EPRI
Electric Power
Research Institute

Keywords:
Cogeneration Options
Financing
Ownership Arrangements
Project Financing
After-Tax Cash Flow

EPRI EM-3126-CCM
Volume 1
Project 1276-8
Computer Code Manual
June 1983

EPRI-EM--3126-CCM-Vol.1

DE83 902645

# COPE: Cogeneration Options Evaluation

## Volume 1. Program Descriptive Evaluation

Prepared by
Synergic Resources Corporation
Bala Cynwyd, Pennsylvania

MASTER

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# COPE: Cogeneration Options Evaluation.
## Volume 1. Program Descriptive Evaluation

EM-3126-CCM, Volume 1
Research Project 1276-8

Computer Code Manual, June 1983

Prepared by

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Prepared by
Synergic Resources Corporation
Bala Cynwyd, Pennsylvania

**ABSTRACT**

A number of computer evaluation tools have been developed as part of RP1276, an EPRI project to comprehensively evaluate the applications of dual-energy-use systems. One of the tools, Cogeneration Options Evaluation (COPE), is a computer model that deals with the institutional and regulatory implications of specific projects.

COPE can help management examine attractive cogeneration options and choose an option that is best suited for a specific site, given the relevant tax and fuel-use regulations. An "option" here refers not only to different technologies, but also to different ownership structures and/or operating modes. For each option under consideration, COPE provides an analysis of the project's impact on the utility, the industry, and where appropriate, a third party.

This document describes the inputs required as well as the assumptions and calculation procedures used in COPE.

## EPRI PERSPECTIVE

### PROJECT DESCRIPTION

This two-volume progress report for RP1276-8, Technical Studies of Dual Energy Use Systems (DEUS), is entitled COPE Computer Model and presents the manuals for the Cogeneration Options Evaluation Computer Model that is available for evaluation of utility options in owning cogeneration systems. Volume 1 is the program descriptive manual, and Volume 2 is the program user's manual. The descriptive manual explains the model's structure, applications, and methodology; the user's manual describes how to access the model, to prepare data for analyzing financing options, and to interpret results.

RP1276-8 is one project in the RP1276 series, which is concerned with cogeneration and district heating. The project has been used to identify utility concerns in cogeneration development, to provide technical service to utilities, and to coordinate activities under the project. The COPE model was thus developed as a result of this effort.

### PROJECT OBJECTIVES

The three main objectives of this project are to provide technical support to utilities for using computer programs, conceptual designs, and methodology developed under RP1276; to develop data bases; and to identify issues of concern to utilities.

### PROJECT RESULTS

Technical service has been provided to more than 20 utilities, enabling them to use the DEUS computer program (EPRI Final Report EM-2776, Volumes 1 and 2). The COPE model has also been distributed to more than 15 utilities. The model is a computer simulation program written in standard FORTRAN. Using performance and cost data of cogeneration systems designed by architect-engineers or engineering models (e.g., DEUS Computer Model), the COPE model evaluates the impact of various cogeneration financing and ownership arrangements on utilities. The model also computes levelized annual revenue requirements, levelized busbar cost of electricity, first-year revenue requirement, and first-year busbar cost of electricity. A number of utility-industry partnership options can be considered and compared to 100% industry ownership. The utility's share of initial capital outlays is fixed at less than 50% owing to the Public Utilities Regulatory Policies Act regulations. The utility's profit share can then be varied to identify an optimal combination of partnerships that can both increase the industry's rate of return and lower the utility's cost of electricity delivered from the cogeneration plant.

The COPE model is available to electric utilities and the public. Public service organizations or government agencies that wish to obtain the COPE software should contact EPRI directly at Patents and Licensing, EPRI, 3412 Hillview Avenue, P.O. Box 10412, Palo Alto, California 94303, (415) 855-2866.

EPRI member utilities and other potential users should contact the Electric Power Software Center, University Computing Company, 1930 Hi Line Drive, Dallas, Texas 75207, (214) 655-8883.

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## ACKNOWLEDGMENTS

This report was prepared by Synergic Resources Corporation (SRC) and was sponsored by the Electric Power Research Institute (EPRI). Dilip R. Limaye directed SRC's efforts. B. Venkateshwara was the principal investigator charged with preparing this report. Numerous other individuals within and outside SRC have contributed to this report.

SRC is grateful to Robert Mauro and S. David Hu of EPRI for their ongoing technical guidance and counsel. Lee Goodwin of Goodwin and Schwartzstein provided very able advice on tax and regulatory considerations. SRC is also grateful to A. Hardy Eubanks III of Blyth Eastman Paine Webber for technical advice during the early stages of project development. SRC acknowledges the assistance provided by Glenn Lovin of the International Cogeneration Society in investigating numerous regulatory issues. The following SRC personnel have contributed significantly to the project: Glenn Colville, Richard Crane, Thomas Hough, Robert Kim, and Eric Petersen. Steve Hastie of SRC provided valuable editorial assistance. Finally, Lisa Cheever, Dawn Coles, Connie Cybulski, Sharon Limaye and others at SRC have been responsible for graphics and production.

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# SUMMARY

## INTRODUCTION

In 1979, the Electric Power Research Institute (EPRI) initiated RP1276, a project to evaluate the applications of dual energy use systems, giving explicit consideration to utility roles, perspectives and impacts. Under RP1276, a methodological framework to evaluate cogeneration systems was developed. Computer tools to implement the methodology were also developed.

The methodology for evaluating cogeneration systems consists of two steps. In the first step, the aggregate benefits, costs and impacts are calculated. This computation is unaffected by the distribution of costs and benefits among the parties involved. The allocation of such costs and benefits depends on institutional, regulatory and ownership arrangements. It is accounted for in the second step of the methodology, which is implemented through a computer model, "Cogeneration Options Evaluation (COPE)."

## OVERVIEW OF COPE

COPE is an evaluation tool that can help management examine attractive cogeneration options and choose an option that is best suited for a specific site, given the relevant tax and fuel use regulations. An "option" here refers not only to different technologies, but also to different ownership structures and/or operating modes. For each option under consideration, COPE requires cost and performance information as input, and provides, as output, an analysis of the project's impact on the utility, the industry, and where appropriate, a third party. The cost and performance information may come from site-specific engineering studies or from other design-oriented computer models.

## COPE OBJECTIVES

The objectives of COPE are to:

- Evaluate, based on after-tax cash flows from cogeneration ventures, the financial and regulatory implications for the utility, the industry, and where relevant, third parties, for all practically feasible combinations of ownership and operating mode.
- Trace, in terms of important dollar flows, the impacts of cogeneration ventures on the utility and the industry for all practically feasible combinations of ownership and operating mode.
- Provide information to potential project participants to identify mutually beneficial institutional arrangements for implementing cogeneration projects.

## APPLICATIONS OF COPE

COPE's principal strength is that the after-tax cash flow analysis is based on detailed site-specific information. For instance, the initial capital outlay is divided into eight categories that can be distinguished for tax purposes. Energy tax credits are determined on the basis of facility status and fuels used. Institutional and regulatory factors such as back-up and buyback rates, operating mode, and ownership structure are taken into account in determining the distribution of after-tax costs and benefits among parties.

Using these after-tax costs and benefits, a financial analysis is performed for each party. Specifically, COPE computes on an after-tax basis, the net present value, the internal rate of return, the payback and the debt-coverage ratio for each project participant. In addition, a pro forma income statement for the project is presented. Thus, for a given implementation mechanism, COPE can be used to judge the impact on the project participants. Conversely, sensitivity analyses can be performed to identify implementation mechanisms that would benefit all parties. Implementation mechanisms that can be readily examined include: 100% ownership by a utility or an industry or a third party; and joint ventures involving any combination of a utility, an industry, and a third party.

Sensitivity analyses can also be used to answer a number of other questions, such as: What PURPA price profile (for electricity) will give an industrial owner a specified rate of return on the project? Alternatively, at given electricity and steam prices, COPE could be used to determine the maximum input fuel cost which would give an industrial owner a desired project rate of return. Similarly, for new technologies, COPE can be used to determine a "maximum allowable total installed cost."

Since COPE maintains separate accounts for three distinct project participants--the utility, the industry, and a third party--a number of innovative schemes involving transfers between parties can be represented. For instance, a scheme in which an industry sells the cogeneration plant to a utility after owning and operating it for a fixed number of years can be represented. COPE can be used to analyze the impact of these transactions on each participant for each year of useful project life. Similarly, a leasing arrangement can be handled by using the third party's account to represent the lessor's inflows and outflows. Thus COPE can be used to analyze the impact of a leasing arrangement for the lessor as well as the lessee.

**OUTPUTS OF COPE**

The output from COPE consists of a series of reports. Reports 1,2,3 and 4 display the inputs used in COPE. Report 1 contains the project schedule. Report 2 summarizes ownership and operating information. Specifically, Report 2 describes the ownership structure, the dispatch arrangement, the electricity sales arrangement and annual average system performance. In Report 3, a number of details related to fuel use and other regulatory issues are provided. Price and cost information is presented in Report 4. An important feature of Report 4 is that the variation of prices/costs/rates over project life is displayed. Thus, the pattern of escalation is evident to the user.

Report 5 contains the results of the analysis performed by COPE. Section A of Report 5 describes the economic inputs used in the analysis. Such details as the financial structure, cost and type of debt, and partnership arrangements are presented in Section A. Section B displays after-tax cash flow accounts for each participant during construction and during operation. In addition, Section B presents, for each participant, the net present value (NPV), the rate of return (ROR), the payback period ($P_b$) and the debt coverage ratio. In the case of industry ownership COPE can be set up so as to perform financial analyses based on incremental investment, i.e., investment over and above that required for a conventional boiler. In the case of the utility, COPE displays both the first year busbar cost and the levelized busbar cost.

Finally, Section C of Report 5 contains the additional impacts, if any, on the utility and the industry. These impacts are presented as dollar values for each year of project life.

**SOFTWARE AND DOCUMENTATION**

The software for COPE is written in FORTRAN and comprises more than 2000 lines. The software itself is made up of analytical modules each of which is a FORTRAN subroutine.

This two-volume progress report for RP1276-8, Technical Studies of Dual Energy Use Systems (DEUS), is entitled COPE Computer Model and presents the manuals for the Cogeneration Options Evaluation Computer Model that is available for evaluation of utility options in owning cogeneration systems. Volume 1 is the program descriptive manual, and Volume 2 is the program user's manual. The descriptive manual explains the model's structure, applications, and methodology; the user's manual describes how to access the model, to prepare data for analyzing financing options, and to interpret results.

This document describes the inputs required as well as the assumptions and calculation procedures used in COPE. Detailed instructions for conducting case studies using the program can be found in "Cogeneration Options Evaluation (COPE): Users Manual," published separately.

# Section 1

# INTRODUCTION

## BACKGROUND

Dual Energy Use Systems (DEUS) have been the subject of many recent studies, which have addressed the technical, economic and institutional issues relevant to the implementation of such systems. However, most of these studies, particularly cogeneration assessments sponsored by the Department of Energy, have focused on industry-owned and -operated systems. Insufficient attention has been paid to the perspectives and potential roles of electric utilities, and the possible industry-utility cooperative efforts and interactions vis-a-vis DEUS implementation. Similarly, many public sector studies of district heating (and integrated community energy systems or ICES) have given insufficient attention to the role and perspective of the local electric utility.

The Electric Power Research Institute therefore initiated a project to evaluate dual energy use systems applications, giving explicit consideration to utility roles, perspectives and impacts. This project, RP 1276, was initiated in early 1979 and numerous activities are currently underway.*

The methodology for evaluating cogeneration projects consists of two steps. In the first step, the aggregate benefits, costs and impacts of cogeneration are calculated, taking into account the impacts on the utility, the industry and society. This calculation is based on the value of electric and thermal energy used, the costs of producing this energy, and the related social and environmental considerations. Institutional and regulatory considerations such as standby and buy-back rates (PURPA rates), tax credits, and alternative ownership and operation arrangements do not affect the overall benefits of cogeneration from the systems viewpoint; they determine how the benefits, costs and impacts are shared by the various parties affected.

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*See Synergic Resources Corporation, <u>Evaluation of Dual Energy-Use Systems</u>, Interim Report, Volume 2, EPRI EM-2695, Palo Alto, California, October 1982.

These factors are therefore considered in the second step, which evaluates the optimum negotiated position of each party relative to the cogeneration venture through the use of Cogeneration Options Evaluation (COPE), a computer model.

## COPE

Cogeneration Options Evaluation (COPE) is a computer model designed to address the institutional and regulatory issues raised by cogeneration. It is an evaluation tool that can help management examine attractive cogeneration options and choose an option that is best suited for a specific site, given the relevant tax and fuel use regulations. An "option" here refers not only to different technologies, but also to different ownership structures and/or operating modes. For each option under consideration, COPE requires cost and performance information as input, and provides, as output, an analysis of the project's impact on the utility, the industry, and where appropriate, a third party. The cost and performance information may come from site-specific engineering studies or from other design-oriented computer models.

The objectives of COPE are to:

- Evaluate, based on after-tax cash flows from cogeneration ventures, the financial and regulatory implications for the utility, the industry, and where relevant, third parties, for all practically feasible combinations of ownership and operating mode.
- Trace, in terms of important dollar flows, the impacts of cogeneration ventures on the utility and the industry for all practically feasible combinations of ownership and operating mode.
- Provide information to potential project participants, identifying mutually beneficial institutional arrangements for implementing cogeneration projects.

COPE's principal strength is that the after-tax cash flow analysis is based on detailed site-specific information. For instance, the initial capital outlay is divided into eight categories that can be distinguished for tax purposes. Energy tax credits are determined on the basis of facility status and fuels used. Institutional and regulatory factors such as back-up and buyback rates, operating mode, and ownership structure are taken into account in determining the distribution of after-tax costs and benefits among parties.

**MODEL CAPABILITIES**

A number of case studies were conducted in cooperation with utilities to test and demonstrate the capabilities of COPE. Selected cases are discussed in Section 4. A summary of the potential applications for COPE is presented here.

The ownership arrangement that is used to implement a cogeneration project determines the after-tax returns that different project participants realize. This is because the ownership arrangement affects the magnitude and distribution of after-tax cash flows in two ways. First, if a cogeneration facility is a qualifying facility under the Public Utility Regulatory Policies Act (PURPA), it is free from public utility regulation. Thus, the electricity from the facility can be sold at PURPA rates (which are based on utility avoided costs). If the utility participates as an "investor" in a qualifying facility (less than 50% utility ownership under current legislation), it can obtain a share of the revenues based on the PURPA rates. The treatment of these revenues by the regulatory commission will determine whether the utility derives any significant benefits from such participation. Second, if a facility is a "qualified facility" under PURPA, it is not deemed "public utility property" for legal purposes, even if it produces electricity for sale. As a result, certain portions of the capital investment could qualify for energy tax credits. Thus, for instance, a coal cogeneration facility would qualify as alternative energy property, and energy tax credits of 10% would be available on fuel handling equipment, boiler(s), pollution control equipment, and specialized buildings or structures. COPE incorporates investment and energy tax credits as part of the cash flow analysis.

In the past, a common assumption was that a cogeneration system is owned entirely either by an industry or a utility. With the increased interest in cogeneration, a number of innovative arrangements are being considered. For example, joint ventures among industry, utility and third parties may offer benefits to all the participants. One arrangement to form a joint venture is to create a separate corporation for the sole purpose of owning and operating the cogeneration project. In this arrangement, the cogeneration project would be taxed as a corporation.

The partnership arrangement can also be used to form joint ventures. Partnerships do not pay a federal tax on earnings comparable to the corporate earnings tax; however, each partner pays federal tax on his share of earnings from the partnership. Also, partnerships enjoy a degree of flexibility in the apportionment of tax and depreciation benefits as well as profits (or losses) among partners. It is possible, therefore, to design partnership arrangements so as to attract private (or "third party") investors by offering them substantial tax-related benefits. At the same time, third parties, having no site-specific thermal or electric requirements, are unlikely to insist on specific operating modes. Thus, partnerships between utilities, industries and "third parties" can often be mutually beneficial.

Any one of the following ownership arrangements can be analyzed by COPE. The utility can be either an investor-owned or a tax-exempt utility.

- 100% Ownership
  - 100% Utility Ownership
  - 100% Industry Ownership
  - 100% Third Party Ownership (or Separate Corporation).
- Joint Ventures
  - Partnership: Utility/Industry
  - Partnership: Utility/Third Party
  - Partnership: Industry/Third Party
  - Partnership: Utility/Industry/Third Party.

COPE uses information about the ownership structure, the cogeneration system and the operating mode to simulate initial and operating cash flows over the project's useful economic life. Subsequently, these cash flows are apportioned among the project participants and each participant's cash flow is computed. Finally, these cash flows are used to compute the net present value, the internal rate of return, the payback and the debt-coverage ratio for each participant. In addition, a pro forma income statement for the project is presented.

For a given implementation mechanism, therefore, COPE can be used to judge the impact on the project participants. Conversely, sensitivity analyses can be performed to identify implementation mechanisms that would benefit all participants. Sensitivity analyses can also be used to answer a number of other questions, such as: What PURPA price profile (for electricity) will give an industrial owner a specified rate of return on the project? Alternatively, at given electricity and steam prices, COPE can be used to determine the maximum input fuel cost which would give an industrial owner a desired project rate of return. Similarly, for new technologies, COPE can be used to determine a "maximum allowable total installed cost."

Since COPE maintains separate accounts for three distinct project participants--the utility, the industry, and a third party--a number of innovative schemes involving transfers between parties can be represented. For instance, a scheme in which an industry sells the cogeneration plant to a utility after owning and operating it for a fixed number of years can be represented. COPE can be used to analyze the impact of such transactions on each participant for each year of useful project life. Similarly, a leasing arrangement can be handled by using the third party's account to represent the lessor's inflows and outflows. Thus COPE can be used to analyze the impact of a leasing arrangement for the lessor as well as the lessee.

The output from COPE consists of a series of reports. Reports 1,2,3 and 4 display the inputs used in COPE. Report 5 presents the outputs from the analysis. Examples of these reports are presented in Section 4 of this report.

The software for COPE is written in FORTRAN and comprises more than 2000 lines. The software itself is made up of analytical modules each of which is a FORTRAN subroutine.

This document describes the inputs required as well as the assumptions and calculation procedures used in COPE. Detailed instructions for conducting case studies using the program can be found in "Cogeneration Options Evaluation (COPE): Users Manual," published separately.

## Section 2

### SYSTEM OPERATION AND OWNERSHIP

**OPERATION OF COGENERATION UNITS**

The manner in which a cogeneration unit is operated is an important determinant of after-tax cash flows from the project. Moreover, since cost and performance are important inputs to COPE, it is important to discuss how system performance is characterized.

The operating mode can be characterized by two features:

- The dispatch arrangement
- The electricity sales arrangement.

**The Dispatch Arrangement***

The demand for the thermal output from a cogeneration unit is, in general, a function of time. Also, unless storage equipment is on hand, thermal energy has to be used instantaneously or wasted. Since there is no readily available alternative steam source to meet sudden peaks in demand, it is reasonable to view process thermal demand as a constraint. In the case of the other output from the cogeneration unit, namely, electricity, the limitations are not as stringent. For the user of process electricity, a sudden surge in demand can be met by buying electricity from the utility. However, depending on the electric supply characteristics and the extent of cogeneration in the region, this could alter the utility's cost of supplying power, thereby raising back-up power charges for cogenerators. So long as such additional back-up costs are factored into the cogenerator's decision, it is reasonable to place no constraints on the system's electric output.

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*"Electricity load following" is a special type of dispatch that is unlikely to be used in grid-interconnected systems. Under this dispatch, the power output of the cogeneration system tracks the profile of on-site power requirements. This type of dispatch is not discussed here.

The dispatch arrangement determines the system electric output with the constraint that the thermal output be at least as large as the thermal demand for every time interval.

- **Thermal Dispatch**

In this dispatch arrangement, the cogeneration unit is sized so as to maximize fuel utilization efficiency, subject to the constraint that the thermal demand under peak conditions is met. If auxiliary boilers are specified as part of the system, it is assumed that they will be utilized in meeting peaks. The system is dispatched so that in every time interval the thermal demand is exactly met. The electric output of the unit corresponding to this condition is the power generated by the system.

- **Economic Dispatch**

As the name suggests, economic dispatch relates plant operations to economic criteria. Under this dispatch arrangement, the cogeneration unit size is chosen by the parties involved. Indeed, the size of the unit itself may be determined to a large extent on the basis of economic criteria. Once the unit is chosen, the manner in which it is dispatched is also determined using economic criteria. Specifically, the system is dispatched so that in every time interval the net operating income (i.e., revenues minus costs) is maximized, subject to the constraint that the thermal output from the unit be at least as large as the thermal demand. Of course, the size of the unit (which is specified by the parties involved) places an upper limit on the electric output from the unit.

**The Electricity Sales Arrangement**

The electricity sales arrangement is an important feature of a cogeneration system, since it determines the amount of electricity that is sold to the utility.

- **Simultaneous-Buy-Sell**

Under this arrangement, the entire electric output from the cogeneration system is sold to the utility. The electricity that is required for the operation of the cogeneration system itself (i.e., the auxiliary power) is bought from the local electric utility along with any necessary on-site process power.

- **Buy-Shortage-Sell-Excess**

Under the buy-shortage-sell-excess arrangement, the electric output from the system is first used in each time interval to meet the auxiliary and process power requirements. If, excess power is then available, it is sold to the local utility. If, on the other hand, the power requirements in a time interval exceed the system's electric output, the deficit is met by buying power from the utility.

### Performance Characteristics

The performance of a cogeneration system under a given operating mode can be characterized by the following physical flows:

- Gross power output from system in kW
- Power required by auxiliaries in kW
- Process power demand (if relevant*) in kW
- Thermal output from system in MBTU/hr
- Fuel(s) use by the system in MBTU/hr.

Each of these performance descriptors can be expressed either on an average annual basis or on a period-by-period basis. In the latter case, the periods correspond to the local utility's PURPA periods. Expressing performance characteristics by PURPA period could be of considerable importance to the economic analysis in situations where PURPA prices vary significantly from period to period.

## OWNERSHIP OF COGENERATION SYSTEMS

The magnitude and distribution of after-tax costs and benefits from a cogeneration venture are determined both by the operating mode and the ownership structure. The ownership structure need not necessarily determine the operating mode, although certain combinations of ownership and operating mode are unlikely. For instance, it is unlikely that a utility owned system would be operated under thermal dispatch. In COPE, the operating mode and the ownership arrangement are independent, user-specified inputs. COPE can examine the following ownership structures:

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*Although the process power demand is not a system characteristic, it is necessary in order to calculate (i) the extra back-up cost, if any, under simultaneous-buy-sell, or (ii) the net power, under buy-shortage-sell-excess.

- 100% ownership
  - 100% utility-owned
  - 100% industry-owned
  - 100% third-party-owned.

Under 100% ownership, all the costs and benefits from the project flow to a single party. The ownership structure does, however, influence both the tax-related benefits and project revenues, and this is discussed further in a subsequent section. With regard to the utility, the user can specify whether the utility is investor-owned or tax-exempt.

- Joint Ventures
  - separate corporation
  - partnerships.

Two methods can be used to implement joint ventures: a separate corporation and a partnership. In both cases, project costs and benefits flow to project participants. There are, however, important differences between the two arrangements.

In the case of a separate corporation, each project participant has an interest in a corporation which, in turn, owns the assets that make up the cogeneration plant. Under this arrangement, we can view the project participants as shareholders in a corporation that is in the cogeneration business. From a managerial standpoint, this has two important implications. First, the "cogeneration corporation" would have to pay a corporate tax on earnings like any other corporation. Second, in providing debt to the corporation, the capital markets would rate the corporation as a whole. This second point may not lower the corporation's cost of debt, since lenders would have no indicators of past financial performance to make judgements. Thus, the cost of debt and the cost of equity for the new corporation are of great importance in evaluating this ownership structure. Indeed, for modeling purposes, evaluating a cogeneration venture from the standpoint of the newly formed corporation is no different from evaluating a project for 100% third party ownership, so long as the appropriate costs of debt and equity are used.

In the partnership arrangement, each project participant holds an undivided interest in the partnership's assets. Commonly, partnerships have a general partner and a number of limited partners.

From a managerial standpoint, there are three noteworthy features of this arrangement. First, all project costs and benefits are shared among project participants by a predetermined formula that is mutually agreed upon by the partners. The "benefits" referred to here include not only project revenues, but also tax credits and depreciation allowances. "Costs," in this context, include both initial outlays and operating costs. Partnerships have a degree of flexibility in apportioning costs and benefits. The partnership agreement also includes the extent of exposure of each partner in the event that the project is not completed. Second, the mode of operation of the plant would also be determined by mutual consent of the partners. Third, the partnership itself is not subject to a federal tax comparable to a corporate tax. Each partner is, however, taxed based on his share of profits (or losses) from the venture.

In the discussion that follows, we present the cash flow calculations for a project owned as a partnership. The case of 100% ownership is a special case of a partnership where all the relevant "shares" are 1. However, it must be noted that the ownership structure can change the status of the facility vis-a-vis PURPA.

## Section 3

## METHODOLOGY

An overview of the structure of COPE is provided in Figure 3-1. It shows that COPE requires cost and performance information as input. COPE uses the performance information along with other information (principally information related to prices and ownership arrangements) to generate project cash flows. These cash flows are apportioned among project participants, and an after-tax cash flow stream is computed for each. Finally, COPE uses the after-tax cash flow stream to perform financial analyses for each participant.

The methodology used in COPE will now be discussed.

### CASH FLOW IMPLICATIONS OF INITIAL INVESTMENT

#### Initial Outlays

COPE requires as input the installed cost for eight specific categories that can be distinguished for tax purposes (see Table 3-1). If only the total installed system cost is available, the cost for each category is estimated as a fraction of total installed cost. The distribution of expenditures over the construction period (expressed as a fraction of total installed cost) is also a required input.

During construction, all expenditures (including interest payments) are borrowed on a short term basis.

In the final year of construction, the long term financing strategy is initiated. At the point when operations commence, all short term borrowings are repaid with interest, and the project is financed by the party/parties involved by a combination of debt and equity (see Figure 3-2 for schematic). The long-term debt and equity fractions are provided as inputs to COPE. With regard to deducting short-term interest expenses, COPE provides the user with two options. The first option allows a deduction of short-term interest expenses for tax purposes. If this option is used, interest expenses incurred during construction are not capitalized for

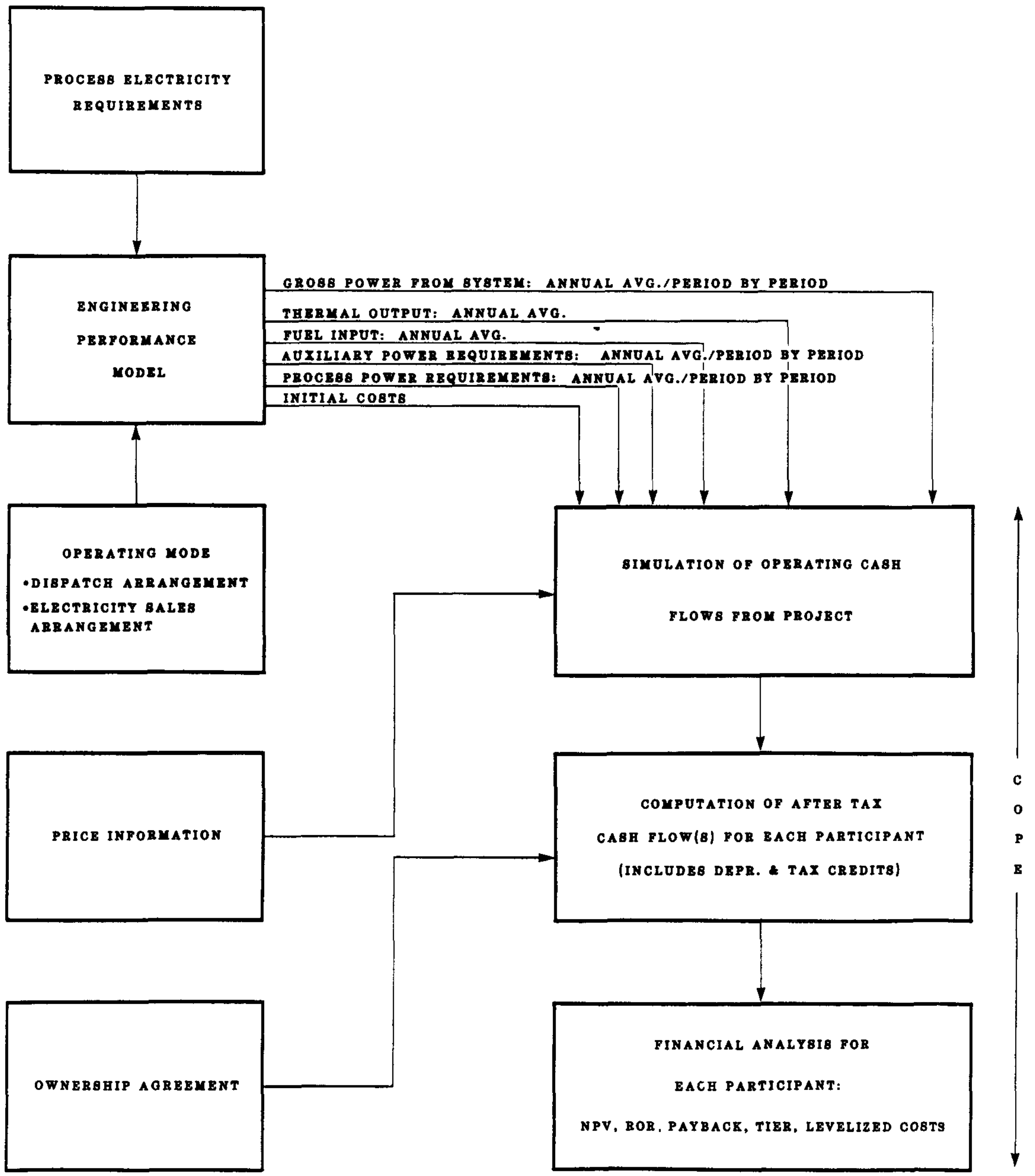


Figure 3-1. Overview of Cogeneration Option Evaluation (COPE).

Table 3-1

EQUIPMENT CATEGORIES

| CATEGORY | DESCRIPTION |
|---|---|
| 1 | Fuel Handling Equipment |
| 2 | Boiler |
| 3 | Pollution Control Equipment |
| 4 | Turbine Generators |
| 5 | Heat Distribution Equipment |
| 6 | Specialized Buildings and Structures |
| 7 | General Purpose Buildings |
| 8 | Land |

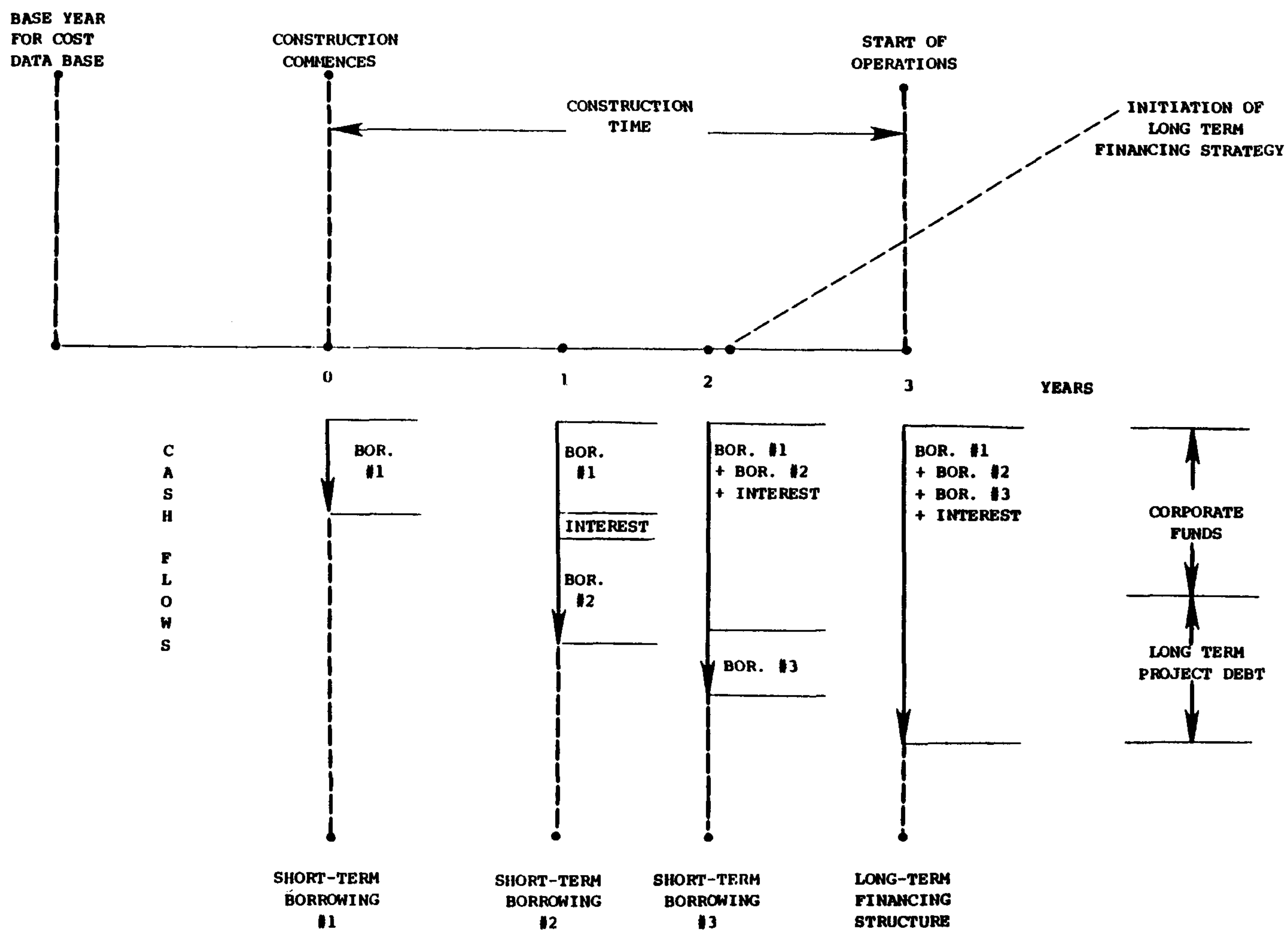


Figure 3-2. Scheme for Initial Outlays.

computing tax credits. The second option does not allow deduction of short-term interest expenses for tax purposes. However, under the second option, interest expenses incurred during construction are capitalized and are included in the property basis for tax credit computations.

The Tax Equity and Fiscal Responsibility Act of 1982 does not permit deductions, for tax purposes, of interest expenses incurred during construction of real property. Therefore, in a number of circumstances, the owners of the cogeneration project may find it advantageous to exercise the second option.

If the first option is used, COPE assumes that each party has adequate unrelated income to realize the full tax benefits of short-term interest expenses.

**Treatment of Long Term Debt**

As can be seen from Figure 3-3, the project is financed upon completion of construction by a combination of long-term debt and participant capital contributions. When only one party is involved, there will be one stream for servicing long-term debt. Also, if preferred equity is involved, COPE requires that it be combined with common equity and an effective cost of equity be provided.

When more than one party is involved, the rate at which each party can raise debt may be different. This is of particular importance in the case of partners with an undivided interest in the partnership. COPE is designed to handle different types of "capital structures."* In order to characterize capital structure we will introduce the following definitions.

- **Project Debt**

  In cases involving 100% ownership by a single party, project debt refers to debt that is provided specifically for the project. COPE assumes that for partnerships, "project debt" is available to the project at a given rate.** Common examples of project debt include industrial development bonds at lower-than-market rates and long term loans secured by project revenues. In the case of project debt, COPE computes separate streams of debt service payments for each party over the term of the loan.

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*Note that "capital structure" should be distinguished from "ownership structure." The latter determines project participants; the former describes the sources of funds.

**It is possible that the lender may sign separate debt instruments with each of the partners involved.

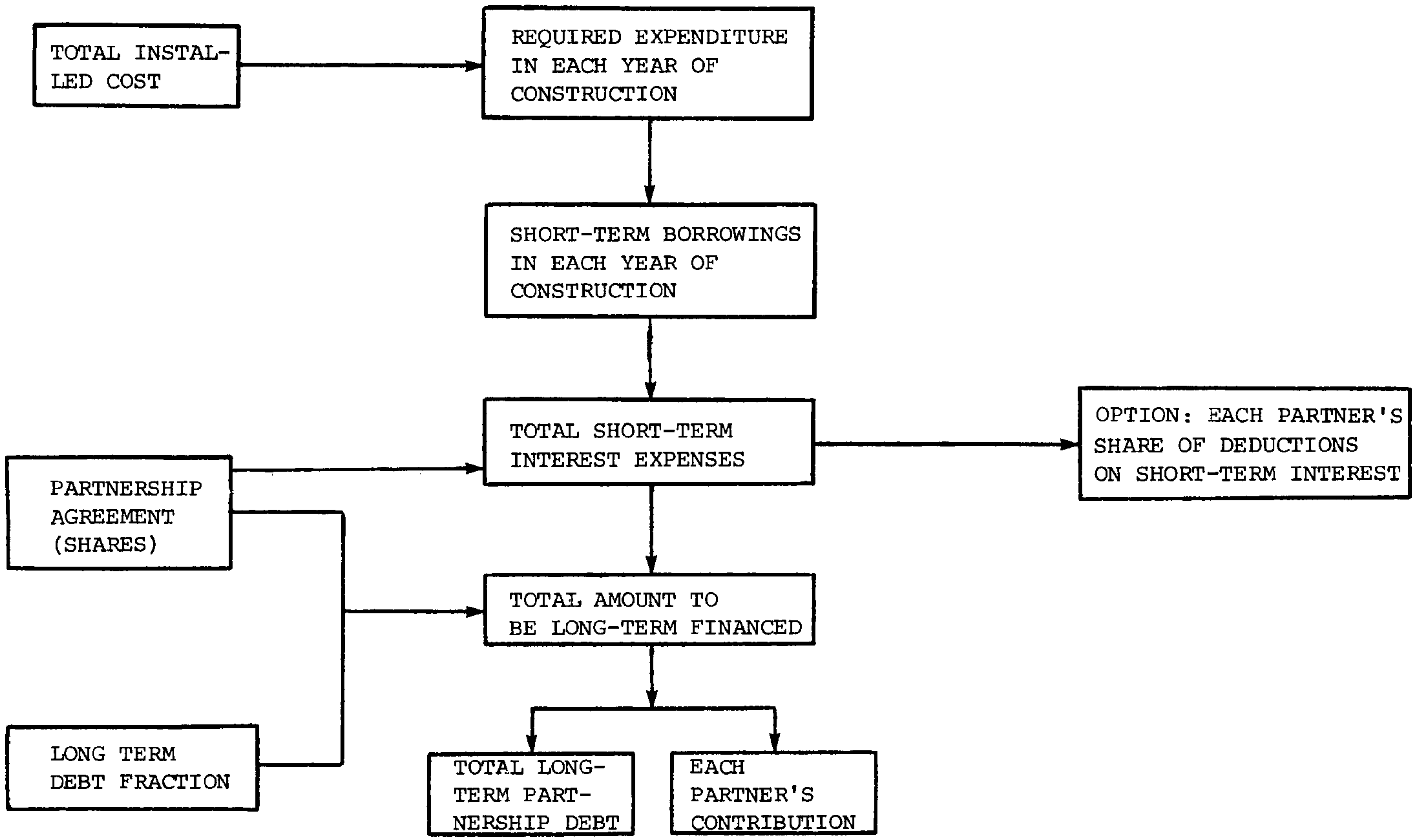


Figure 3-3. Logic Diagram to Determine Long-Term Debt and Capital Contributions.

- **Corporate Contributions**

  "Corporate Contributions" refers to funds that make up the portion of total investment that is not financed by project debt. Corporate contributions of capital come from some combination of "corporate debt" and "corporate equity." The rates at which different parties can raise debt and equity are different, and are provided as inputs to COPE. COPE does not compute a stream of debt service payments for the debt portion of corporate contribution. Instead, the tax benefits of debt are accounted for by using an after-tax weighted average cost of capital as the appropriate discount rate. Corporate contributions may also come entirely from equity.

Thus, the "capital structure" defines the mix of project debt and corporate contributions that make up the total investment. Also, the capital structure specifies the composition of corporate contributions.

Once the total partnership debt is computed, repayment can be scheduled either as an annuity or by using a sinking fund. The amounts that correspond to interest payments (as distinct from principal payments) are computed and appropriately apportioned among project participants. Interest payments on long-term debts are, of course, deductible from taxable income and the cash flow computation accounts for this.

**Treatment of Corporate Contributions**

The total amount of corporate contribution is computed as the non-debt portion of the project. This corporate contribution is split among the parties according to the partnership agreement. The case of 100% equity financing is a special case where the entire investment is made up of corporate contributions. It must be emphasized that all corporate contributions come from the parties in the final year of construction. During construction, as was discussed earlier, all expenditures are financed by short term borrowing.

**Investment Tax Credits**

COPE computes the appropriate investment tax credits that accrue to each party in a project by including : (i) property classification, (ii) separate treatment of each of the eight equipment categories, and (iii) partnership agreements on distribution of tax credits. Figure 3-4 depicts the logic that is built into COPE.* Table 3-1

*Relevant provisions of the Tax Equity and Fiscal Responsibility Act (TEFRA, 1982) have recently been incorporated in COPE. Reduction of the depreciation basis by one half of the tax credits taken, which is discussed later, is of particular importance.

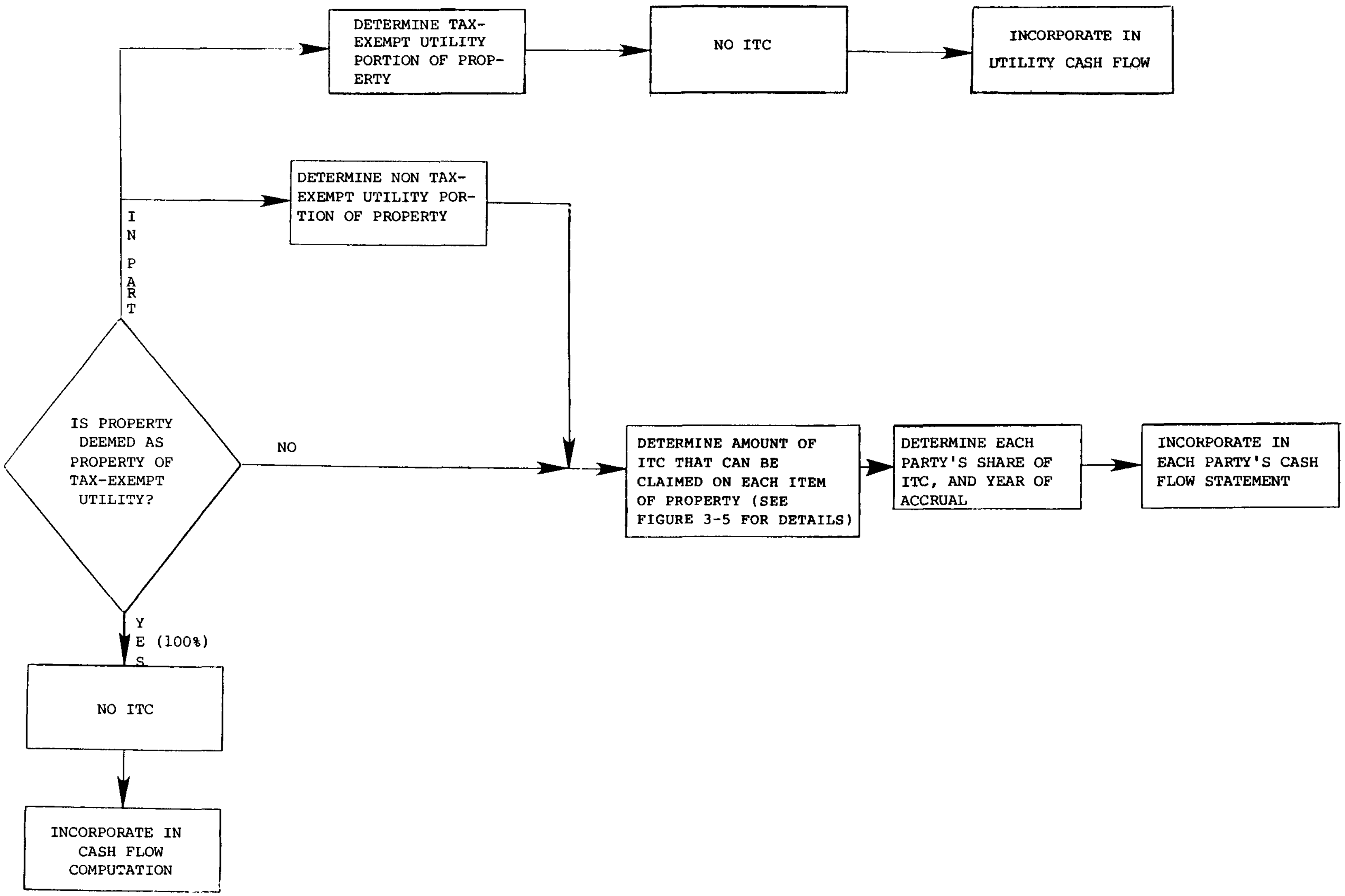


Figure 3-4. Logic Diagram to Determine Investment Tax Credits.

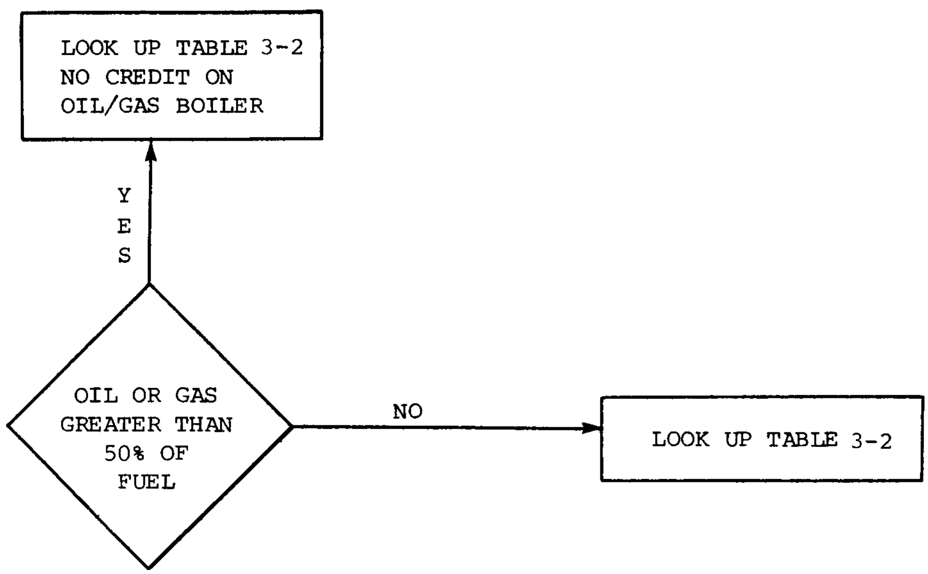


Figure 3-5. Investment Tax Credit Details.

contains the equipment categories and Table 3-2 describes the tax credit rates applicable under current law. A user can readily change these tax credit rates.

As can be seen from Figure 3-4, the first step is to determine the eligibility of the entire property. Once the portion of the property that is eligible is determined, and this could be 100%, the tax credit that can be claimed by each party on each piece of equipment is computed. COPE ensures that a tax-exempt utility receives no tax credits.

The first step in computing the magnitude of the credit that can be claimed on a piece of equipment involves a determination of the basis. This is important since tax credits are computed using this basis. If tax deductions on short-term interest expenses are taken, the basis is computed by estimating the nominal cost of equipment (not including interest on borrowing) at the mid-point of construction life. If tax deductions on short-term interest expenses are foregone, interest expenses incurred during construction are included in the basis.

In the next step, the tax credit that accrues to each party on each piece of equipment is calculated. This is done by dividing the total investment tax credit that is available on a given piece of equipment among project participants according to the partnership arrangement. After this step, the total investment tax credit accruing to each project participant is computed by adding the available tax credits on each piece of equipment.

The final step involves calculating the time period when the tax credits can be claimed. For physical construction periods of greater than two years, COPE allows the parties to claim tax credits during construction. If the physical construction period is less than two years, COPE assumes accrual in the first year of operation.

**Energy Tax Credits**

The procedure for computing energy tax credits is different from the procedure used for investment tax credits for two reasons: (i) the property classification is more complicated, and (ii) the same property can be eligible for energy tax credits in more than one way.

With regard to property classification, the point to be noted is that if a property is deemed in law as providing public utility-type regulated service, it is not eligible for energy tax credits. Cogeneration projects that are "qualifying

Table 3-2

APPLICABLE TAX CREDIT RATES

AND DEPRECIATION CATEGORIES

| Property Category | Investment Tax Credit | Energy Tax Credit | | | | Depreciation Yrs (ACRS)† | | |
|---|---|---|---|---|---|---|---|---|
| | | Coal | Biomass | Solid Waste | Retrofit | Utility Property (SE/CC) | Utility Property (NUC./CT) | Non-Utility Property |
| Fuel Handling Equipment | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 15 | 10 | 5 |
| Boiler | 0.1/0.0* | 0.1 | 0.1 | 0.1 | 0.1 | 15 | 10 | 5 |
| Pollution Control Equipment | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 15 | 10 | 5 |
| Turbine Generators | 0.1 | 0.0 | 0.0 | 0.1 | 0.0/0.1** | 15 | 10 | 5 |
| Heat Distribution Equipment | 0.1 | 0.0 | 0.0 | 0.0 | 0.1 | 15 | 10 | 5 |
| Specialized Buildings | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 15 | 10 | 5 |
| General Purpose Buildings | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15 | 15 | 15 |
| Land | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | N.A. | N.A. | N.A. |

* 0.0 applies to oil/gas boilers only

** 0.1 applies only if retrofit is primarily thermal

† Depreciation is based on accelerated cost recovery system (ACRS)

SE: steam electric

CC: combined cycle

NUC: nuclear

CT: combustion turbine

facilities" under PURPA are not subject to public utility-type regulation, and therefore, are eligible for energy tax credits.*

The second point relates to the energy tax credits that can be claimed for eligible property. Broadly, there are two ways in which a property qualifies for energy tax credits. First, under the National Energy Act of 1978, pieces of equipment of an "eligible property" may qualify for "alternative energy tax credits." This determination is made on the basis of the primary fuel used. Facilities that use coal, biomass or solid waste as the primary fuel qualify for "alternative energy tax credits." The Windfall Profits Tax Act (WPTA) of 1980 offers a second way for project participants to claim energy tax credits. The WPTA offers energy credits on certain pieces of cogeneration equipment that can be considered as part of a retrofit.

There are important details (under both NEA and WPTA) regarding the energy credits allowed by law on different pieces of equipment (see Table 3-2 for details). The COPE user can readily change these rates to investigate alternative tax incentives. COPE assumes that project participants will choose between NEA and WPTA (when both are applicable) in a manner that will maximize the accrual of energy tax credits. For a description of model logic, see Figure 3-6.

The steps involved in determining the magnitude of energy tax credits accruing to each project participant are similar to those used in the investment tax credit computation. First, as in the case of investment tax credits, the property basis is determined depending on whether or not short-term interest expenses are deducted. Second, the amount available on each piece of equipment is divided among project participants according to the partnership arrangement. Third, the total amount available to each project participant is computed by summing up the available amounts on each piece of equipment. Finally, COPE determines the year of accrual of energy tax credits based on length of construction period.

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*Although many legal experts concur with this view, some regard it as only "arguably valid" for investor-owned utilities that participate in PURPA-qualified cogeneration projects.

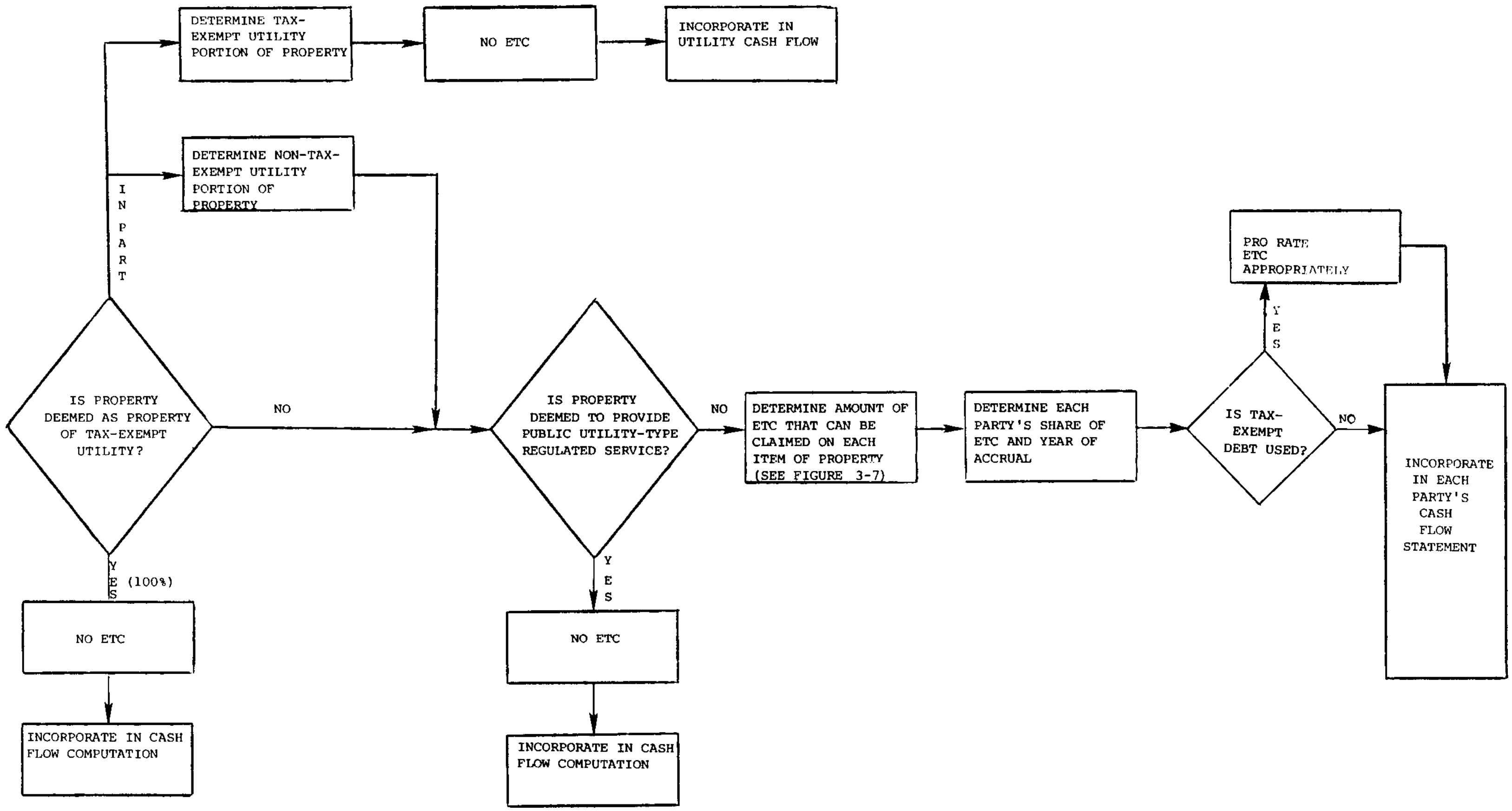


Figure 3-6. Logic Diagram to Determine Energy Tax Credits.

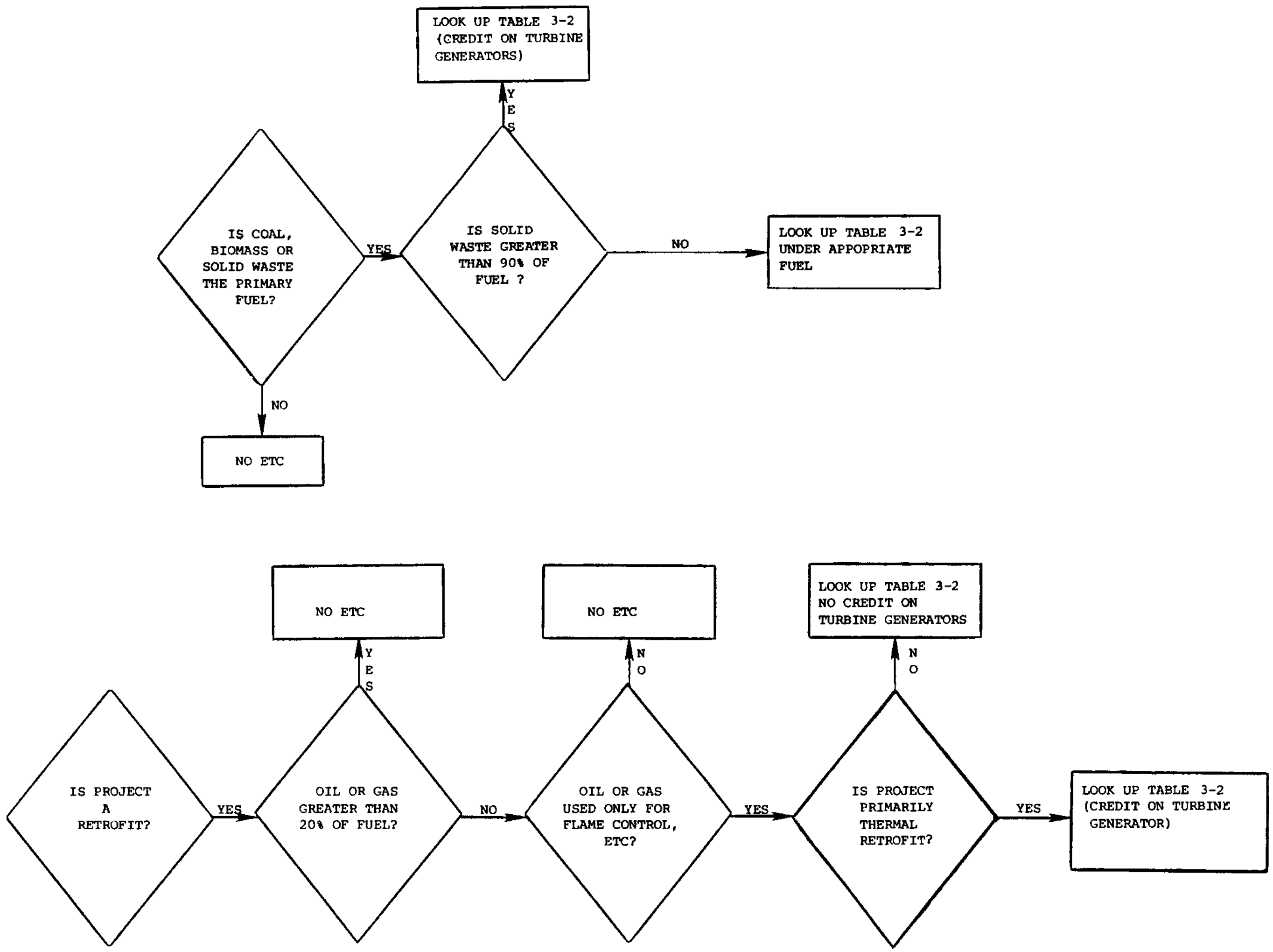


Figure 3-7. Energy Tax Credit Details.

## Depreciation

As in the case of investment tax credits, COPE accounts for property classification, differing treatment for equipment categories, and partnership agreements in the computation of allowable depreciation. Property classification for depreciation purposes is, however, more complicated than the classification for investment tax credit purposes. Figure 3-8 shows the logic used in computing depreciation.

According to the Tax Equity and Fiscal Responsibility Act (1982), the basis of the property for computation of depreciation is the basis used for tax credit computations less one half of the total tax credits claimed. COPE adjusts the property basis for depreciation purposes in accordance with this latest piece of legislation.

As can be seen from Figure 3-8, eligibility is determined in the first step. If part of the property is owned by a tax-exempt utility, then that part has to be depreciated using straight line depreciation over economic life, regardless of the classification of the property under PURPA. Classification under PURPA does matter for that part of the property not owned by a tax-exempt utility. If the property is a "qualifying facility" under PURPA, most pieces of equipment can be depreciated, under current law, using the 5-year accelerated cost recovery system (ACRS). If the property is not a "qualifying facility" and is deemed "public utility property," the applicable depreciation schedule (under current law) is 10 years (ACRS) for some equipment categories and 15 years (ACRS) for others. Table 3-2 provides the applicable depreciation lives for different equipment categories. As can be seen from Table 3-2, the depreciation life does depend on the type of generating equipment--steam electric, combustion turbine, etc. Another feature of current law, as laid down in the Economic Recovery Tax Act (ERTA) of 1981, is that the fractions that can be depreciated in each year are specified in the Act and do not have to be calculated. These fractions are part of the data provided to COPE. They can be changed by a user to examine alternative depreciation methods. The computation is performed as follows: (i) the amount of depreciation that can be claimed (under the appropriate classification) on each piece of equipment for each year of tax life is computed. As was discussed, the "adjusted basis" is used for depreciation purposes; (ii) this amount is then divided among project participants according to the partnership arrangements for each year of tax life; (iii) finally, the total amount that can be claimed by each participant is computed for each year of tax life.

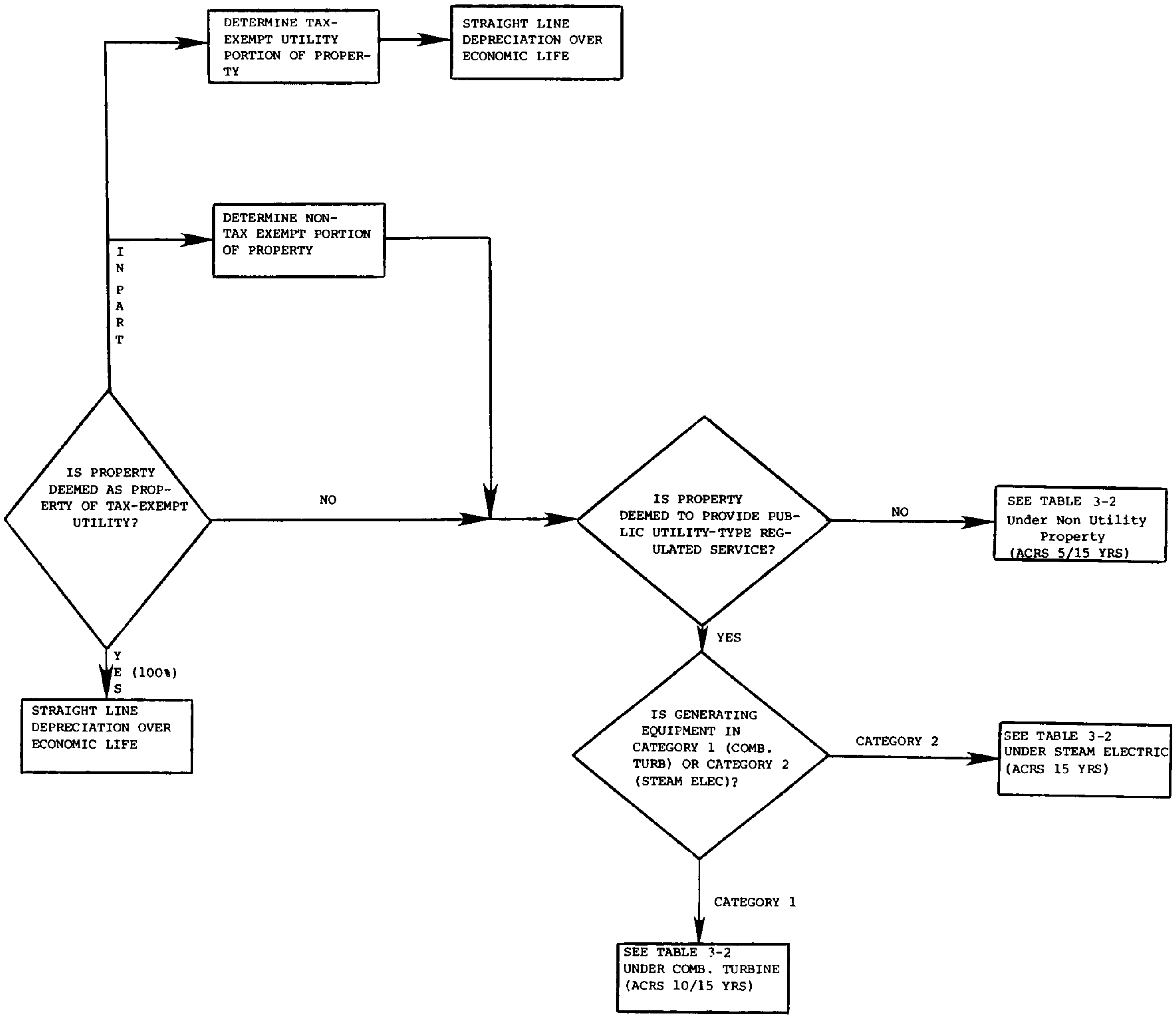


Figure 3-8. Logic Diagram for Depreciation Computations.

## CASH FLOWS FROM OPERATIONS

"Operating Cash Flows" refer to the inflows and outflows of cash during each year of useful economic life. Broadly, they include all annual revenues (primarily steam and electric revenues in our case) all annual costs (primarily fuel and operation and maintenance, in our case) and tax effects. With regard to taxes, the major tax deductions are depreciation and interest payments on long-term debt. The major tax burden is the federal tax on earnings. In a large number of cases, investment and energy tax credits significantly lower the tax burden in the first year of operations. The computation of investment and energy tax credits and depreciation has already been discussed. Here, the focus will be the computation of annual revenues and expenditures.

An operating cash flow can be computed, in general, as the product of price (or cost) per unit and quantity flow per unit time. It is essential, therefore, that both the price and quantity be properly accounted for. Prices/rates/costs will be discussed first.

### Electricity Rates

Six rate types are relevant in the computation of operating cash flows:

- PURPA Avoided Energy Cost (¢/kWh). This refers to the rate offered to a cogenerator qualified under PURPA for energy (or kWh) sales to the utility.
- PURPA Avoided Capacity Cost ($/kW/year). This is the rate at which a cogenerator qualified under PURPA is compensated for capacity that he contracts to make available to the utility.
- Industrial Energy Charge (¢/kWh). This is the rate which the utility's industrial customers are charged for energy (or kWh) consumed.
- Industrial Demand Charge ($/kW/year). The industrial demand charge is the rate that the utility's industrial customers are charged for the capacity demands they place on the utility system.
- Industrial Back-Up Energy Charge (¢/kWh). This is the industrial energy charge rate that is charged only for a cogenerator. It may or may not be different from the industrial charge rate.
- Industrial Back-Up Demand Charge ($/kW/yr). As in the case of energy charges, this is the industrial demand charge that is charged only for a cogenerator. As before, it may or may not differ from the industrial demand charge.

Electricity rates frequently vary by time of day. Each of the above rates can be provided to COPE in one of two ways: (i) on a period by period basis, and (ii) as an annual average. In the former case, the periods correspond to the utility's PURPA periods. COPE can handle a maximum of 36 periods per year.

The rates in each period (or year, if annual average rates are used) also change to reflect inflation and other market adjustments. Many users provide rates in base year terms and specify a constant annual escalation rate. In special situations, a user might provide an entire profile of prices over time. COPE can handle both cases.

In a period-by-period specification of rates, the rate in year i for rate type t in PURPA period q is given by

$$p^t_{i,q} = k^t_i \, (p^t_{o,q}) \, (1+r^t)^g$$

$p^t_{i,q}$ = rate in year i for rate type t in PURPA period q

$p^t_{o,q}$ = rate in <u>base year terms</u> for rate type t in PURPA period q

$r^t$ = constant annual escalator for rate type t

$g$ = number of years from base year to year i

$k^t_i$ = multiplier for year i and rate type t

If the user requires a special price profile over time, the constant annual escalator can first be set and the $k^t_i$'s varied so as to follow the price profile. If constant annual escalation is required, all $k^t_i$'s are set at 1.

If all rates are provided on an annual average basis, the price is computed as

$$p^t_i = k^t_i \, (p^t_o) \, (1+r^t)^g$$

$p^t_i$ = rate in year i for rate type t

$p^t_o$ = rate in <u>base year terms</u> for rate type t

$r^t$ = constant annual escalator for rate type t

$g$ = number of years from base year to year i

$k^t_i$ as defined before.

This method of representing price/costs/rates profiles is used throughout COPE.

## Steam Price

The steam price is the value in $/million Btu realized by the cogeneration venture for steam sold. While this value may correspond to the cost (in $/million Btu) of producing the same quality steam by alternative means, it does not have to. Put another way, the steam price could be arrived at by negotiation between the owners of the cogeneration project and the customer.

This steam price is, in general, a function of the pressure at which it is delivered. It is important to note that even if two streams of steam deliver identical energy per unit time (i.e., identical million Btu/hr), their price in $/million Btu may be different if they are delivered at different pressures. Steam at a higher pressure is valued at a higher price.

COPE requires the user to specify the price of steam in base year dollars per million Btu at two different pressures: a maximum pressure and a minimum pressure. As a rule, the range from minimum to maximum pressure should cover the range of process steam pressure requirements. As in the case of electricity rates, any price profile over time for steam can be created. An important difference between electricity rates and steam prices is that in the case of the latter, two prices (corresponding to minimum and maximum pressures) are provided in base year terms. The price in base year dollars corresponding to the relevant process steam pressure is computed by a linear interpolation between the price at minimum pressure and price at maximum pressure. Thereafter, the price profile over time is created using the method employed in the case of electricity rates. It must also be noted that steam prices do not vary from period to period during a year.

COPE can process a maximum of three streams of steam, each with a different delivery pressure.

## Input Fuel Costs

The input fuel cost is expressed in $/million Btu. As in the case of steam prices, there is no variation in the input fuel cost between periods of a year. COPE can handle a maximum of three input fuel streams, each priced differently. The creation of a fuel cost profile over time is straightforward. The appropriate escalation factor for each year is applied to the base year fuel cost.

## Utility Electricity Costs

Utility electricity costs are important inputs to COPE, and are used in the computation of utility impacts.

Four cost types are used in COPE:

- Marginal Energy Cost for Industrial Customers: This is the cost incurred by the utility (in cents) to provide an additional kWh of energy to an industrial customer. In general, this cost is used to compute the PURPA avoided energy cost discussed earlier. In some service areas, the two could be identical.

- Marginal Capacity Cost for Industrial Customers: This is the cost incurred by the utility in meeting an additional capacity demand of one kW. Again, this cost provides the basis for the computation of PURPA avoided capacity costs. As is the case with all prices, COPE requires enough information to create a price profile over time. In the case of marginal capacity costs, this information embodies many judgements.

- Marginal Back-up Energy Cost for Industrial Customers: This cost represents the cost incurred by the utility to provide a cogenerator with an additional kWh. The cost may or may not be different from the marginal energy cost for industrial customers.

- Marginal Back-up Capacity Cost for Industrial Customers: This cost is the cost incurred by the utility to serve an additional capacity demand of one kW by a cogenerator.

For electric utility costs, the user has to provide information very similar to that provided for electricity rates. As in the case of electricity rates, the information can be provided by PURPA period or on an average annual basis. The cost can be provided as a base year cost escalating at a constant rate or as an year-by-year profile.

## Cost of Alternative Steam

As was discussed under Steam Price, the price of steam does not have to correspond to the cost of producing it by alternative means. The common alternative for producing steam is by using boilers. Calculating the cost of producing alternative steam involves a summation of a number of cost components: an appropriately annualized cost to cover the capital costs of the boiler; an annual fuel expenditure; an annual operation and maintenance expenditure; and adjustments for tax expenses and tax benefits. Such a "cost of production" computation can be viewed as one way of arriving at a steam price that will yield a "competitive rate of return" on an investment in steam generation facilities. The cost of producing steam (on a

$/million Btu basis) rises with pressure because handling of higher pressure streams requires additional hardware. COPE assumes that the user provides a cost of alternative steam, although COPE can be used to compute this cost as well. (This will become clear in a subsequent section where a discussion is provided of the boiler as an investment.)

If the user provides the cost of alternative steam, the following information has to be provided: cost of alternative steam in base year dollars at minimum and maximum pressure; and the pattern of escalation. As before, a profile over time is created by COPE.

<u>Power Flows</u>

Beginning with power flows, the manner in which annual quantity flows are handled in COPE will now be discussed.

As was discussed under operation of cogeneration systems, the power flows from a cogeneration system can be characterized by gross power flow, auxiliary power requirement and process power requirement.

Since the decision on level of power production from the cogeneration system is frequently determined by economic considerations, and prices vary both by PURPA period and year, it is quite conceivable that the owner (or owners ) of a cogeneration system may choose to operate the system differently for each (i) PURPA period during the year, and (ii) year of operation during the project's economic life.

At the present time, COPE allows the user to vary the power flow from PURPA period to PURPA period, but does not allow for changing power flows from year to year. In other words, it is assumed that the plant is operated identically for each year of project life. However, with software changes, COPE can be modified to permit a change of operating characteristics from year to year.

When the system is operated differently for each PURPA period, the inputs provided to COPE are

$$PWGNG_q, \quad q = 1,2,......36$$

$$PWAUX_q, \quad q = 1,2,......36$$

$$PWPRS_q, \quad q = 1,2,......36$$

$PWGNG_q$ = gross power produced by system during period q (in kW)

$PWAUX_q$ = auxiliary power required by system during period q (in kW)

$PWPRS_q$ = process power required by system during period q (in kW).

COPE allows for a maximum of 36 periods per year. When the system is operated identically in each PURPA period during the year, the gross power, auxiliary power and process power are provided to COPE on an annual basis.

**Steam Flows**

COPE requires that the useful steam delivered by the cogeneration system be provided as input. There are two important points related to this flow. First, if any steam is used by system auxiliaries, the user should ensure that it is properly accounted for. The useful steam is a "net item," and system auxiliary steam must not come from useful steam. Second, if the system is operated in such a manner as to generate more steam than is required by the process, the excess steam must not be included under useful steam, unless it is readily marketable at a known price.

Even if the system is operated differently in each PURPA period, COPE requires that the useful steam delivered be provided on an annual basis. This simplification is possible because steam prices do not vary by PURPA period.

**Input Fuel Flows**

The input fuel flow is also an input to COPE. As in the case of power flows, input fuel flows can be provided to COPE either by PURPA period or as an annual average.

**Net Electric Revenues**

The price/rate/cost profiles and physical flows discussed thus far are used to compute annual revenues and costs for each year of project life. Net electric revenues will be discussed first.

The net electric revenue realized by a project depends on (i) the status of the project vis-a-vis PURPA, (ii) the electricity sales agreement, and (iii) all the relevant electricity rates.

The term "net" in net electric revenues is appropriate because operating a cogeneration plant may, in addition to generating electricity revenues, entail specific electricity costs. First, the cogeneration system requires auxiliary power. If this auxiliary power is bought from the utility and the entire output of the cogeneration system sold to the utility, it is appropriate to account for the cost of supplying auxiliary power in the computation of net electric revenues. Second, as we discussed under electricity rates, the cogenerator could be charged a rate different from the industrial rate. If this were to occur, it would be appropriate to account for extra back-up costs in the computation of net electric revenues.

COPE first computes the project electric revenues for each year. The net electric revenue is made up of four items: electric revenues from sales to the utility, revenues attributable to electricity savings, cost of operating auxiliaries, and the extra cost of back-up power. Each electric revenue item is computed based on an energy component and a capacity component. For instance, the revenues from electricity sales are computed as follows:

Electricity Sales = (Power Flow) (Hours per Period) (PURPA Energy Price) + (Capacity Contracted) (PURPA Capacity Price)

Inserting units into the above yields:

Electricity Sales = (kW) (HRS/PERIOD) ($/kWh) + (kW) ($/kW/PERIOD)
= $/PERIOD.

The term shown as (Power Flow) in the above equation is determined in COPE taking into account the electricity sales arrangement and power plant operations in that period. Similar calculations are performed for each electric cost item as well. For instance, extra back-up costs are computed as follows:

Extra Back-Up Cost
= (Power Flow) (Hours per period) (Industrial Back-up Energy Charge - Industrial Energy Charge) + (Peak Back-Up Demand) (Industrial Back-up Capacity Charge - Industrial Capacity Charge)

An important point to be noted about computing the extra back-up cost is that it is the difference between the industrial back-up energy/capacity charge and the industrial energy/capacity charge that is used. In other words, only the <u>extra</u> back-up cost is included.

Net electric revenues is given by:

Net Electric Revenues = (Electricity Sales) + (Electricity Saved) - (Auxiliary Cost) - (Extra Back-up Cost)

Net electric revenue is first computed in \$/period for each period. (In the case of electricity sales it was shown that inserting appropriate units yields a value in \$/period.) COPE then sums net electric revenues in each period to provide net electric revenues per year. This is repeated for each year of project life.

If there is no period to period variation, the case can be regarded as a special one where all the annual operating hours make up one period.

**Net Steam Revenues**

As was discussed earlier, the useful steam provided by the system is expressed in net terms. Moreover, the useful steam is expressed in average annual terms. Therefore, the computation of net steam revenues is straightforward and is given by:

Net Steam Revs = (Net Steam Delivered) (Price of Steam) (Hours per Year)

Inserting units yields:

Net Steam Revenues = (Million Btu/hr) (\$/Million Btu) (hrs/year)
= \$/year.

**Input Fuel Expenditures**

If input fuel flow is provided on a period by period basis, COPE first converts it to an annual average. Since input fuel costs do not vary for different periods of the year, averaging fuel flow does not affect the calculation of fuel expenditures. Computation of input fuel expenditures is performed as follows:

Input Fuel Expenditures = (Avg. Fuel Use)(Cost of Fuel)(Hrs. per Year)

The units for input fuel expenditures can be seen from the following:

Input Fuel Expenditures = (Million Btu/hr) (\$/Million Btu) (Hrs/Year)
= \$/Year

This computation is repeated for each year of project life and each stream of input fuel.

## Operation and Maintenance Expenditures

The most important input to this calculation is the first year operation and maintenance expenditure in base year dollars. Since the manner in which the cogeneration system is operated does not change from year to year, the operation and maintenance expenditure changes from year to year only because of escalation. The user must ensure either by judgement or by using a detailed engineering performance model that the first year operation and maintenance expenditure is consistent with the first year physical flows. Judgement is especially important when operation and maintenance expenditures are estimated as a fraction of total installed cost.

COPE computes operation and maintenance expenditures for each year of project life. As in the case of other annual costs, any pattern of escalation over time can be represented in COPE.

## Real Estate Taxes and Insurance

The expenditures for real estate taxes and insurance are calculated as a fraction of property value. The first year expenditure for real estate taxes and insurance is calculated based on the property's depreciation basis. Expenditures in subsequent years can be escalated at the inflation rate or some other rate.

## General and Administrative Expenses

General and administrative expenses are computed as a fraction of operation and maintenance expenditures for each year of project life.

## After-Tax Cash Flows

Thus far the discussion has focused on annual cash flows from the project. These cash flows are used to generate after-tax cash flows for each participant.

The first step is to compute each participant's net operating income. This is given by:

Share of Net Operating Income
= (Share of Net Electric Revenues + Share of Net Steam Revenues) - (Share of Fuel Costs + Share of Operation and Maintenance Costs)

This computation is performed for each year of project life.

In the next step, each participant's net taxable income is computed as:

Share of Net Taxable Income
= (Share of Net Operating Income) - (Share of Real Estate Taxes) - (Share of General and Administrative Expenses) - (Share of Interest Expenses on Long-Term Debt) - (Share of Depreciation)

Recall that the share of interest expenses on long-term debt and the share of depreciation for each participant are calculated earlier. Again, this computation is performed for each year of the project life.

The net income after taxes for each participant (for each year) is calculated as:

Participant's Net Income After Taxes
= (1-Applicable Federal Tax Rate) (Share of Net Taxable Income)

Finally, each participant's after-tax cash flow is computed as:

- **For First Year of Operation:**

  Participant's After-Tax Cash Flow
  = (Participant's Net Income After Taxes) + (Share of Depreciation) - (Share of Prin. Pymt.) + (Share of Inv. and Energy Tax Credits)

- **For the Remaining Years of Operation:**

  Participant's After-Tax Cash Flow
  = (Participant's Net Income After Taxes) + (Share of Depreciation) - (Share of Prin. Pymt.)

To perform a project evaluation, it is necesary to generate after-tax cash flows during construction in addition to the after-tax cash flows during operation. We will now turn to after-tax cash flows during construction.

In all years of construction except the last, the items of importance are: tax savings due to short-term borrowings, if relevant; and investment and energy tax credits, if any. The after-tax cash flow in the final year of construction includes the major project cash outflow, i.e., each participant's capital contribution. Thus, we have:

- **For all years of construction except the last:**

  Participant's After-Tax Cash Flow
  = (Share of Tax Savings on Short-Term Int. Expenses, if relevant)
  + (Share of Investment and Energy Tax Credits, if any)

- **For the final year of construction:**

  Participant's After-Tax Cash Flow
  = (Share of Tax Savings on Short-Term Int. Expenses, if relevant)
  + (Share of Inv. and Energy Tax Credits, if any) - (Participant's Contribution to Project)

Two points must be noted here. First, investment and energy tax credits can be claimed during construction only if the physical construction period exceeds two years. If not, this term will be zero. Second, in all years of construction except the last, the after-tax cash flow will, in general, be positive or zero. During the final year of construction when each participant makes his contribution to the project, it will be negative.

**PROJECT EVALUATION**

COPE performs an evaluation of the project, for each party, based on after-tax cash flows. We will denote the after-tax cash flow by the following stream:

$$(F_1, F_2, \ldots\ F_C, F_{C+1}, F_{C+2}, \ldots\ F_{C+N})$$

C = last year of construction

In general, $F_C$ will be negative. Also, $(F_1, F_2, \ldots\ F_{C-1})$ will not be negative, since they represent the tax benefits from short term borrowing.

The evaluation procedure will be discussed in terms of $(F_1, F_2, \ldots F_C, F_{C+1}, \ldots F_{C+N})$.

COPE performs separate evaluations for each party.

**Net Present Value**

The net present value is computed as follows:

$$NPV = \sum_{i=1}^{N} \frac{F_{C+i}}{(1+k)^i} + \sum_{j=0}^{C-1} F_{C-j}\,(1+k)^j$$

NPV = net present value in year C

k = discount rate

N = useful economic life in years

C = construction period in years

$F_1, F_2 \ldots F_C, F_{C+1}, \ldots. F_{C+N}$ represent cash flows with appropriate signs.

The above expression is a standard expression for net present value. Two points, however, deserve mention.

First, the net present value is calculated in year C. The cash flows in the years before C are therefore "discounted forwards" to year C. As we discussed earlier, the major negative cash flow occurs in year C. To the extent that the discount rate, k, embodies some allowance for risk, it is not a good practice to discount cash outflows. Put another way, discounting cash outflows like cash inflows leads to an understatement of cash outflows. Adjustments for risk, on the other hand, require a measured amount of overstatement with regard to cash outflows, and understatement with regard to cash inflows. It is for this reason that COPE is designed to compute the net present value in year C.

Second is the issue of the discount rate itself. If the "corporate contribution" comes completely from equity, COPE uses the cost of equity as the discount rate. If the "corporate contribution" is a mixture of debt and equity, COPE uses an after-tax weighted average cost of capital, where the weighting corresponds to the firm's target debt to equity ratio. It must be noted that the costs of equity and debt are user-specified and can reflect "risk premiums" chosen by the user.

**Internal Rate of Return**

The internal rate of return, r, is computed by solving the following equation for r:

$$0 = \sum_{i=1}^{N} \frac{F_{C+i}}{(1+r)^i} + \sum_{j=0}^{C-1} F_{C-j} (1+r)^j$$

r = internal rate of return

N = useful economic life in years

C = construction period in years

$F_1, F_2, \ldots F_C, F_{C+1}, F_{C+2}, \ldots\ldots\ldots F_{C+N}$ represent cash flows with appropriate signs

The equation for r is an n th order equation and COPE uses an iterative method to solve for r. As in the case of net present value, COPE avoids discounting the major cash outflow by discounting all other cash flows to the year where the major cash outflow occurs.

**Payback**

The payback index computed by COPE is usually referred to as "simple payback." The payback is computed by solving the following equation for p:

$$- \sum_{j=0}^{C-1} F_{C-j} (1+k)^j = \sum_{i=1}^{p} F_{C+i}$$

C = construction period in years

p = payback

k = discount rate

$F_1$, $F_2$, .... $F_C$ .... $F_{C+N}$ represent cash flows with appropriate signs.

The left hand side of the above equation is the net cash outflow after accounting for the tax benefits of short term borrowing. The negative sign ensures that only the magnitude is considered. The tax benefits are "discounted forward" in this computation. The cash outflow includes escalation and interest during construction. The right hand side of the equation generates an undiscounted cumulative cash flow during project operations. At some point in the life of the project, these cumulative cash flows will exceed the net initial outflow. The payback p is calculated as the point in time when the cumulative cash flows from operations equal the net initial outflow. COPE performs this by prorating the cash flows in the final year of payback to estimate the point of payback. Therefore, the payback period will not ordinarily be an integer.

**Debt Coverage Ratio**

The debt coverage ratio is a measure of the number of times the interest expense for a project can be covered by the income from the project. In general, the higher the debt coverage ratio on a project, the easier it is to raise capital at "reasonable rates." The reason for this is that with a high debt coverage ratio, even if project earnings are less than expected, the lender is reasonably confident that there exists an adequate "margin" for interest payments.

There are, however, a number of definitions of debt coverage ratio, and the difference between definitions centers around the question of "project income." The debt coverage ratio as defined in COPE is given below:

$$\text{Debt Coverage Ratio} = \frac{\text{Earnings Before Interest and Taxes}}{\text{Interest Payments}}$$

Typically, project debt is repaid as an annuity. As a result, in the early years of project life, interest payments are high and debt coverage low. In making judgements on the credit worthiness of a project, therefore, it is the first year debt coverage ratio that is of greatest importance. COPE computes this ratio as follows:

$$\text{Participant's Debt Coverage Ratio} = \frac{\text{(Share of First Year Net Operating Income) - (Economic Depr.)}}{\text{(Share of First Year Int. Pymt. on Long-Term Debt)}}$$

The second term in the numerator represents a "capital consumption allowance" (typically straight line depreciation). Some definitions of debt coverage ratio do not include economic depreciation.

With a limited amount of effort, the software in COPE can be modified to generate differently defined debt coverage ratios that meet user requirements. COPE's modular structure facilitates this type of modification.

## Incremental Investment Analysis

The computation of net present value, internal rate of return, payback and debt coverage ratio is performed, as we discussed, based on after-tax cash flows. In cases involving partnerships, the after-tax cash flow for each partner corresponds to his share in the entire project. In the case of 100% industry ownership, it is quite conceivable that the COPE user would be interested in the project viewed as an incremental investment, i.e., as a venture that would involve outlays and concomitant benefits beyond those corresponding to a boiler. In particular, a cogeneration project would involve additional initial outlays for the power plant, but would generate additional revenues (or cost savings) from the power generated.

COPE can be used to evaluate a project on an incremental basis by triggering a selector. However, before using the incremental investment selector it is necessary for the user to perform a single run with only the boiler as an investment. Clearly, there will be no electricity revenues in this case. The after-tax cash flows corresponding to the boiler are stored in a separate file.* When the incremental selector is triggered and COPE is run with an investment schedule corresponding to a cogeneration project, the after-tax cash flows corresponding to a boiler are retrieved and subtracted from project after-tax cash flows to yield an incremental after-tax cash flow stream which can be denoted as

$$(F_1', F_2', \ldots F_C', F_{C+1}', F_{C+2}', \ldots. F_{C+N}')$$

It must be pointed out that for the two runs referred to above, steam revenues in each year should be identical, unless excess steam from the cogeneration project is sold to some user. Once the incremental after-tax cash flow stream is obtained, COPE performs, as before, a project evaluation using this stream.

**Utility Evaluation**

COPE performs project evaluations for all project participants. Thus, if a utility is a project participant, COPE generates the net present value, rate of return, payback and debt coverage ratio based on the utility's share of the investment. If the returns from a utility's share in a PURPA-qualified cogeneration project are not subject to a regulated rate of return, it would be appropriate for the utility to evaluate the project like other investors. However, it is possible that utilities might be interested in evaluating cogeneration projects as additional options for power generation. In this context, 100% utility ownership is also an option. Accordingly, they may require the cost of producing power (in mills/kWh) from a cogeneration project. COPE is designed to address this question.

Two types of costs (in mills/kWh) are computed in COPE: (i) a levelized busbar cost; and (ii) a first year busbar cost.

- **Levelized Busbar Cost**

  The levelized busbar cost is calculated by translating the capital cost, and all annual costs to a level annual cost per kWh over project life. Clearly, the levelized busbar cost will depend strongly on the pattern of escalation for annual costs.

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*As we discussed under steam price, the boiler can be viewed as an investment in the computation of a "competitive price" for steam.

- **First Year Busbar Cost**

  As we pointed out above, the levelized busbar cost depends strongly on the escalation of annual costs. Many users, however, do not hold expectations about escalation rates with a high degree of confidence. Therefore, they may also be interested in the first year busbar cost. The first year busbar cost is the sum of all the annual costs and an appropriately allocated portion of the capital costs incurred in the first year of operation, expressed in mills/kWh.

The annual costs referred to above include fuel costs, operation and maintenance costs, and general and administrative costs. In the case of 100% utility ownership, an appropriate credit must be provided for annual steam revenues. In partnerships, accounting for utility annual costs is more involved since the cost of buying power, the share of operating revenues and costs, and the extra revenues from back-up, if any, must also be included. The calculation procedure is discussed below for two distinct cases: 100% utility ownership and a partnership arrangement.

A number of concepts are common to the calculation procedure in either case. They are:

- **Levelized Fixed Charge Rate**

  The levelized fixed charge rate is the factor that is applied to the capital costs to obtain a level annual capital charge. The levelized fixed charge rate should reflect the opportunity cost of capital. This can be accounted for by the capital recovery factor given by

$$KRF = \frac{k\ (1+k)^N}{(1+k)^N - 1}$$

KRF = capital recovery factor

N = useful economic life of project

k = discount rate

As in the case of net present value, the discount rate, k, is user specified. Commonly, users specify a discount rate, k, that corresponds to a weighted average cost of capital (debt and equity). However, users can choose to include a "risk premium" in the discount rate. In addition to the capital recovery factor, the levelized fixed charge rate should, in the case of utilities, reflect allowances for (i) retirement dispersal among plants, (ii) federal tax expenses, and (iii) local taxes and insurance. Finally, the levelized fixed charge rate should be adjusted downwards to account for the tax benefits from accelerated depreciation and the tax benefits from <u>all</u> available tax credits. The precise magnitude of these adjustments depends on whether the utility uses "normalized" or "flow-through" accounting for rate purposes. The user should ensure that the levelized fixed charge rate provided to COPE adequately accounts for all these factors.

- **First Year Fixed Charge Rate**

  Like the levelized fixed charge rate, the first year fixed charge rate should reflect the capital recovery factor; allowances for retirement dispersal, federal taxes, and local taxes and insurance; and downward adjustments for accelerated depreciation and tax credits. The first year fixed charge rate might, however, differ in magnitude from the levelized fixed charge rate. This is because the manner in which a utility is allowed to recover its capital costs over time depends on the practices of the local regulatory body.

- **Utility Power Added (UPWADD)**

  Since both the levelized busbar cost and the first year busbar cost are expressed in mills/kWh, it is important to properly compute the total kWh available to the utility. This will, of course, depend on the electricity sales arrangement.

  With a simultaneous-buy-sell arrangement, the total power available to the utility in every PURPA period is the gross power. The total kWh available to the utility is given by:

  UPWADD = (Gross Power) (HRS per Period)

  UPWADD is computed for every period in the year and summed to yield the kWh available over the year.

  If only the net power (i.e., after serving system auxiliaries) is sold to the utility, it is accounted for by using (Gross Power -Auxiliary Power) instead of (Gross Power) in the above equation.

  With a buy-shortage-sell-excess arrangement, the total power available to the utility in every PURPA period depends on power plant operations. In periods where excess power is sold to the utility, the total kWh available to the utility is given by:

  UPWADD = (Gross Power - Process power - Aux. Power) (Hrs/Period).

  In periods where power is bought from the utility, no energy (kWh) is sold to the utility. Therefore, for such periods, UPWADD = 0.0

  As before, UPWADD is computed for every period in the year and summed.

- **Levelizing Annual Cash Flows**

  An annual cash flow stream given by ($A_1$, $A_2$, $A_3$ ... $A_N$) can be expressed as a level annual cash flow stream ($A_L$, $A_L$, $A_L$.......... $A_L$). The calculation procedure is presented below.

$$A_L = (KRF) \sum_{i=1}^{N} \frac{A_i}{(1+k)^i}$$

where

$A_i$ = annual cash flow in year i

$A_L$ = levelized annual cash flow

N = length of cash flow stream (i.e., economic life of project)

Recall from earlier discussions that

KRF = capital recovery factor

k = discount rate.

## Utility Busbar Cost

- **100% Utility Ownership**

If the cogeneration project is owned completely by the utility, no utility costs are incurred in buying electricity from the project. Also, there is no sharing of revenues and fuel expenses.

Thus, the costs associated with producing electricity are: capital, fuel, operation and maintenance, and general and administrative. Since we are interested in the cost of producing electricity, a credit is provided for steam revenues. The revenue requirements and busbar costs are calculated as follows.

First Year Costs

First Year Revenue Requirement
= (Total Capital Invested x First Year Fixed Charge Rate)
+ (First Yr Fuel Costs + First Yr O&M + First Yr G&A)
- (First Year Steam Revs.)

$$\text{First Year Busbar Costs} = \frac{\text{First Year Revenue Requirement}}{\text{UPWADD}}$$

- **Levelized Costs**

Levelized Annual Revenue Requirement

= (Total Capital Invested x Levelized Fixed Charge Rate)
+ (Levelized Annual Fuel Costs + Levelized Annual O&M + Levelized Annual G&A) - (Levelized Annual Steam Revenue)

$$\text{Levelized Busbar Cost} = \frac{\text{Levelized Annual Revenue Requirement}}{\text{UPWADD}}$$

- **Partnership Arrangements**

Under a partnership arrangement the utility's costs are: a share of the total capital invested; the cost of power purchased from the project; a share of total fuel expenses; a share of total operation and maintenance costs; a share of general and administrative costs; a share of auxiliary power costs, if any; a share of extra back-up costs, if any. Utility credits under a partnership arrangement are: a share of total electric revenues (includes electric sales and savings); a share of total steam revenues; net gain from providing back-up power, if any; net gain, if any, from providing auxiliary power. The costs of electricity computations are performed as shown below.

First Year Costs

First Year Revenue Requirement
= (Share of Total Invested Capital x First year Fixed Charge Rate) + (Share of First Yr Fuel Costs + Share of First Yr O&M + Share of First Yr G&A Costs + Share of Aux. Costs, if any + Share of Extra Back-up Costs, if any) + (First Yr Cost of Purch. Power) - (Share of Steam Revs + Share of Elec Revs) - (Net Gain, if any, from Aux.) - (Net Gain, if any, from Back-up Power)

$$\text{First Year Busbar Cost} = \frac{\text{First Year Revenue Requirement}}{\text{UPWADD}}$$

The equations for the levelized annual revenue requirement and levelized busbar cost have identical terms with the important difference that all items are expressed on a levelized annual basis. We have already discussed the manner in which UPWADD is computed. Also, all levelization is performed according to the procedure already discussed.

There are two other points that must be noted. First, many of the terms in the equations above may, in a number of circumstances, be zero. For instance, if the utility does not charge different back-up rates, there is no net gain from providing back-up power. Similarly, if all auxiliary power is provided by the cogeneration system, there is no auxiliary cost. Second, COPE has the additional capability of computing a busbar cost profile over project life.

**Additional Utility Impact**

The additional utility impact is computed in COPE whether or not the utility is a project participant. For instance, the utility could participate in a PURPA-qualified project and be allowed to earn an unregulated rate of return on its investment. At the same time, the utility would incur costs in buying power from the project and would realize benefits in terms of avoided generation costs. The additional utility impact is concerned only with the latter issue. In cases where the utility is not a project participant, the impact on it can be described fully in terms of the costs of purchased (or lost) power and the benefits of avoided generation costs.

The electricity cost types discussed earlier are used in computing utility impact. For each period during the year COPE computes the net utility cost as:

Net Utility Cost
= (Cost of Purch Power + Cost of Displaced Power + Cost of Aux.) - (Savings from Avoided Generation due to Purchases + Savings from Avoided Generation due to Displaced Power + Revs from Aux. + Net gain, if any, from Backup Power)

The net utility cost is summed over all the periods in an year to yield a net annual utility cost. The computation is repeated for all years of project life.

It must be emphasized that each item above has an energy and capacity component. For instance, the cost of purchased power is the dollar value of the electricity sales made by the project to the utility. As we discussed earlier, this dollar value is based on a PURPA energy and PURPA capacity price. Similarly, savings in avoided generation attributable to purchases is computed based on the utility's marginal energy cost, marginal capacity cost and the kWh of power purchased by the utility.

## Additional Industry Impact

The additional industry impact refers to the cost savings that are realized if steam is supplied to the industry at a price that is lower than the cost of producing identical quality steam by alternative means. The question arises principally because there is no "market price" for steam that can be readily identified. In partnerships, the steam is either priced by computing a "competitive price" based on cost of production by alternative means or it is negotiated. In the former case, there is no additional impact on the industry. In the latter case, there is an impact. Indeed, if the steam price is a negotiated one and the industry is also a project participant, the industry will examine the project by looking both at the return from project investment and the net steam benefits.

The annual net steam benefits are computed as:

Net Steam Benefits
= (Net Steam) (Hrs./Year) (Cost of Alt. Steam - Price of Steam)

This computation is repeated for every year of project life.

**OUTPUTS**

The output from COPE consists of a series of reports. Reports 1,2,3 and 4 display the inputs used in COPE. Report 1 contains the project schedule. Report 2 summarizes ownership and operating information. Specifically, Report 2 describes the ownership structure, the dispatch arrangement, the electricity sales arrangement and annual average system performance. In Report 3, a number of details related to fuel use and other regulatory issues are provided. As was discussed, fuel use information is used to determine eligibility for energy tax credits. Price and cost information is presented in Report 4. An important feature of Report 4 is that the variation of prices/costs/rates over project life is displayed. Thus, the pattern of escalation is evident to the user.

Report 5 contains the results of the analysis performed by COPE. Section A of Report 5 describes the economic inputs used in the analysis. Such details as the financial structure, cost and type of debt, and partnership arrangements are presented in Section A. Section B displays after-tax cash flow accounts for each participant during construction and during operation. In addition, Section B presents, for each participant, the net present value (NPV), the rate of return (ROR), the payback period ($P_b$) and the debt coverage ratio. In the case of industry ownership COPE can be set up so as to perform financial analyses based on incremental investment, i.e., investment over and above that required for a conventional boiler. In the case of the utility, COPE displays both the first year busbar cost and the levelized busbar cost.

Finally, Section C of Report 5 contains the additional impacts, if any, on the utility and the industry. These impacts are presented as dollar values for each year of project life.

**Additional User Information**

COPE's existing software and accounting mechanisms can be used in a number of ways to solve special problems.

In addition to evaluating a project at given prices, COPE can be used to determine "required prices" for a viable project. For instance, a number of sensitivity runs can be performed to answer such questions as: What PURPA price profile (for electricity) will give an industrial owner an x% rate of return on the project? Alternatively, at given electricity and steam prices, COPE could be used to determine the maximum input fuel cost which would give an industrial owner a project rate of return of y%. Similarly, for new technologies, COPE can be used to determine a "maximum allowable total installed cost."

Since COPE maintains separate accounts for three distinct project participants--the utility, the industry, and a third party--a number of innovative schemes involving transfers between parties can be represented. For instance, a scheme in which an industry sells the cogeneration plant to a utility after owning and operating it for a fixed number of years can be represented. COPE can be used to analyze the impact of these transactions on each participant for each year of useful project life. Similarly, a leasing arrangement can be handled by using the third party's account to represent the lessor's inflows and outflows. Thus COPE can be used to analyze the impact of a leasing arrangement for the lessor as well as the lessee.

## Section 4

## CASE STUDIES AND MODEL APPLICATION

### BACKGROUND

A number of case studies were conducted in cooperation with utilities to test and demonstrate the capabilities of COPE. Data for these case studies were gathered in the period from April to June of 1982. Results from the first set of runs were presented at the EPRI Cogeneration Seminar in July 1982 at Oakland, California.*

The results presented in this section are based on the data gathered from April to June of 1982. However, as the discussion below indicates, there are important differences between the economic assumptions made for the earlier case studies and those made here. Also, the results presented here include the impact of provisions of the Tax Equity and Fiscal Responsibility Act (TEFRA), 1982.

### CASE STUDY 1: ARKANSAS POWER AND LIGHT

The Arkansas Power and Light (AP&L) Company cogeneration program has four objectives:**

- Protect existing industrial electric market
- Diversify revenue sources through sale of steam
- Enter an unregulated market with the prospect of investing in "high risk/high return" ventures
- Establish precedent for viewing the utility industry as a "deliverer" of alternative energy supply options.

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*See Proceedings: EPRI Cogeneration Seminar, Oakland, California, Report prepared for Electric Power Research Institute, October 1982.

**See Ralph Mitchell, "The Electric Utility and Cogeneration: Post-PURPA," in Proceedings: EPRI Cogeneration Seminar, Oakland, California, Report prepared for Electric Power Research Institute, October 1982.

As part of its cogeneration program, AP&L has assessed the feasibility of a number of cogeneration projects. A summary of the information provided by AP&L for this case study is presented in Tables 4-1 and 4-2. Table 4-1 provides plant characteristics for an industrial facility, and Table 4-2 provides system performance for a combined cycle system designed to serve the plant.

In this case study alternative capital structures for financing the combined cycle system are investigated. A number of points about the analysis must be noted:

- As can be seen from Table 4-1, the steam demand profile is flat. The computational procedure in COPE is therefore considerably simplified.
- The fuel price profile used here (see Report 4 of the computer printout) differs from that used in the earlier case study of the same system.
- In accordance with the Tax Equity and Fiscal Responsibility Act (TEFRA), 1982, interest expenses incurred during construction are capitalized, and not deducted for tax purposes. Also, as TEFRA requires, the depreciation basis is reduced by an amount equal to one half of all tax credits claimed.
- The economic life of the project is assumed to be 10 years, and the term of project debt is 5 years.
- The steam price is fixed at $6.00 per million Btu. No escalation is provided for steam price.
- All evaluations are conducted for 100% third party ownership. A key sensitivity parameter is the capital structure. Two capital structures (A and B), the details of which can be seen in Table 4-3, are examined. The implications of each capital structure are evaluated for a number of PURPA energy prices (or buyback rates).

The computer output from one run is presented in the following pages. Reports 1 through 4 of the computer output contain the assumptions underlying the analysis.

**CONCLUSIONS**

Report 5 of the computer output presented on the following pages shows results for the case when the 1985 PURPA energy price is 7.57¢/kWh, and capital structure A is used. A number of sensitivity runs were made and the results are summarized in Table 4-4. Also, the variation of rate of return on equity with the buyback rate is shown in Figure 4-1.

Table 4-1

INDUSTRIAL PLANT CHARACTERISTICS

| | |
|---|---|
| ELECTRIC DEMAND | |
| Average Electric Demand | 1786 kW |
| Electric Demand Profile | flat |
| STEAM DEMAND | |
| Average Steam Demand* | |
| @ 250 psig | 53,000 lb/hr. |
| @ 150 psig | 112,000 lb/hr. |
| Steam Demand Profile | flat |
| OPERATING HOURS | |
| At 75% process steam demand | 8760 hrs/yr. |
| FUEL CHOICE | |
| Natural Gas (23,860 BTU/lb) | |
| MAKEUP WATER | |
| Makeup Water Requirements | 25% @ 210$^{\circ}$F |

*The two streams can be approximated by one stream delivering 173.8 million BTU/hr.

Table 4-2

COMBINED CYCLE SYSTEM PERFORMANCE

| SYSTEM | TOTAL INSTALLED COST 1980 $ MILLION | FUEL FLOW @ 75% LOAD MILLION BTU/HR. | MW CAPACITY @ 75% LOAD |
|---|---|---|---|
| Combined Cycle with full condensing capacity | 24.8 | 589 | 55.2 |

Table 4-3

ALTERNATIVE CAPITAL STRUCTURES

| STRUCTURE A | | |
|---|---|---|
| | Fraction | Rate |
| Common Equity: | 71% | 20% |
| Long Term Debt: | 29% | 18.1% |

| STRUCTURE B | | |
|---|---|---|
| | Fraction | Rate |
| Common Equity: | 50% | 20% |
| Long Term Debt: | 50% | 12% |

$ REPORT 1: PROJECT INFORMATION

| | |
|---|---|
| TECHNOLOGY: | CGCC |
| DEUS #: | 5 |
| START OF CONSTRUCTION: | JANUARY 1982 |
| START OF OPERATIONS: | JANUARY 1985 |
| ECONOMIC LIFE OF PROJECT: | 10 YEARS |
| BASE YEAR FOR COST AND PRICE DATA: | 1980 (END-OF-YEAR) |

REPORT 2: OWNERSHIP AND OPERATING INFORMATION

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| | |
|---|---|
| OWNERSHIP ARRANGEMENT: | OWNED ENTIRELY BY THIRD PARTY |
| DISPATCH ARRANGEMENT: | THERMAL FOLLOWING |
| ELECTRICITY SALES ARRANGEMENT: | SIMULTANEOUS BUY-SELL |
| AVERAGE SYSTEM PERFORMANCE: | |
| POWER FLOWS | |
| GROSS POWER FROM SYSTEM (KW) | 55200.0 |
| AUXILIARY POWER REQUIREMENT (KW) | 0.0 |
| PROCESS POWER REQUIREMENT (KW) | 0.0 |
| CAPACITY CONTRACTED TO UTILITY (KW) | 55200.0 |
| CONTRACT FRACTION | 0.0 |
| USEFUL THERMAL OUTPUT | |
| PROCESS STEAM AT 200. PSI (MILLION BTU/HR) | 173.8 |
| FUEL INPUT | |
| STREAM #1 (MILLION BTU/HR) | 589.4 |

REPORT 3: REGULATORY AND FUEL USE INFORMATION

| | |
|---|---|
| PRIMARY FUEL USED: | OIL/GAS |
| FACILITY STATUS: | QUALIFIED UNDER PURPA |
| | GREENFIELD UNIT |
| OIL/GAS USE: | OIL/GAS USE EXCEEDS 20 PER CENT OF FUEL INPUT |
| | OIL/GAS USE NOT RESTRICTED TO BACK-UP,FLAME CONTROL OR FLAME STABILIZATION |
| TYPE OF GENERATING EQUIPMENT: | COMBINED CYCLE |
| DEPRECIATION: | |
| UTILITY(IOU): | ERTA 1981 |
| INDUSTRY: | ERTA 1981 |
| THIRD PARTY: | ERTA 1981 |

REPORT 4 : PRICE & COST INFORMATION

AVERAGE ELECTRICITY RATES AND COSTS:

| | 1985 | 1988 | 1991 | 1994 |
|---|---|---|---|---|
| PURPA ENERGY PRICE (CENTS/KW-HR): | 7.57 | 10.07 | 13.41 | 17.85 |
| PURPA CAPACITY PRICE ($/KW/YEAR): | 0.00 | 0.00 | 0.00 | 0.00 |
| INDUSTRIAL ENERGY CHARGE (CENTS/KW-HR): | 3.87 | 5.15 | 6.85 | 9.12 |
| INDUSTRIAL CAPACITY CHARGE ($/KW/YEAR): | 73.10 | 73.10 | 73.10 | 73.10 |
| BACK-UP ENERGY CHARGE (CENTS/KW-HR): | 3.87 | 5.15 | 6.85 | 9.12 |
| BACK-UP CAPACITY CHARGE ($/KW/YEAR): | 73.10 | 73.10 | 73.10 | 73.10 |
| UTILITY MARGINAL ENERGY COST (CENTS/KW-HR): | 7.57 | 10.07 | 13.41 | 17.85 |
| UTILITY MARGINAL CAPACITY COST ($/KW/YEAR): | 0.00 | 0.00 | 0.00 | 0.00 |
| UTILITY MARGINAL BACK-UP ENERGY COST(CENTS/KW-HR): | 3.87 | 5.15 | 6.85 | 9.12 |
| UTILITY MARGINAL BACK-UP CAPACITY COST($/KW/YEAR): | 73.10 | 73.10 | 73.10 | 73.10 |

AVERAGE STEAM PRICES AND COSTS:

| | 1985 | 1988 | 1991 | 1994 |
|---|---|---|---|---|
| PRICE OF PROCESS STEAM AT 200. PSI($/MILLION BTU): | 6.00 | 6.00 | 6.00 | 6.00 |
| COST OF ALTERNATIVE STEAM AT 200. PSI($/MILLIONBTU): | 6.00 | 6.00 | 6.00 | 6.00 |

INPUT FUEL COSTS:

| | 1985 | 1988 | 1991 | 1994 |
|---|---|---|---|---|
| INPUT FUEL #1 ($/MILLION BTU): | 6.19 | 7.96 | 10.22 | 13.12 |

CONSTANT ANNUAL ESCALATORS:

| | |
|---|---|
| GNP DEFLATOR (CORE INFLATION): | 0.080 |
| CAPITAL COST ESCALATION: | 0.100 |
| OPERATION & MAINTENANCE COST ESCALATION: | 0.100 |

REPORT 5: CONSOLIDATED IMPACT STATEMENT

A. PROJECT FINANCE

TOTAL INSTALLED COST OF SYSTEM (THOUSANDS OF BASE YEAR DOLLARS) 24825.14

FINANCIAL STRUCTURE

| | | | |
|---|---|---|---|
| SHORT TERM INTEREST RATE ON BORROWINGS DURING CONSTRUCTION: | 0.14 | | |
| LONG TERM DEBT FRACTION: | .29 | | |
| LONG TERM DEBT INSTRUMENT: | | | |
| TYPE | REGULAR | | |
| TERM | 5 YEARS | | |
| INTEREST RATE | .181 | | |
| MODE OF PAYMENT | ANNUITY | | |
| CORPORATE CONTRIBUTION : | CORPORATE CONTRIBUTION COMES FROM EQUITY | | |
| | UTILITY | INDUSTRY | THIRD PARTY |
| LEVELIZED FIXED CHARGE RATE: | 0.24 | | |
| FIRST YEAR FIXED CHARGE RATE: | 0.20 | | |
| COST OF NEW CORPORATE DEBT (BEFORE TAX): | 0.12 | 0.12 | 0.12 |
| COST OF NEW CORPORATE EQUITY: | 0.16 | 0.16 | 0.20 |
| TARGET CORPORATE DEBT FRACTION: | 0.50 | 0.30 | 0.10 |
| TARGET CORPORATE EQUITY FRACTION: | 0.50 | 0.70 | 0.90 |
| MARGINAL FEDERAL TAX RATE ON EARNINGS: | 0.50 | 0.50 | 0.50 |

B. CASH FLOW STATEMENT

***********
THIRD PARTY
***********

DEPRECIATION AND TAX CREDITS

(THOUSANDS OF DOLLARS)

| | BASIS (A) | PROPERTY STATUS (B) | DEPRECIATION METHOD (C) | FIRST YEAR DEPRECIATION | INVESTMENT TAX CREDIT (D) | ENERGY TAX CREDIT (D) |
|---|---|---|---|---|---|---|
| FUEL HANDLING EQUIPMENT | 1473.41 | NPP | 1 | 265.21 | 155.10 | 0.00 |
| BOILER | 387.74 | NPP | 1 | 69.79 | 0.00 | 0.00 |
| POLLUTION CONTROL EQUIPMENT | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| TURBINE GENERATORS | 32230.79 | NPP | 1 | 5801.54 | 3392.72 | 0.00 |
| HEAT DISTRIBUTION EQUIPMENT | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| SPECIALIZED BLDGS & STRUCTURES | 2762.64 | NPP | 1 | 497.27 | 290.80 | 0.00 |
| GENERAL PURPOSE BLDGS | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| LAND | 0.00 | NPP | 4 | 0.00 | 0.00 | 0.00 |
| | 36854.57 | | | 6633.82 | 3838.61 | 0.00 |

(A) FOR DEPRECIATION;OPTION TO CAPITALIZE IDC
(B) NPP: NON PUBLIC-UTILITY PROPERTY; PP: PUBLIC UTILITY PROPERTY
(C) 1: 5 YR ACRS; 2: 10 YR ACRS; 3: 15 YRACRS; 4: NON-DEPRECIABLE; 5: ST. LINE
(D) TAX CREDITS ACCRUE IN FIRST YEAR OF OPERATION UNLESS CONSTR. PERIOD > 2 YRS

CASH FLOWS DURING CONSTRUCTION FOR THIRD PARTY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1982 | 1983 | 1984 |
|---|---|---|---|
| TAX BENEFITS ON S/T INTEREST PAYMENTS: | 0.00 | 0.00 | 0.00 |
| LONG TERM PROJECT OUTLAYS: | 0.00 | 0.00 | 27529.45 |
| INVESTMENT TAX CREDITS DURING CONSTRUCTION: | 767.72 | 1535.45 | 1535.45 |
| ENERGY TAX CREDITS DURING CONSTRUCTION: | 0.00 | 0.00 | 0.00 |
| NET AFTER TAX CASH FLOWS: | 767.72 | 1535.45 | -25994.00 |

CASH FLOWS FROM OPERATIONS FOR THIRD PARTY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1985 | 1988 | 1991 | 1994 |
|---|---|---|---|---|
| ELECTRIC OPERATIONS: | | | | |
| ELECTRICITY SALES: | 36601.81 | 48716.87 | 64841.97 | 86304.44 |
| ELECTRICITY SAVED: | 0.00 | 0.00 | 0.00 | 0.00 |
| EXTRA BACK-UP COSTS: | 0.00 | 0.00 | 0.00 | 0.00 |
| AUXILIARY COSTS: | 0.00 | 0.00 | 0.00 | 0.00 |
| NET ELECTRIC REVENUES: | 36601.81 | 48716.87 | 64841.97 | 86304.44 |
| STEAM OPERATIONS: | | | | |
| NET STEAM REVENUES: | 9134.92 | 9134.92 | 9134.92 | 9134.92 |
| OPERATING COSTS: | | | | |
| FUEL COSTS: | 31984.06 | 41079.16 | 52760.57 | 67763.75 |
| OPERATION & MAINTENANCE: | 2934.82 | 3906.23 | 5199.18 | 6920.09 |
| OPERATING INCOME: | 10817.85 | 12866.40 | 16017.11 | 20755.44 |
| GENERAL & ADMINISTRATIVE: | 0.00 | 0.00 | 0.00 | 0.00 |
| LOCAL TAXES & INSURANCE: | 81.23 | 102.32 | 128.90 | 162.37 |
| DEPRECIATION: | 6633.82 | 5896.73 | 0.00 | 0.00 |
| INTEREST PAYMENTS: | 2035.24 | 1020.00 | 0.00 | 0.00 |
| NET TAXABLE INCOME: | 2067.56 | 5847.34 | 15888.21 | 20593.06 |
| FEDERAL TAX: | 1033.78 | 2923.67 | 7944.11 | 10296.53 |
| NET INCOME AFTER TAX: | 1033.78 | 2923.67 | 7944.11 | 10296.53 |
| PRINCIPAL PAID(-): | 1568.63 | 2583.86 | 0.00 | 0.00 |
| DEPRECIATION (+): | 6633.82 | 5896.73 | 0.00 | 0.00 |
| INVESTMENT TAX CREDITS: | 0.00 | | | |
| ENERGY TAX CREDITS: | 0.00 | | | |
| AFTER-TAX CASH FLOW: | 6098.97 | 6236.53 | 7944.11 | 10296.53 |

## FINANCIAL ANALYSIS BASED ON TOTAL INVESTMENT

ALL DOLLARS IN 1984 (END-OF-YEAR) TERMS:

| | |
|---|---|
| NET PRESENT VALUE (THOUSANDS OF DOLLARS) | 7027.63 |
| RATE OF RETURN | 0.285 |
| PAYBACK (YEARS) | 3.25 |
| FIRST YEAR DEBT COVERAGE RATIO | 3.41 |

## C. ADDITIONAL IMPACTS

### IMPACT ON UTILITY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1985 | 1988 | 1991 | 1994 |
|---|---|---|---|---|
| COST OF POWER PURCHASED UNDER PURPA: | 36601.81 | 48716.87 | 64841.97 | 86304.44 |
| COST OF DISPLACED POWER: | 0.00 | 0.00 | 0.00 | 0.00 |
| COST OF SERVING AUXILIARIES: | 0.00 | 0.00 | 0.00 | 0.00 |
| SAVINGS FROM AVOIDED GENERATION COSTS: | | | | |
| DUE TO PURCHASED POWER: | 36601.81 | 48716.87 | 64841.97 | 86304.44 |
| DUE TO DISPLACED POWER: | 0.00 | 0.00 | 0.00 | 0.00 |
| REVENUES FROM AUXILIARIES: | 0.00 | 0.00 | 0.00 | 0.00 |
| REVENUES FROM DIFFERENTIAL BACK-UP RATES: | 0.00 | 0.00 | 0.00 | 0.00 |
| NET UTILITY COST: | 0.00 | 0.00 | 0.00 | 0.00 |

### IMPACT ON INDUSTRY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1985 | 1988 | 1991 | 1994 |
|---|---|---|---|---|
| SAVINGS FROM AVOIDED STEAM GENERATION: | 9134.92 | 9134.92 | 9134.92 | 9134.92 |
| COST OF PURCHASED STEAM: | 9134.92 | 9134.92 | 9134.92 | 9134.92 |
| NET INDUSTRY BENEFIT: | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4-4

IMPACT OF ALTERNATIVE CAPITAL STRUCTURES

SUMMARY

| PURPA Energy Price in 1985 ¢ per kWh | STRUCTURE A 20% debt at 18.1% | | | | STRUCTURE B 50% debt at 18.1% | | | |
|---|---|---|---|---|---|---|---|---|
| | NPV* $ Thou. | ROR(%) | Payback (yrs.) | First Yr. Debt Cov. | NPV* $ Thou. | ROR(%) | Payback (yrs.) | First Yr. Debt Cov. |
| 6.76 | -7504 | 10.3 | 6.61 | 1.50 | -6926 | 8.8 | 7.54 | 0.87 |
| 7.25 | 1755 | 22.1 | 4.01 | 2.64 | 2564 | 24.2 | 5.05 | 1.53 |
| 7.41 | 4468 | 25.5 | 3.57 | 3.03 | 5721 | 29.5 | 3.60 | 1.76 |
| 7.57 | 7028 | 28.5 | 3.25 | 3.41 | 8535 | 34.3 | 2.99 | 1.98 |

*Net Present Value (NPV) is based on a discount rate of 20%.

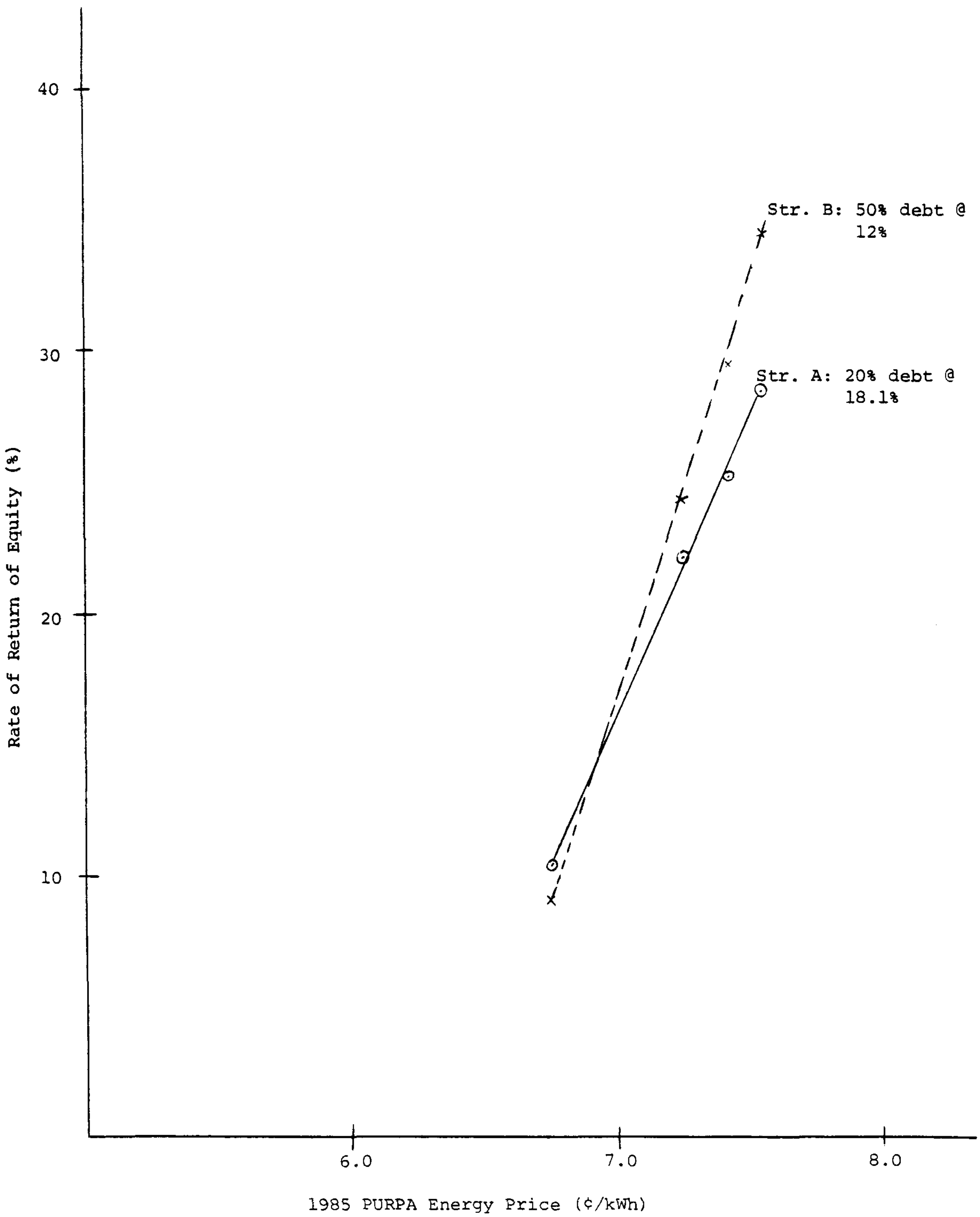


Figure 4-1. Alternative Capital Structures for a Combined Cycle System.

Figure 4-1 shows the familiar "leverage effect." As can be seen from Figure 4-1, the line that corresponds to capital structure B is steeper than that which corresponds to capital structure A. Therefore, if PURPA energy prices are high enough to yield a rate of return on total investment that exceeds the cost of debt, having more debt in the capital structure is advantageous. On the other hand, if PURPA energy prices fall so low as to decrease the rate of return on total investment below the cost of debt, greater debt fractions cut sharply into returns on equity. An interesting assumption of the analysis is that structure B, although it has a greater debt fraction, is made up of debt that is cheaper than that of structure A. In spite of this assumption, the first year debt coverage ratio under structure B is lowered sharply (see Table 4-4).

To summarize, this case study shows that while a capital structure that is heavily debt-laden can yield very high returns on equity, such returns are very sensitive to the price profile for electricity buyback rates. Small changes in the buyback rate can seriously erode the rate of return on equity for heavily debt-laden structures.

**CASE STUDY 2: CAROLINA POWER AND LIGHT**

The Carolina Power and Light (CP&L) company has concluded that to face the challenges posed by the high costs of capital and construction, and increased regulation, conservation and load management should substitute for construction to the extent that this is achievable. CP&L has adopted a goal of 1,750 MW reduction in its 1995 summer peak demand over what it would otherwise be. It is expected that about 480 MW of this load reduction will come from cogeneration and small power production (see Figure 4-2). To achieve this goal, CP&L has embarked on a comprehensive program.*

The case study presented here deals with a chemical plant scheduled to begin operation within the Carolina Power and Light service territory. Both the plant owner and CP&L were interested in assessing cogeneration feasibility, and so provided the required data.

Table 4-5 describes the characteristics of the proposed plant. The DEUS computer program, an engineering simulation model, was used to design a number of technologically feasible cogeneration systems for the proposed plant. Based on these runs, a

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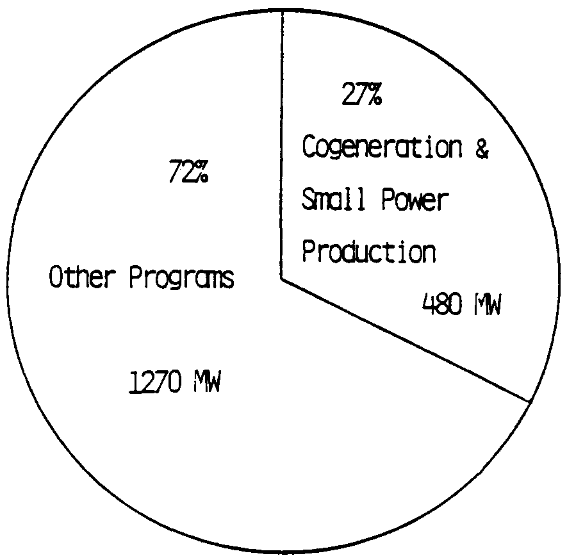
*See John Glasgow, "Introduction to Carolina Power and Light Company Case Study," in Proceedings: EPRI Cogeneration Seminar, Oakland, California, Report prepared for Electric Power Research Institute, October 1982.




Source: Proceedings: EPRI Cogeneration Seminar, Oakland California, October 1982.

Figure 4-2: CP&L Load Management Program.

Table 4-5

CHARACTERISTICS OF PROPOSED PLANT

| | |
|---|---|
| ELECTRIC DEMAND | |
| Average Electric Demand | 11000 kW |
| Electric Demand Profile | flat |
| STEAM DEMAND | |
| Average Steam Demand @ 165 psig saturated | 175,000 lb/hr. |
| Steam Demand Profile | flat |
| OPERATING HOURS | 8,000 hrs/yr. |
| FUEL CHOICE | |
| Coal (12,000 BTU/lb) | |
| MAKEUP WATER | |
| Makeup Water Requirements | 10% @ 200°F |

coal-fired cogeneration system, sized for thermal following and using a steam turbine with turbine inlet conditions of 1,465 psia and 950°F was selected for further analysis. The cost and performance of this system, as determined by DEUS, is presented in Table 4-6. The total installed cost presented in Table 4-6 is expressed in end-of-1980 dollars, and does not include any interest during construction. Also, the system does not include flue gas desulfurization.

The objective of the case study is to compare 100% industry ownership with a number of possible utility/industry partnership arrangements. The results presented in this section are based on COPE runs made in October 1982. While the data used are basically the same as those used for an earlier set of runs, the results of which were presented in Oakland, California,* there are some important differences in the assumptions used here:

- In accordance with the Tax Equity and Fiscal Responsibility Act (TEFRA), 1982, interest expenses incurred during construction are capitalized, and not deducted for tax purposes. Also, as TEFRA requires, the depreciation basis is reduced by an amount equal to one half of all tax credits claimed.
- As in the earlier runs using CP&L data, the economic life of the proposed plant is assumed to be 20 years. However, the term of debt is assumed to be 10 years. In the earlier runs, the term of debt was also assumed to be 20 years.
- In the earlier runs, it was assumed, in the case of a utility/industry partnership, that all depreciation allowances and tax credits would go to the industry. Here, it is assumed that depreciation allowances are divided between utility and industry in the same ratio as the initial outlays. The profit ratio and the ratio in which interest payments are made is assumed to be different from the ratio in which initial outlays are divided. A number of sensitivity runs are performed.

An interesting feature of this case study is the use of CP&L's levelized buyback rate. Table 4-7 summarizes the current and levelized buyback rates offered under PURPA. Two points related to the use of (PURPA) buyback rates in the analysis must be noted. First, since the economic life of the proposed plant is 20 years, it is assumed that the owner(s) of the cogeneration plant will sign a 15-year contract at the currently available levelized rate, and will, at the end of these 15 years, sign

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*See Proceedings: EPRI Cogeneration Seminar, Oakland, California, Report prepared for Electric Power Research Institute, October 1982.

Table 4-6

SYSTEM PERFORMANCE

STB 1465

| System | Total Installed Cost,* 1980 $ Million | MW Rating | Fuel Flow Million BTU/Hr. | Heat Million BTU/Hr. |
|---|---|---|---|---|
| Steam Turbine (1465 psig, 950$^{o}$F). No FGD | 15.98 | 11.1 | 277.36 | 181.9 |

*Does not include interest during construction.

Table 4-7

CP&L CSP-4 BUYBACK RATE SCHEDULE

| | | |
|---|---|---|
| SEASONS | | |
| SUMMER | APRIL - SEPTEMBER | |
| WINTER | JANUARY - MARCH, OCTOBER - DECEMBER | |
| PERIODS | | |
| ON-PEAK SUMMER | 10AM - 10PM MONDAY - FRIDAY | |
| ON-PEAK WINTER | 6AM - 1PM, 4PM - 9PM MONDAY - FRIDAY | |
| OFF-PEAK | ALL OTHER TIMES | |
| RATES (1982 DOLLARS) | | |
| CURRENT | ON-PEAK SUMMER | 6.66 ¢/kWh |
| | ON-PEAK WINTER | 6.37 ¢/kWh |
| | OFF-PEAK | 2.92 ¢/kWh |
| 5 YEAR LEVELIZED | ON-PEAK SUMMER | 7.08 ¢/kWh |
| | ON-PEAK WINTER | 6.79 ¢/kWh |
| | OFF-PEAK | 3.08 ¢/kWh |
| 10 YEAR LEVELIZED | ON-PEAK SUMMER | 8.13 ¢/kWh |
| | ON-PEAK WINTER | 7.84 ¢/kWh |
| | OFF-PEAK | 3.62 ¢/kWh |
| 15 YEAR LEVELIZED | ON-PEAK SUMMER | 11.31 ¢/kWh |
| | ON-PEAK WINTER | 10.82 ¢/kWh |
| | OFF-PEAK | 4.49 ¢/kWh |

a five-year contract at the prevailing levelized rate. The prevailing levelized rate is computed by escalating the current levelized rate. Second, although CP&L has three distinct rates during the year (on-peak summer, on-peak winter, and off-peak), the cogeneration plant performance does not vary during the year. Therefore, for computational purposes, an annual weighted average rate is utilized.

Finally, the price of steam is based on the cost of producing identical quality steam from new coal-fired boilers. The computer output (presented on the following pages) contains details of the assumptions used in the case study.

**CONCLUSIONS**

Report 5 of the computer output (on the following pages) contains the results of one run using COPE. The results presented correspond to a case involving a utility/industry partnership with the utility's share of costs (and benefits) fixed at 40% and the industry's share at 60%. A number of other runs assuming a different division of costs and benefits were also run. In addition, 100% industry ownership was also examined. The results from these sensitivity runs are summarized in Table 4-8. Table 4-8 contains standard measures of investment performance for industry, i.e., net present value (NPV), rate of return (ROR), payback ($P_b$) and debt-coverage. For the utility, in addition to the rate of return and debt coverage, the first year and levelized busbar costs are presented. The latter computations are based on the revenue requirements methodology. The utility's rate of return is also computed, using the standard discounted cash flow approach. Run #1 of Table 4-8 shows that if the proposed plant is owned entirely by industry, the rate of return, under the assumptions, is 41.9%. The net present value to the industry is upwards of $21 million (end-of-1983 terms). If the plant is owned entirely by industry, the utility's cost of power is the rate at which power is purchased from the facility, i.e., the PURPA buyback rate. In levelized terms (over 20 years) this is 81.2 mills/kWh (end-of-1983 terms).

Runs 2 through 5 show that depending on the actual details of the partnership arrangement, the industry's rate of return can be increased beyond 41.9% and, at the same time, the utility's cost of power is reduced. Two points about the partnership arrangement must be stressed. First, while the industry's rate of return can be increased beyond 41.9%, its net present value falls to under $16 million (see, for instance, runs 3, 4 and 5). The drop in net present value is, of course, a direct result of a smaller industry share of initial costs. Thus, a partnership limits the

REPORT 1: PROJECT INFORMATION

| | |
|---|---|
| TECHNOLOGY: | MPSTF |
| DEUS #: | 3 |
| START OF CONSTRUCTION: | JANUARY 1981 |
| START OF OPERATIONS: | JANUARY 1984 |
| ECONOMIC LIFE OF PROJECT: | 20 YEARS |
| BASE YEAR FOR COST AND PRICE DATA: | 1980 (END-OF-YEAR) |

REPORT 2: OWNERSHIP AND OPERATING INFORMATION

---

| | |
|---|---|
| OWNERSHIP ARRANGEMENT: | OWNED AS PARTNERSHIP BY UTILITY AND INDUSTRY |
| DISPATCH ARRANGEMENT: | THERMAL FOLLOWING |
| ELECTRICITY SALES ARRANGEMENT: | SIMULTANEOUS BUY-SELL |
| AVERAGE SYSTEM PERFORMANCE: | |
| POWER FLOWS | |
| GROSS POWER FROM SYSTEM (KW) | 10127.9 |
| AUXILIARY POWER REQUIREMENT (KW) | 0.0 |
| PROCESS POWER REQUIREMENT (KW) | 10045.7 |
| CAPACITY CONTRACTED TO UTILITY (KW) | 10045.7 |
| CONTRACT FRACTION | 0.0 |
| USEFUL THERMAL OUTPUT | |
| PROCESS STEAM AT 165 PSI (MILLION BTU/HR) | 166.1 |
| FUEL INPUT | |
| STREAM #1 (MILLION BTU/HR) | 253.3 |

REPORT 3: REGULATORY AND FUEL USE INFORMATION

| | |
|---|---|
| PRIMARY FUEL USED: | COAL |
| FACILITY STATUS: | QUALIFIED UNDER PURPA |
| | GREENFIELD UNIT |
| | RETROFIT: NOT PRIMARILY THERMAL |
| OIL/GAS USE: | OIL/GAS USE LESS THAN 20 PER CENT OF FUEL INPUT |
| | OIL/GAS USED ONLY FOR BACK-UP, FLAME CONTROL,OR FLAME STABILIZATION |
| TYPE OF GENERATING EQUIPMENT: | STEAM ELECTRIC |
| DEPRECIATION: | |
| UTILITY(IOU): | ERTA 1981 |
| INDUSTRY: | ERTA 1981 |
| THIRD PARTY: | ERTA 1981 |

REPORT 4 : PRICE & COST INFORMATION

AVERAGE ELECTRICITY RATES AND COSTS:

| | 1984 | 1989 | 1994 | 1999 |
|---|---|---|---|---|
| PURPA ENERGY PRICE (CENTS/KW-HR): | 6.73 | 6.73 | 6.73 | 25.90 |
| PURPA CAPACITY PRICE ($/KW/YEAR): | 0.00 | 0.00 | 0.00 | 0.00 |
| INDUSTRIAL ENERGY CHARGE (CENTS/KW-HR): | 3.64 | 6.14 | 10.35 | 17.44 |
| INDUSTRIAL CAPACITY CHARGE ($/KW/YEAR): | 110.97 | 186.99 | 315.09 | 530.95 |
| BACK-UP ENERGY CHARGE (CENTS/KW-HR): | 3.64 | 6.14 | 10.35 | 17.44 |
| BACK-UP CAPACITY CHARGE ($/KW/YEAR): | 110.97 | 186.99 | 315.09 | 530.95 |
| UTILITY MARGINAL ENERGY COST (CENTS/KW-HR): | 6.73 | 6.73 | 6.73 | 25.90 |
| UTILITY MARGINAL CAPACITY COST ($/KW/YEAR): | 0.00 | 0.00 | 0.00 | 0.00 |
| UTILITY MARGINAL BACK-UP ENERGY COST(CENTS/KW-HR): | 3.64 | 6.14 | 10.35 | 17.44 |
| UTILITY MARGINAL BACK-UP CAPACITY COST($/KW/YEAR): | 110.97 | 186.99 | 315.09 | 530.95 |

AVERAGE STEAM PRICES AND COSTS:

| | 1984 | 1989 | 1994 | 1999 |
|---|---|---|---|---|
| PRICE OF PROCESS STEAM AT 165 PSI($/MILLION BTU): | 5.92 | 9.98 | 16.81 | 28.33 |
| COST OF ALTERNATIVE STEAM AT 165 PSI($/MILLION BTU): | 5.92 | 9.98 | 16.81 | 28.33 |

INPUT FUEL COSTS:

| | 1984 | 1989 | 1994 | 1999 |
|---|---|---|---|---|
| INPUT FUEL #1 ($/MILLION BTU): | 2.38 | 4.01 | 6.76 | 11.39 |

CONSTANT ANNUAL ESCALATORS:

| | |
|---|---|
| GNP DEFLATOR (CORE INFLATION): | 0.090 |
| CAPITAL COST ESCALATION: | 0.090 |
| OPERATION & MAINTENANCE COST ESCALATION: | 0.110 |

REPORT 5: CONSOLIDATED IMPACT STATEMENT

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## A. PROJECT FINANCE

| | | | |
|---|---|---|---|
| TOTAL INSTALLED COST OF SYSTEM (THOUSANDS OF BASE YEAR DOLLARS) | 15984.00 | | |

### FINANCIAL STRUCTURE

| | | | |
|---|---|---|---|
| SHORT TERM INTEREST RATE ON BORROWINGS DURING CONSTRUCTION: | 0.18 | | |
| LONG TERM DEBT FRACTION: | .30 | | |
| LONG TERM DEBT INSTRUMENT: | | | |
| TYPE | REGULAR | | |
| TERM | 10 YEARS | | |
| INTEREST RATE | .120 | | |
| MODE OF PAYMENT | ANNUITY | | |
| CORPORATE CONTRIBUTION : | CORPORATE CONTRIBUTION COMES FROM EQUITY | | |

| | UTILITY | INDUSTRY | THIRD PARTY |
|---|---|---|---|
| LEVELIZED FIXED CHARGE RATE: | 0.20 | | |
| FIRST YEAR FIXED CHARGE RATE: | 0.20 | | |
| COST OF NEW CORPORATE DEBT (BEFORE TAX): | 0.12 | 0.12 | 0.15 |
| COST OF NEW CORPORATE EQUITY: | 0.16 | 0.16 | 0.21 |
| TARGET CORPORATE DEBT FRACTION: | 0.50 | 0.30 | 0.10 |
| TARGET CORPORATE EQUITY FRACTION: | 0.50 | 0.70 | 0.90 |
| MARGINAL FEDERAL TAX RATE ON EARNINGS: | 0.50 | 0.50 | 0.50 |

### PARTNERSHIP INFORMATION

| | UTILITY | INDUSTRY | THIRD PARTY |
|---|---|---|---|
| SHARE OF LONG TERM OUTLAYS: | 0.40 | 0.60 | 0.00 |
| SHARE OF DEPRECIATION BENEFITS: | 0.40 | 0.60 | 0.00 |
| SHARE OF INTEREST DEDUCTIONS: | 0.40 | 0.60 | 0.00 |
| SHARE OF PROFITS & TAX CREDITS: | 0.40 | 0.60 | 0.00 |

B. CASH FLOW STATEMENT

***********
UTILITY
***********

DEPRECIATION AND TAX CREDITS

(THOUSANDS OF DOLLARS)

| | BASIS (A) | PROPERTY STATUS (B) | DEPRECIATION METHOD (C) | FIRST YEAR DEPRECIATION | INVESTMENT TAX CREDIT (D) | ENERGY TAX CREDIT (D) |
|---|---|---|---|---|---|---|
| FUEL HANDLING EQUIPMENT | 1350.69 | NPP | 1 | 202.60 | 150.08 | 150.08 |
| BOILER | 4305.32 | NPP | 1 | 645.80 | 478.37 | 478.37 |
| POLLUTION CONTROL EQUIPMENT | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| TURBINE GENERATORS | 1960.37 | NPP | 1 | 294.06 | 206.36 | 0.00 |
| HEAT DISTRIBUTION EQUIPMENT | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| SPECIALIZED BLDGS & STRUCTURES | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| GENERAL PURPOSE BLDGS | 281.39 | NPP | 1 | 42.21 | 0.00 | 0.00 |
| LAND | 0.00 | NPP | 4 | 0.00 | 0.00 | 0.00 |
| | 8648.15 | | | 1184.67 | 834.80 | 628.45 |

(A) FOR DEPRECIATION;OPTION TO CAPITALIZE IDC
(B) NPP: NON PUBLIC-UTILITY PROPERTY; PP: PUBLIC UTILITY PROPERTY
(C) 1: 5 YR ACRS; 2: 10 YR ACRS; 3: 15 YRACRS; 4: NON-DEPRECIABLE; 5: ST. LINE
(D) TAX CREDITS ACCRUE IN FIRST YEAR OF OPERATION UNLESS CONSTR. PERIOD > 2 YRS

CASH FLOWS DURING CONSTRUCTION FOR UTILITY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1981 | 1982 | 1983 |
|---|---|---|---|
| TAX BENEFITS ON S/T INTEREST PAYMENTS: | 0.00 | 0.00 | 0.00 |
| LONG TERM PROJECT OUTLAYS: | 0.00 | 0.00 | 6565.85 |
| INVESTMENT TAX CREDITS DURING CONSTRUCTION: | 125.22 | 208.70 | 500.88 |
| ENERGY TAX CREDITS DURING CONSTRUCTION: | 94.27 | 157.11 | 377.07 |
| NET AFTER TAX CASH FLOWS: | 219.49 | 365.81 | -5687.90 |

CASH FLOWS FROM OPERATIONS FOR UTILITY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1984 | 1989 | 1994 | 1999 |
|---|---|---|---|---|
| ELECTRIC OPERATIONS: | | | | |
| ELECTRICITY SALES: | 2386.92 | 2386.92 | 2386.92 | 9189.65 |
| ELECTRICITY SAVED: | 0.00 | 0.00 | 0.00 | 0.00 |
| EXTRA BACK-UP COSTS: | 0.00 | 0.00 | 0.00 | 0.00 |
| AUXILIARY COSTS: | 0.00 | 0.00 | 0.00 | 0.00 |
| NET ELECTRIC REVENUES: | 2386.92 | 2386.92 | 2386.92 | 9189.65 |
| STEAM OPERATIONS: | | | | |
| NET STEAM REVENUES: | 3446.53 | 5807.60 | 9786.13 | 16490.20 |
| OPERATING COSTS: | | | | |
| FUEL COSTS: | 2112.29 | 3559.32 | 5997.66 | 10106.39 |
| OPERATION & MAINTENANCE: | 368.00 | 620.10 | 1044.90 | 1760.72 |
| OPERATING INCOME: | 3353.17 | 4015.10 | 5130.49 | 13812.73 |
| GENERAL & ADMINISTRATIVE: | 0.00 | 0.00 | 0.00 | 0.00 |
| LOCAL TAXES & INSURANCE: | 244.15 | 375.66 | 577.99 | 889.31 |
| DEPRECIATION: | 1184.67 | 0.00 | 0.00 | 0.00 |
| INTEREST PAYMENTS: | 337.67 | 215.43 | 0.00 | 0.00 |
| NET TAXABLE INCOME: | 1586.68 | 3424.02 | 4552.50 | 12923.41 |
| FEDERAL TAX: | 793.34 | 1712.01 | 2276.25 | 6461.71 |
| NET INCOME AFTER TAX: | 793.34 | 1712.01 | 2276.25 | 6461.71 |
| PRINCIPAL PAID(-): | 160.35 | 282.59 | 0.00 | 0.00 |
| DEPRECIATION (+): | 1184.67 | 0.00 | 0.00 | 0.00 |
| INVESTMENT TAX CREDITS: | 0.00 | | | |
| ENERGY TAX CREDITS: | 0.00 | | | |
| AFTER-TAX CASH FLOW: | 1817.66 | 1429.42 | 2276.25 | 6461.71 |

FINANCIAL ANALYSIS BASED ON TOTAL INVESTMENT

ALL DOLLARS IN 1983 (END-OF-YEAR) TERMS:

| | |
|---|---|
| NET PRESENT VALUE (THOUSANDS OF DOLLARS) | 8470.97 |
| RATE OF RETURN | 0.419 |
| PAYBACK (YEARS) | 2.48 |
| FIRST YEAR DEBT COVERAGE RATIO | 8.54 |
| LEVELIZED ANNUAL REVENUE REQUIREMENT (THOUSANDS OF DOLLARS) | 4196.38 |
| LEVELIZED BUSBAR COST (MILLS/KW-HR) | 47.30 |
| FIRST YEAR REVENUE REQUIREMENT (THOUSANDS OF DOLLARS) | 4169.06 |
| FIRST YEAR BUSBAR COST (MILLS/KW-HR) | 46.99 |

B. CASH FLOW STATEMENT

***********
INDUSTRY
***********

DEPRECIATION AND TAX CREDITS

(THOUSANDS OF DOLLARS)

| | BASIS (A) | PROPERTY STATUS (B) | DEPRECIATION METHOD (C) | FIRST YEAR DEPRECIATION | INVESTMENT TAX CREDIT (D) | ENERGY TAX CREDIT (D) |
|---|---|---|---|---|---|---|
| FUEL HANDLING EQUIPMENT | 2026.03 | NPP | 1 | 303.90 | 225.11 | 225.11 |
| BOILER | 6457.98 | NPP | 1 | 968.70 | 717.55 | 717.55 |
| POLLUTION CONTROL EQUIPMENT | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| TURBINE GENERATORS | 2940.56 | NPP | 1 | 441.08 | 309.53 | 0.00 |
| HEAT DISTRIBUTION EQUIPMENT | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| SPECIALIZED BLDGS & STRUCTURES | 0.00 | NPP | 1 | 0.00 | 0.00 | 0.00 |
| GENERAL PURPOSE BLDGS | 422.09 | NPP | 1 | 63.31 | 0.00 | 0.00 |
| LAND | 0.00 | NPP | 4 | 0.00 | 0.00 | 0.00 |
| | 12972.23 | | | 1777.00 | 1252.20 | 942.67 |

(A) FOR DEPRECIATION;OPTION TO CAPITALIZE IDC
(B) NPP: NON PUBLIC-UTILITY PROPERTY; PP: PUBLIC UTILITY PROPERTY
(C) 1: 5 YR ACRS; 2: 10 YR ACRS; 3: 15 YRACRS; 4: NON-DEPRECIABLE; 5: ST. LINE
(D) TAX CREDITS ACCRUE IN FIRST YEAR OF OPERATION UNLESS CONSTR. PERIOD > 2 YRS

CASH FLOWS DURING CONSTRUCTION FOR INDUSTRY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1981 | 1982 | 1983 |
|---|---|---|---|
| TAX BENEFITS ON S/T INTEREST PAYMENTS: | 0.00 | 0.00 | 0.00 |
| LONG TERM PROJECT OUTLAYS: | 0.00 | 0.00 | 9848.77 |
| INVESTMENT TAX CREDITS DURING CONSTRUCTION: | 187.83 | 313.05 | 751.32 |
| ENERGY TAX CREDITS DURING CONSTRUCTION: | 141.40 | 235.67 | 565.60 |
| NET AFTER TAX CASH FLOWS: | 329.23 | 548.72 | -8531.85 |

CASH FLOWS FROM OPERATIONS FOR INDUSTRY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1984 | 1989 | 1994 | 1999 |
|---|---|---|---|---|
| ELECTRIC OPERATIONS: | | | | |
| ELECTRICITY SALES: | 3580.38 | 3580.38 | 3580.38 | 13784.47 |
| ELECTRICITY SAVED: | 0.00 | 0.00 | 0.00 | 0.00 |
| EXTRA BACK-UP COSTS: | 0.00 | 0.00 | 0.00 | 0.00 |
| AUXILIARY COSTS: | 0.00 | 0.00 | 0.00 | 0.00 |
| NET ELECTRIC REVENUES: | 3580.38 | 3580.38 | 3580.38 | 13784.47 |
| STEAM OPERATIONS: | | | | |
| NET STEAM REVENUES: | 5169.80 | 8711.41 | 14679.20 | 24735.29 |
| OPERATING COSTS: | | | | |
| FUEL COSTS: | 3168.43 | 5338.99 | 8996.49 | 15159.59 |
| OPERATION & MAINTENANCE: | 552.00 | 930.15 | 1567.35 | 2641.08 |
| OPERATING INCOME: | 5029.75 | 6022.65 | 7695.74 | 20719.09 |
| GENERAL & ADMINISTRATIVE: | 0.00 | 0.00 | 0.00 | 0.00 |
| LOCAL TAXES & INSURANCE: | 366.23 | 563.49 | 866.99 | 1333.97 |
| DEPRECIATION: | 1777.00 | 0.00 | 0.00 | 0.00 |
| INTEREST PAYMENTS: | 506.51 | 323.15 | 0.00 | 0.00 |
| NET TAXABLE INCOME: | 2380.02 | 5136.02 | 6828.75 | 19385.12 |
| FEDERAL TAX: | 1190.01 | 2568.01 | 3414.38 | 9692.56 |
| NET INCOME AFTER TAX: | 1190.01 | 2568.01 | 3414.38 | 9692.56 |
| PRINCIPAL PAID(-): | 240.52 | 423.89 | 0.00 | 0.00 |
| DEPRECIATION (+): | 1777.00 | 0.00 | 0.00 | 0.00 |
| INVESTMENT TAX CREDITS: | 0.00 | | | |
| ENERGY TAX CREDITS: | 0.00 | | | |
| AFTER-TAX CASH FLOW: | 2726.48 | 2144.12 | 3414.38 | 9692.56 |

FINANCIAL ANALYSIS BASED ON TOTAL INVESTMENT

| | |
|---|---|
| TOTAL INSTALLED COST OF BOILER<br>(THOUSANDS OF BASE YEAR DOLLARS) | 10000.00 |
| **ALL DOLLARS IN 1983 (END-OF-YEAR) TERMS:** | |
| NET PRESENT VALUE<br>(THOUSANDS OF DOLLARS) | 12706.45 |
| RATE OF RETURN | 0.419 |
| PAYBACK (YEARS) | 2.48 |
| FIRST YEAR DEBT COVERAGE RATIO | 8.54 |

## C. ADDITIONAL IMPACTS

### IMPACT ON UTILITY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1984 | 1989 | 1994 | 1999 |
|---|---|---|---|---|
| COST OF POWER PURCHASED UNDER PURPA: | 5967.31 | 5967.31 | 5967.31 | 22974.13 |
| COST OF DISPLACED POWER: | 0.00 | 0.00 | 0.00 | 0.00 |
| COST OF SERVING AUXILIARIES: | 0.00 | 0.00 | 0.00 | 0.00 |
| SAVINGS FROM AVOIDED GENERATION COSTS: | | | | |
| DUE TO PURCHASED POWER: | 5967.31 | 5967.31 | 5967.31 | 22974.13 |
| DUE TO DISPLACED POWER: | 0.00 | 0.00 | 0.00 | 0.00 |
| REVENUES FROM AUXILIARIES: | 0.00 | 0.00 | 0.00 | 0.00 |
| REVENUES FROM DIFFERENTIAL BACK-UP RATES: | 0.00 | 0.00 | 0.00 | 0.00 |
| NET UTILITY COST: | 0.00 | 0.00 | 0.00 | 0.00 |

### IMPACT ON INDUSTRY

(END-OF-YEAR FLOWS IN THOUSANDS OF DOLLARS)

| | 1984 | 1989 | 1994 | 1999 |
|---|---|---|---|---|
| SAVINGS FROM AVOIDED STEAM GENERATION: | 8616.33 | 14519.01 | 24465.34 | 41225.49 |
| COST OF PURCHASED STEAM: | 8616.33 | 14519.01 | 24465.34 | 41225.49 |
| NET INDUSTRY BENEFIT: | 0.00 | 0.00 | 0.00 | 0.00 |

Table 4-8

UTILITY-INDUSTRY PARTNERSHIPS

SUMMARY OF RESULTS

| Run # | Ownership Option | Util. | Ind. | INDUSTRY NPV* $ thou. | INDUSTRY ROR(%) | INDUSTRY Payback (yrs.) | INDUSTRY First Yr. Debt Cov. | UTILITY First Yr. Cost 1983 mills/kWh | UTILITY Levelized Cost 1983 mills/kWh | UTILITY First Yr. Debt Cov | UTILITY ROR(%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1. | 100% Industry | | | 21.177 | 41.9 | 2.48 | 8.54 | 67.3 | 81.2 | ... | ... |
| | PARTNERSHIPS | | | | | | | | | | |
| 2. | Capital Outlays | 0.4 | 0.6 | | | | | | | | |
| | Depreciation | 0.4 | 0.6 | | | | | | | | |
| | Interest | 0.4 | 0.6 | 12,706 | 41.9 | 2.48 | 8.54 | 46.99 | 47.30 | 8.54 | 41.9 |
| | Profits & Tax Credits | 0.4 | 0.6 | | | | | | | | |
| 3. | Capital Outlays | 0.4 | 0.6 | | | | | | | | |
| | Depreciation | 0.4 | 0.6 | | | | | | | | |
| | Interest | 0.38 | 0.62 | 13,391 | 43.7 | 2.40 | 8.59 | 48.65 | 50.06 | 8.47 | 39.4 |
| | Profits & Tax Credits | 0.38 | 0.62 | | | | | | | | |
| 4. | Capital Outlays | 0.4 | 0.6 | | | | | | | | |
| | Depreciation | 0.4 | 0.6 | | | | | | | | |
| | Interest | 0.35 | 0.65 | 14,417 | 46.5 | 2.29 | 8.65 | 51.14 | 54.19 | 8.34 | 35.8 |
| | Profits & Tax Credits | 0.35 | 0.65 | | | | | | | | |
| 5. | Capital Outlays | 0.4 | 0.6 | | | | | | | | |
| | Depreciation | 0.4 | 0.6 | | | | | | | | |
| | Interest | 0.32 | 0.68 | 15,443 | 49.6 | 2.19 | 8.70 | 53.62 | 58.33 | 8.19 | 32.5 |
| | Profits & Tax Credits | 0.32 | 0.68 | | | | | | | | |

*Net Present Value is expressed in end-of 1983 dollars and is based on a discount rate of 16%.

total capital that the industry is placing at risk. This is particularly important if uncertainty exists about future prices and costs.

Second, the lower cost of power to the utility occurs for two reasons: (i) Compared to the case of 100% industry ownership, the utility's net cost of purchased power is considerably lower, since the utility shares electric revenues. (ii) To the extent that the plant has a favorable heat rate, the utility's share of fuel cost (when viewed in relation to the steam credit and electric power obtained) is also lowered. Figure 4-3 graphically illustrates the components that make up the utility's cost of power. The utility's cost of power computation assumes that its investment in the cogeneration facility will be regulated as any other public utility investment would be. However, if the utility's share of investment is not subject to rate of return regulation, the partnership arrangement can offer high rates of return (see runs 3, 4, 5 of Table 4-8).

To summarize, this case study demonstrates that utility-industry partnerships can be mutually beneficial.

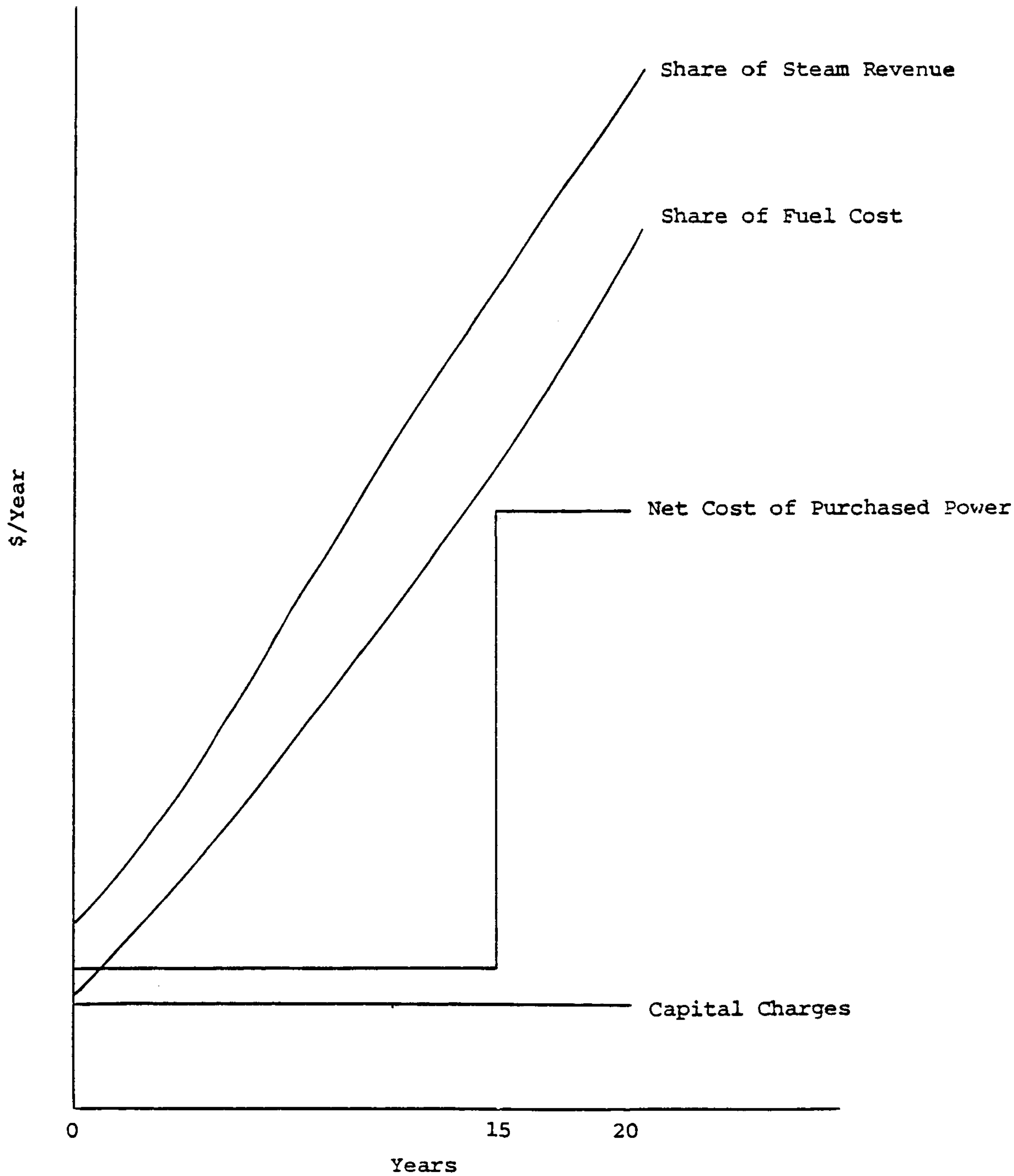


Figure 4-3. Utility Costs/Credits Under Partnership

# APPENDIX A

## GLOSSARY

**ACRS** - Accelerated Cost Recovery System. This refers to the depreciation rules established in 1981.

**Avoided Cost** - This phrase is used to describe the rate paid by a utility to buy power from a cogenerator under the provisions of the Public Utility Regulatory Policies Act (PURPA).

**Buyback Rate** - In this report, "avoided cost" and "buyback rate" are used interchangeably.

**Buy-Shortage Sell-Excess** - An operating arrangement for a cogeneration plant. Under the arrangement, all the electricity from the plant is used on-site if process demand exceeds system output; if system output falls short of process demand, power is bought from the utility.

**Corporate Contributions** - This phrase refers to corporate capital that flows into the project. Corporate capital could be made up of "corporate debt" and "corporate equity". However, "corporate debt" must be distinguished from "project debt", the latter being a project-related obligation.

**Dispatch** - This refers to the manner in which the cogeneration system is operated.

**Economic Dispatch** - Under this dispatch arrangement, the cogeneration system is operated so as to meet an economic criterion such as minimize total cost.

**ERTA** - Economic Recovery Tax Act (passed in 1981).

**Operating Cash Flows** - The cash flow generated during a period of system operation. In this model, operating cash flows are computed for each year of operation.

**Performance** - This work refers to the physical inputs and outputs from the cogeneration system, e.g., fuel input, power output, thermal output, etc.

**Project Debt** - This is used to refer to debt that is made available for the project in question. In general, such debt is not secured by revenues from non-project sources.

**Project Participant** - Any individual/corporation/entity that has an interest in the project. Also referred to as "party". In this model, the impact on three different parties can be evaluated: utility; industry; and third party.

**PURPA Period** - The year is divided into "periods" of identical characteristics. That is, for all the hours in a single period, identical conditions prevail. Since utility avoided costs under PURPA are established by period, it is referred to as the "PURPA period."

**Simultaneous Buy-Sell** - An operating arrangement for a cogeneration plant. Under the arrangement, all the electricity from the plant is sold to the utility; all requirements for process power are bought from the utility.

**TEFRA** - Tax Equity and Fiscal Responsibility Act (passed in 1982).

**Thermal Dispatch** - Under this dispatch arrangement, the cogeneration system is operated so as to always provide the required thermal energy.