
<td>57M</td>
<td>31M</td>
<td>21M</td>
</tr>
</tbody>
</table>

The probability distributions of the present worth of the cogeneration venture relative to business as usual are indicated on the facing page. Also indicated are lines of constant chance of being exceeded. These indicate the present worth as a function of discount rate which will be exceeded with a specified chance. The probability distribution of internal rate of return or ROI can thus be established by noting the intersection of these lines of constant probability with the horizontal axis. The resulting risk profile of ROI is given in the following chart.

*This assumes that the "with" and "without" situation results are independent (i.e., \( \sigma_1 \) and \( \sigma_2 \) are uncorrelated).
DETERMINATION OF RETURN ON INVESTMENT PROBABILITY DISTRIBUTION
(HIGH LEVEL OF INITIAL END USER THERMAL DEMAND)
The developed risk profiles of return on investment are presented on the facing page. These risk profiles represent the chance that different levels of return on investment will be exceeded. The risk profile entitled "high level of initial end user thermal demand" is that which results from the nominal set of data presented and discussed in the previous pages. The risk profile entitled "high level of initial end user thermal demand plus public sector cost sharing" is that which results from the nominal set of data but with all private sector expenditures reduced by 50 percent (i.e., cost sharing by the public sector is assumed in order to influence private sector decisions and speed-up the rate of introduction of cogeneration).

There appears to be only a 40 percent chance of the cogeneration business venture producing an ROI in excess of a 10 percent cost of capital. This can be increased to about a 65-70 percent chance if substantial public sector cost sharing is undertaken. As a result, the investment in cogeneration in Washington does not appear to be an attractive business venture.

A risk analysis was also performed for a business venture concerned solely with the thermal energy products. The business venture received the revenues, incurred the expenses and funded the capital expenditures associated with the thermal products. The net result, in terms of the risk profile of return on investment is also illustrated on the facing page. There is less risk associated with this situation since the uncertainty associated with the pricing of the electrical products is not considered and because of the assumed statistical independence of the thermal and electrical product uncertainty variables.

Before making a final judgment, it should be noted that because of funding constraints, a number of possibly important factors were not adequately investigated. Several of these are:

- The impact of a higher initial thermal demand. To a certain extent, this is under the control of the investor since it is obvious that large financial investments would not be made without significant end-user commitment. On the other hand, significant end-user commitment may be difficult to obtain since end-user investments are required.

- The lack of detailed analysis of thermal product pricing policy and its impact upon end-user demand which, in turn, affects the economics of the business venture.

- The inability, with the existing RISK Model, of adequately modeling the regulated business environment of the utility industry.

- The lack of consideration of the impact of alternative depreciation schemes (only 20 year straight-line depreciation was considered).
5. CASE STUDY OF DHCS—MINNEAPOLIS/ST. PAUL
A brief financial risk analysis case study of a district heating system business venture in Washington, D.C. was previously performed (the results are reported in Section 4). Its purpose was to demonstrate the use of risk analysis techniques to assist in the evaluation of business ventures that might be impacted by DOE RD&D and incentive programs and evaluate the effect of DOE policy options. The basic data was primarily provided by Dr. Santini of the Argonne National Laboratory. Upon completion of this study it was decided to perform a more thorough analysis. It was originally intended to redo the Washington case study; however, it was determined that a very detailed data base existed for a DHCS in the Minneapolis/St. Paul Twin Cities area. This data base is the result of a series of in-depth application studies performed cooperatively by the Department of Energy, Minnesota Energy Agency, Northern States Power Company and other local government and private organizations. The initial effort, a joint U.S./Swedish study, looked at the overall feasibility. The studies covered buildings and distribution systems, energy sources, environmental issues and institutional issues. It was thus decided to perform the financial risk analysis case study of a district heating system business venture in the Twin Cities area. This study had the active cooperation of the NSP Co. All data utilized in this study was provided either directly by the NSP Co. and DOE or was obtained from reports which describe the results of the studies and analyses supported by DOE and the NSP Co. 4, 5, 7, 13. The basic system configuration and data identified in Reference 4 serves as the basic scenario for the analyses described in the following pages.

The Twin Cities area contains two concentrated downtown areas in Minneapolis and St. Paul spaced about seven miles from one another. Around these is a region of industrial sites and residential housing which practically links the areas into one continuous metropolitan region. Approximately 800,000 people live within the two city boundaries with well in excess of one million people residing within the two cities and close-by suburbs. This large population together with the cold climate gives rise to a large heat demand.

At present, the vast majority of the heat demand is satisfied by natural gas, though gas supplies for the larger customers have been cut during winter and have had to be replaced by oil. A large part of the industrial gas supply is interrupted when temperatures drop below 15 degrees Fahrenheit. Three small steam-based district heating systems exist in the area — and old one in downtown Minneapolis (about 80 MW, including also some district cooling) and one for the University of Minnesota (about 125 MW, also including some cooling) close by. All use steam as the distribution medium and none presently use cogeneration. Hither to mainly gas and oil have been used as fuels for district heating though some conversion to coal is taking place for the St. Paul and university systems.

There are two fairly large coal-fired electric generating stations within the city boundaries, High Bridge for St. Paul and Riverside for Minneapolis. A third station, Black Dog, is just south of Minneapolis, and several newer coal-fired and nuclear plants are at various distances outside the metropolitan area. The closest of these is King, 17 miles from downtown St. Paul.
AREA MAP WITH MAIN THERMAL POWER PLANTS

- SHERBURNE (coal, 2 x 680 MW)
  - (2 x 800 MW 1980/85)

- MONTICELLO (nuclear, 557 MW)

- MISSISSIPPI RIVER

- ST CROIX RIVER

- MINNESOTA RIVER

- BLACK DOG (coal, 407 MW)

- RIVERSIDE (coal, 334 MW)

- KING (coal, 524 MW)

- KINGDOM

- MINNEAPOLIS

- D.H.

- PRAIRIE ISLAND (nuclear, 2 x 520 MW)

- D.H. = Existing district heating scheme (steam)

- Source: Ref. 4

- Approx extent of reasonably dense residential area

- Miles

- Scale: 0 5 10 15 20 25

- Miles
Two levels of penetration of district heating were considered in the DOE/NSP studies -- scenario A which restricts district heating to the downtown and industrial commercial areas and nearby residential districts, and scenario B covering in addition also medium density residential districts with one and two family houses at a greater distance from the central parts of the cities. The following risk analysis discussion considers only scenario A. Over a 20 year build up period it is estimated (for scenario A) that a thermal load of approximately 2,600 MW of heat will develop. This excludes the loads of the existing district heating schemes in Minneapolis and at the University. It also excludes the loads of several large industries requiring more detailed study and all loads due to future establishments within the area. To compensate for the conservatism of these assumptions, it was assumed that all remaining consumers within the area would ultimately connect. 1980 was the assumed starting date for the development, but practical questions are likely to delay the earliest starting date by one or more years. The basic technology assumed is that used in modern Swedish schemes, which now supply a large and increasing part of the National demand for space heating and domestic hot water by hot water distribution systems. Some 3 million people of a population of 8 million are now served by district heating at their homes or places of work.

The principle features of the district heating system considered as the basis for the risk analysis are as follows:

- The base load of the district heating scheme is supplied by cogeneration plants which provide about half the required heat capacity but close to 90% of the annual heat quantities. Most of the cogeneration units are obtained by converting turbo-generators to pass-out machines at two existing power stations, Riverside in Minneapolis and High Bridge in St. Paul. This greatly improves fuel utilization. Towards the end of the twenty year period these units are complemented by new units. A new unit at Riverside is assumed. The cogeneration plants replace large quantities of oil and gas by small quantities of coal.

- The peak load and reserve capacity requirements are covered by oil-fired heat-only boilers. These have a large total capacity but supply only a small percentage of the heat energy. They are located at various points of the supply area, thus reducing the size of pipes necessary between the central cogeneration plant sites and the supply areas.

- The heat is transported from the production plants to the various parts of the supply area by hot water mains in accordance with modern European district heating technology. Large pipes run through tunnels for the parts of the area having good rock. Elsewhere underground pipes protected by concrete culverts are used. Initially the transport systems are built up separately in Minneapolis and St. Paul. During the second half of the period they are interconnected.

The details of the system can be obtained from Reference 4 and its appendices.
The heat is distributed from the regional system to individual buildings and houses by a hot water distribution system running under pavements, under streets or where possible, through cellars. Prefabricated pipes complete with insulation and protection ducts are used.

The heating systems of existing buildings are adapted so that they can be connected to the district heating system through heat exchangers. Different solutions are used for buildings and houses currently supplied by hot water, steam or hot air.

The cooling loads were ignored in the analysis though in principle existing absorption chillers could be converted to be operated from hot water and supplied from the district heating scheme if certain restrictions were placed on the lowest permissible summer hot water temperatures. There are at present only a small proportion of such coolers so that the import on economics would be small.

It is assumed that the system will be built up progressively starting with the most attractive densest areas in a way that allows them to start generating revenues as soon as possible. The heat loads of the two existing district heating systems in central Minneapolis as well as the heat loads of some large industries have been ignored until more detailed studies are performed as to the best ways of integrating these loads into the overall scheme.

The Twin City area has many attributes which make the use of a district heating and cooling system attractive, including:

- A cold climate and a city structure well adapted to district heating and with a large potential heat load.
- The present use of fuels which will become increasingly expensive and scarce (natural gas and oil)
- The existence of some old generating stations close to the city with units suitable for conversion to cogeneration, which use cheap coal as fuel
- The existence of some district heating tradition and yet not so large existing district heating supply areas that the current steam distribution technology should strongly influence the technology to be used in the future
- The existence of interested and cooperative local authorities and utilities with a desire to improve fuel usage and reduce air pollution.
The basic structure of the district heating system risk analysis is illustrated in the facing page. It should be noted that this structure is imposed to a considerable extent by the form and availability of data which characterizes the business venture. The structure is also imposed to a certain extent by the use of the RISK Model which, though extremely flexible, was not designed with this type of application in mind. Specifically, the RISK Model was designed to simulate unregulated manufacturing and sales types of ventures. The district heating system business venture will either be privately owned and operated or publicly owned and operated. Both of these are considered. In the former case it is likely to be regulated with constraints imposed on allowed rate of return. In this situation it is not possible to accurately simulate the utility investment analysis since the Model does not compute the price required to yield the allowed rate of return. The results of the risk analysis can provide insights into the financial merits of the business venture by first utilizing a nominal set of data which yields anticipated allowed rates of return and then performing the risk analysis about this data set and observing its effect on the probability distribution of return on assets. When the business venture is publicly owned and operated it is anticipated that the rate of return constraint will not be imposed and a more accurate simulation is possible. These problems and solutions are discussed in following pages.

The analysis is incremented in nature -- that is, the district heating business venture is analyzed as an independent business venture. Capital expenditures are included, however, for modifying the existing electrical generating system and expenses include increases in electrical system fuel costs due to reduced electrical generating capacity at the more efficient power plants (requiring the utilization of plants of higher operating costs). The analysis considers the hot water product as consisting of hot water from the base-load power plants and hot water from the heat-only boilers. Therefore two thermal products are considered - both having the same price but different unit sales. The reason for doing this is that data is available on energy available from base-load and heat-only boilers. Data is also available that relates various expense items to these two thermal products.

The revenue from each product is the product of unit sales, unit selling price and market share (assumed as 100%). Operating cost is the sum of the fuel (including coal and displaced electricity) cost and operations and maintenance (O&M) cost for both the base-load and heat-only products.

A number of capital expenditures are specified in magnitude and time (for example, the retrofitting of High Bridge No. 3) and a number of capital expenditures (for example, local network) are established in terms of total unit sales. This is discussed in more detail in following pages. It should be noted that consumer equipment related capital expenditures are part of the capital structure of the business venture. It is assumed that the business venture will pay for the consumer expenditures for hookup and modification. These expenditures will then form a part of the rate base with the consumer receiving a single bill that is proportional to energy use. It is anticipated that this approach will stimulate conversion to hot water since the consumer need only compare the hot water cost.
with his current heating bill (the consumer does not have to consider the more complex decision involving both capital expenditures and operating costs).

Depreciation is considered separately for each expenditure. Total expense is the sum of total depreciation and total operating cost. Before tax profit is revenue less the sum of total expenses and interest expense. Interest expense is based upon the previous year's indebtedness (negative of cumulative cash flow to date). After tax profit takes into account carry forward losses and investment tax credits as per the current tax law. After-tax profit is combined with annual capital expenditures, depreciation and changes in balance sheet items to produce annual cash flow, indebtedness and present value of cash flow. The after-tax profit is divided by the book value of total assets to obtain return-on-assets.

As will be described in the following pages, most of the input data is characterized by uncertainty profiles which are sampled using Mante Carlo techniques to produce risk profiles of pertinent financial performance measures.

Studsvik [4] has analyzed the heat demand in the Minneapolis/St. Paul area. The results of this analysis are indicated on the facing page as the projected thermal energy sales to consumers. This is broken down as base-load and heat-only boilers energy sales since costs and capital expenditures are related to these sales.

The heat demand was established by subdividing the Twin Cities area into 43 district heating areas. The establishment of the districts considered homogeneity of building types and natural geographic boundaries. The main basis for the subdivision and for the estimation of the energy demand were records of consumption of natural gas for the year 1976 and the building classification according to zoning maps. The gas consumption figures were corrected for gas supply curtailments and for gas used for purposes other than space heating and domestic hot water. Detailed analysis of the thermal load characteristics together with the cogeneration and peak-boiler implementation schedule resulted in the division of total thermal energy sales into base-load and heat-only boiler energy sales.

The districts considered most economical for district heating were grouped together under the notation "Scenario A." These districts encompass approximately 50 percent (2,600 MW) of the total heat load in the two cities concentrated in 30 percent of the gross land area. It was assumed that 100 percent connectivity would be achieved in the scenario A areas by the end of the 20th year of the analysis.

The thermal energy sales forecast on the facing page has been used as the nominal sales forecast in the risk analysis. Uncertainty estimates have been made, and are discussed in following pages, with respect to the possible variability in the energy sales forecast.
PROJECTED THERMAL ENERGY SALES TO CONSUMER (REF. 4)
The projected thermal energy price to the consumer is illustrated on the facing page. These price projections, made by Northern States Power and given to Studsvik [4], and were used as the nominal values for the deterministic analysis described in the following pages and as the basis for making uncertainty assessments for the uncertainty scenarios which follow.

Whereas in practice the cost of consumer heat system connections and conversions could be borne by the consumers or the utility—or a combination—it was assumed that the utility would finance these investments. As a result, the rate charged for heat can be compared directly with the value of the fuel replaced by the elimination of individual boilers. The rate was set at a value of 10 percent below the cost of the fuel consumed by the cheapest alternative using individual boilers.

The cheapest of the fuels, natural gas or oil, was used (by Studsvik) for assessing these alternative costs, based on fuel price projections prepared by the Northern states Power Company [4]. Initially this cheapest fuel was assumed to be gas, but starting in the mid-eighties it was assumed to be oil. Swedish experience indicates that most consumers connect to a district heating system when heat is sold at the same cost as alternative heat supplies, in view of the greater convenience of the district heating solution for building owners.
PROJECTED THERMAL ENERGY TARIFF TO CONSUMER (REF. 4)

- CURRENT DOLLARS
- CONSTANT DOLLARS (1978)

TIME, YRS.

THERMAL ENERGY TARIFF, K$/$KWH
Predictions by Northern States Power [as indicated in Reference 4] on future inflation rate and development trends for fuel costs were used. For inflation, this represents a rate of 5 to 6 percent per year at the beginning of the period (1980) and falling off to 4 percent per year by the year 2000. All analyses detailed in the following pages are based upon current dollars.

Coal costs were assumed to increase by about 1.3 percent per year in terms of 1978 dollars throughout the 20 year period of the analyses. Also, electricity costs for auxiliaries, such as pumps, is assumed to increase only slightly in terms of 1978 dollars, as the influence of some fuel price increases will be counteracted by cost reductions due to the growth of the overall system.

Oil costs were assumed to reach world market prices by 1981 and to increase thereafter at approximately 2 percent per year in terms of 1978 dollars. Mean individual boiler efficiency was estimated at 70 percent and the efficiency for large heat-only district heating boilers was estimated at 90 percent.

Gas prices were assumed to increase by a factor of 2.4 over the 1980–2000 time period. By the mid-eighties, the gas price consumers have to pay begins to exceed those which consumers have to pay for light oil (houses) and medium grade oil (buildings).

The projected annual fuel cost and O&M expenses (K$/KMWH) used by Studsvik [4] are shown on the facing page for energy produced by base-load and heat-only boilers. The fuel cost, for base-load energy, includes the cost of coal and displaced electricity costs. Costs of operation and maintenance for the transport and distribution were assumed to be one percent per year of the investment, in accordance with practice in many Swedish district heating utilities. For a production plant, it was assumed that operation and maintenance costs would be 2 percent per year on the investment.
SUMMARY OF EXPENSES, CURRENT $ (BASED ON REF. 4)
The analyses assume that a water-based district heating system will be built up gradually in Minneapolis/St. Paul during a 20-year period. The development will begin with the dense city areas and proceed down to suitable areas with two- and four-family houses. The total coinciding demand amounts to 1,781 MW\(_t\) for Minneapolis and 840 MW\(_t\) for St. Paul, totalling 2,621 MW\(_t\).

The Studsvik \([4]\) capital expenditure scenario is illustrated on the facing page where the capital item is indicated together with the year of start of operation (The analyses in the following pages assume that the capital expenditures occur at the indicated times and are not spread out over time as is actually the case. This introduces some minor distortions to the cash flow analyses.), the magnitude of the expenditure in thousands of current dollars and the depreciation life. All depreciation computations are based upon the sum-of-the-years-digits method.

It should be noted that the basic scenario involves conversion of existing turbines (High Bridge Nos. 3, 4, 5, 6 and 9 and Riverside Nos. 6 and 9) and the addition of a new back-pressure turbine (No. 7A) at Riverside. The scenario also includes the addition of a number of heat-only boilers which are needed for peak loads and reserve capacity. Additional heat-only boilers are required and are discussed in the following page. The scenario also includes transmission line, local network (distribution) and consumer related capital expenditures. Two of the initial transmission expenditures are included in the facing table. The remainder of the capital expenditures are discussed in the following page.

The specific capital expenditures indicated on the facing page are those expenditures that are large in magnitude, specifically identifiable, and would be required, to a large extent, independent of minor changes in the projected demand. There are other capital expenditures which are directly related to consumer demand and their timing and magnitude are a function of demand. These are discussed in the following page.
# Capital Expenditure Summary (Based on Ref. 4)

<table>
<thead>
<tr>
<th>Capital Item</th>
<th>Year</th>
<th>Amount, K$ (Current)</th>
<th>Depreciation Life, Yrs.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. High Bridge No. 3</td>
<td>11 (1990)</td>
<td>5860</td>
<td>20</td>
</tr>
<tr>
<td>2. High Bridge No. 4</td>
<td>7 (1986)</td>
<td>4950</td>
<td>20</td>
</tr>
<tr>
<td>3. High Bridge No. 5</td>
<td>3 (1982)</td>
<td>4940</td>
<td>20</td>
</tr>
<tr>
<td>4. High Bridge No. 6</td>
<td>2 (1981)</td>
<td>5280</td>
<td>20</td>
</tr>
<tr>
<td>5. Riverside No. 6 &amp; No. 8</td>
<td>4 (1983)</td>
<td>9890</td>
<td>20</td>
</tr>
<tr>
<td>7. High Bridge No. 9 or Riverside No. 9</td>
<td>17 (1996)</td>
<td>65250</td>
<td>30</td>
</tr>
<tr>
<td>8. Peak Load Boilers (81, 82, 83)</td>
<td>2 (1981)</td>
<td>4870</td>
<td>25</td>
</tr>
</tbody>
</table>
The previous page indicated the magnitude and timing of the major capital expenditures that are easily related to thermal energy sales. Other capital expenditures are necessary that are related to the local distribution network, the consumer equipment, transmission lines and heat-only boilers. The analysis performed by Studsvik [4] developed the desired sales. These capital expenditures are plotted on the facing page where total investment in local networks, consumer equipment, transmission lines and heat-only boilers, is indicated (millions of current dollars) in terms of thermal energy sales ($10^6$ MWH). It can be seen that there exist functional relationships between thermal energy demand and investment which may be approximated by a series of straight lines -- i.e., there appears to be a linear relationship between thermal energy demand and investment. These linear relationships have been used in the analyses described in the following pages to establish the magnitude and timing of capital expenditures in terms of thermal demand. These are important functional relationships since they provide the structural mechanism that allows the impact of demand uncertainty (in the following risk analyses) to be converted into the magnitude and timing of capital expenditures.

The RISK Model establishes the production level (or energy demand) related capital expenditures in the following manner. Unit Sales, US, are established in year I. If adequate production capacity has not been installed in previous years, i.e., an initial production increment, IP, plus the previously added production increments, then additional production increments, N, must be added at a cost of $\delta M$ where $\delta$ is the cost per unit sold (K$/KMWH)$ and $M$ is the production increment added (KMWH). The cost of the initial production level, IP, is established through the capital expenditures given on the previous page. Therefore, the mathematical procedure is as follows where $CPC_{L-1}$ is the cumulative production capacity at the end of the previous year.

\[
CPC_{L-1} = IP + M\sum_{A=1}^{L-1} N_A \quad (N_0 = 0)
\]

If $US \leq CPC_{L-1}$

Then

$N_I = 0$

If $US > CPC_{L-1}$

Then

$N_I = \text{integer} \left(\frac{US - CPC_{L-1}}{M}\right) + 0.9999$

Annual Cap. Expend. = $N_I \cdot \delta M$

\[
(1) \quad (2) \quad (3) \quad (4) \quad (5) \quad (6)
\]

F-68
FUNCTIONAL RELATIONSHIPS OF CAPITAL EXPENDITURES AND CONSUMER DEMAND

LOCAL NETWORK (○)
CONSUMER EQUIPMENT (●)
TRANSMISSION LINES (x)
HEAT-ONLY BOILERS (★)

δ = 133.79$/KWH
δ = 29.63$/KWH
δ = 16.774$/KWH
δ = 12.857$/KWH
δ = 30$/KWH
δ = 20.313$/KWH

INVESTMENT, 10^6 $ (CURRENT)

CONSUMER DEMAND, 10^6 MWH
The unit dependent capital expenditures are summarized on the facing page. Note that the transmission lines and local network capital expenditures have been approximated by two straight lines, one representing the low end of the demand and the other representing the high end of the demand. The data on the facing page can be explained by example.

Consider the local network related capital expenditures. An initial production capability is established via the capital expenditures indicated on page F-101. Thus as long as the demand is less than 200 KMWH no further capital expenditures are necessary. When the demand exceeds 200 KMWH per year but is less than approximately 4000 KMWH then production capacity will be added such that capital expenditures of $9365K$ are necessary per 70 KMWH increment.

It should be noted that the increase in capital expenditures per unit of demand satisfied increase with demand (for local network and transmission line capital expenditures) since the high density demand areas are served first and to increase the energy demand it is necessary to reach those areas of lower demand density.
## SUMMARY OF UNIT DEPENDENT CAPITAL EXPENDITURES

<table>
<thead>
<tr>
<th>CAPITAL ITEM</th>
<th>IP MINIMUM PRODUCTION LEVEL, KWH</th>
<th>M PRODUCTION INCREMENT, KWH</th>
<th>δ*M COST FOR PRODUCTION INCREMENT, K$</th>
</tr>
</thead>
<tbody>
<tr>
<td>TRANSM. LINES (LOW END OF DEMAND)</td>
<td>0</td>
<td>70</td>
<td>899.99</td>
</tr>
<tr>
<td>TRANSM. LINES (HIGH END OF DEMAND)</td>
<td>3980</td>
<td>70</td>
<td>1174.18</td>
</tr>
<tr>
<td>CONSUMER EQUIP.</td>
<td>0</td>
<td>70</td>
<td>2074.1</td>
</tr>
<tr>
<td>LOCAL NETWORK (LOW END)</td>
<td>200</td>
<td>70</td>
<td>2100.0</td>
</tr>
<tr>
<td>LOCAL NETWORK (HIGH END)</td>
<td>4100</td>
<td>70</td>
<td>9365.3</td>
</tr>
<tr>
<td>HEAT-ONLY PLANTS</td>
<td>2800</td>
<td>70</td>
<td>1421.91</td>
</tr>
</tbody>
</table>
A comparison of the cumulative investment indicated by the Studsvik analysis [4] and the approximation employed when using the RISK Model in a deterministic model (i.e., all ranges of uncertainty set equal to zero and deterministic data utilized). It can be seen that the RISK Model computed capital expenditures track those of Studsvik reasonably well. (The differences could be further reduced by approximating the previously determined functional relationships with additional line segments. Time constraints did not allow this to be done.)
CUMULATIVE INVESTMENTS (CURRENT DOLLARS)

STUDSVIK [4] DATA

RISK MODEL DETERMINISTIC RESULTS

TIME, YRS.
The facing page presents summary financial data of two deterministic DHCS business scenarios. Both utilize the data summarized in the previous pages concerning the revenue, expense and capital expenditures. The scenarios represent private ownership/operation (the solid lines) and public ownership/operation (the dotted lines).

The financial analyses were performed for each year of the planning horizon (20 years). It was assumed that the cash flow in future (greater than 20) years would be similar to that of the last year of the planning horizon. It was assumed that the venture was a separate entity with the current tax law structure (carry forward losses, investment tax credit and carry forward of unused tax credits) assumed to apply for all future years. Four weeks of outstanding receivables and payables were assumed as was the need for two weeks of working capital. All capital facilities were depreciated using appropriate depreciation lives and according to the sum-of-the-years-digits method.

The results indicate that the private ownership/operation business venture will be profitable a year earlier than the public ownership/operation business venture (beginning of the seventh and eighth years, respectively). The public ownership/operation, starting in the 12th year, is more profitable. These are important results because they indicate the impact of interest rate and taxes. The interest rate was assumed to be 6.0 percent and 8.4 percent on debt financing for public and private ownership/operation, respectively. Since only interest on debt (not dividends on preferred or common stock) is an allowed income tax deduction and since it was assumed that 50 percent of the public ownership business investment would be debt, the effective interest rate on indebtedness is 4.2 percent. In the case of public ownership it was assumed that 100 percent of the funds would be obtained through debt instruments. Therefore interest expense is larger for public ownership than for private ownership.

The impact of taxes is not seen till the 13th year. The combination of losses in the early years and unused investment tax credits eliminate the need for paying taxes until the 13th year for the private ownership business. The public-owned business does not pay taxes. Thus, the advantage of public ownership does not occur until halfway into the second decade of the business venture. The cash flow and indebtedness data is also summarized on the facing page. Cash flows become positive (cash inflow exceeds cash outflow) in the tenth year and then become negative again during the 13th through 17th years. This is due to the need for several large capital expenditures. The indebtedness curves indicate the need for a maximum funding level of $250 million and $225 million for the private and public ventures, respectively. The analyses assume that funds are available as required and interest expense is based upon funds utilized (note that if funds are provided that are not utilized, the unused portion is invested with the net expense (on the unused portion) equal to zero). Return on asset results are also summarized. The results indicate that by the 11th year return on assets may approach and exceed 10 percent. It should be noted that return on assets is not discounted.

The present value of the cash flow streams at different discount rates is also indicated. The present value indicates the value of the venture to an investor at different investor cost of capital. For example, if an investor's cost of capital was 8 percent, investment in the private venture is desirable, at 9.5 percent it is marginal and at cost of capital above this it is an unattractive investment.

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The present value of the energy savings is indicated on the facing page as a function of discount rate. The savings are negative, indicating additional consumption, for oil for the heat-only boilers and for coal consumed for the base-load produced thermal products. The present value is the sum of the future energy expenses incurred in the production of the thermal products all discounted to the present. The present value of consumer oil/gas represents savings to the consumer in the form of oil/gas consumption foregone because of the use of the thermal products for heating and hot water. The net energy savings are the consumer savings less the expense of oil for the heat only boilers and the coal for the base-load. Net present value of energy savings is approximately $600 million (at a 10 percent discount rate). This corresponds to an annuity (levelized) of $60 million per year—the equivalent of 2 to 3 million barrels of oil saved per year.
SUMMARY OF ENERGY SAVINGS (DETERMINISTIC SCENARIO)
A number of uncertainty scenarios were considered and are described in the following pages. These were considered in order to (1) assess the sensitivity of results to assumptions and (2) assess the impact of policy alternatives upon the business venture. On the facing page is a summary of the nominal uncertainty scenario. The nominal uncertainty is the nominal private ownership/operation scenario described in the previous pages but with the indicated variables considered as uncertainty variables. The ranges of uncertainty and associated uncertainty profiles are shown on the facing page. These estimates were provided by representatives of the Northern States Power Company and the Department of Energy. Since inflation is taken into account in all of the estimates (i.e., current dollars are used throughout) it was felt that the magnitude of the capital expenditures associated with the retrofit of existing power plants and the purchase of heat-only boiler is fairly predictable, that is the range of uncertainty is +10 percent. This is the result of a firm understanding of the technology. The capital expenditures associated with transmission and distribution have greater ranges of uncertainty. The costs are based upon Swedish experience, the application of which in the United States is not totally known--thus the greater the range of uncertainty of higher costs than lower costs (-10 percent to +20 percent). The largest range of uncertainty is associated with the cost of consumer equipment since this has been analyzed in less detail than the other capital expenditure items.

It was estimated that the demand in the early years is fairly predictable--signed long-term contracts prior to implementation. In the latter years there is great uncertainty associated with the demand. It was felt that the assumed near 100 percent long-term hook-up was somewhat optimistic. It was assumed that in the long term the demand might be as much as 25 percent less than originally estimated. Thus the range of uncertainty varies from +5 percent in the early years to +5 to -25 percent in the latter years.

The tariff was assumed [4] to be 90 percent of the minimum of gas and oil prices. It was felt that because of consumer reduced maintenance costs and increased continuity of services, customers would be willing to pay up to 10 percent more than they would have to pay for gas or oil. Thus the range of uncertainty (with respect to the Studsvik data) is 0 to +20 percent. Finally, expenses were felt to be relatively well known and predictable. Therefore the range of uncertainty for O&M and fuel costs was estimated as +10 percent.

It should be noted that all of the ranges of uncertainty are relative to the deterministic data presented in the previous pages that describes the nominal deterministic scenario.
### SUMMARY OF NOMINAL UNCERTAINTY SCENARIO
(RELATIVE TO NOMINAL DETERMINISTIC SCENARIO)

<table>
<thead>
<tr>
<th>UNCERTAINTY VARIABLE</th>
<th>RANGE OF UNCERTAINTY</th>
<th>UNCERTAINTY PROFILE*</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPITAL EXPENDITURES:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• HIGH BRIDGE NO. 3</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• HIGH BRIDGE NO. 4</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• HIGH BRIDGE NO. 5</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• HIGH BRIDGE NO. 6</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• RIVERSIDE NO. 6 AND NO. 8</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• RIVERSIDE NO. 7A</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• HIGH BRIDGE NO. 9 OR RIVERSIDE NO. 9</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• HEAT-ONLY BOILERS</td>
<td>-10%</td>
<td>+10%</td>
</tr>
<tr>
<td>• TRANSMISSION LINES (INITIAL)</td>
<td>-10%</td>
<td>+20%</td>
</tr>
<tr>
<td>• TRANSMISSION LINES</td>
<td>-10%</td>
<td>+20%</td>
</tr>
<tr>
<td>• LOCAL NETWORK (DISTRIBUTION)</td>
<td>-10%</td>
<td>+30%</td>
</tr>
<tr>
<td>• CONSUMER EQUIPMENT</td>
<td>-20%</td>
<td>+20%</td>
</tr>
<tr>
<td>DEMAND</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• IN EARLY YEARS</td>
<td>-5%</td>
<td>+5%</td>
</tr>
<tr>
<td>• IN LATER YEARS</td>
<td>-25%</td>
<td>+5%</td>
</tr>
<tr>
<td>PRICE (TARIFF)</td>
<td>0%</td>
<td>+20%</td>
</tr>
<tr>
<td>EXPENSES</td>
<td>-10%</td>
<td>+10%</td>
</tr>
</tbody>
</table>

*A SMOOTH TRANSITION ASSUMED

*DEFINITION OF UNCERTAINTY PROFILES:

![Uncertainty Profiles](image-url)
A number of other uncertainty scenarios were also considered. These are summarized on the facing page. All of these scenarios are variants of the nominal uncertainty scenario.

Scenario #1 considers the impact of more pessimistic attitudes with respect to transmission and distribution capital expenditures.

Scenarios #2 is identical to the nominal scenario with the single exception that 50 percent debt financing is increased to 100 percent debt financing.

Scenario #3 combines both Scenarios #1 and #2.

Scenario #4 investigates the impact of interest rate upon the financial performance of the business venture. Interest rate is reduced from 8.4 to zero percent.

Scenario #5 combines both Scenarios #1 and #4.

Scenario #6 allows the financial performance of a publicly owned/operated district heating business venture to be evaluated. The principal considerations are that the interest rate on debt financing is 6 percent (municipal tax exempt bonds) and the normal corporate tax structure has been changed to account for the tax exempt status of municipally-owned ventures.

Scenario #7 considers the impact of an incentive policy such that all depreciation lives are reduced to 75 percent of the nominal values. This, in essence, increases the deferral of income taxes.

Scenario #8 considers the impact of an incentive policy such that the government undertakes a program to subsidize (50 percent) expenditures for consumer equipment.

Scenario #9 considers the impact of legislation that mandates hook-up to the district heating system. This is modeled by eliminating the uncertainty associated with unit sales (this is only approximation since an effect of mandated hook-up would most likely be to increase the rate of growth of the demand in the early years).

These scenarios have all been analyzed with the results summarized in the following pages.
## SUMMARY OF UNCERTAINTY SCENARIOS
(RELATIVE TO NOMINAL UNCERTAINTY SCENARIO)

<table>
<thead>
<tr>
<th>UNCERTAINTY SCENARIO</th>
<th>VARIABLES CHANGED</th>
<th>CHANGED FROM</th>
<th>CHANGED TO</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>TRANSMISSION LINES (INITIAL) UNCERTAINTY PROFILE</td>
<td>#16*</td>
<td>#15*</td>
</tr>
<tr>
<td></td>
<td>TRANSMISSION LINES UNCERTAINTY PROFILE</td>
<td>#6</td>
<td>#15</td>
</tr>
<tr>
<td></td>
<td>LOCAL NETWORK UNCERTAINTY PROFILE</td>
<td>#15</td>
<td>#24</td>
</tr>
<tr>
<td>2</td>
<td>DEBT FUNDING</td>
<td>50%*</td>
<td>100%*</td>
</tr>
<tr>
<td>3</td>
<td>TRANSMISSION LINES (INITIAL) UNCERTAINTY PROFILE</td>
<td>#16</td>
<td>#15</td>
</tr>
<tr>
<td></td>
<td>TRANSMISSION LINES UNCERTAINTY PROFILE</td>
<td>#6</td>
<td>#15</td>
</tr>
<tr>
<td></td>
<td>LOCAL NETWORK UNCERTAINTY PROFILE</td>
<td>#15</td>
<td>#24</td>
</tr>
<tr>
<td></td>
<td>DEBT FUNDING</td>
<td>50%(1)</td>
<td>100%(2)</td>
</tr>
<tr>
<td>4</td>
<td>INTEREST RATE</td>
<td>8.4%</td>
<td>0.0%</td>
</tr>
<tr>
<td>5</td>
<td>TRANSMISSION LINES (INITIAL) UNCERTAINTY PROFILE</td>
<td>#16</td>
<td>#15</td>
</tr>
<tr>
<td></td>
<td>TRANSMISSION LINES UNCERTAINTY PROFILE</td>
<td>#6</td>
<td>#15</td>
</tr>
<tr>
<td></td>
<td>LOCAL NETWORK UNCERTAINTY PROFILE</td>
<td>#15</td>
<td>#24</td>
</tr>
<tr>
<td></td>
<td>INTEREST RATE</td>
<td>0.4%</td>
<td>0.0%</td>
</tr>
<tr>
<td>6</td>
<td>TRANSMISSION LINES (INITIAL) UNCERTAINTY PROFILE</td>
<td>#16</td>
<td>#15</td>
</tr>
<tr>
<td></td>
<td>TRANSMISSION LINES UNCERTAINTY PROFILE</td>
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<td>#15</td>
</tr>
<tr>
<td></td>
<td>LOCAL NETWORK UNCERTAINTY PROFILE</td>
<td>#15</td>
<td>#24</td>
</tr>
<tr>
<td></td>
<td>TAX STRUCTURE</td>
<td>NORMAL CORP. TAX STRUCTURE</td>
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<tr>
<td></td>
<td>INTEREST RATE</td>
<td>8.4%</td>
<td>6.0%</td>
</tr>
<tr>
<td>7</td>
<td>DEPRECIATION LIVES</td>
<td>NOMINAL VALUES</td>
<td>75% OF NOMINAL VALUES</td>
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<tr>
<td>8</td>
<td>COST OF CONSUMER EQUIPMENT</td>
<td>NOMINAL RANGE</td>
<td>50% OF NOMINAL RANGE</td>
</tr>
<tr>
<td>9</td>
<td>UNIT SALES</td>
<td>UNCERTAINTY</td>
<td>KNOWN WITH CERTAINTY</td>
</tr>
</tbody>
</table>

*CORRESPONDS TO AN EFFECTIVE INTEREST RATE OF 4.2% ON DEBT
**CORRESPONDS TO AN EFFECTIVE INTEREST RATE OF 8.4% ON DEBT

*DEFINITION OF UNCERTAINTY PROFILES:
The risk profiles of after-tax profit, cash flow and indebtedness as a function of time are summarized on the facing page for the nominal uncertainty scenario. The nominal uncertainty scenario is that of private ownership/operation. The summarization is in the form of contours of equal profitability. For example, there is a 50 percent chance that profits will exceed those indicated by the 50 percent contour, etc.

Referring to the curves of after-tax profit, it can be seen that there is little or no chance that the venture will be profitable prior to the fifth year and will most likely be profitable by the seventh year. All unused investment tax credits have been consumed by the 11th year. This is evidenced by the sudden change in slope of the profit contours.

The risk profiles of cash flow and indebtedness are summarized in a similar manner. For example, there is little or no chance that indebtedness will exceed the zero percent contour. The cash flow and indebtedness clearly indicate the risk associated with the DHCS business venture. The deterministic scenario indicated a maximum funding requirement (maximum indebtedness) of approximately $260 million and a maximum negative annual cash flow (i.e., cash outflow) of approximately $40 million. The risk analysis indicates that maximum funding requirements are in the range of $350 to $460 million with a maximum of $460 million possible. The risk analysis also indicates that there is a chance that negative cash flows may be well in excess of $100 million. A large part of this is undoubtedly controllable since it has to do with system growth. There is also a reasonable chance that cash flows will not become positive (i.e., net cash inflows) until the end of the second decade of the business venture. Further, the risk analysis indicates that payback period (the point in time when cumulative cash inflows equal cumulative cash outflows. In other words, the point in time when the indebtedness curve passes through zero) will exceed 19 years.
ANNUAL AFTER-TAX PROFIT, CASH FLOW AND INDEBTEDNESS AS A FUNCTION OF TIME AND CHANCE OF EXCEEDING DIFFERENT LEVELS—NOMINAL LINE UNCERTAINTY SCENARIO (SCENARIO #0)
The risk profiles of after-tax profit, cash flow and indebtedness as a function of time are summarized on the facing page for 'uncertainty scenario #6. This scenario represents public ownership/operation of the DHCS business venture. The risk profiles are summarized (as for the nominal uncertainty scenario) in the form of contours of equal probability.

Referring to the curves of after-tax profit, it can be seen that there is little or no chance that the venture will be profitable prior to the sixth year and will most likely be profitable by the eighth year. Since the publicly-owned venture will not be taxed nor will it thus be concerned with investment tax credits, the annual profit continues to rise in a rather steady fashion.

The risk profiles of cash flow and indebtedness are summarized in a similar manner. For example, there is little or no chance that cash flow will exceed the zero percent contour. The cash flow and indebtedness clearly indicate the risk associated with the publicly-owned DHCS business venture. The deterministic scenario indicated a maximum funding requirement (maximum indebtedness) of approximately $230 million and a maximum negative annual cash flow (i.e., cash outflow) of approximately $40 million. The risk analysis indicates that maximum funding requirements are in the range of $300 to $425 million with a maximum of $425 million possible. The risk analysis also indicates that there is a chance that negative cash flows may be well in excess of $100 million. A large part of this is undoubtedly controllable since it has to do with system growth. There is also a reasonable chance that cash flows will not become positive (i.e., net cash inflows) until the end of the second decade of the business venture. Further, the risk analysis indicates that payback period will exceed 17 years.
ANNUAL AFTER-TAX PROFIT, CASH FLOW AND INDEBTEDNESS AS A FUNCTION OF TIME AND CHANCE OF EXCEEDING DIFFERENT LEVELS -UNCERTAINTY SCENARIO #6-
The expected after-tax profits, as a function of time, are illustrated on the facing page for a number of the considered scenarios. Both the deterministic and uncertainty scenarios are shown. Both the private ownership/operation and public ownership/operation deterministic scenarios are seen as being somewhat pessimistic with respect to the uncertainty scenarios. The basic reason for this is that the deterministic scenarios are based upon a set of input data which is somewhat on the conservative side (as per the feelings of DOE and NSP Co.).

The nominal uncertainty scenario is that of private ownership/operation with 50 percent of the funding being derived from debt financing (it should be noted that only interest on debt financing is considered in the tax computation—dividends on equity capital is an after-tax consideration). Scenario #3 primarily indicates the sensitivity of after-tax profit to interest rate. The nominal uncertainty scenario assumes 50 percent debt at 8.4 percent interest (i.e., 4.2 percent interest on indebtedness). It is implied that unused funds are invested at the same rate so that interest on indebtedness is the interest on funds currently utilized by the business venture) whereas scenario #3 assumes 100 percent debt at 8.4 percent interest. The impact of the increased interest expense is to delay the time of profitability by two years.

Scenario #5 further indicates the sensitivity of profit to interest rate. By reducing the interest rate to zero the first profitable year occurs one year earlier (than when effective interest rate is 4.2 percent).

Scenario #6 is the uncertainty scenario associated with public ownership/operation (i.e., no taxes and 6 percent interest on debt). One hundred percent debt financing is assumed at 6 percent interest.
COMPARISON OF EXPECTED AFTER-TAX PROFIT FOR SELECTED SCENARIOS
The rate of return on assets risk data is summarized on the facing page for both private and public owner/operator scenarios. The rate of return results are constrained by the pricing policy which is such that thermal energy price is determined by oil/gas prices. Consider the impact of a return on investment constraint of 10 percent imposed on the private owner/operator scenario. It is evident that there is only about a 50 percent chance of encountering this constraint starting in about the tenth year. The implication of this is that if the constraint is not encountered then the market price of oil/gas will set the price of the thermal products. There is a 50 percent chance of this occurring. On the other hand, there is a 50 percent chance that the constraint will be encountered thereby causing the price of the thermal products to be reduced so as not to exceed the allowed rate of return.

The rate of return on assets risk data of the public ownership/operation scenario indicates that relatively high rates of return will be achieved. It is thus evident that price reductions are likely that will provide benefits to all thermal energy consumers and further stimulate the growth of DHCS.
RETURN ON ASSETS AS A FUNCTION OF TIME AND CHANCE OF EXCEEDING DIFFERENT LEVELS

SCENARIO #1
(PRIVATE OWNERSHIP)

SCENARIO #6
(PUBLIC OWNERSHIP)
The return on investment (ROI) risk profiles of all considered scenarios are indicated on the facing page. The ROI is the discount rate that makes the present value of cash inflows equal to the present value of cash outflows (i.e., the present value of the cash flow stream is equal to zero). ROI is therefore the internal rate of return of the investment. If the investor's cost of capital is equal to the internal rate of return then he is no better nor worse off for making the investment. If the internal rate of return is less than the investor's cost of capital then the investment is not worthwhile. If the internal rate of return exceeds the investor's cost of capital then the investor is better off making the investment.

On the facing page, the first two risk profiles (indicating the chance that different returns will be exceeded) represent the deterministic scenarios. If the investment community demands a return on investment for equity funds in excess of 10 percent then the private owner/operator scenario is not viable in the absence of incentives. The public owner/operator scenario offers a relatively high return on investment. Since the total funding is provided by debt financing, the interest on which is included in the profit and cash flow computations, the public owner/operator appears to be a very viable business venture.

The impact of uncertainty on ROI can be seen from the ROI risk profiles of the various uncertainty scenarios. Only scenarios #6, 8 and 9 appear to offer reasonable chances of adequate returns on investment. Scenario #6 is the public owner/operator uncertainty scenario. Scenario #8 is the private owner/operator uncertainty scenario with government subsidy (50 percent) of the cost of consumer equipment. Scenario #9 is the private owner/operator uncertainty scenario with a legislative mandate for hook-up to the DHCS. It can thus be seen that there exists a set of policy and legislative options that can have a significant impact on the economic viability of district heating and cooling systems particularly when private owner/operator business ventures are considered.
ROI RISK PROFILES FOR ALL SCENARIOS CONSIDERED
The risk profiles of the present value of energy saving are indicated on the facing page for both the nominal deterministic and nominal uncertainty scenarios. These include the risk profiles of the present value of coal consumed for base-load heat, the present value of oil consumed for the heat-only boilers, the present value of oil/gas foregone by consumers using the thermal energy products and the present value of net energy savings (consumer oil/gas less oil for heat-only boilers and coal for base-load.)
ENERGY SAVINGS SUMMARY (RISK PROFILES OF PRESENT VALUE OF ENERGY SAVINGS)

**Nominal Deterministic Scenario:**

- Coal (Base-Load)
- Oil (Heat-Only)
- Oil/Gas (Consumer)
- Net Energy Savings

**Nominal Uncertainty Scenario:**

- Coal (Base-Load)
- Oil (Heat-Only)
- Oil/Gas (Consumer)
- Net Energy Savings

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6. RISK ANALYSIS METHODOLOGY FOR EVALUATING REGULATED UTILITY BUSINESS VENTURES
The designated model, described in the previous pages, was used to analyze, from the perspective of the private sector, the financial merits of cogeneration district heating and cooling system business ventures located in Washington, DC and Minneapolis/St. Paul. The results of these risk analyses are also described in the previous pages with the latter analysis being more meaningful since it had the active participation of an involved power company. The RISK Model used for these analyses was originally developed to perform a financial simulation of a generalized manufacturing and sales business venture in a non-regulated environment.

Since the specific form of ownership/operation of the district heating system business ventures will most likely depend upon many factors including regulation, legislation, financial projections, fuel price forecasts and others, it is necessary to have a risk analysis methodology that is flexible enough to handle at least private owner/operation and public owner/operation. In the former case it is highly likely that regulation will exist in the form of allowed return on investment. In both cases it appears that market constraints will exist in the form of competitive products, namely oil/gas, that will establish maximum allowable prices for the thermal energy products independent of the regulatory constraints. It must be emphasized that one normally thinks of regulation in an environment where there is a lack of competition which is the result of a government action. In the case of DHCS business ventures this is not the case—it appears that there will be competition unless legislation mandates otherwise. Be that as it may, it appears desirable to be able to evaluate business ventures with and without the allowed return on investment constraint. It is also necessary to have the ability of considering the price of competitive products and its impact on thermal energy pricing.

BCS undertakes RD&D and incentive programs and effects policy decisions which have impacts on a wide range of products, services, consumers and business ventures. The products range from consumer (gas-fired heat pumps) to industrial products (cogeneration systems) and to business ventures ranging from nonregulated manufacturing and sales businesses (manufacture and sale of gas-fired heat pumps) to regulated district heating and cooling ventures using cogeneration techniques. The risk analysis methodology should allow for these diverse business ventures to be evaluated. The RISK Model, as modified for DOE use, is a very flexible tool. It however has a number of limitation, most of which can be eliminated through modifications, some relatively simple and some relatively complex. One of the limitations (i.e., not performing the financial computations as per commonly used utility revenue requirements method) can only be eliminated with a major modification.

The overall structure of the business ventures resulting from, or impacted by the BCS RD&D and incentive projects is illustrated on the facing page. There are situations where regulation is an important consideration and there are situations where regulation is not an important issue. In the latter case the RISK Model in its current form is applicable—a number of modifications are indicated to improve its utility. In the former case there are two situations the first of which is when the result of the BCS project is cost reduction for public utilities and the second of which is when the end result is a new business venture. In the latter case the venture may be privately owned/operated or publicly owned/operated. In either case it is highly desirable to use a modified version of the RISK Model. The modifications are of two types namely those concerned with improving the Model's utility and those concerned with providing a market price and regulatory constraint capability.

When the end result of the BCS project is cost reduction for the public utilities either it is important to have utility endorsement of results or it is not important. When utility endorsement is not critical the RISK Model is applicable, modified as above, for rate of return (regulatory) constraints. When utility endorsement is important it is necessary to significantly alter the RISK Model so as to perform the financial computations as per the minimum revenue requirements method.
RISK METHODOLOGY

BUSINESS VENTURES RESULTING FROM DCS R&D & INCENTIVE PROJECTS

REGULATION AN IMPORTANT CONSIDERATION

END RESULT IS COST REDUCTION FOR PUBLIC UTILITY

NOT IMPORTANT TO OBTAIN UTILITY ENDORSEMENT

USE RISK MODEL WITH FOLLOWING MODIFICATIONS
- SEGMENT EXISTING MODEL
- LOW SPEED TERMINAL
- OUTPUT SUBROUTINE
- ENERGY SAVINGS BY YEAR
- ALLOWED RATE OF RETURN
- CONSTRAINT (ANNUAL)
- ALLOWED RATE OF RETURN
- CONSTRAINT (DISCOUNTED)

USE RISK MODEL WITH FOLLOWING MODIFICATIONS
- DEVELOP NEW RISK MODEL THAT ACCOUNTS FOR MINIMUM REVENUE REQUIREMENTS METHOD

IMPORTANT TO OBTAIN UTILITY ENDORSEMENT

PRIVATE OWNER/OPERATOR

USE RISK MODEL WITH FOLLOWING MODIFICATIONS
- SEGMENT EXISTING MODEL
- LOW SPEED TERMINAL
- OUTPUT SUBROUTINE
- ENERGY SAVINGS BY YEAR
- ALLOWED RATE OF RETURN
- CONSTRAINT (ANNUAL)
- ALLOWED RATE OF RETURN
- CONSTRAINT (DISCOUNTED)
- COMPETITIVE PRICING
- CONSTRAINT (MULTIPLE PRODUCTS)

PUBLIC OWNER/OPERATOR

USE RISK MODEL WITH FOLLOWING MODIFICATIONS
- SEGMENT EXISTING MODEL
- LOW SPEED TERMINAL
- OUTPUT SUBROUTINE
- ENERGY SAVINGS BY YEAR
- ALLOWED RATE OF RETURN
- CONSTRAINT (ANNUAL)
- ALLOWED RATE OF RETURN
- CONSTRAINT (DISCOUNTED)
- COMPETITIVE PRICING
- CONSTRAINT (MULTIPLE PRODUCTS)
A risk methodology structure was outlined on the previous chart. This structure indicated the use of the RISK model and various modifications in terms of the business situations that might be encountered when transferring the technology to the private sector. The table on the facing page summarizes the indicated improvements in terms of the business situation and presents rough-order-of-magnitude budgetary estimates for accomplishing the modification.

**Segment Existing Model:** The RISK Model consists of a large complex program. If additional modifications are to be made to this model it is highly desirable to segment the larger subroutines. This will significantly increase the efficiency with which modifications can be made to the Model.

**Low-Speed Terminal Output Subroutine:** The RISK Model outputs are designed for printing on a relatively high-speed terminal. It appears desirable to have the ability to print the detailed reports on a high-speed printer and to have the option of printing summary reports on a low-speed terminal. The desired set of summary reports needs to be established and the Model suitably modified.

**Energy Savings by Year:** The RISK Model has been modified so that the risk profile of the present value of energy savings (by product and energy type) is established. The risk profiles, or at the minimum, the expected value and standard deviation of energy savings (by product and energy type) should be provided for each year of the time horizon. The energy savings computations need to be modified to accomplish this.

**Sales Forecast Subroutine:** Currently, the RISK Model requires input data to be provided in the form of a sales forecast (i.e., number of units sold as a function of time including ranges of uncertainty). It is recommended that a sales forecast subroutine be developed that has two levels of capability. The first level of capability would allow the potential market to be specified (for example, number of residential units) in a disaggregated fashion together with market penetration rate for the products in each market segment. These would be provided as uncertainty variables so that the resulting sales forecast would be in the form of a range of uncertainty together with the form of the uncertainty. The second level of capability would allow the sales forecast to be established in terms of user economics. The sales forecast, done at a disaggregate level, would take into account consumer economics in terms of annual savings and initial purchase price and develop performance measures such as payback period. The sales forecast would then be related to the number of consumers having different payback periods where both the potential number of purchasers and the rate of purchase are related to payback period.

**Allowed Rate of Return Constraint (Annual):** This improvement is aimed at increasing the ability of the RISK Model to evaluate regulated ventures. The improvement would provide the capability of specifying allowed annual return on investment which would then be used to establish the appropriate price which could be charged and not exceed the allowable constraint.
## METHODOLOGY IMPROVEMENTS--BUDGETARY ESTIMATES

<table>
<thead>
<tr>
<th>MODIFICATION/IMPROVEMENT</th>
<th>NON-REGULATED BUSINESS VENTURE</th>
<th>PUBLIC OWNER/OPERATOR</th>
<th>PRIVATE OWNER/OPERATOR</th>
<th>COST REDUCTION TO OBTAIN UTILITY ENDORSEMENT</th>
<th>COST REDUCTION TO OBTAIN UTILITY ENDORSEMENT</th>
<th>ROUGH-ORDER-OF-MAGNITUDE BUDGETARY ESTIMATE* ($1000)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SEGMENT EXISTING MODEL</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>5 - 8</td>
</tr>
<tr>
<td>LOW SPEED TERMINAL OUTPUT SUBROUTINE</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>3 - 5</td>
</tr>
<tr>
<td>ENERGY SAVINGS BY YEAR</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>3 - 5</td>
</tr>
<tr>
<td>SALES FORECAST SUBROUTINE</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>10 - 20</td>
</tr>
<tr>
<td>ALLOWED RATE OF RETURN CONSTRAINT (ANNUAL)</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>5 - 8</td>
</tr>
<tr>
<td>ALLOWED RATE OF RETURN CONSTRAINT (DISCOUNTED)</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>7 - 12</td>
</tr>
<tr>
<td>COMPETITIVE PRICING CONSTRAINT (MULTIPLE PRODUCTS)</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
<td>3 - 5</td>
</tr>
<tr>
<td>MINIMUM REVENUE REQUIREMENT RISK MODEL</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
<td>25 - 40</td>
</tr>
</tbody>
</table>

*The indicated amounts are not additive. There will be savings if more than one modification/improvement is undertaken concurrently.
Allowed Rate of Return Constraint (Discounted): This improvement is also aimed at increasing the ability of the RISK Model to evaluate regulated ventures and to consider alternative regulatory constraints. The improvement would provide the capability of specifying allowed rate of return (i.e., the discounted return on investment or internal rate of return— that rate that makes the net present value equal to zero) on investment which would then be used to establish the appropriate price which could be charged and not exceed the allowable constraint. It should be noted that this constraint is not an annual constraint but measured over an extended period of time.

Competitive Pricing Constraint (Multiple Products): This improvement is aimed at increasing the ability of the RISK Model to evaluate both regulated and unregulated district heating and cooling business ventures. Multiple competitive products would be considered with price forecasts input for each. The minimum price would result in a market constraint placed upon the pricing of thermal products from the DHCS. The market price constraint could be used in conjunction with the return on investment regulatory constraints to accurately model the regulated DHCS business environment.

Minimum Revenue Requirement Risk Model: This is a significant modification aimed at developing a risk model that simulates the utility minimum revenue requirements method computational procedures.
7. CONCLUSIONS
The effort reported involved four separate steps. The first included examination of commercially available risk analysis models which had potential application to DOE's energy conservation project selection methodology. The second task, summarized in an ECON report entitled “Risk Analysis Results: Cogeneration,” dated August 10, 1978, was concerned with the use of ECON's RISK Model and the conduct of a risk analysis case study in the area of district energy systems using thermal energy cogenerated at existing electric power plants in Washington, DC. The third task was concerned with modifying the ECON RISK Model so as to extend its time horizon and to provide a means for computing energy savings that might result from the introduction of new products. This model, including the modifications, was installed (and is currently operational) at the DOE Germanstown computer facility. The final task was concerned with establishing a better understanding of the regulated utility industry investment decision process and thence refining the district energy system case study. This task was also concerned with outlining a methodology for evaluating public utility investment decisions in terms of DOE RD&D and incentive projects and recommending specific modifications which may be made to the acquired model in order to make it more applicable for evaluating regulated business ventures.

The overall intent of these tasks was twofold. The primary objective was to demonstrate and evaluate the use of risk analysis techniques with respect to the development of improved project selection methods and procedures for the Division of Buildings and Community Systems. The secondary objective was to provide better insights into the financial merits of a business venture that might evolve from DOE-developed technology and might be affected by DOE incentive programs or other government actions.

Based upon the completed studies and analyses the following general conclusions have been reached:

- Risk analysis techniques are applicable and useful for evaluating BCS RD&D and incentive projects and for providing information necessary for making informed policy decisions. It is recommended that a number of additional modifications be made to the RISK Model so as to increase its general scope and capability. In order to properly model regulated business ventures it is necessary that modifications be made which will allow return on investment regulatory constraints and market pricing constraints to be taken into account.

- DHCS decisions are very site specific. Since DHCS business ventures are very capital intensive with the magnitude and timing of the investments tied to the specific existing power plant locations and configurations and thermal product demand density, it is very difficult to generalize or extrapolate the results of one location to another. In order to make decisions concerning DHCS, site specific business venture analyses are necessary.
SUMMARY AND CONCLUSIONS

SUMMARY:
- SURVEY OF RISK MODELS
- PRELIMINARY CASE STUDY: DHCS IN WASHINGTON, DC
- MODIFICATION/INSTALLATION OF ECON'S RISK MODEL
- RISK ANALYSIS CASE STUDY: DHCS IN MINNEAPOLIS/ST. PAUL

CONCLUSIONS:
- RISK ANALYSIS TECHNIQUES ARE APPLICABLE AND USEFUL FOR EVALUATING BCS RD&D AND INCENTIVE PROJECTS AND FOR PROVIDING INFORMATION NECESSARY FOR MAKING INFORMED POLICY DECISIONS
- DHCS DECISIONS ARE VERY SITE SPECIFIC
- DHCS BUSINESS VENTURES MAY BE PRIVATELY OWNED/OPERATED OR PUBLICLY OWNED/OPERATED
- PRIVATELY OWNED/OPERATED DHCS WILL BE REGULATED WITH RETURN ON INVESTMENT CONSTRAINTS
- PUBLICLY OWNED/OPERATED DHCS WILL BE UNREGULATED
- PRICE OF THERMAL PRODUCTS WILL BE DETERMINED BY MARKET CONDITIONS (OIL/GAS)
- A VIABLE CAPITAL INTENSIVE RISKY DHCS BUSINESS VENTURE IS POSSIBLE IN MINNEAPOLIS/ST. PAUL
- CHANGES IN REGULATION AND LEGISLATION (LOCAL) CAN REDUCE THE RISK AND INCREASE THE ATTRACTIVENESS OF DHCS BUSINESS VENTURE
• DHCS business ventures may take the general forms of private ownership/operation and public ownership/operation. Private ownership/operation implies debt and equity funding and the current income tax laws. Public ownership/operation implies debt financing (i.e., tax exempt bonds) and exemption from income and other taxes.

• The general current attitude (of both regulators and utility management) is that privately owned/operated DHCS business ventures will be regulated in the same manner as existing utilities. This implies annual return on investment constraints. These constraints, when taken together with market price constraints resulting from competitive products (oil/gas), act as a major deterrent to the establishment of DHCS business ventures.

• Publicly owned/operated DHCS business ventures will not be regulated. The price of the thermal products will depend upon the desired profit-nonprofit status and the price of competitive products (oil/gas).

• The maximum price of thermal products will be determined by the future prices of competitive products such as oil and gas used for heating and cooling applications. It is likely that prices somewhat in excess of oil/gas prices are possible because of costs (such as maintenance, gas interruptions, etc.) that may be foregone by thermal product customers.

• A viable capital intensive risky DHCS business venture is possible in Minneapolis/St. Paul. The business is very capital intensive with investment requirements in the range of $250 to $450 million depending upon the level of risk that is tolerable.

• Changes in regulation and legislation can reduce the risk and increase the attractiveness of DHCS business ventures. Current regulation of rate of return is on an annual basis. This has a very negative effect on investment decisions since the business venture will be in a loss position for a number of years and the current return on investment regulation does not make provision for carrying these losses forward by allowing higher rates of return until the losses are compensated. It would be helpful if the regulation allowed for return on investment constraints over an extended time period rather than annually. Local legislation can also have a major impact on the viability of the business venture. Mandating hook-up to the hot water system would both reduce market uncertainty and guarantee an early influx of large revenues.
8. REFERENCES
Specific References


General References


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