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April, 1979

ORNL/SUB-79/13521/1

**FINANCIAL CONSIDERATIONS
AFFECTING IMPLEMENTATION OF
A LARGE MULTIPARTY
COGENERATION PROJECT**

WORK PERFORMED BY

**KIDDER, PEABODY & CO.
INCORPORATED**

FOR

**GULF STATES UTILITIES COMPANY
BEAUMONT, TEXAS 77704**

FOR

**OAK RIDGE NATIONAL LABORATORY
OAK RIDGE, TENNESSEE 37830**

OPERATED BY

UNION CARBIDE CORPORATION

FOR THE

**DEPARTMENT OF ENERGY
CONTRACT NO. W-7405-ENG-26**

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Preface

Kidder, Peabody & Co. Incorporated was retained to provide support in connection with the preparation of a broad economic and engineering feasibility study of cogeneration under the sponsorship of the Department of Energy (ORNL Subcontract 7317) and to study and prepare a companion report on the financial considerations affecting implementation of large scale multiparty cogeneration projects. For their assistance during the preparation of the following report we would like to thank the other firms participating in the DOE feasibility study—Gulf States Utilities Company (in whose service area the sites examined in the DOE feasibility study were located), Stone & Webster Management Consultants, Inc. and Stone & Webster Engineering Corporation. We wish to express our appreciation to Mr. Malcolm Williams of Gulf States Utilities Company for his assistance in formulating and implementing the arrangements with his company under which this report was prepared. We would also like to thank Mr. Benny Hughes of Messrs. Orgain, Bell & Tucker and Mr. Kendyl K. Monroe of Sullivan & Cromwell for their counsel as to certain legal and tax matters and Mr. Louis C. Moscarello of Coopers & Lybrand for his assistance as to certain accounting matters. We are particularly grateful to Mr. Dunlap Scott of Oak Ridge National Laboratories for his guidance in setting the objectives to be met and the standards to be employed in this report. None of these gentlemen or their firms are responsible, however, for the views expressed in this report or for its technical accuracy, both of which matters are the full responsibility of Kidder, Peabody.

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SUMMARY

With the rising cost of energy has come an increasing interest in achieving the greatest possible efficiency in energy production and utilization. Cogeneration, which is the term used to describe the production of steam for both industrial process and electrical production purposes, has received attention as a means of attaining this objective.

Engineering studies show that economies of scale can be realized by increasing the number of parties using the output of a cogeneration facility but the complexities of organizing such parties into a venture are substantial and are a major hurdle to be cleared in bringing new facilities into being. This report (a companion to the site-specific economic and engineering feasibility study of cogeneration sponsored by the Department of Energy under ORNL Subcontract 7317) is intended to identify problems inhibiting large scale multiparty cogeneration development and to suggest means to reconcile the parties' differing interests. There is no single approach which will readily resolve all problems in all situations but this report does develop a methodology and framework, on a non-site-specific basis, with which to analyze issues and consider the principal means available to participants to resolve them.

The analytical approach adopted for structuring ownership arrangements for a cogeneration project, once engineering studies confirm that the requisite technical advantages exist, is to attempt to resolve three specific issues:

1. Identification of the potential participants (industrial customers, the electric utility serving the area, equipment vendors and erectors, design and engineering firms, fuel suppliers and transporters, passive investors, governmental interests, insurance carriers and others);
2. Selection of one or more of the three principal roles which each participant may play: (a) purchaser of project output, (b) provider of other commitments to support financing of the project and (c) investor in the project; and
3. As to those participants taking an ownership role in the project, deciding whether one participant will act as sole owner or, if joint ownership is selected, deciding which of two structural formats they prefer: (a) an undivided interest approach in which each participant is responsible for and bears the full burden of providing its proportionate share of funding for the project; or (b) a project entity approach in which each participant owns an interest in a newly organized entity

which in turn owns project assets, thereby making the funding of the project the common responsibility of all of the participants.

The foregoing determinations as well as development of other detailed elements of an organizational structure will be made by each participant in light of its desire to achieve, to the greatest extent practicable, six specific objectives:

1. Allocating to itself the greatest economic benefit;
2. Limiting its assumption of project risks in respect of both the developmental and operational stages of the project;
3. Maximizing its control over project operations, particularly over such fundamental considerations as modifying the facility's production;
4. Selecting funding arrangements which achieve leverage without dilution of debt raising capacity;
5. Maximizing utilization of tax benefits; and
6. Avoiding burdensome governmental regulation, particularly federal regulation under the Federal Power Act (principally arising because of the wholesale sale of electricity in interstate commerce) and the Public Utility Holding Company Act of 1935 (principally arising when one company owns or controls 10% or more of the voting securities of an electric utility) and state regulation of public utility service (which normally arises because of sales of electricity to third parties).

In dealing with the foregoing issues certain considerations, which are discussed below, tend to emerge as focal points.

In the case of those participants who are both purchasers of project output and investors (or suppliers of credit support to facilitate investment by others), in order to determine the advantages of participation in a project it is necessary to reconcile two analytical methods: (1) the cost of service method which compares the cost of output which is derived from the project with the cost of obtaining the same output from other available sources and (2) the return on investment method which compares the return on investment (or commitment to invest) expected from the project with the returns available from alternative investments. This latter comparison normally entails estimating a stream of future net after-tax cash benefits from investment and discounting them back to the investment base to derive an internal rate of return. Reconciliation should be possible if cost of service differences are treated as additional benefits or expenses, as the case may be, to be evaluated by the return on investment method.

In conducting the foregoing analysis it is difficult to develop reliable future cost of service comparisons, which should be based on marginal pricing advantages over comparable alternatives as to each specific co-

generated output. Current costs of various cogenerated outputs, even if known, are not good indicators of future costs in view of unfolding changes in respect of the costs of energy and governmental involvement in fixing energy prices. In addition, in order to analyze benefits it is necessary to select an appropriate depreciation rate — which can be a utility-type rate of 30 years or longer, an industrial-type rate of 15 years or less, or some intermediate rate based on the factual circumstances of the project. It is also necessary for purposes of applying the return on investment method to select an investment base, which can either be the entire cost of the project (including that financed by both debt and equity) or the equity portion alone.

In order to justify recognition of the higher apparent return on investment derived by using only the equity portion as an investment base, the debt financing for a portion of project cost should be arranged in a way which does not unduly dilute the sponsoring companies' debt raising capacity. Companies look at their capacity to borrow in terms of three principal considerations:

1. The accounting treatment of debt, including whether debt is reflected as an obligation on a company's consolidated balance sheet and whether related interest charges are required to be included in calculations of fixed charges;
2. The credit agreement treatment, particularly the effect under credit agreement limitations upon the ability to incur additional debt and whether standards with respect to maintenance of appropriate ratios and coverage in respect of outstanding debt are adversely affected; and
3. The credit analysis treatment, particularly the effect that the issuance of debt has upon the ratings which the principal bond rating agencies will assign to outstanding and future security issues.

In order to borrow money for the project but at the same time avoid an adverse impact on their own borrowing capacities under each of the foregoing considerations, project sponsors will have to use a project entity approach, as opposed to an undivided interest approach. Sole ownership of a project by a single participant, while sometimes a feasible alternative to be considered, does not offer any benefit in terms of avoiding dilution of the owner's borrowing capacity and is difficult for industrial participants to justify in view of the utility characteristics of a cogeneration project in economic, financial and regulatory terms. As for potential utility participants, sole ownership is beyond the means of many utilities today because of their problems in financing construction of new generating facilities.

If a co-owned project entity is employed, in order for that entity to borrow on a basis which does not dilute its participating co-owners' bor-

rowing capacities, no single participant should own a majority interest in the entity or otherwise control the entity. If this result were achieved, no participant would be compelled, under current accounting practice, to include the entity's borrowings within its own consolidated financial accounts. Moreover, for the project entity to borrow funds it will normally be necessary to provide lenders with protection against project risks in the form of both equity investment (generally in a range of from 5% to 40% of project cost) and ancillary credit support from the participants. The forms of such credit support are many and varied and each can have a different effect on the borrowing capacity of the participant providing such support. Among the forms which can be employed are guarantees; indirect but unconditional assurances such as funds maintenance and keepwell agreements or functional obligations like completion agreements or take-or-pay purchase agreements; and conditional assurances which may represent only nominal contingencies or, if integrated with complementary assurances of others, may represent substantial contingencies as to the exposure of each participant. Each such form of credit support can be employed with a participant responsible for supporting only its pro rata portion of the project borrowings (several liability) or with broader responsibility (going as far as joint and several liability) and it will be necessary to derive a composite credit standing for the project entity based principally upon the form, weight and relative contributions of the respective credit supports, the percentage of the cost represented by the borrowing and an economic evaluation of the facility itself. In order to achieve credit support for the project entity which will satisfy lenders' requirements while retaining some advantages to the participants in avoiding dilution of their credit it will be necessary to develop a finely balanced set of mechanics which take into consideration the circumstances and objectives of each of the sponsors. At the same time attention must be paid to the tax implications; as a general rule, tax considerations will prompt the use of a partnership entity (to the extent the sponsors wish to retain the tax benefits for themselves) or a lease financing (to the extent the sponsors cannot fully utilize such tax benefits). The regulatory consequences of the arrangement adopted will also have to be considered and in general will have to be such that they do not subject the project or its industrial participants to utility-type regulation and do not subject any utility participant to any new regulatory jurisdiction.

Offering additional flexibility in structuring satisfactory arrangements, at the cost of additional complexity, there are opportunities to combine aspects of the principal alternative methods of organizing the project in various ways, including the following:

1. Various equipment elements can be subject to different ownership arrangements. In particular, electric generating turbines, which create the greatest exposure to utility regulation, may be separately

owned by utility participants while other ownership arrangements can be made for non-regulated steam generating facilities.

2. Various ownership arrangements can be made for different time phases of the project. In particular, industrial company credit support or ownership may be provided during the development phase, thereby obviating a utility's most substantial problem, that of financing construction. The project could be owned by a utility and financed on a typical utility basis after completion of construction, thereby avoiding a permanent capital commitment by industrial participants and providing them, in the cost of the output purchased, with savings attributable to the lower capital cost associated with utility-type financial structures.

3. Various ownership arrangements can be combined for different parties. For example, one or more participants can combine to create a project entity which can own and finance an undivided interest in some or all of the project assets, while other participants act separately as owners of other undivided interests.

Legal and financial formats and techniques are available through which the interests of several participants can be reconciled and financial leverage can be employed in the creation of a large scale cogeneration project. The process of successfully applying those formats and techniques to organize a specific project is a challenging one which may require considerable time, effort, skill, patience and, above all, willingness to innovate and cooperate, on the part of the organizers. However, such efforts, if successful, can provide significant rewards in the form of energy savings for the nation and cost savings or equivalent financial benefits for the participants.

INTRODUCTION

With the rising cost of energy has come an increasing interest in achieving the greatest possible efficiency in energy production and utilization. Cogeneration, which is the term used to describe the production of steam for both industrial process and electrical production purposes, has accordingly been receiving more and more attention not only at governmental levels but also by utility and industry managements.

Engineers suggest that economies of scale can be realized in cogeneration projects, just as such economies have typified the increasingly larger electric production facilities that have been installed in recent years. Generally speaking, however, if one is to increase the production capacity of a facility in order to realize economies of scale, one must also increase the number of parties taking the output of such a facility. As the number of users of the output of a new venture increases, so too do the complexities of organizing the venture and accommodating their diverse interests.

The expectations raised only a few years ago that the economies afforded by large scale multiparty cogeneration projects would lead to a proliferation of new ventures of that type have largely been disappointed. Several promising situations have failed to materialize, some having been abandoned and others proceeding more slowly than originally scheduled and in some cases on a more modest scale than initially contemplated. Attention, at least in the press, has lately focused on small scale utilization, primarily diesel fired, rather than large scale industrial projects.* Cogeneration normally will involve existing technology, although more esoteric energy systems may be considered in the course of evaluating the relative economics of a possible project. Thus, the disappointing progress with respect to new large scale multiparty projects is not primarily due to technological or engineering barriers, although accommodating the differing energy needs of a number of potential participants can be a complicated task. Rather, much of the lack of progress is due to the difficulties which business people have encoun-

* See, for example, articles in *Fortune*, "The Little Engine That Scares Con Ed" (Dec. 31, 1978, p. 80) and *The Wall Street Journal*, "Idea of Producing Own Power Intrigues Many Companies; Utilities Are Alarmed" (Mar. 1, 1979, p. 46). In addition, a significant amount of interest in cogeneration is being shifted to non-industrial applications such as the so-called MIUS (Modular Integrated Utility Systems) or total energy concept in which heating, cooling and electricity requirements of an activity such as a residential complex, shopping center or community are supplied by a single integrated system.

tered in resolving the complex series of interrelated business, financial and regulatory issues raised by the prospect of participating in a new multiparty cogeneration project.

These issues come into sharpest focus from the vantage point of someone, such as an investment banker, charged with the task of formulating a financing structure and program for a new cogeneration facility. Our object in this report is to (1) identify the problems which have to be solved before the potential participants in such a venture can reach agreement and actually commence development, (2) describe the way in which the presence of these problems has typically inhibited this process and (3) suggest some of the measures which might be employed to reconcile the parties' differing interests in order to permit them to enjoy the fundamental economic advantages which engineering studies (such as the companion DOE study) suggest are available.

Unfortunately this report cannot purport to be a blueprint for the successful business engineering of a multiparty transaction. As indicated above, the historical record does not offer encouraging examples of venturers who have succeeded in overcoming the obstacles. Even if it did, those with experience in arranging complex business and financial transactions will vouch for the uniqueness of each situation. While the general issues may be similar in a number of cases, the particular circumstances of the parties — their technical needs, their financial capabilities and requirements, their regulatory postures and even the personalities of the individual business people involved — make each situation a special challenge. In attempting to meet that challenge, an awareness of the problems and of the experience of others in coping with those problems is invaluable. Though disappointed by the lack of progress thus far we are by no means convinced that the goal of the widespread use of multiparty cogeneration is beyond reach. We hope that this report will contribute to the efforts to achieve that objective.

Though this report has been commissioned as a companion to the DOE study, which focuses on site-specific projects, we believe that our report would be most helpful to those interested in the subject if it treated the full range of problems which can confront business people dealing with new cogeneration ventures wherever they are situated in the United States. Therefore we have chosen not to confine ourselves to the parameters of the factual patterns considered in the DOE study. Neither have we attempted to resolve the issues in terms specific to the participants in those factual patterns.

FORMULATION OF PROJECT STRUCTURE

Once the preliminary engineering study indicates the presence of the technical requisites for the project, the rudiments of an organizational structure can be formulated. This will require the identification of the project participants, a determination as to their respective roles and the selection of a structural framework within which their specific relationships can be defined.

Project Participants

Broadly speaking, for purposes of formulating a project organizational structure, the term "project participants" should include all parties whose commitment to the project may have a direct bearing on its financeability. These will include all investors in the project and all parties who commit on a long term basis to take the steam and/or electric output directly from the project, whether or not they are investors. Specifically, the following are potential project participants:

1. The industrial companies looking to the project to meet their process steam and/or electric load requirements. They expect the project to provide services essential to their industrial operations. They may but are not necessarily required to invest in the project.

2. The electric utility company within whose service area the project is located. The utility may have any one or more of several motivations for participating in the project. For example, the utility may be interested in the project as a source of power generation, presently or in the future. Or it may wish to earn income by providing services in connection with the design, construction, operation and/or fuel supply of the project. The utility may also be interested in making an investment of funds to earn an expected return, with the investment possibly being perceived as a desirable diversification from its conventional regulated activities. The utility may further be motivated by a desire to maintain a role in the energy generation activities of its industrial customers whose base load electric requirements it may continue to service and whose backup electrical energy requirements it may undertake to meet.

3. Equipment vendors and erectors, design and engineering firms and, possibly, fuel suppliers and transporters (sometimes generally referred to herein as "contractors") — all of whom anticipate deriving business benefits from dealing with the project and, in furtherance of this business interest, may be willing to make commitments which would facilitate financing (including, perhaps, a commitment to invest funds in the project).

4. Passive investors seeking returns on their investments in the project. Such investors are likely to be interested primarily in a more secure, hence more limited, return, in which event they will probably supply debt funds to the project. If they are seeking higher returns and are prepared to accept a higher degree of risk, they would probably seek an equity interest in the project. Passive investors would include financial institutions and, under circumstances where the investment is of a reasonably high quality and has other appropriate characteristics, could include members of the general public. Passive investors in a project such as a new cogeneration facility are unlikely to assume risks of project failure and tend to confine their risks to the creditworthiness of companies with established credit standing. Passive institutional investors include commercial banks, insurance companies, pension funds, thrift institutions and educational and other eleemosynary institutions. Of these, commercial banks are the most willing to accept some degree of credit risk but generally limit the terms of their investments to short or intermediate periods — normally not longer than eight years and, preferably, three years or less. Commercial banks also prefer to lend at an interest rate which fluctuates with a standard such as the prime rate, which is the rate they charge their most creditworthy customers at a particular time. Commercial bank loans often require the borrower to keep a portion of the proceeds on deposit with the lender at all times. Such loans generally are prepayable by the borrower on short notice without penalty. Loans from institutional investors which are not commercial banks, in contrast, are normally for longer terms, generally seven to twenty-five years, are not prepayable without a substantial penalty, are at interest rates fixed in advance and require no compensating balances to be maintained. Non-bank institutional lenders are extremely risk averse.

Other parties, who are not specifically "project participants" but who may play roles in supporting a project's financeability, might include carriers providing insurance for the project where the financing structure contemplates that such insurance will be relied upon as an element of the project's credit support. Governmental entities might also play a role by guaranteeing all or a portion of the financing and, in the case of a municipal electric system interested in gaining a share of the project's electrical output, by making an investment in the project. Other governmental support may take the form of loans, grants and the issuance of tax exempt revenue bonds.*

* Tax exempt revenue bonds may be a factor in the financing plan of any cogeneration facility, particularly to the extent they are employed to finance the cost of pollution control equipment incorporated in a cogeneration facility or of equipment for the local furnishing of electric energy. However, in order for tax exempt bonds to play a more significant part in the financing of a cogeneration facility, the public bodies involved would be required to take a more active role than has been the case in the past. Treatment of the special considerations associated with the involvement of public bodies in a multiparty venture or with the issuance of tax exempt bonds would add substantial complexity and length to this report. Accordingly, we have not addressed those issues.

Ownership Patterns

When considering the various roles which project participants may play, one should distinguish between three broad categories of participation: (1) a commitment to use project output, (2) other support to facilitate financing (which might take the form of a guarantee or other ancillary credit support) and (3) investment. Some project participants may act in only one capacity; others may serve in two or three capacities. Where participants act in more than one capacity it is useful to differentiate among those capacities in terms of a participant's responsibilities and objectives.

Of the three categories of participation, investment is most central to formulating a structural framework for the project and, within the types of investment which can be made, equity investment carrying with it an ownership role is the most fundamental.

Any cogeneration project with several participants may be structured so that only one of them is the equity investor and owner of the project. In many cogeneration projects, however, particularly those of larger size, a number of considerations militate against single-party ownership and in favor of sharing the equity investment and ownership role among two or more participants.

Where several participants share ownership, their interests can be encompassed within two general structural formats. The first, generally referred to as the undivided interest approach, is one in which each participant holds its ownership interest in the project either (1) directly in the form of an undivided interest in project assets or (2) indirectly through a wholly owned subsidiary which itself holds an undivided interest in project assets. This approach is illustrated in Chart 1 on page 11.

The second general structural approach to co-ownership, generally referred to as the project entity approach, is one in which participants, either directly or indirectly through wholly owned subsidiaries, acquire an equity interest in a new entity formed for the purpose of holding the direct ownership interest in the project assets. This approach is illustrated in Chart 2 on page 12.

The concepts of undivided interest and project entity can also apply in circumstances where a participant has no ownership interest, directly or indirectly, in project assets but does have a direct or indirect property right to the use of those assets in the form of a lease from the owner who has invested in the assets. Under the undivided interest approach the participants or their subsidiaries would hold the leasehold interest in the project assets. Under the project entity approach a newly formed

Chart 1

UNDIVIDED INTEREST APPROACH (a) DIRECTLY AND (b) INDIRECTLY THROUGH SUBSIDIARIES

Chart 2

PROJECT ENTITY APPROACH (a) DIRECTLY AND (b) INDIRECTLY THROUGH SUBSIDIARIES

entity would hold the leasehold interest in the project assets and each participant or its subsidiary would acquire an equity interest in that new entity.

UNDERLYING ISSUES

The object of any organizational structure for a multiparty cogeneration project is to achieve certain basic goals for each of the participants. It is necessary for them to identify those goals at the outset before determining which structural formulation best contributes to their realization in the particular circumstances. The underlying issues to be considered by each participant when determining its objectives can be catalogued as follows:

1. Allocation of economic benefits from project participation.
2. Allocation of risks associated with the project.
3. Management control of the project.
4. Considerations pertaining to sources of funding and the use of financial leverage for the project.
5. Tax considerations.
6. Exposure to governmental regulation.

A number of the foregoing issues are interrelated. For example, a participant's willingness to accept a defined share of a project's economic benefits will be dependent upon the degree of risk it assumes and the degree of management control it can exercise. We will discuss these issues below in the order indicated.

Allocation of Economic Benefits

In order for a corporation to accept as the proper allocation to it of a specified share of the economic benefits from participation in a cogeneration project it should have a methodology for measuring the benefits it expects to derive.

Many participants in a cogeneration project have two roles — user of project output and investor in the project — each of which would be evaluated on a different basis. As a user of project output, a participant seeks to obtain that output at the lowest possible cost and will measure the desirability of project participation in terms of whether that cost is lower than that which he would be required to pay to other available sources. As investor, the participant will seek the highest price for the project output so as to obtain the highest possible return on investment; generally the participant-investor will employ the discounted cash flow method of analysis to calculate that return.

These two approaches — cost of service and return on investment — though different are not mutually exclusive. Indeed they interact in that by assuming a lesser value for the project output, return on investment will be penalized and by assuming a higher value the return will be enhanced. From the point of view of the participant, however, the two are in perfect balance only if that participant's interest as a user of services is precisely equal to its interest as an investor. An exact balance will rarely be present and consequently it is usually necessary for a participant to employ both approaches when evaluating a project. Factoring both into a participant's decisionmaking process is complicated because each of the two approaches has its own internal complexities and each reflects the perspective of a different discipline — the cost of service approach being primarily that of the engineer or other technical evaluator of utility services while the return on investment approach is that of the financial evaluator. A cogeneration project raises a greater risk of a failure of communication between the technical evaluators and financial evaluators than do conventional investment situations involving other production facilities.

The cost of service approach is not one easily applied to a cogeneration project. When computing cost of service, the engineer first ascertains the capital costs of a facility providing the requisite services, applies an assumed cost of capital (including a depreciation factor for return of capital and a return factor on capital) and, after recognizing operating and fuel costs, computes an overall cost of output. This overall cost is then allocated among the project's various products. The project is then evaluated in terms of whether the resultant costs are greater or less than those which would be derived from alternative means of obtaining the same products.

Among the special difficulties of applying this approach to a cogeneration project are the problems of allocating the overall cost among various types of output. Not only does a cogeneration facility produce two different types of products — steam and electricity — but the steam outputs can differ in terms of temperatures and pressures, the electric outputs can differ in terms of voltages and the availability of the different types of service can vary from time to time depending on the particular production mix at any given moment.

There are various ways in which this cost allocation can be attempted. One method is that of attempting to relate each class of service to the costs associated with rendering it. Another might allocate cost to output in accordance with the relative heat or energy values associated with each class of service. These two methods may be technically valid (though the areas for technical disputes about incremental costs of each

type of service and the appropriateness of allocation of facilities employed in each class of service are substantial) but neither has any particular grounding in economic substance. Economists understand that goods and services are priced not on a cost basis (particularly one which involves technical or arbitrary cost allocations) but on a marginal pricing basis. That is, goods and services are purchased only if priced to compete effectively with alternative goods and services. Accordingly, the soundest basis for fixing the values of the various outputs of a multiparty cogeneration project is to ascertain the costs of the same services provided by the next best available means and to price the cogenerated output so that it retains a marginal advantage.

While application of the fundamental principle of marginal pricing should be one of the focal elements in evaluating cogeneration projects, the barriers to its employment represent a major pragmatic hurdle for many cogeneration projects. It is extremely difficult to identify the proper prices of alternatives to cogeneration and consequently it is correspondingly difficult to price and evaluate cogeneration itself.

Both the cogenerated outputs and the alternatives to which it is to be compared will be in the future, commencing when the cogeneration facility begins to provide service. While all project evaluations, not just those involving cogeneration, require judgments about the future, when considering cogeneration a greater number of uncertainties are involved and current practice provides little in the way of reliable guidelines to permit a reasoned judgment as to future trends. For example, most market price analyses start with the current pricing considerations derived from current competitive market conditions. Direct evidence of current market prices is not always available in respect of the products of cogeneration and, even when available, is not fully relevant to the pricing of the output of a new cogeneration facility. Steam is not a commodity which is readily available in the market or whose price is readily determinable. Normally steam is either individually generated by an industrial user or purchased from a utility. The considerations which lead an industrial company to consider participation in a new cogeneration project are generally that the existing steam supply is no longer available on the same price or reliability basis as before and/or that an additional requirement cannot be met on current terms. This may be due to the obsolescence of an existing steam production facility, the lack of an assured supply of fuel or a governmental prohibition on the continued use of a particular type of fuel*, or the prospect of prices for that fuel accelerating beyond normal inflationary expectations. Especially is this the case with respect to steam production facilities,

* Most particularly, the federal Power Plant and Industrial Fuel Utilization Act of 1978 (the Fuel Utilization Act) contemplates the issuance of orders to preclude use of natural gas or petroleum as a primary energy source. As another example, the Texas Railway Commission in a proceeding entitled "*In re: Elimination of Natural Gas as a Boiler Fuel in Texas*," Gas Utilities Docket 600, has ordered a reduction of use within the state of natural gas as a boiler fuel but that order is presently under reconsideration.

whether operated by industrial users or by utilities, which have been fueled with oil or natural gas. These considerations suggest that the pricing basis for the steam output of a new facility will require judgments as to a number of matters beyond the participant's control and will not merely extend into the future any present cost experience as to steam production.*

While electricity is a service whose current price is readily determinable, changing patterns of rate design suggest that the industrial sector may be asked to shoulder an increasing share of the burden of providing utilities with their income requirements. Though it is possible to predict the elimination of declining block rates in a number of jurisdictions, it is difficult to estimate how far this trend will progress, or precisely what impact it will have. Cogenerated electricity from a new facility may not benefit from the embedded costs of construction or capital which affect the cost of electric service supplied by a utility out of its general regulated service. In addition, other costs of utilities are escalating at rates in excess of general inflation. These increases in items such as fuel and capital costs also make current pricing an inadequate index of the future cost of cogenerated electric output. Finally, recently enacted and proposed legislation in various jurisdictions contemplates compelling utilities to purchase the electric output of cogeneration facilities at prices to be established by regulatory agencies. Furthermore, the federal Public Utility Regulatory Policies Act of 1978 contains a provision designed to result in the application of such a mandatory purchase requirement on a nationwide level. The uncertainties in this regard further complicate a cost of service analysis of a proposed cogeneration project.

In summary, the pricing of cogenerated service is an extremely uncertain process. Even when based on a cost of service approach, that approach does not normally provide ready or easy answers to the questions of how cogenerated output should be priced or whether the resulting prices render cogeneration competitive with its alternatives and consequently economically desirable to its potential participants.

Although the government may assume a larger role in the pricing of the electrical output of the future cogeneration, in current practice cogeneration output pricing is established through negotiation among the potential participants in a project. Those with greater interest in the

* While governmental action or threat of action under the Fuel Utilization Act may spur private efforts to employ cogeneration facilities in place of existing oil or gas fired steam generating facilities, that act is, by its terms, unclear as to prospects for exemptions for cogeneration facilities. Even if such exemptions become available they are likely to be subject to annual renewal. Equally unclear at this time is whether and to what extent new cogeneration facilities will be required under the federal Clean Air Act and various State Implementation Plans to meet comprehensive New Source Pollution Standards, whose applicability would substantially increase the cost of providing cogenerated steam and electricity.

steam output will argue for lower steam prices, those with greater interest in the electric output will argue for lower electric prices and those whose investment interest is proportionately greater than their interest as users of output will argue for higher prices. Hopefully the users of production will develop at least a tentative consensus as to pricing. Each participant with an investment interest will then evaluate the project on a return on investment basis, assuming that pricing schedule, but it is also appropriate and desirable for each investor which is also a user of production to integrate the cost of service analysis into its return on investment evaluation.

Most corporations conduct a return on investment evaluation before making commitments to new ventures. They do this by applying a discounted cash flow method of analysis. This technique requires estimation of future net after-tax cash benefits flowing from an investment. (A commitment which supports financing without requiring an up-front cash expenditure may nevertheless be regarded as the equivalent of a cash investment to the extent that such commitment may eventually require a cash expenditure.) The corporation derives an annual percentage return on its investment from the stream of anticipated benefits. Alternative investment opportunities are ranked in accordance with their relative returns on investment with the highest ranking opportunities being pursued, assuming they exceed the corporation's cost of capital.*

To the extent that the cost of the output to an investor differs from that which the investor would pay for its next best alternative source for comparable output, the investor should regard any such difference as an additional benefit (if the cogenerated cost is lower) or an additional expense (if it is higher) to be factored into the stream of benefits on an after-tax basis to be used in developing a return on investment. Such an analysis should permit accommodating the participant's interests as both user and investor. Presumably, if a cogeneration venture truly offers economic efficiencies over conventional means of producing steam and electricity this analysis will permit each party to ascertain whether it is obtaining its own minimal appropriate share of these efficiencies in the form of either lower costs of service or higher investment returns or both.

Before leaving the subject of the techniques for evaluating the allocation of benefits or participation in a multiparty cogeneration venture, there are at least two other aspects of the economic evaluation process which will have an effect upon a corporation's decision to participate in such a venture and which therefore require discussion.

* In addition to deriving an internal rate of return on a potential investment, some corporations in the process of their financial evaluation of a project will also apply a specified present value factor (determined by reference to their cost of capital) to the stream of cash benefits, and thus ascertain a "cost" in present value dollars of the investment.

One question is that of the annual depreciation charge which should be used when evaluating the economics of a project. Briefly, a depreciation charge, though generally a non-cash item, is intended to reflect the loss in value through wear and tear and technical obsolescence over time of an asset and to provide a fund for its replacement. It is a means of providing for the return of capital. To the extent that the financing of an asset is tied to its owner's net investment in the asset, depreciation may parallel the amortization of that financing. Most corporations, however, separate their investment decisions from their financing decisions, unless the investment decision is expressly conditioned upon or affected by a specific mode of financing. Even if not tied to a particular financing approach depreciation charges should be established to repay the cost of the asset over its useful economic life.

The dilemma associated with the choice of a depreciable life is based on the different standards employed in respect of industrial and utility equipment. Depreciable lives are generally longer in respect of utility equipment because such equipment is regarded as being unlikely to become technologically outmoded before the end of its physical life. This is due not only to the technical aspects of utility service production but the nature of the business as well. Utilities provide essential services to the public, often on a monopoly or quasi-monopoly basis, the demand for which historically has always grown and never basically changed in character. Consequently, until it wears out or its maintenance requirements become excessive, utility generating equipment will continue to be employed. Industrial equipment, particularly process equipment, is far more susceptible to being retired from service before its physical life is over. This may be due to technological changes which obsolete a particular item of equipment or an entire process in which a particular piece of equipment may be a part or to changes in the market demand for a product which result in a productive facility no longer being economically profitable. The lesser exposure of utility assets to technical or market obsolescence causes them to be built to last longer from a physical point of view and the reverse is true for industrial equipment. These differences are reflected in their different depreciable lives. On the one hand, electrical generating facilities customarily have depreciable lives of between 30 and 40 years, generally averaging about $33 \frac{1}{3}$ years. On the other hand, chemical plants, oil refineries and the like have substantially shorter lives, normally between 7 and 15 years, with 10 years being a common midpoint. The shorter the depreciable life, the greater the percentage of a plant's cost which must be recovered in each year and this in turn increases the unit charges for a plant's output.

The problem for the evaluator of a cogeneration facility, which resembles utility equipment in its physical and functional characteristics but is

tied to the industrial assets which it supports in terms of its usefulness, is whether its depreciable life for analytical purposes should be like that of an industrial asset or a utility asset or should be somewhere between the two. This question cannot be answered abstractly but the resolution will depend upon an evaluation of the characteristics of the particular cogeneration project. If the industrial assets, though individually short-lived, are part of a large facility or complex of facilities (like a petrochemical plant) which can be assumed to continue functioning far into the future with the resulting need for the cogenerated output, then a longer utility-type life for the cogeneration assets would seem appropriate. Similarly, even if currently only associated with a specified production process whose usefulness can be expected to be short-lived, a longer depreciable life may be justified if the cogeneration plant is so situated as to be likely to serve other functions or users. In some cases, however, a cogeneration facility may reasonably be expected to serve only a particular group of assets with a short useful life, in which case it is probably appropriate to deem the cogeneration assets as adjuncts to those facilities they support and to give them the same depreciable lives.*

A second question associated with the evaluation of a cogeneration facility is one which relates directly to the selection of a financing structure — that is, what should properly be considered as the investment base on which a rate of return is calculated when the discounted cash flow method is employed. Specifically, if the project is financed in part with debt, should the debt portion be considered as part of the participant's investment or should that be limited to the equity furnished by that participant. If only the equity portion of investment is included, the rate of return will generally be enhanced substantially because of the lower return requirements generally associated with debt investment. If the entire investment is considered, the rate of return will be lower. This issue, which turns upon the participant's evaluation of its exposure for repayment of that debt and the extent to which its involvement in respect of that debt curtails its ability to issue other debt, is one to which a simple and definitive answer cannot be given. It is, however, pivotal when selecting a financing structure for a cogeneration project and is discussed in greater detail in subsequent sections of this report.

Risk Sharing

In any multiparty venture the business arrangements among the parties can be viewed primarily as a means of allocating among them the

* The foregoing discussion of the considerations associated with the selection of depreciable lives for analytical purposes would generally also be applicable to the selection of depreciable lives for book accounting purposes. Depreciable lives for federal income tax purposes are affected by other considerations. See discussion beginning on page 41, below.

risks associated with and flowing from the venture. Risk encompasses the possibility of realizing benefits or suffering losses. Generally, of course, participants will only be willing to bear losses commensurate with the benefits they expect to receive, but perceptions as to potential advantages and disadvantages may differ among participants and some participants may be better situated to avoid or bear certain losses and/or to take advantage of expected benefits. The risks which flow from a cogeneration venture include certain specific credit, tax and regulatory consequences which will be discussed as separate issues in this report. The more fundamental concept of risk associated with a cogeneration venture is the probability of success or failure in economic terms in the development and operation of a project. It is convenient, for analytical purposes, to consider separately the development phase and the operational phase of a venture in terms of risk, though there is an obvious linkage between the two.

Development Phase. Looking first at the development phase, the goal is to deploy assets which are capable of producing the desired physical results within a given time frame and capital budget. If the development phase is successful in these terms, benefits should be realized in that the venture should be able to generate during its operating phase economic profits from the use or disposition of the cogenerated production of steam and electricity. The benefit of successful development can also be viewed from the perspective of what this ability to produce future economic profits means in terms of the value of the production assets. The expectation is of course that such value will equal or exceed the value of the investment in such assets. If, for any reason, the development phase experiences greater than anticipated costs or is otherwise unsuccessful, the potential economic profit from future use of the production assets will have been diminished and those assets will consequently have a lesser value, possibly less than the investment in them. This possibility represents the principal development phase risk of the venture. Losses may result from any one or more of a number of events, including:

1. Natural disasters such as fires, floods, earthquakes and the like;
2. Uncontrollable private actions of third parties such as strikes and unavailability of materials;
3. Governmental action such as the adoption of laws or regulations which inhibit development and the failure to obtain necessary permits;
4. Negligence or willful default of parties such as contractors who are responsible for developing the project; and
5. Financial circumstances such as the higher cost or unavailability of financing due to general market conditions or an adverse financial development with respect to a party responsible for such financing.

Materialization of any of these risk circumstances will result in delay and higher cost. Delay normally means a lesser economic value because the assets do not produce revenues until a later time and because the investment in the assets must be increased to cover both the financing charges which must be carried over the longer development period and, in an inflationary economy, the higher direct fabrication and installation costs. Delay and higher costs, if carried to extremes, can lead to complete project frustration, *i.e.*, the failure to complete the project or completion of the project at a cost which makes operation unprofitable. Project frustration would compel the disposition or abandonment of the project on a basis which curtails further losses and realizes whatever salvage value is possible.

Operating Phase. Once the development phase has concluded, operating risk becomes the principal focus of concern. Operating risk means, in general, the prospect that the production assets will, over a given period of time, fail to provide an expected level of economic production and profit. Productivity and profit will be affected from time to time by a number of circumstances, including:

1. The capability of the production assets to continue to perform their assigned functions without failure due to (a) inadequacies in design or workmanship, (b) faulty maintenance, (c) interruption of supply of raw materials or fuel, (d) labor stoppages, (e) destruction of assets by natural disasters, (f) taking of the assets by condemnation and (g) governmental actions which require curtailment or modification of operations (such as evolving pollution control and/or safety requirements);
2. Changes in the costs of operation, including labor and other service expense, the cost of fuel and raw materials, tax assessments and insurance; and
3. Economic impacts on the project of changes in demand or price levels for the output of the project including those attributable to (a) technological changes, (b) general economic conditions and/or (c) specific local conditions such as changes in customer requirements.

Both in the development and in the operational phase risks can be allocated in accordance with the mutual understanding of the parties and different allocation arrangements may be appropriate in each phase. Selection among alternative financial structures is part of the mechanism of risk allocation. That is, certain structures tend to allocate risks in certain ways so that the fundamental business decisions as to risk sharing will tend to be reflected in the selection of a financial structure, though general structural decisions still leave significant latitude for specific risk allocations by contract.

Management

Management, encompassing both broad policy determinations with respect to the conduct of the venture and specific supervision of the day-to-day operations, is a matter of obvious concern to the participants, who will normally seek a degree of control in management matters commensurate with their respective risk exposures. Management responsibilities can be assigned through the choice of the financial structure, though in this area (as in risk allocation) general structural decisions normally do not fully define all of the specific management details, which can be fixed or varied by specific contractual agreements.

Of particular importance within the area of management decision-making for a multiparty venture is control over fundamental changes. A cogeneration project merely provides a utility service to support industrial activities whose production plant is likely to have a book and market value far in excess of the corresponding value of the supporting cogeneration facilities. Each owner of production plant will want the freedom to make changes in the cogeneration project to reflect changes in the operational requirements of its production. Thus, a production plant's long term requirements for steam and/or electric power may increase, decrease (to the point of termination) or be modified in other respects (such as the character of the service or the periods of time during which it is needed) over the term of a cogeneration venture. In each instance the industrial participant will want the cogeneration capacity to be appropriately expanded, contracted, modified or closed down—or at least to have the power to dispose of its interest in the venture if the interests of fellow participants or other concerns preclude such a course of action. These desires may not complement co-participants' needs or desires; before deciding to join a proposed venture, the industrial participants will have to satisfy themselves that appropriate arrangements for the resolution of issues of this type have been incorporated within the venture's structure.

Sources of Funding

A project may be deemed to be economically sound, the parties may have agreed in principle to an allocation among themselves of benefits, risks and control and they may have even agreed in principle on their respective shares of ownership. Another issue remains: who will supply funding for the project and on what basis. Though this issue is normally part of the resolution of the preceding questions, it can be divorced from the others for the purposes of analyzing the manner in which a choice as to funding affects the specific interests of the participants.

The choice as to funding sources is, in the first instance, made by the industrial companies and/or utility initiating the project in the interest of obtaining its output. These participants (generally referred to herein as "user participants") will initially decide whether, and to what extent, they will provide funding from their own capital or seek participation in the form of investment in the project by others.

Other classes of potential participants, such as contractors or passive investors, who may invest funds in the project (generally referred to herein as "investor participants") have been identified earlier in this report. Generally, investor participants may be invited to act as either debt or equity investors in respect of the project; in certain circumstances they may be invited to participate as owners and lessors of project assets.

User participants will generally seek the participation of investor participants only where the user participants expect to realize advantages in respect of the availability and cost of capital. A user participant's capital includes both the cash currently available in its treasury and funds which it can generate through the sale of its debt or equity securities or otherwise. Debt issued by a company and backed by its general credit is of course part of its capital structure, even if such debt is also secured by the pledge of particular assets. Any asset pledged to one group of creditors is not available to secure other creditors on an equivalent basis. Any company at any given time has a finite amount of capital available to it and that capital has a calculable cost. When calculating a user participant's cost of capital at any particular time it is generally appropriate to blend the costs of all of the types of capital available to the user participant. The cost of each type of capital is a function of the extent to which the company's earnings potential is committed to servicing that type of capital. A company can invest its available capital in a variety of ways but each such investment should be expected to produce a return in excess of the cost to the company of its capital. A company can expand its capital by issuing new debt or equity securities but each new security issuance in effect preempts that portion of the issuer's earnings which are required to service the new securities. The price and cost of new securities are determined as they are issued on the basis of the then current earnings expectation in respect of the issuer. If new securities are issued which dilute the shares of all investors in the current earnings expectation of the issuer the issuer's capital costs will tend to increase and its capability of raising new capital will tend to be diminished.

A user participant must evaluate its willingness to invest funds in a new venture such as a cogeneration facility in light of the foregoing

considerations. It must decide (1) whether it has adequate capital funds to pay for its full share of investment in the project, taking into consideration its other capital requirements and opportunities, (2) whether its investment will return more than its cost of capital and, finally, (3) if it needs additional capital in order to make such investment whether it can do so without unduly diluting its earnings, increasing its cost of capital or reducing its ability to generate additional capital.

If a user participant opts on the foregoing basis not to fund its full share of a cogeneration project out of its capital, but still wishes the project to be developed so that it can purchase project output, it may induce an investor to take up some or all of its responsibility for furnishing capital. Presumably also the user participant would forego and the investor would gain a proportionate interest in the earnings of the project and a degree of control over it. The investor would have to evaluate the adequacy of the benefits it can expect to derive from its investment. The passive investor's evaluation would be based on its expected return on investment as compared with that of other available investments of like character. The contractor who makes an investment would consider both its return on investment and the other business benefits it expects to derive from the project's going forward. Any prospective investor participant must also consider the risks which it would bear in respect of its investment. Generally, the types of risks associated with the development and operation phases of a cogeneration project are unlikely to be acceptable to most passive investors. Contractors will normally also be averse to accepting these risks although there are likely to be more exceptions in this respect than in the case of passive investors. By rejecting these risks investors are normally opting for debt rather than equity participation in a project; returns of a magnitude appropriate for equity investors normally cannot be earned without an assumption of such risks.

An important question remains for a user participant attempting to arrange third party debt investment in a venture. Does that debt investment really relieve the user participant of the burden of supplying capital to the project? If debt participation arranged in respect of the project is considered for various purposes to be the equivalent of debt issued by the user participant itself, the user participant has not accomplished what may be its principal objective by utilizing this type of third party financing. If such debt is equivalent to debt issued by the user participant itself, the user participant in applying the discounted cash flow method of analysis to the project will probably wish to utilize its full proportionate investment in the project for the purpose of calculating its

return on investment, thereby tending to make the economics of participation appear less desirable.*

The three principal respects in which the user participant will be concerned with the possible equivalency of project debt with its own debt are the accounting, credit agreement and credit analysis treatments.

1. *The accounting effect.* A company reflects its outstanding debt and other securities in its financial statements. Debt is shown as a liability on the right hand side of a balance sheet and interest on debt will be a charge against income on an income statement. In addition, when securities representing fixed obligations such as debt or preferred stock are issued in transactions subject to Securities and Exchange Commission (SEC) registration, SEC accounting practice requires disclosure in the related prospectus, at the foot of the income statement, of the number of times the fixed charges of such obligations are covered by earnings.** If project debt is required to be included on a user participant's balance sheet with interest on that debt being included as an expense and as part of the fixed charges in the coverage calculations, the project debt is, for accounting purposes, the equivalent of the user participant's own debt. This accounting equivalency can come about in either of two ways.

One route which can lead to debt equivalency for accounting purposes is application of the general accepted accounting principles affecting consolidation of related entities. These principles are primarily set forth in Accounting Research Bulletin No. 51 (ARB No. 51) and Accounting Principles Board Opinion No. 18 (APB No. 18). ARB No. 51 in effect requires an entity which controls another entity to publish consolidated financial statements in which all of the assets and liabilities and income and expenses of the controlled entity are consolidated on a line-by-line basis. Where required such consolidated statements are normally the

* Circumstances may permit a project to be structured so that the adverse consequences of project debt can be made to fall upon parties which have a lesser concern with their own creditworthiness than do most companies. One example may be that of a holding company whose operating subsidiaries normally raise their own debt and senior equity. This pattern often occurs in the public utility industry. If the holding company were to assume the burden of raising debt for a cogeneration project the adverse impact on its credit would not directly impair the borrowing capabilities of its operating subsidiaries, although the implications would have to be weighed in terms of future sales of common stock. Another example is that of the privately owned company which has minimal borrowing requirements in the ordinary course of its own business. Such companies, often engaged primarily in service activities, may be asked to participate in ventures as the borrowers of debt (on either a recourse or non-recourse basis) to fund a project because of their capacity to absorb that debt without significant adverse impact on their normal business. Such an arrangement is most likely to arise where a privately owned service company can also benefit by obtaining a contract to provide its customary services to the project.

** Such earnings coverage ratios may be set forth on alternative bases and ratios which are supplemental to the primary ratios may either be included immediately below the primary ratios at the foot of the income statement or may be set forth in a footnote to the income statement. The precise format of this disclosure may vary from issuer to issuer. See SEC Accounting Series Release No. 122, dated August 10, 1971, and SEC Staff Accounting Bulletin No. 28, dated December 6, 1978.

most significant financial statements which the controlling entity employs. Control for these purposes normally means ownership of *more than 50%* of the voting interest in the affiliate, unless control can be exercised by means other than voting as, for example, by operation of an agreement vesting control in a party irrespective of voting. Where voting is the basis of control, a mere 50% voting interest, though it may prevent other interests from carrying decisions, is not in itself equivalent to control. For example, if there are two 50% owners, neither is in control.

Where control is present and consolidation is required,* 100% of the assets and liabilities are consolidated, on a line-by-line basis, even when less than 100% ownership exists. The difference between the ownership share and the consolidated amount is normally reflected in a "minority interest" line entry. If control is not present or full consolidation is otherwise not required, only disclosure of the equity investment in the affiliate, and not full consolidation of all debits and credits, is required. This may be shown as a single line item on the balance sheet by employing the so-called "equity" method of consolidation where the parent has a significant influence over the affiliate, which is presumed to exist where the ownership interest in the affiliate equals or exceeds 20%. The equity investment is shown as an asset and adjusted periodically to reflect undistributed *pro rata* earnings of the affiliate which have been included in income. If a less than 20% interest is held in the affiliate the "cost" method applies and the investment is shown as an asset on the parent's balance sheet and will be adjusted only to reflect actual distributions received in excess of earnings subsequent to the date of investment or permanent diminutions in value. In either case, if the equity investment is material, summary financials of the affiliate may be required to be disclosed in a footnote, which would include the affiliate's own indebtedness.**

* Although ARB No. 51 states that there is a presumption that consolidated statements are more meaningful than separate statements and that they are usually necessary for a fair presentation, there are some circumstances in which control exists but full consolidation may not be required. If the affiliate's business is such that full consolidation would be less meaningful than separate statements (as may be the case when the affiliate's principal business is financing and the parent's is manufacturing), or if the parent is engaged in a regulated business but the affiliate is not, or if the investment in the affiliate is not material, the "equity" method may be acceptable in lieu of full consolidation. Ownership by an industrial company of more than 50% control of a venture supplying steam to a production facility of that industrial company would probably require line-by-line consolidation and not the "equity" method described in the text below.

** There is one possible approach which might lead to consolidation of an affiliate's debt even if control does not exist—that is, the application of the *pro rata* consolidation method. Where this method is employed an investor in a venture would account for its *pro rata* share of the assets, liabilities, revenues and expenses of the venture. This method, rather than the equity method, has generally only been applied to unincorporated oil and gas ventures where an established industry practice as to its use prevails. Interpretation 2 of ARB No. 18 (issued in November, 1971) makes it clear that, although ARB No. 18 applies by its terms only to stock corporations, its provisions and the equity method of consolidation are also generally applicable to partnerships and to unincorporated ventures in the absence of an established industry practice to the contrary.

The second circumstance in which a user participant may be treated for accounting purposes as having incurred a debt obligation though it is not the direct issuer of project debt may occur when a user participant enters into an ancillary agreement to provide credit support for the issuer of project debt. Such ancillary agreements are frequently required in connection with the debt financing of facilities such as a cogeneration project as a means of injecting additional credit support into a financing situation. In the absence of such ancillary agreements lenders would be required to rely principally on the collateral value of the project assets and thereby to bear significant project risks. It is possible to reduce the need for an ancillary credit support by having the user participants invest a substantial amount of equity, thereby reducing the lenders' exposure, but some risks, particularly the completion risks associated with the development phase, are difficult to dispose of even when a very substantial percentage of the cost is represented by equity. Such ancillary credit support agreements can take a variety of forms, each with its own degree of efficacy and characteristics. The principal types of ancillary credit supports are:

1. Guarantees of debt, which are normally direct and unequivocal commitments to lenders that they will be paid all principal, interest and premium with respect to their loans in timely fashion.

2. Agreements which, though not guarantees, are designed to act as their functional equivalents. Such agreements (sometimes called keepwell or funds maintenance or deficiency agreements) oblige a party to advance funds to meet any cash shortfall required for payment in full of another party's debt. Such assurances may relate specifically to cash shortfalls to pay particular indebtedness or, more generally, may support the maintenance of a positive net worth or positive working capital or a positive value in a particular fund with the agreement assigned for the benefit of a specific lender or group of lenders. In the event of a cash shortfall, funds are normally supplied to the project through loans from the project's sponsor on a subordinated basis, but may also be furnished through equity contributions, acquisitions of one or more assets, current or advanced payments for goods or services or in any of a number of other ways.

3. Other unconditional assurances, which are designed to serve ends similar to guarantees or keepwells but are drawn in terms of more specific functional obligations such as obligations to complete or operate a project without regard to exculpation for events such as *force majeure*, or to purchase or pay for a product or service whether or not tendered, or to keep a project fully insured against certain risks whether or not insurance is commercially available. This type of assurance is characterized by being of a more limited duration than a guarantee or keepwell

and may cover only specific risks or time phases of a project. Such assurances, particularly with respect to completion or operation, may be general and non-specific with respect to the consequences of non-performance or may be tied directly or indirectly to the repayment of specific obligations as, for example, by requiring the obligor to purchase the incomplete or non-operating facility for an amount sufficient to repay such obligations.

4. Agreements which provide lenders with assurances of repayment in all but the most remote events. These agreements are designed to preserve an element of contingency so that it cannot be said that the obligor is liable in all events. Some narrow circumstances which have been used to exculpate the obligor from performance are remote casualties such as nuclear disasters. Others place the risk of insurance carriers' solvency on lenders; in such circumstances lenders will normally insist upon having the opportunity to review and approve the carriers in question.

5. Agreements which provide lenders with protection against project risks but which limit the obligor's exposure to specific risks, or limit the amount of the obligor's exposure (measured, for example, by the amount of tax benefits which the obligor will derive from the project) or contain provisions exculpating the obligor which are broader and more likely to occur than those referred to in 4 above. Such agreements are designed to be integrated with complementary obligations of other parties such as other user participants, contractors, insurance carriers or others so as to assure lenders that, while no single party is obligated in all events, in every circumstance one of several responsible parties will support the borrowing by supplying the necessary funds. In effect such agreements may be a combination of the types of undertakings referred to in paragraph 3 above, arranged so that effectively the lenders' exposure with respect to non-payment does not include risks beyond the creditworthiness of the sponsors providing such undertakings. Such agreements may be structured so that a participant assumes responsibility for specific risks for which it may receive specific compensation. For example, a contractor with responsibility for construction may undertake turnkey responsibility for completion risks without the normal contractor's *force majeure* exculpation and may factor that exposure into its construction price or fee.

As a general rule current accounting practice does not appear to require any of these ancillary credit supports to be regarded as the accounting equivalent of debt issued directly by the user participant so long as it can be demonstrated that the project has an economic substance which is capable of generating revenues to support the project debt. If the project itself is viable in that respect the ancillary credit

support would, under current practice, be considered merely a commitment or contingency for accounting purposes which, depending on materiality, at most would require footnote disclosure. Moreover, those agreements requiring some performance or purchase may not even represent a quantifiable contingency to be set forth in a footnote. Where a user participant is required to set forth coverage calculations at the foot of the income statement in an SEC registered offering of debt or senior equity securities the user participant may be required to include the fixed charges of any debt enjoying the benefits of its ancillary support. However, SEC requirements in this respect are unclear and have been implemented in an inconsistent manner. Recent SEC staff actions, such as the publication of Staff Accounting Bulletin No. 28, dated December 6, 1978, suggest that the direction of regulation will tend to be in favor of inclusion of such fixed charges in coverage calculations.

Furthermore, general accounting principles appear to be moving in the direction of requiring a reporting party to include within its debt not only obligations which it has issued but those which it supports with an ancillary credit agreement.* Accordingly, though current accounting practice may not require such treatment, user participants must be concerned about the manner in which accountants are likely to treat their ancillary credit supports under future standards which have not yet been adopted and have not even been definitively formulated. In these circumstances it is difficult for a user participant to accept a proposed project structure which entails use of its indirect credit support with confidence as to its ultimate effect on the participant's accounting picture.

2. *The credit agreement effect.* Many companies in the course of borrowing funds are required by their lenders to enter into agreements which are designed to prevent the incurrence of excessive indebtedness and which otherwise require the maintenance of certain standards of creditworthiness. Such credit agreements will vary considerably in form but most have certain similar characteristics. Such agreements commonly preclude a company from having debt outstanding in excess of a particular percentage of its tangible net worth and also require a company to demonstrate pre-tax earnings coverages equal to a particular multiple of the fixed charges associated with outstanding indebtedness. Such requirements may be either "incurrence" tests which preclude a company from issuing or otherwise becoming subject to new debt or "maintenance" tests which require the tests to be met in respect of all

* See, e.g., the Statement of Position on Accounting for Product Financing Arrangements which was issued on December 26, 1978 by the Accounting Standards Division of the American Institute of Certified Public Accountants. This Statement would require on-balance sheet accounting treatment of certain inventory financing arrangements.

outstanding debt. Failure to comply means that a default may be declared leading to an acceleration of the maturity of outstanding debt. Such credit agreements normally cover the borrowing entity and such of its subsidiaries as are denominated as "restricted". Normally in order to qualify as a restricted subsidiary a majority or in some cases greater than a majority interest must be held by the borrower subject to the credit agreements. If a subsidiary is denominated as restricted, its assets and earnings as well as its liabilities are considered when applying the tests. Where such restrictive covenants are applicable, they have the effect of specifically limiting a company's borrowing ability. A user participant contemplating use of project debt issued not by itself but by another entity will be particularly concerned that such project debt not be considered as its own debt when applying the restrictive covenants in its credit agreements.

Assuming that the issuer of the project debt is not a restricted subsidiary, the principal focus will be on the definition of "indebtedness" contained in the credit agreement. The scope of this definition has expanded substantially over the years as lenders' counsel have reacted to borrowers' efforts to utilize their credit to support financings of others without restricting their own borrowing power. Whether the term "indebtedness" includes a third party's debt which is supported by an ancillary credit agreement will turn in large part on how the credit agreement is drafted. Many such agreements start by defining "indebtedness" by reference to generally accepted accounting principles, either by requiring all debt for accounting purposes to be included as "indebtedness" or, occasionally, by requiring anything which must be disclosed on the right hand side of a balance sheet (other than equity) to be deemed "indebtedness". As noted above a straightforward accounting definition of debt under current practice should not include the types of ancillary credit supports enumerated above. The definition in conventional credit agreements will normally, however, explicitly include "guarantees" and may also be broad enough to cover any arrangement, direct or indirect, by which money or property is to be provided in order to facilitate the repayment of a third party's indebtedness.

A definition which is as comprehensive as the latter would very likely encompass a keepwell or deficiency agreement and probably, but not definitely, also include an unconditional form of performance or purchase agreement. If a performance or purchase agreement is not tied into a defined amount of liability it may be difficult to quantify for purposes of applying any of the objective tests in a credit agreement. A commitment with a remote type of contingency may also be deemed to be within the scope of such a definition, but the contingency is normally adopted for the specific purpose of permitting the argument to be made

that the credit support falls outside the scope of "indebtedness" as defined in the credit agreement. An agreement with a broad exculpatory provision, which is intended to provide only a portion of the credit support and which in form is similar to a commercial (as opposed to a financial) undertaking, is much more likely to fall outside the definition of "indebtedness" than within it, though even this form of agreement may be subject to the challenge that it constitutes "indebtedness" under some credit agreements. It is not possible to be categorical as to the effect accorded to any particular type of credit support agreement; the outcome will turn upon the specific terms of the particular credit support agreement and the governing credit agreement, as well as the judgment and opinions of the parties who interpret the credit agreement; most specifically counsel for the lenders or for any trustee acting for the lenders.

3. *The credit analysis effect.* A third and final aspect of the question of whether the issuance of project debt will adversely impact the capital raising capability of a user participant which has not itself issued such debt is whether prospective lenders are likely to treat such debt as the equivalent of that issued by the user in evaluating its credit for the purpose of deciding whether to make loans to the user participant and at what rates and on what terms such loans are to be made. Some lenders employ their own credit analysts but all lenders rely to some degree on the analytical judgments of the principal rating agencies which reflect their credit analyses in published ratings. Of the three credit rating agencies, Standard & Poor's, Moody's and Fitch, the first two enjoy the widest acceptance of their ratings. Each agency will assign ratings to specific debt obligations of issuers derived from various subjective and objective measurements of the issuer's ability to repay the rated obligation and the interest thereon. The highest credit rating awarded by either agency is triple-A, which Moody's expresses as Aaa and Standard & Poor's as AAA. Lesser ratings are Aa/AA, A/A and Baa/BBB, the latter of which, though still of investment quality, signifies that adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity to meet debt service requirements. Ratings below Baa/BBB are for securities which are predominantly speculative. The nature and amounts of that issuer's outstanding obligations will be significant factors determining the ratings accorded to new obligations. Ratings are a prime determinant of the availability and cost to an issuer of new debt capital. They also impact whether certain institutional investors and fiduciaries may legally purchase securities, thereby affecting the marketability and cost of such securities. Rating agencies and other sophisticated credit evaluators are not bound by formalistic rules of accounting or law in deciding whether to treat project debt and/or ancillary supports provided by a user participant as the equivalent of a user

participant's own debt for credit evaluation purposes. Such credit analysts will normally take cognizance of the existence of such debt and ancillary credit supports, even if they are not reflected on an issuer's balance sheet, and will weigh the impact of such obligations upon the user participant's credit in a very subjective manner. Rating agencies which have commented publicly about their methodology in making this type of evaluation have stressed that they will examine the qualitative specifics of the commitments being undertaken and, where the sum of such obligations is substantial, impute some negative effect to such commitments. The test of substantiality is not rigid but Standard & Poor's, for example, has mentioned as a rule of thumb that it tends to regard off-balance sheet obligations equal to 5% of capitalization as significant.

To summarize, obtaining at-risk equity participation from parties which are not user participants is not likely to be fruitful in view of the risks associated with cogeneration projects. While debt participation is more readily arranged, the advantages to a user participant in terms of preserving its own capital resources are dependent upon the debt participation being arranged on a basis which does not subject the user in accounting, credit agreement and credit evaluation terms to consequences which equate to those which would occur if the user were to issue such debt directly. Whether debt can be secured on such a basis will depend upon a specific examination of the form and substance of each proposed arrangement.

If a participant, after considering such of the three specific credit aspects which have been discussed above as are significant to it in its particular circumstances, finds that debt issued by another entity will on balance be regarded as the equivalent of its own direct debt obligations, the participant will probably evaluate the project on the basis of the participant's full investment exposure, not merely its equity investment. If the participant goes forward with the project but finds no leverage or other advantage in using another entity to issue debt to fund the project, the participant will be more likely to choose to fund the project completely with equity or to issue debt for the project directly rather than through another entity.

Tax Considerations

Related to the issues of funding sources and evaluation of project economics are considerations associated with the income tax consequences of participation in a cogeneration project.

A major objective of the participants is to optimize the tax consequences of a project and to translate such tax optimization into economic benefit for the participants. Tax optimization entails, in the first instance, assuring the availability to the fullest extent of all of the tax credits and the deductions (principally for depreciation and interest) which the law permits to be claimed and then assuring that they are used in an appropriate time frame.

There are two specific investment tax credits which may be available under federal tax law in respect of a cogeneration project: (1) the regular 10%* investment tax credit which accrues to an owner of property which qualifies as "Section 38 property" under the Internal Revenue Code (the Code) and (2) an additional 10% tax credit allowed in respect of "alternative energy property" by 1978 amendments to the Code.** All cogeneration equipment should qualify for the regular 10% investment tax credit except, as a result of 1978 amendments to the Code, boilers fired with petroleum or petroleum products (including natural gas). Even oil or gas fired boilers can qualify for the regular 10% investment tax credit provided that the use of coal is precluded by federal or state air pollution regulations or that the use of the boilers is an "exempt use." A boiler used in a facility which is an integral part of manufacturing, processing or mining will not be deemed to be used in an "exempt use" unless it is in Hawaii or the facility produces electric power with a high degree of efficiency (specifically, a heat rate of less than 9,500 Btu's per kilowatt hour) and can be converted to synthetic fuels.***

Most cogeneration equipment (but not the turbine generators) which qualifies for the regular investment tax credit will also qualify for the additional investment tax credit if it uses as its primary fuel a substance other than oil or natural gas or any product thereof, subject to two important provisos: (1) it must not be "public utility property" within the meaning of Section 46 (f) (5) of the Code and (2) it must meet performance and quality standards (if any) prescribed by the Secretary of the Treasury after consultation with the Secretary of Energy. For these purposes "public utility property" would include property used predominantly in the trade or business of the furnishing or sale of electrical energy, steam through a local distribution system or transportation of steam by pipeline, if the rates for such furnishing or sale are established or approved by a State or political subdivision thereof, by an

* An additional 1% to 1½% is allowed to corporations that adopt certain employee stock ownership plans.

** The regular 10% credit and the additional 10% credit are each reduced to 5% for property financed by tax exempt industrial development bonds.

*** Any such new oil or gas fired boiler which cannot qualify for the regular 10% investment tax credit will also be limited to straight line depreciation for tax purposes rather than the accelerated depreciation methods discussed in the text below.

agency or instrumentality of the United States, or by a public service or public utility commission or other similar body of any State or political subdivision thereof. Whether some or all of the equipment would constitute "public utility property" by reason of the rates for the output being subject to governmental regulation is an issue of tax law which cannot be answered with certainty at this time. However, the text of the law makes it appear likely that if the steam service is unregulated (either because the furnishing of steam is an unregulated activity or because the number of purchasers of steam is too limited to constitute rendering of service to the public or for any other reason) and if the steam output represents a majority of the value of the output of the facility, the fact that all or a portion of the electric output is sold to a utility which resells it to the public at regulated rates should not disqualify the equipment from treatment as alternative energy property eligible for the additional credit.*

A final consideration bearing on the availability of the use of investment tax credits is the time period within which such credits will be available. The regular investment tax credit was made permanent at 10% as a result of changes in the Code enacted during 1978. However, the additional 10% credit for energy property, which includes both "alternative energy property" and "specially defined energy property" terminates after December 31, 1982. The additional 10% credit will apply to property placed in service before that date and also to qualifying progress payment expenditures made before that date but the long lead time required to develop a large scale cogeneration project may make it difficult to rely on the availability of the additional 10% credit.

In addition to the credits which the Code allows to owners of property, it provides benefits in the form of deductions for depreciation and for interest, both of which represent significant elements in the tax optimization of any project.

The depreciation deduction in respect of new equipment can generally be computed under the most favorable of various methods which accelerate the depreciation of the asset, including the double declining balance method and the sum of the years-digits method. Use of such

* Another provision of the new tax law may make the additional 10% tax credit applicable to some elements of cogeneration equipment without constraint as to either the type of fuel employed or its public utility property characterization. This provision applies to "specially defined energy property" which is limited to certain specified types of equipment, the principal purpose of which is reducing the amount of energy consumed in an *existing* industrial or commercial facility. Although the list of eligible property may be expanded pursuant to future regulations, it currently does not include the major components of a cogeneration system such as the burner, boiler, turbine or any fuel handling equipment. Equipment may qualify for the additional credit as either alternative energy property or as specially defined energy property but the additional credit is available only once; the categories are not cumulative.

methods would, for example, permit 43% of the cost of an asset to be deducted during the first five years of a nominal twenty year useful life.

Most assets are also subject to depreciation under the Class Life Asset Depreciation Range System (ADR System) which contemplates the use of depreciable lives which may be shorter than those utilized for accounting or analytical purposes. The ADR System, which can be elected on a year-by-year basis for most property placed in service during the year, establishes class lives for particular described categories of depreciable assets and permits employment of a useful life for all assets within a category which ranges from 20% less (the lower limit) to 20% more (the upper limit) than the class life. At the present time the ADR System includes an asset class 00.4 entitled "Industrial Steam and Electric Generation and/or Distribution Systems" which includes depreciable assets "used in the production and/or distribution of electricity with rated total capacity in excess of 500 kilowatts and/or . . . steam with rated total capacity in excess of 12,500 pounds per hour, *for use by the taxpayer in his industrial manufacturing process or plant activity and not ordinarily available for sale to others*" (emphasis added). This class has a lower limit life of 22.5 years. Assets which would be included in Class 00.4 but for a lesser rated capacity are included in the appropriate manufacturing equipment classes such as chemicals (lower limit life of 9 years), pulp and paper (lower limit life of 8 years) or petroleum refining (lower limit life of 13 years).

Assets excluded from Class 00.4 because they fall outside the underscored definitional limits (that is, the taxpayer owning the assets does not own the manufacturing process and/or the steam or electricity produced is ordinarily available for sale to others) would probably fall into Class 49.13 entitled "Electric Utility Steam Production Plant" or 49.4 entitled "Central Steam Utility Production and Distribution", both of which involve production for sale and both of which prescribe lower limit lives of 22.5 years, the same lower limit life as that in Class 00.4. Another class, 49.15 entitled "Electric Utility Combustion Turbine Production Plant" which covers assets involved in production of electricity for sale by use of such prime movers as combustion turbines, diesel engines, gasoline engines and other internal combustion engines, does have a shorter lower limit life of 16 years. Accordingly, unless a possibility exists for inclusion in Class 49.15 or unless the output is so small as to be excluded from Class 00.4 (not a likely circumstance for any significant cogeneration project) the ownership arrangements and regulatory characteristics of the assets should not alter the availability of a 22.5 year lower limit life under the ADR system.

It is possible, however, to employ a useful life shorter than the lower limit life prescribed under the ADR System guidelines if the taxpayer

can make a showing of facts and circumstances sufficient to justify such shorter life. The considerations discussed on pages 22 and 23 above as to the actual prospective duration of the employment of the cogeneration system will affect this possibility.

The interest deduction which the Code permits generally does not require that the taxpayer be fully liable on the debt involved, but does permit the deduction of interest on debt secured by property in which the taxpayer has an ownership interest, even if the debt is non-recourse to the taxpayer. Similarly, tax credits and depreciation deductions can generally be claimed based on the full cost of property even if a portion of such cost has been financed by issuance of debt which is non-recourse to the owner of the property.

All of these tax benefits are significant only to the extent they can be employed to offset tax liabilities. If the party to whom the benefits are available has insufficient tax liabilities for offset, the benefits will be wasted. Moreover, since economic evaluation takes into consideration the time value of money, which is reflected in the use of a discounted cash flow method of analysis in which cash benefits received earlier in time are of greater significance than equivalent benefits received later, tax benefits availed of earlier will have greater impact than the same tax benefits availed of later. Thus, it is important to utilize tax benefits fully at the earliest point in time they become available.

Any participant owning a direct interest in project assets will be qualified to use the tax benefits associated with that interest. Any corporate subsidiary holding a direct interest in project assets will similarly be qualified to use tax benefits associated with that interest and, if its parent owns 80% or more of all voting stock and 80% or more of each class of non-voting stock, except stock which is limited and preferred as to dividends, that subsidiary will be able to consolidate for tax purposes with its parent and other members of the parent's consolidated group and thus make available tax benefits to offset taxable income of the consolidated group, regardless of the source of the income.

Though creditworthy corporations of the type likely to act as participants in a cogeneration venture will normally have within their corporations or corporate consolidated groups sufficient taxable income to permit full current utilization of tax benefits, there may be occasions when this is not so. For example, participants may have suffered operating losses resulting in tax losses or they may have a surfeit of tax benefits resulting from other investments and the limitations of the Code in respect of the employment of such benefits (such as the limitation on the use of the regular investment tax credit to offset more than a specific

percentage of tax liability*). In such circumstances, arrangements may be made to have a third party which has the capacity to absorb the tax benefits acquire ownership of project assets with the third party owner leasing the assets to the participant at a lease rental rate which provides savings to the lessee when compared to the cost of other financing arrangements. Usually the lessor and the lessee can both benefit by having the lessor borrow a major portion of the acquisition cost on a non-recourse basis, with the borrowing secured by a pledge of the asset and the lessee's unconditional commitment to pay lease rentals. This is generally referred to as a leveraged lease.

In circumstances where users cannot efficiently and fully employ all of the tax benefits stemming from ownership of project assets, leasing should be considered. However, there are a number of circumstances which may inhibit the ability to consummate a lease financing. They include the magnitude of the investment required and the tax rules associated with leasing.

As to the size of the investment, even a 25% interest in a major cogeneration project sized in accordance with the DOE study's model would exceed the amount of any previously consummated lease financing of a facility. This is not to say that there is not an adequate supply of funds to permit such a financing. In fact, under current conditions, there is an abundant supply of lease equity funds available for investment in equipment in large-sized energy oriented projects. However, the magnitude of the investment will serve to make the financing more difficult and more costly. To mitigate the problem it may be possible to lease only certain specified components of a project or, alternatively, to lease only an undivided interest in project assets. Creation of undivided interests in a project of this character normally also entails waiver by contract of the right of partition so that the owner of an undivided interest or any creditor with a lien on that interest is precluded from causing the entire facility to be sold in order to obtain cash proceeds, a portion of which will be applied to satisfy the obligation due to an investor. Such owner or creditor is normally limited to the right to sell the undivided interest holder's right to take its share of the proceeds of the facility which may include the stream of earnings and/or the share of output accruing to such interest.** This limitation on the right to realize the value of its investment may discourage participation by prospective lessors in a large cogeneration project. This restraint on the saleability of the lessor's interest may also pose a problem in assuring that the lessor will be

* The percentages of tax liability which may be offset by regular investment tax credits are 60% currently (70% for utilities), rising to 70% in 1980, 80% in 1981 and 90% thereafter.

** But see the footnote on page 66, below, which describes recent federal bankruptcy legislation which may impair the ability of the co-owners of a cogeneration facility to waive the right of partition.

accepted by the Internal Revenue Service (IRS) as the true owner of its interest and will therefore qualify to use all the tax benefits associated with its ownership interest.

The IRS has developed a complex series of requirements which must be met if a lessor in a leveraged lease is to be assured of receiving the tax benefits of ownership. These requirements, embodied in Revenue Procedures 75-21, 75-28 and 76-30, specifically pertain only where an advance revenue ruling is being sought. In practice, counsel have accorded these Revenue Procedures significant weight when formulating legal opinions as to the "true lease" character of an arrangement. This becomes an important factor even in a transaction which is being consummated in the absence of a revenue ruling request although some counsel consider some aspects of these Revenue Procedures as extremely conservative in light of recent judicial interpretations and, accordingly, do not feel that it is necessary for a transaction to be in accord with the Revenue Procedures in every respect. The requirements include (1) a minimum equity investment by the lessor of 20% of the cost of the asset throughout the life of the lease, (2) a maximum firm lease term equal to 80% of the asset's useful life, (3) a residual value at the end of the fixed lease (estimated, but without giving consideration to inflation or deflation) equal to at least 20% of the asset's original cost, (4) no lessee investment in the asset or guarantee of any debt through which the lessor has financed acquisition of the asset, (5) no options with respect to the lessee's purchasing the asset or renewing the lease which can result in the lessee acquiring use of the asset at less than its fair value at the time the option is exercised and (6) a profit to the lessor apart from tax benefits. A requirement which may pose difficulties in the case of a cogeneration facility is the prohibition of unwind provisions (requirements that the lessee purchase the asset under certain defined circumstances) which may be sought by a lessor as a protection against acquisition of a facility which does not perform its assigned functions satisfactorily. Of equal importance, the IRS requires a demonstration that the asset is not "special purpose", *i.e.*, that it is useful to someone other than the lessee. It may be possible to meet this requirement by arguing in appropriate cases that the other participants or third parties are potential users of the steam and electric output of the facility, but the IRS may resist where the steam supply, because of transmission limitations, may have an extremely limited market.

One aspect of the tax benefit timing problem is not readily soluble by leasing. During the construction period of any facility which has a construction period in excess of two years and whose owner has made an appropriate election under the Code, investment tax credits (including those attributable to alternative energy property) may be claimed as construction costs are incurred. In addition, interest on funds borrowed

and real estate and local taxes incurred during construction can be deducted as incurred. However, it is questionable whether such tax benefits can feasibly be transferred to a lessor during the construction period. Lessors, generally being passive investors, normally prefer not to take construction risks and normally will want to have their investment repurchased if development of the facility is not successfully completed. It is possible that such unwind provisions included in order to protect the lessor against noncompletion will preclude it from claiming such construction period tax benefits, making it necessary for those tax benefits to be availed of currently by the user participant itself or deferred until after the completion of construction.

Finally, while the investor participant acting as owner and lessor of project assets represents another source of capital, it is by no means clear that the use of such a lessor's capital fully relieves the user participant of the capital burden. Owner-lessors of project assets are normally passive investors in much the same sense that debt investors are. They normally seek fixed minimum yields from their share of lease rentals and the tax benefits they expect to derive with the principal variable being the value of the asset following the end of the initial lease term. Accordingly, it is a general rule, subject to few exceptions, that the owner-lessor will require the lease to be unconditional and to impose all business risks of development and operation of the leased assets on the lessee. The lessee may be a user participant or an entity in which the user participant has an interest. If any such entity is employed to act as lessee it is unlikely to have a sufficient credit substance on its own to satisfy the owner-lessor that it can bear the business risks imposed on it. Consequently the user participant in such circumstances is likely to be required to furnish its own backup assurances as an ancillary credit support in one of the forms described above.

If the user participant acts as a lessee directly, it will have to consider whether its commitments as lessee will be deemed to be like debt obligations for purposes of evaluating their impact on its credit and its capital raising ability under the three categories of accounting, credit agreement and credit analysis referred to above. For accounting purposes, primary attention would focus on the possible capitalization for balance sheet purposes of lease obligations under Statement of Financial Accounting Standards (SFAS) No. 13 which was adopted in 1976. Under SFAS No. 13, capitalization of a lease obligation, on the balance sheet, similar to debt, is required if the basic lease term exceeds 75% of the asset's useful life or if the lessee acquires ownership at the end of the lease term or has a bargain purchase option or if the present value of the lease rentals exceed 90% of the initial value of the asset less any investment tax credit retained by the lessor. Essentially, in order to

avoid the latter standard the lessor must accept a relatively low return on investment or rely upon its expectation of residual value of the assets at the end of the lease term to represent a significant portion of its overall yield.*

Even if not required to be capitalized, all lease obligations will be set forth by category in footnotes to financial statements. For purposes of most credit agreements lease obligations are normally not the equivalent of debt *per se*. However, if required to be capitalized under SFAS No. 13 they may be included within the meaning of "indebtedness" where that word is defined by reference to items required to be shown on the balance sheet under generally accepted accounting principles. Modern credit agreements will normally make specific provision for lease obligations, either providing a specific allowance for an amount of lease commitments which can be incurred over and above the permitted debt incurrence or by providing a mechanism for capitalizing leases and adding the capitalized amount to debt for purposes of applying debt tests and, in a similar vein, treating a portion of the lease rentals as fixed charges to be added to interest charges for purposes of applying coverage tests.

Credit analysts will take cognizance of lease rentals, not necessarily as the equivalent of debt, but at least as another type of fixed obligation which, if substantial in the aggregate, should receive some negative weight in analyzing a lessee's credit.

To the extent that a user participant acts not as a lessee directly but as the owner of an interest in an entity which is itself a lessee and/or as a supplier of credit support to the entity through an ancillary agreement, most of the considerations discussed above in the context of a user participant's indirect relationship to project debt will also be applicable. For example, the same rules with respect to consolidated accounting statements will apply so that, if the user participant is required to adopt full consolidation with that entity, all of the capitalized lease obligation will be disclosed on the user participant's consolidated balance sheet.

* Under the authority of the Addendum to APB Opinion No. 2, which recognizes that differences "... may arise in the application of generally accepted accounting principles as between regulated and nonregulated businesses because of the effect in regulated businesses of the rate-making process ...", lessees which are regulated utilities may not be required to comply with SFAS No. 13. The SEC, in Securities Act Release No. 33-5812 (March 2, 1977), initially sought to require such compliance but, after public comment, decided, in Securities Act Release No. 33-5860 (August 31, 1977), to require only footnote disclosure of the additional expense that would have been recognized, but for the Addendum to APB Opinion No. 2, had leases been accounted for as capital leases.

The accounting, credit agreement and credit analysis considerations for providing ancillary credit support of lease obligations should be similar to those applicable to direct debt obligations except that no greater weight should be accorded for each of these purposes to ancillary credit supports of a lease by a user participant than would be accorded to direct lease obligations if the user participant were the direct lessee.

Government Regulation

Both the utility and industrial participants will be anxious to avoid any organizational structure which will increase the jurisdiction of regulatory agencies over the project, over the participants or over the sale of steam or electricity generated by the project.

The production and sale of steam is unregulated at the federal level and is regulated in some but not all state or local jurisdictions. The production and sale of electricity is generally regulated at both the federal and state levels.

Federal Utility Regulation. On the federal level, where regulation is limited to electricity, utility regulation of cogeneration projects will result, if at all, by reason of the operation of either or both of the following statutes:

1. The *Public Utility Holding Company Act of 1935* (the 1935 Act), which is administered by the Securities and Exchange Commission, provides for the broad regulation of registered public utility holding company systems as to a number of matters, including issuance of securities, sales and acquisitions of certain assets and acquisitions of certain types of securities. Whether a potential participant is an industrial entity or a utility not otherwise subject to the 1935 Act, the imposition of regulatory jurisdiction under the 1935 Act would probably be sufficient to cause the potential participant to withdraw from a proposed cogeneration project.

Generally, any company directly or indirectly owning or controlling 10% or more of the outstanding voting securities of an "electric utility company" is a "holding company" and must register under the 1935 Act unless it can qualify for an exemption. An "electric utility company" (as defined in the 1935 Act) means any company which runs or operates facilities used for the generation, transmission or distribution of electric energy for sale, other than sale to tenants or employees of the company operating such facilities for their own use and not for resale. Upon application, the SEC is required to declare a company not an "electric utility company" if it finds that the public interest or the protection of investors does not require regulation and (1) such company is primarily

engaged in one or more businesses other than the business of an electric utility company, or (2) such company operates within a single state and sells its electric production to its parent for its own consumption and such parent is primarily engaged in manufacturing.

Even if jurisdiction under the 1935 Act cannot be avoided on the basis that a subsidiary is not an "electric utility company" within the statutory definition, the 1935 Act also provides for exemptions of both the holding company and its subsidiaries based upon various factors which include (1) the predominantly intrastate character of the operations of the holding company and its subsidiaries, (2) the holding company being predominantly an operating public utility company whose operations do not extend beyond the state in which it is organized and contiguous states, or (3) the holding company being only incidentally a holding company, being primarily engaged in non-public utility business and not deriving a material part of its income from public utility subsidiaries. It may be noted, however, that an exemption, once granted, must be supported by annual filings and is subject to withdrawal in the future if circumstances change.

The determination of whether a particular financing structure would result in initial or additional regulation under the 1935 Act is an extremely technical one which this report cannot address in detail and which requires careful consideration by counsel. Nevertheless, it is possible to observe that certain structural approaches are more likely than others to raise issues under the 1935 Act and that there may be ways to organize a cogeneration project which would not give rise to regulation under the 1935 Act. In this regard, it may be possible to obtain a no-action letter from the staff of the SEC, or even an order from the SEC if greater assurance is required, in order to eliminate any serious questions.

2. The *Federal Power Act*, which is administered by the Federal Energy Regulatory Commission (FERC) and provides for the regulation of public utilities as to jurisdictional assets (which would not include generation equipment, but might include certain transmission equipment), the issuance of securities under certain circumstances, accounting matters and rates charged for wholesale sales of electricity in interstate commerce. FERC regulation would have a number of ramifications. First, the rate charged for power would be subject to FERC jurisdiction; although a tariff is likely to become effective if reasonable and non-discriminatory, the presence of FERC regulation would introduce an element of uncertainty for the potential owners and users of a cogeneration project and also for passive investors looking to the project's revenues to assure them a return on and of their investments in the project. Secondly, with FERC regulation will come

limitations upon the return which potential participants can reasonably expect to realize upon investments in the project. Again, FERC regulation would mean that FERC's uniform System of Accounts must be followed with respect to the project. Finally, there is the possibility of regulation as to security issues and other matters.

State Utility Regulation. Most states also have public utility laws and have established public service commissions to regulate companies providing a public utility service within their jurisdictions. Normally, a company generating electricity for consumption in its own plant is not considered a public utility under state law. The matter becomes less susceptible to a categorical conclusion, however, where a generator of electricity also serves a number of other industrial customers. If public service commission jurisdiction is present, regulation is ordinarily pervasive and the public utility will probably find itself subject to substantial filing requirements and to close supervision of the pricing of its electric (and, if regulated, steam) service, of its accounting, of its ability to construct additional utility plants and other matters. Frequently, prior commission approval is also required for the issuance of securities. As is true in the case of federal utility regulation, the prospect of state utility regulation of a participant or a project would undoubtedly deter that participant from undertaking that project, unless the participant were already a public utility subject to commission regulation.

Recognizing these federal and state regulatory barriers to industrial entities' participation in cogeneration projects, the recently enacted national energy legislation included among its provisions Section 210 of the Public Utility Regulatory Policies Act of 1978 which attempts to correct the situation by instructing FERC to publish rules to exempt qualifying cogeneration facilities from the Federal Power Act (with certain exceptions), from the 1935 Act and from state laws and regulations, if FERC determines that such exemption is necessary to encourage cogeneration. The effectiveness of this provision will turn upon the scope of the implementing regulations issued by FERC. The same section also instructs FERC to publish rules to require public utilities to sell electric energy to and purchase electric energy from qualifying cogenerators at rates which are just and reasonable to the utilities' customers, which are in the public interest and which do not discriminate against the qualifying cogenerators. Such rates for the purchase by a utility of cogenerated electricity are not to exceed the incremental cost to the utility of alternative electric energy. Under Section 202 of the same statute FERC may, under certain circumstances, order the physical interconnection of any cogeneration facility with the transmission facilities of any electric utility. The definition of "qualifying cogeneration" in the statute is generally left to rulemaking by FERC for its substantive content except that

the statute calls for FERC to prescribe requirements respecting minimum size, fuel use and fuel efficiency and the term may not include a facility owned by a person primarily engaged in the generation or sale of electric power (other than power which is cogenerated or comes from small power production facilities).^{*} Rulemaking is also prescribed with respect to minimum reliability of electric energy service to be made available by utilities to qualifying cogenerators during emergencies. The statute also provides that no rules with respect to such purchases of electricity from or sales to a utility prescribed pursuant to its authority shall authorize a qualifying cogenerator to make any sales for purposes other than resale. All of the rules which the statute directs to be promulgated are to involve consultation with federal and state ratemaking authorities.

In addition to the above matters, other areas of regulatory involvement would be considered in the course of planning and implementing a cogeneration project. For example, the application of environmental regulations would be of considerable importance to a project, although they are not likely to affect the financing structure employed. Similarly, if a nuclear plant were involved, Nuclear Regulatory Commission action would be required. The 1935 Act, the Federal Power Act and state public utility regulation, however, will have the principal impact upon the design of a project's financing plan.

^{*} In defining "qualifying cogeneration facility" Section 201 of the statute excludes a facility which "is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities)." While a cogeneration facility which is wholly and directly owned by an electric utility would surely not be a qualifying cogeneration facility, it is unclear what effect indirect ownership, ownership of an undivided interest or ownership in a project entity by an electric utility would have in applying the statutory definition. Resolution of this issue may have a significant impact on the decisions of potential industrial cogenerators to participate with utilities in the joint development of cogeneration facilities. If electric utility participation in these forms precludes a facility from being included in the definition of a qualifying cogeneration facility, the effect will be to deny to the facility and its owners the benefits of exemption from regulation which may be provided by the statute as well as the statutory rights to compel sales of excess electricity to and purchase of backup electricity from public utilities and the opportunity to apply to FERC for an order requiring interconnection with electric utility transmission facilities.

BASIC ALTERNATIVES AS TO PROJECT STRUCTURE

Having set forth the background of the six primary underlying issues, it is appropriate to turn next to detailed consideration of the principal alternative organizational structures of a project.

A first possibility is for one participant to be the sole equity owner of the project with others purchasing project output and perhaps making additional contributions in respect of credit support and/or having some measure of management control. If this possibility is not selected the alternative is co-ownership in either an undivided interest format or through a co-owned project entity.

Sole ownership has been the principal approach employed to date in cogeneration projects but most of these projects have not had multiple industrial users of output. They generally have been of a modest size, have been designed to serve only a single industrial owner and have been owned either by that industrial company or by the public utility which served the area. One of the most notable early instances of multiparty cogeneration is the Louisiana Station at Baton Rouge, Louisiana owned and operated by Gulf States Utilities Company for about forty years and currently serving three industrial customers with steam service and cogenerated electricity while also producing electricity which enters Gulf States' overall supply grid.

Under current conditions, sole ownership of a large scale multiparty cogeneration project is unlikely to represent an attractive investment for each of the types of participants who might consider that possibility. The considerations will differ depending on the type of participant.

Sole Ownership by an Industrial User

From the point of view of an industrial user of the output of the project, the most serious negative factor is likely to be the consequences of governmental regulation as a public utility if sole ownership results in such regulation. Whether or not such regulation exists can depend on technical and legal considerations dealing with either or both the steam and electric outputs.

Steam. A preliminary question is whether the state or local jurisdiction regulates the production and sale of industrial steam as a public

utility function. Federally and in some states (*e.g.*, Louisiana) the production and sale of industrial steam is not a regulated public utility function; other states (*e.g.*, New York) do treat this as a public utility function subject to regulation. Even if steam production or sale is subject to regulation as a public utility function in the jurisdiction involved, it is necessary to consider whether the furnishing of steam by one company to a limited number of industrial customers within a limited area from a single production facility which also serves the owner's own steam requirements puts the owner in the business of serving the public so as to subject it to regulation. The answer to that question may depend, in turn, on the number of customers served, the size of the output provided to such customers and its relationship to the output consumed by the owner and upon the terms and interpretations of the specific statutes which define the imposition of such regulation. Formal considerations may have a bearing on the outcome, such as whether the industrial participant has formed a separate subsidiary corporation to own the cogeneration facility and is therefore technically purchasing its share of the output from that subsidiary or whether the industrial participant owns the cogeneration facility directly and obtains the output without a sale.

Electricity. The production and sale of electricity are functions which provide a basis for public utility regulation both federally and in all states. Whether the sole owner of a cogeneration facility becomes subject to public utility regulation by reason of a project's electricity output therefore depends on the particulars of how that electricity is disposed of and what the legal consequences of such disposition are. There are three possible fact patterns in respect of the disposition of electricity:

1. The owner utilizes all of the electric output itself, in which case there is no furnishing of service to the public and there should be no basis for regulation;
2. Some of the electricity is sold to a public utility for further resale, in which case the owner is likely to be subject to federal and/or local regulation as a public utility; or
3. All of the electricity is used by the owner and a limited number of other industrial customers; in this case the issue of whether regulation applies is one which depends upon an interpretation of the facts and applicable law in order to ascertain whether the sales constitute service to the public.*

As mentioned earlier, Section 210 of the Public Utilities Regulatory Policies Act of 1978, when implemented by FERC regulation, will probably

* Considered on pages 83 to 85, below, is the possibility of avoiding regulation under circumstances 2 or 3 above by assigning the electric generating function and the assets related thereto to an already regulated public utility.

go a long way to limiting the possibility of regulation in qualifying cogeneration projects.

If, on either a steam or electric basis or both, an owner were to be subject to public utility regulation, the consequences are generally thought by most companies not already subject to such regulation to be so severely adverse as to preclude their participation in the venture. This is true in spite of at least one favorable consequence of public utility status which can be very helpful in organizing a cogeneration venture — *i.e.*, the right to acquire by condemnation property to be used in providing the utility service. Such adverse consequences may include the inability to engage in the proposed activity without a franchise or certificate of convenience and necessity or other prior governmental approval. They also include the loss of full control over the regulated business, with the regulators having the power to require certain actions, to preclude others and generally to intrude into the management of a company's affairs based upon the regulator's perceptions of the requirements of the public interest and not merely the company's view of how it should act from a normal corporate profit-motivated orientation. For example, public utility status may carry with it an obligation to provide service to certain parties whom the owner would prefer not to serve, such as competitors. If a facility is operating and serving the owner and other customers, public utility status may preclude the owner, even if it is contractually free to do so, from curtailing service to other customers in order to increase or otherwise modify its own share of the output. It may even be compelled to construct new facilities to accommodate new load requirements of existing customers and may be precluded from terminating any service without regulatory permission. It may also be required to secure regulatory approval before it enters into certain contracts, builds certain facilities and issues securities. It may be required to issue securities in certain ways, such as through competitive bidding rather than through negotiation. Depending on the nature of the particular type of regulation, it may have far reaching consequences affecting the industrial company's other activities. The regulated entity may be precluded from engaging in other non-regulated activities (including possibly non-regulated steam generation and sale) if the electricity is regulated. Under the 1935 Act, if holding company status is incurred and an exemption is not procured, other non-regulated activities may be precluded even by affiliates of the holding company, not merely the regulated public utility itself.

In addition to loss of control, regulation normally entails increased public scrutiny of matters which, in an unregulated business, are free from public inquiry. This aspect of regulation is especially troubling to a company which is also engaged in non-regulated business activities, not

merely because of a general preference and predilection for secrecy, but because of the possibility that such public scrutiny may result in exposure of proprietary information to competitors or customers of the unregulated business. For example, inquiry for regulatory purposes in respect of the electric output of a cogeneration facility owned by an industrial company may entail undesired disclosure of plans to expand the owner's industrial facilities. Moreover, the public scrutiny associated with regulation involves a substantial administrative burden and expense which is normally thought of as not being economically productive to the party bearing the expense and therefore undesirable.

As seriously adverse as the foregoing consequences of regulation may be, the ultimate objection to regulation normally lies in the application of governmentally prescribed ratemaking in respect of the regulated activity. Such ratemaking is designed to limit the prices charged and the rate of return on investment derived to that which is "fair and reasonable" or some other similar standard. Returns on investment associated with utility operations are generally below those associated with industrial operations to the extent that even the maximum return on investment regarded by some regulators as reasonable for some utility operations may be below the minimum returns regarded as acceptable by many industrial companies.

While these differences in acceptable returns may in part be attributable to the different degrees of risk involved in utility and industrial operations, it is unlikely that it will be possible to bridge the gap merely by reducing the industrial company's return requirement on the assumption that a reduced risk is in fact being experienced. Indeed, to the extent that a cogeneration facility's usefulness is primarily dependent upon its continuing to serve a particular industrial operation, it probably should be considered to have the same risk characteristics as that industrial operation and not a lower degree of risk merely because it is legally classified as a public utility. Moreover, the regulatory process is sometimes thought to create an additional degree of risk through loss of control over pricing and other constraints which are not always offset by the quasi-monopoly characteristics which apply to some utilities. In any event, the return requirements for industrials are not merely arbitrarily established but instead are a reflection of their cost of capital. So long as an industrial company is perceived by its investors to be such, it will have a cost of capital which requires a higher return than a utility and consequently will have difficulty undertaking activities whose returns are governed by utility standards.

In a related vein, the relatively low returns on equity which normally are the maximum permitted for utilities are realized despite the low

depreciation factors and the high degree of leverage which are normally required by utility regulators but which may be inappropriate for industries. The differing approaches to depreciation have been discussed above. The differences in leverage are affected by differences in perceived risk but, as in the discussion of return on investment in the preceding paragraph, cannot necessarily be appropriately resolved by assuming that a lower degree of risk is applicable. Even a relatively strong electric utility is normally financed with a maximum of 50% long term debt (generally secured by a first mortgage on assets and having a term of 30 or even 35 years) as well as up to 15% of senior equity (normally preferred stock) leaving only about 35% of the electric utility's capital to be represented by common stock. In contrast, only relatively weak industrial credits have as much as 50% debt; that debt only occasionally has a final maturity in excess of 20 years and only very rarely in excess of 25 years. Such debt is more often than not unsecured. These differences are so substantial that it may be very difficult to convince a traditional utility regulatory body to accept an industrial company's capitalization in the context of ratemaking, but it would tend to impair the creditworthiness of an industrial company if it were compelled to include within its capital structure a typical utility capitalization for the assets of a regulated business which it owned.

Obviously, if a cogeneration activity is not subject to regulation and if all of the foregoing adverse consequences of regulation do not apply, the most serious impediment to ownership of a cogeneration project by a single industrial company falls away. This does not mean, however, that in the absence of regulation sole ownership is desirable or is a format in which such a project is likely to be organized. The desirability of such a format turns on a balancing of pros and cons. Among the positive considerations are the availability to the sole owner of all of the equity earnings and all of the tax benefits of the project, including, assuming the rates for the sale of the project output are not governmentally regulated, the full additional 10% tax credit which may be associated with the cogeneration project. If the industrial corporation were unable to use all the tax benefits promptly, it could act as sole lessee of some or all of the assets of the project. Sole ownership also implies having a large degree of management control over a project. Balancing such positive factors are the facts that the control normally implied by sole ownership may have to be relinquished in part to customers by contract and that sole ownership implies the full exposure to project risks (except to the extent that customers or others can be induced to accept such risks by contract). The most significant negative considerations, however, tend to surface when evaluating a project's economics and the employment of capital.

A sole owner will normally either fund all of the necessary capital itself or borrow all or a portion of it. For accounting purposes, by consol-

idation or otherwise, the entire cost of the facility represents a capital burden on the owner and, unless debt incurred can be borrowed in an unrestricted subsidiary, it will be charged against the owner under restrictive covenant tests in its credit agreements. The owner's rate of return evaluation will therefore normally be based on the entire cost of the facility rather than merely its equity share. While all of the equity return will belong to the owner, whether the return on that unleveraged capital base will be sufficiently high to induce the owner to make its capital commitment will depend upon the prices the owner charges to its customers. Even in the absence of governmental ratemaking, it is questionable whether most significant industrial customers will pay sufficiently high rates for utility-type steam and/or electric service to permit an owner to earn a full industrial-type return on its capital. The foregoing considerations are what eventually tend to make ownership by a single industrial user of an entire facility serving several industrial customers unlikely. If returns on an industrial investment basis are inadequate, no single industrial user will want to bear the entire capital burden of the project. If, on the other hand, the return is sufficient to attract such investment, the other industrial customers dependent on the facility's output are likely to be unwilling to forego their shares of those returns or to surrender the degree of management control which commonly derives from ownership and will probably insist on having ownership interests and control commensurate with their commitments to acquire output. This probable result is by no means automatic; sole ownership may evolve from various circumstances such as one industrial user requiring a significantly larger share of the output than each of the others or controlling key resources such as a prime site or a fuel supply or having a financial position or credit rating which dominates those of the other users. Nevertheless, it is highly likely, where a project is truly sized to accommodate the needs of a number of substantial industrial users, that no one of them will acquire sole ownership.

Sole Ownership by a Public Utility

If sole ownership by an industrial issuer is unlikely because of concern about regulation or otherwise, another possibility is sole ownership by a party already subject to regulation — *i.e.*, the public utility in whose service territory the facility is situated and which may desire to acquire a portion of the electric output of the facility for resale to its customers.

In many ways, this might be considered a "traditional" approach to cogeneration. The public utility company has the operating experience

with the electric generating equipment and, presumably, trained personnel to supervise both the fabrication and installation of the equipment during the developmental stage and to operate the equipment once installation is completed. Similarly, the construction and operation of large steam boilers is also part of a public utility's ordinary business experience. This would include the procurement, transportation and handling of a long-term reliable fuel supply and the disposal of the waste produced at the back-end of the boiler. Industrial entities, on the other hand, are not likely to have the same broad experience with large-sized steam production and electric generation facilities. Consequently, the "utility" aspects of a cogeneration facility militate in favor of operation by a public utility and, absent other considerations, would represent an investment in plant that a public utility might be traditionally expected to make.

But times have changed. Many utilities now shy away from assuming financial burdens of the magnitude represented by large-sized cogeneration projects. In part, this is due to the strain placed on their financing capabilities by rapidly escalating costs and lengthened lead-times in bringing new plant on line, and regulatory lag in obtaining needed rate relief. Unless a cogeneration facility is likely to produce a substantial quantity of electric energy which is surplus to the requirements of the industrial customers taking steam from the facility, a utility may be reluctant to take on the burden of financing the entire facility.

A utility evaluating sole ownership of a cogeneration facility will consider a number of matters when making its decision. One of its principal concerns will undoubtedly be the magnitude of its financial commitment to a large scale cogeneration facility in terms of the utility's projected internal and external sources of funds and other projected construction expenditure commitments. Many utilities have announced construction programs which will double their total assets over the next five years — and this continues to be true even in light of indicated curtailments in such programs. To the extent that reduced load forecasts, however, may provide a basis for additional financing capability, such utilities may find a renewed interest in positioning themselves — through the installation of cogeneration facilities — as the primary power and steam supplier to major industrial entities located in their service area.

Related to the question of the size of the construction financing requirement is the question of regulatory ratemaking considerations affecting construction financing. Some regulatory agencies permit construction work in progress (CWIP) to be included in a utility's rate base without an offset for the related allowance for funds used during construction. Where this is the case, a utility will be more inclined to undertake construction of a cogeneration facility, since it will be able to earn

upon its investment during the construction period and not have to wait until commercial operation of the facility to realize cash revenues. On the other hand, where CWIP is not included in rate base, or is included on a basis where the utility is not in a position to realize additional cash flow during the construction period, the major investment in a facility such as a large-sized cogeneration project, which may have a substantial lead time, may be an investment which the utility would wish to avoid.

The problem might be alleviated by the industrial users making contributions in aid of construction, which would later be reflected in lower rates or which would be reimbursable during the operating period. The objection to this, however, is that industrial users prefer not to surrender the perceived advantages of ownership while, at the same time, providing from their own resources the capital to finance construction. Such a solution, by settling on the industrials the principal funding responsibility, may remove, in their view, one of the principal incentives for utility ownership — *i.e.*, by assuming financing responsibility for the project, the utility would otherwise permit the industrials to employ their capital more fruitfully elsewhere.

Another approach which has received a great deal of attention in recent years is the employment of a construction entity (such as a subsidiary corporation or a trust) to assume responsibility for the CWIP. The construction entity might externally finance the entire cost through debt, with those providing the debt looking to an obligation on the part of a project's sponsor to buy back (or perhaps lease) the facility by the earlier of a specified date or commercial operation. A significant difficulty with such construction vehicles, however, has been the position taken by the SEC (most recently in Staff Accounting Bulletin 28) and the accounting profession that the obligation of a project's sponsor to the construction entity represents an obligation in the nature of debt and should be so recorded on the sponsor's financial statements. If faced with this possibility the utility will be concerned about its capitalization ratios being thrown out of proportion, a circumstance which would tend to increase the utility's overall cost of capital.

In addition to the broad issue of the availability of financing capacity, the utility will probably also be required to establish, to the industrial users' satisfaction, that the utility can provide the steam and electric power at a cost which is competitive to that which the industrials could hope to realize if they proceeded on their own. In this regard, the utility has the advantage of (1) a capital structure which traditionally employs a higher level of cheaper debt capital, (2) an approach to the booking of depreciation charges which tends to recover investment in plant over a longer period of time than that typical in the industrial sector and (3) the lower return on equity which is commonplace in the utility industry.

The utility will also be required to determine the implications of undertaking a cogeneration project under its first mortgage bond and debenture indentures and its charter. Under its first mortgage bond indenture, the utility will wish to establish the impact, if any, which the project may have in terms of existing and future earnings coverage ratios. If these ratios are seriously impaired, this may in turn affect the utility's ability to issue additional series of first mortgage bonds to finance its other activities. Similarly, CWIP may be excluded from the definition of bondable property* under the utility's mortgage, thereby restricting the ability of the utility to issue additional bonds while constructing the cogeneration project. If the utility has a debenture agreement, that indenture may also have stringent earnings coverage and funded debt incurrence limitations. Also, the utility has to be conscious of the impact which involvement in a cogeneration project may have upon its ability to issue senior equity securities (such as preferred stock) under its charter. Again, earnings coverage ratios are generally applicable.

Surprisingly, these instruments normally operate only on a corporate basis and, if the utility were to organize another entity to own the CWIP, that other entity's debt might not be counted against the utility for purposes of the earnings tests. As indicated above, however, the structure of the utility's obligation with respect to the facility at the end of the construction period will have accounting consequences, which may in turn have an impact in terms of the debenture agreement and charter provisions.

As indicated elsewhere in this report, cogeneration facilities fired by a fuel other than gas or oil may be eligible for a 20% investment tax credit, unless such facilities are "public utility property" as defined by statute. Where a public utility company owns a cogeneration facility and operationally integrates the electric portion of the project with its system, it may lose eligibility for one-half of this tax credit, possibly in respect of the entire facility and not the electric portion alone — a result which would have a major impact upon the economics of the project. Consequently, the tax implications may militate against utility ownership. In addition, some utilities have experienced an erosion in earnings to such a degree that they cannot fully and efficiently absorb the tax benefits flowing from a cogeneration project. To the extent this is the

* The concept of "bondable property" in utility mortgages relates to the principle that a utility is ordinarily permitted to issue first mortgage bonds up to a specified percentage of the value of certain qualifying property additions; this helps to assure bondholders that the collateral (*i.e.*, the certified utility plant) supporting the bonds will not be less valuable than the aggregate amount of bonds outstanding. If an asset is precluded from being "bondable property", the investment in the asset cannot be certified to the first mortgage trustee and thus cannot be used to support the issuance of additional first mortgage bonds.

case, it provides an additional reason for the utility not taking an ownership position.*

The utility will be anxious to avoid additional regulation. To the extent that it creates an additional entity for the construction period, it may — especially if the entity is also empowered to operate the cogeneration facility — encounter problems under the 1935 Act.

To the extent that the utility's ownership and operation of the cogeneration facility may be regarded as outside the scope of regulation, as for example if the furnishing of steam were regarded as an unregulated activity, the opportunity to earn a return from that activity which is higher than that permitted by regulated ratemaking may appear as an attractive opportunity. However, it is an opportunity fraught with hidden snares to the extent that it eventually proves difficult to segregate regulated and unregulated activities, even where the 1935 Act permits both to be conducted. Governmental regulators have a tendency to try to reduce the allowed rate of return from regulated activities when higher profits are available from affiliated unregulated activities. When the two activities share common costs or facilities a searching inquiry may be made to assure that costs are properly allocated, with regulators tending to resolve doubts by penalizing the unregulated activity. This may go so far as to amount to indirect ratemaking for the unregulated activity by basing an allocation of costs on a finding of the reasonable return from that activity and assigning costs so that no more than that return is achieved. Needless to say, such an intrusion of regulation does not carry with it any reciprocal prospect that losses sustained in the unregulated activity will be recoverable through ratemaking in the area of business subject to regulation.

Summarizing the prospects for a utility assuming sole ownership of a large scale multiparty cogeneration project, while industrial customers would normally be pleased to have a utility undertake such responsibility and charge reasonable rates for service, the major difficulty currently is in finding a utility which is both capable and willing to do so. The willingness and ability of a utility to act will diminish as project size increases. With respect to large scale projects, though not beyond the competence of some large and financially sound utilities and therefore a practical possibility, in most cases sole ownership by a utility is unlikely.

Sole Ownership by Other Participants

Most of the considerations adverse to sole ownership by an industrial user also apply to sole ownership by others such as contractors or pas-

* However, it would not preclude the utility acting as sole lessee of some portion or all of the facility.

sive investors, who also normally lack the overriding inducement of the need for project output.

Passive investors are extremely unlikely to accept this role if to do so would entail the assumption of project risk and exposure to regulation which are normally associated with sole ownership. Only if such consequences can be reduced to a minimum, as is normally the case with the equity investors in leveraged leases, would such involvement be feasible. However, to achieve such protection for the passive investor requires other participants to assume responsibilities which make a characterization of the structure as sole ownership only nominally correct.

Contractors are somewhat more likely to assume a true sole ownership role but the likelihood of this eventuating in the case of a large scale project is small. Even if they were willing to assume the burden of such ownership most erectors and design and engineering companies lack the financial strength to fulfill such responsibilities. Some, however, are not capital intensive and/or are privately owned and therefore may be willing to absorb the balance sheet effect of project debt if the credit can be supported through ancillary agreements provided by others. Contractors, like other non-regulated parties, would be unwilling to assume the burden of regulation by reason of this participation.

Though prospects of ownership by any one party — be it an industrial company, utility, contractor or passive investor — exist and should be explored, the likelihood is slim in a large scale cogeneration project with significant use of product by more than one industrial company and it is therefore desirable to consider in some detail the possibilities of alternative arrangements involving multiparty ownership.

Multiparty Ownership

Undivided Interest Approach. The first of the two approaches to multiparty ownership is the undivided interest approach. This refers to a structure in which participants with ownership or leasehold interests in the project hold those interests either in the form of an undivided interest as tenants-in-common in the project assets or in a wholly owned subsidiary which itself holds such an undivided interest in the project assets.

The essence of the undivided interest approach is that each participant with a property interest in the project is responsible for funding its respective share of the cost of the project assets. As in the sole ownership approach, each participant electing to acquire a property interest in

the project bears the full capital burden of that interest in accounting, credit agreement and credit analysis terms. All of the costs of financing the project will be separately determined based upon the separate financing decisions and creditworthiness of each of the participants. None of such financing costs will be determined on a common basis by more than one participant.

Whether it owns project assets directly or through a wholly owned subsidiary, a participant under the undivided interest approach is obligated to fund its share of project development as funds are required and normally as funds are called for by the participant serving as the project's development manager. The risk of non-completion is normally borne by the participants either by making calls on their capital which are unlimited in amount (thereby assuring, within the limits of their resources, all of the funds necessary to complete) or by limiting their capital commitments (as for example by holding their interest through a subsidiary with a limited amount of capital) and thereby exposing the capital they invest to risk of loss if it proves to be inadequate to complete. Each participant is free to determine its own means of financing its share of project cost and each participant's decision in that respect is independent of that of the other participants. Participants may choose to fund their shares out of internally generated or externally raised funds or any combination of the two. A participant may or may not (depending upon the terms of its arrangements with the other participants) pledge its undivided interest in the project as security for loans, but even if such interest can be pledged, the right of partition is expected to be waived so as to preclude a creditor foreclosing against any one participant from having the right to sell all of the project assets in order to realize cash proceeds representing its debtor's share. The creditor is limited to selling an operating share in an ongoing business so as not to disturb the ability of the other holders of undivided interests to continue to enjoy their shares of the project's production.*

* The ability to enforce a contractual waiver of a co-owner's right to seek partition of its undivided interest in property has been clouded by the enactment of new federal bankruptcy legislation during 1978. Section 363 of this legislation provides that a trustee in bankruptcy "may sell both the estate's interest . . . and the interest of any co-owner in property in which the debtor had, immediately before the commencement of the case, an undivided interest as a tenant in common, joint tenant or tenant by the entirety, only if:

1. partition in kind of such property among the estate and such co-owners is impracticable;
2. sale of the estate's undivided interest in such property would realize significantly less for the estate than sale of such property free of the interests of such co-owners;
3. the benefit to the estate of a sale of such property free of the interests of co-owners outweighs the detriment, if any, to such co-owners; and
4. such property is not used in the production, transmission, or distribution, for sale, of electric energy or of natural or synthetic gas for heat, light, or power" (emphasis added).

Thus, the participants holding an undivided interest in a cogeneration plant may be able to protect themselves against a distress sale of the entire facility only if they can establish that one of the above criteria cannot be met. In this regard, the fourth criterion may not be available if the production of electricity is not "for sale" — i.e., if the owners intend to use all (or perhaps a very substantial portion) of the electric, as well as steam, production.

From an accounting viewpoint each participant owning an undivided interest in project assets will show as an asset its investment in the project, net of any appropriate book depreciation. To the extent that any debt has been arranged to fund the acquisition of the participant's share in the project, that financing will be reflected in full as a liability on the participant's balance sheet. If the interest of the participant in project assets is that of a lessee, appropriate treatment as such will be required under generally accepted accounting principles including SFAS No. 13.

Should a wholly owned subsidiary of the participant own an undivided interest in project assets, the participant will normally have to consolidate that subsidiary's accounting with its own and show the same consolidated picture as if it had owned the undivided interest directly. Securities issued by the subsidiary in respect of the project will also be fully reflected on the participant's balance sheet, whether or not there is recourse to the participant and whether or not secured by the subsidiary's undivided interest in the project.

Credit agreements of a participant will normally operate so that the participant's undivided interest in the project will be considered an asset and the income derived therefrom will be considered income available to cover fixed charges, while debt financing incurred in respect of the project will be treated as "indebtedness" and the fixed charges associated with such debt will have to be covered by an appropriate multiple of income for purposes of the various restrictive covenant tests contained in those credit agreements.

If the participant's interest is held through a subsidiary, the significance of the project and associated debt under the participant's credit agreements generally will depend on whether the subsidiary is "restricted" or "unrestricted" for purposes of such agreements. If restricted, both assets and debt will generally be counted as those of the parent. If unrestricted, neither will count, except to the extent that the parent's liability in respect of any ancillary credit support agreement might cause the parent to be charged with the consequences of such debt for the purposes of applying restrictive covenant tests.

Credit analysts, including rating agencies, will generally regard holdings of undivided interests and associated debt financing as they would any other assets or liabilities of the subject company, even where held through a wholly owned subsidiary, unless debt financing of the subsidiary is non-recourse, in which case the subsidiary's debt may be disregarded (although its asset holdings are likely to be disregarded as well). It will normally be necessary for a parent to provide some ancillary credit support to a wholly owned subsidiary, in which event credit analysts would give consideration to such credit support in accordance with the principles discussed above.

As has been stated above, management arrangements are only partially defined by decisions as to basic organizational structure and even that partial definition can be modified through contractual arrangements. This is particularly true in terms of the undivided interest approach. Though this approach entails ownership of undivided interests by participants with the implication that direct ownership of such interests implies a control over the share of the assets so owned, including a freedom to dispose or not to dispose of such assets in the discretion of the participant, in practice the terms of a negotiated joint construction and ownership agreement will define those and other management control rights. As previously noted, such agreement will normally include a waiver of the right to seek partition and may, as well, do the following:

1. Modify the requirement of unanimity normally associated with tenancies-in-common with a resulting veto right for each participant to one based on voting in accordance with shares of interest in the venture with vetoes not being available except in narrowly defined circumstances. Alternatively, it is possible to have *per capita* voting, with each participant having an equal vote regardless of its percentage of ownership. Other variations or combinations of voting are also possible. In addition, certain management responsibilities may be vested in certain parties free from control by all of the owners. For example, an operator may be designated to take charge of construction and/or daily operation and the operator may be free to exercise control of those functions. There may or may not be limitations imposed on the operator and the operator may or may not be subject to owner control and/or removal, depending on the agreement of the parties. These limitations, for example, may even permit the operator to effect certain changes in the services provided by the venture or the pricing thereof.

2. Limit dispositions of interests to third parties, either on the basis of outright prohibitions or by imposing requirements of the prior offer of such interests to other participants. Such limitations may, but do not necessarily, have the effect of limiting financing of a participant's interest by precluding the mortgaging or the sale and leaseback of such interest.

3. Provide for expansions of service upon the decision of less than all of the owners, thereby modifying the conventional requirement of unanimity associated with tenancies-in-common. If such expansion requires additional funding, the agreement may require each participant to provide its proportionate share, though it may also provide that an owner can decline to provide funds and that other owners providing funds in that owner's stead gain a greater proportionate interest in the expansion and/or in the project as an entirety.

In short, though the separate interest participation format implies that each participant will retain a fundamental element of control, those control rights may be partially or entirely bargained away in the process of initially organizing the venture.

With regard to the regulatory effect of choosing the undivided interest approach, as indicated previously the principal areas of regulatory concern focus upon the 1935 Act, the Federal Power Act and the state public utility statutes. Jurisdictional considerations under the latter two bodies of law would not turn upon the structure employed, but would rather look to the nature of the activity (steam or electric generation and sale) involved. It has not been the practice under the Federal Power Act or any state statutes with which we are familiar to construe joint ownership of a generating facility on an undivided interest basis as giving rise to a sale by one of the tenants-in-common where such co-tenants take the output of the facility in direct proportion to their ownership interests. (This construction appears to be applicable even if there are temporary variations in shares of off-take which are subject to later adjustment.) While it is possible that some jurisdictions might deem sales to take place in cases of undivided joint ownership, before regulatory jurisdiction would attach it would normally also be necessary to deem those sales as having been made to the public. Whether such sales as among co-owners will be considered public sales depends on the specific facts and the law of the pertinent jurisdiction. If confined to a limited number of industrial co-owners whose shares of off-take generally correspond with their ownership shares, there is little reason to expect a finding that such activity involves a public sale since policy considerations do not require regulation to protect such industrial co-owners as consumers of the output. If a utility shares co-ownership there is a greater risk that there will be a finding of a public sale or a sale for resale, either of which findings could result in the imposition of regulatory jurisdiction.

The 1935 Act regulates certain public utility holding companies and their subsidiaries. Thus, employing a financing structure such as an undivided interest approach which avoids a holding company-subsidiary company ownership structure may remove an enterprise from SEC regulation under the 1935 Act. However, even an undivided interest approach, if ownership is vested in a subsidiary, may involve a holding company-subsidiary company format.

When analyzing the applicability of the 1935 Act, the first issue posed is whether the entity owning the facility is an "electric utility company" — *i.e.*, a company which owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale. Even if the entity is an "electric utility company", one of several exemptions may be applicable. Section 3(a)(3) of the 1935 Act offers what is perhaps the most promising exemption for an industrial cogenerator. Under that section, an industrial company having a 10% or greater voting stock interest in an electric utility company may apply for an exemption if it is only incidentally a holding company, being engaged in one or more busi-

nesses other than that of a public utility, and does not derive a material part of its income from public utility subsidiaries. As has been noted above, exemptions must be applied for, are subject to annual filings and may be revoked by the SEC at some time in the future. Thus, the existence of these exemptions mitigates, but does not completely eliminate, the fear of industrial cogenerators that they may become subject to 1935 Act regulation as a result of their participation in a cogeneration project through wholly owned subsidiaries. It was to eliminate this concern that Congress enacted Section 210 in the Public Utility Regulatory Policies Act of 1978, which has been discussed earlier. In this regard, FERC's implementing regulations, which must still be promulgated, will determine the terms and scope of the exemptions afforded industrial cogenerators.

In addition, the 1935 Act will also tend to influence utility participants who are not already subject to the 1935 Act to take their ownership interest directly, and not through a generating subsidiary, if the revenues from the cogeneration project are likely to be substantial. Otherwise, their participation in the cogeneration venture may trigger an additional (and quite onerous) layer of regulation — a result few, if any, would accept.

Project Entity Approach. The essence of the project entity approach is that each participant, either directly or indirectly through a wholly owned subsidiary, owns an interest in a newly formed entity which in turn holds a property interest in the project assets.

The principal objective of this approach is to insulate the participants to some degree from the venture. In addition to certain changes which the interposition of the entity causes in the regulatory posture of the participants and in certain mechanics as to their utilization of tax benefits, its main significance is financial. The principal financial objective is to shield the participants from the accounting, credit agreement and credit evaluation impacts which might otherwise result from third party funding of debt. The project entity serves as the vehicle through which third party funding of the venture is arranged and such funding will generally be due to the participants acting in combination rather than separately.

Funding obtained from third parties through a project entity will normally have a uniform cost which is common to each participant regardless of its credit or other contribution to the fund raising effort. Such funding, normally in the form of debt, but possibly also equity or lease financing, is likely to have a different cost from that which an individual participant would pay if it obtained funding directly. Any such third

party borrowing or lease financing will also generally look to the participants for ancillary credit support since the new project entity will have limited financial substance, lack a history of earning capability and will therefore be unable to protect lenders adequately on its own from the development and operating risks of the venture. Since some participants may find financing in combination with other participants through a project entity to be more expensive than financing directly on a separate basis, and since such participants will in any event be expected to provide ancillary credit support to make the financing feasible, they will wish to explore carefully the purported advantages of a project entity approach.

The amount of any borrowing undertaken by the new project entity directly will normally not exceed the collateral value of the assets involved. The relationship of the collateral value to the amount borrowed can be improved by reducing the percentage of the cost borrowed and increasing the amount of equity invested in the new entity. This will have the effect of reducing the amount of leverage employed and depressing the expected rate of return calculated on the equity investment base. The appropriate percentage of equity in a particular case will vary depending upon the degree of comfort which can be established in respect of the lenders' ability to realize the anticipated collateral value of the assets and upon the weight accorded to any ancillary credit supports which are provided.

Even with a relatively high percentage of equity invested, the collateral value of a cogeneration project is unlikely to provide a sufficient measure of protection to lenders to permit them to dispense with ancillary credit supports. This is because collateral value is likely to be measured primarily in terms of the ability of the assets to earn revenues when operating. Though the components of a cogeneration plant may have some meaningful resale value if disassembled, it is likely that the expenses of transporting the components to the site and assembling them together in a configuration designed to provide the expected steam and electric output required by the participants, the value of which expenses would be lost if the plant were disassembled and moved, would represent a significant portion of the total investment in the project. Both the collateral value and earning power of a cogeneration project depend therefore on the ability to complete development on an economic basis (the development risk) and maintain operations on a profitable basis (the operating risk). The new project entity, with no operating history or surplus funds or other assets to support its assurances, is unlikely to be able to satisfy lenders on its own. Consequently, assurances as to these matters will have to be sought from others, principally the participating sponsors which will have ownership interests in, and be the principal customers of, the project entity.

Lessors will generally also require assurances of a similar type but with more urgency since they will not have the same cushion of equity investment by project sponsors to support their investment as do lenders to the project entity.

Assurances necessary to attract debt capital or lease financing from third parties can take any of the forms of ancillary credit support discussed earlier, including principally (1) guarantees, (2) keepwell agreements, (3) unconditional performance or purchase agreements, (4) remotely contingent commitments or (5) a combination of several different commitments, each with a broad commercial type of exculpation. As mentioned above, each of the first four types of assurances carries with it, to some degree, the possibility of being characterized as the utilization of the obligor's credit in one or more of the accounting, credit agreement or credit evaluation senses. The fifth approach, that of dividing the risks among the parties in such a way that no one party is liable under all anticipated circumstances but at least one responsible party is liable in each such circumstance, seems to offer the least exposure. This approach would be exemplified by a so-called commercial take-or-pay agreement under which one party is committed to purchase plant output at prices adjusted so as to be sufficient to meet debt service requirements, but only if the plant is operating and output is tendered for sale. Another party may be obligated to maintain plant production and/or to provide insurance adequate to service the outstanding debt against all events which might result in a termination of production from the plant. Because the functional responsibility is divided among several obligors, it becomes extremely difficult to charge any one of them with having employed its own credit. For accounting purposes, the obligation of each should be so conditional as to escape treatment as debt. (However, even if the condition associated with the obligation is regarded as a normal commercial contingency, if the resulting obligation is sufficiently material it may require footnote disclosure.) Such obligations should be so close in both form and substance to ordinary course of business obligations as to avoid characterization as "indebtedness" under even the broadest definition of "indebtedness" contained in a credit agreement and should also escape treatment as a fixed obligation by rating agencies or other credit evaluators.

A major difficulty with the divided responsibility approach is the extreme difficulty in finding acceptable methods of avoiding indebtedness characterization under the credit agreements of each of several parties and then persuading them to accept risk exposure on that basis. The more parties involved in the allocation of such risks, the more difficult

the task of developing a credit structure acceptable to lenders or lessors.

Moreover, co-venturers who are called upon to provide ancillary credit support for the financing of a project in which each has an equity interest will prefer to share the same risks and not wish to be liable for the entire project in the event of the occurrence of specific circumstances. Thus, despite the advantages of creating a mosaic of different types of liability covering all risks, it may be necessary to find a single form of agreement covering all risks which accommodates the interests of each participant to the greatest practicable extent.

Assuming that such a common ground can be found, each participant is likely to seek to limit its liability, on a several basis, to a share proportionate to its equity interest in the venture. Several liability means that each obligor fulfills its responsibility when it discharges its defined proportion of the total obligation. It should be distinguished from joint and several liability which means that each obligor is fully liable for the entire obligation but can obtain reimbursement from the other obligors should it pay more than its proportionate share to a third party creditor.*

Corporations are normally reluctant to assume joint and several financial obligations which they regard as the equivalent of guaranteeing their co-venturers' shares of an obligation. Despite this attitude, joint and several responsibility can be justified because each co-venturer is simultaneously extending its obligation to cover its co-venturers' shares, thereby mutually strengthening the credit of the obligation being issued by the jointly owned entity. Further justification can be provided by the fact that the equity investment of each co-venturer in the entity will be at risk in the event of a default by any other co-venturer in the performance of its supporting obligation since the entire interest of the entity in project assets will be pledged to support the entity's debt or lease. Even a partial default in the payment of the debt, attributable to only one co-venturer's failure to perform its obligation, will result in the lenders having rights to proceed against the entire collateral, disposing of the entire asset (thereby eliminating each participant's equity stake) and requiring performance by each co-venturer to discharge fully its respective share of the supporting obligation until the lenders are made whole. Even with several liability only, each participant will have an economic inducement (though no legal obligation) to cure defaults by its co-ven-

* Joint liability, which would rarely be adopted, means that each obligor is fully liable but cannot obtain reimbursement from the other obligors.

turers in the performance of their supporting obligations to avoid its own interest being lost. Of course, if the difficulty is not peculiar to the defaulting participant but stems from the failure of the project, the economic incentive of non-defaulting participants to cure the default of a co-venturer is substantially reduced, if not altogether eliminated. Consequently, even if interest savings may accrue from the use of joint and several obligations and may tend to justify that approach, the willingness of co-venturers to employ that approach should depend upon their confidence in their ability to avoid project failure.

Lenders and lessors not only prefer joint and several obligations because of the overlapping coverage which they afford but tend to look skeptically at obligations which are several and not joint because of the multiplication of opportunities for default which they create. When obligations are several, lenders and lessors may evaluate and price such credits not on the basis of the average credit among the obligors, but rather at something below the average to reflect the probability that any default which occurs will be associated with the weakest credit involved in the transaction. In contrast, joint and several obligations should be evaluated at the highest credit level involved (or arguably even higher because of the further assurances provided by multiple coverage of the same debt).

In practice, the pricing of debt or lease obligations supported by multiple credits depends on the differences and weightings of the respective credits and cannot be formularized but in each case will be derived on a composite basis which may be an average or more or less than an average. For example, minor credit deviations may be disregarded; if three strong credits represent 90% of a project's support, the presence of a weak credit representing the balance may be substantially disregarded by lenders relying on the supposition that, because the strong credits' share of the project will be part of the security for the entire debt, the strong credits will likely make up any deficiency in the weak credit, even if not legally required to do so.

Should there be some weak credits involved or should the lenders require an interest rate differential simply to reflect the greater probability of default associated with several obligations, it is possible for the parties to overcome the interest penalty, even without resort to full joint and several liability, by adopting a limited joint and several liability, that is, each party might be severally liable for a greater percentage of the total obligation than its proportionate share of ownership of the entity. For example, each might agree to be severally liable for 120% or 150% or 200% of its proportionate share of ownership. A 20% participant

agreeing to be severally liable for 150% of its ownership share might thus become legally obligated with respect to as much as 30% of the total obligation. This is a means of achieving coverage of a greater proportion of the entity's obligation by better credit rated parties and keeping the commonly determined interest cost of the obligation at the lowest attainable level. To the extent that such obligations are reflected in financial accounting statements, the fact of more than several liability, though possibly deserving of disclosure, should not increase the recorded amount of the liability so long as there is a right of contribution from a responsible party, even if that party has a lesser credit rating. On the other hand, joint and several liabilities may be deemed under credit agreements to be equivalent to the incurrence of the full amount of the obligation. This should emphasize the need for selection of a form of credit support which will not be treated as "indebtedness" for this purpose.

In addition to a general aversion to supporting another party's obligation, another objection which some parties will have to joint and several or overlapping several obligations in excess of their ownership share is that they are conferring a benefit on their co-participants by allowing the use of their credit to bring about a lower interest cost without receiving anything in return. A higher rated credit may therefore ask for some compensation for the benefit thus conferred upon the lower rated credit, and such compensation may take the form of a specific charge related to the interest saving experienced by the lower rated credit or it may be reflected in some other element of the arrangements between the parties, for example, different pricing arrangements in respect of the purchase of the output or, in less quantifiable terms, in respect of priority rights to purchase output or special rights in respect of management control. The same argument for special compensation or other consideration for a higher rated participant can be made, as well, when only several liabilities are employed, for in these circumstances the lesser rated credit still benefits from the credit contribution which the higher rated credit makes. In other words, if higher rated and lower rated credits severally support a single obligation, the composite credit should carry an interest or lease rate which is lower than the lower credit rating, acting on an individual basis, would command in the market. The lower rated credit here does not benefit as much from the several participation in the credit of the higher rated company as would have been the case if the credit had been joint and several, but it does derive some interest cost saving for which the higher rated company may seek to be compensated.

It is also possible to arrange debt or lease financings for a project entity which reflect the separate credit contributions of each of the par-

ticipants and thereby determine separate costs attributable to each participant's individual credit. This could be done, for example, by dividing a proposed debt financing into several components, each of which would be secured by the separate ancillary credit support of a particular participant and each of which would have a different interest rate based upon the efficacy of its own credit support. This separate pricing of credit could then lead to specific adjustments in the price of the output of the project for each participant. Relating such a separate credit cost specifically to a pricing benefit in terms of production tends, however, to facilitate charging each participant with an identifiable share of the credit consequences of the issuance of debt by the project entity, thereby undermining one of the principal objectives of employing the project entity.

Returning to the question of the percentage of equity which it is appropriate for the owner of an interest in a project entity to invest, the answer in a particular case will turn upon an evaluation of all of the credit factors involved. To reiterate, they are the value of the assets owned by the project entity and the strength of the ancillary assurances provided by the entity's owners, with the latter generally carrying more weight than the former.

Before development of a project is completed the collateral value of the assets will be of minimal significance. Once the assets are operating, asset value will be determined by an evaluation of (1) what the assets would command on a resale basis if disassembled or removed, (2) what the assets are worth in place and operating to users of output, including both the initial sponsors and purchasers of output and potential substitute purchasers, and (3) the degree of risk associated with the prospect of the venture being unsuccessful to the point of having to dispose of the assets on either a disassembled or in-place basis. While an evaluation of the project assets on the foregoing bases is a necessary and fruitful exercise, it is unlikely that a grass roots cogeneration venture will attract any meaningful debt investment without ancillary credit support. Prior to completion of development ancillary assurances as to completion are almost an absolute necessity irrespective of the percentage of equity invested.* Subsequent to completion the possibility of loans to a project entity conditioned on equity investment of a significant

* On occasion, sponsors may induce banks to lend funds to a project entity during the development phase without an explicit completion commitment from sponsors or other creditworthy parties, but such loans are normally based upon a sponsor investment of substantial equity, say 50% of cost, and a preexisting relationship between the banks and the sponsors which may entail a tacit commitment on the part of the sponsors to complete. The lenders will probably also have evaluated the risks of non-completion as less than average, based on the technology and contractual commitments involved.

percentage of the cost, say 40%, improves, but any such loan unsupported by ancillary credit agreements remains unlikely at least until the project entity has established several years of profitable operating experience and has earned some cash reserves.

Ancillary credit supports from creditworthy parties can diminish or eliminate lenders' concerns as to project risks and can reduce or eliminate the need for equity. Lenders will normally prefer at least a nominal equity, say 5% or more, even when sponsors with high credit standings provide strong ancillary credit supports, but it is possible to obtain 100% debt financing. Evaluation of the strength of the ancillary credit support (the form of the support, the creditworthiness of the parties providing it and whether the support is overlapping, such as joint and several liability) together with evaluation of the assets of the project entity will form the basis for selecting the specific equity percentage to be invested within the approximate range of 5% to 40%. The percentage of equity invested will also impact on the interest rate charged and affect the rate at which lenders will require their loan to be amortized. An equity investment of 25% of the cost would be considered a normal percentage.

In the event that a project entity is employed, the ability to maximize the use of tax benefits will depend upon the type of entity chosen. If a corporation is selected, the likelihood is that tax optimization will not occur. Since the corporate entity owning the project assets presumably will have no other activities producing tax liabilities which can be offset with the tax benefits of the project, those tax benefits can only be availed of by passing such benefits through to another corporation through tax consolidation, by passing them through to a third party through leasing or by generating tax liabilities through operation of the project, none of which alternatives is fully satisfactory.

Some tax benefits (construction interest and progress payment tax credits) will be available prior to the time the facility will be operating and capable of generating tax liabilities. Other benefits such as non-progress payment tax credits and the largest annual amount of accelerated depreciation will be available in the first year of operation before the full earnings capability of the project is likely to be experienced. Accordingly, it can be expected that a corporate entity itself will not generate its own tax liabilities which can be fully offset with tax benefits sufficiently early to assure that such tax benefits will be employed at the earliest feasible point in time.

Leasing normally entails some higher cost than direct full utilization of tax benefits because of the return which the lessor expects and because of the lessor's obtaining the residual benefits of the asset at the conclusion of the initial lease term.

Tax consolidation will normally not benefit the situation in a multiparty ownership case because of the requirement that the consolidating parent own 80% of the voting stock and 80% of each class of non-voting stock, other than stock which is limited and preferred as to dividends, of the subsidiary. A multiparty ownership situation generally does not permit such a concentration of ownership and control in one party, thereby precluding any such consolidation. Due to these limitations it will normally be preferable, in order to achieve tax optimization, to employ a type of entity which permits the pass-through of tax benefits to its owners. The partnership type of entity meets this requirement and accordingly has been the preferred vehicle to achieve this objective.*

Under the partnership form, each partner is entitled to show on its own tax return its respective distributive share of all partnership credits and deductions. If, for limitation of liability or other reasons, any or all of the partners are wholly owned subsidiaries of investor participants, the subsidiaries are entitled to their distributive shares of the partnership's tax benefits but can pass those shares through to the consolidated returns of their parents.

Partnerships do not inherently possess the attributes of limited liability normally associated with corporations but liability limitations generally comparable to those of corporations can be achieved by (1) use of sole purpose subsidiary corporations as partners, (2) including provisions exculpating partners from responsibility for partnership liabilities in contracts and loan agreements, and (3) judicious use of insurance protection. Not every potential exposure of the investor participants will be eliminated by these means but such exposure can generally be reduced to a level which does not represent a major impediment to the use of this type of entity.

Another potential problem associated with use of a partnership which is sometimes mentioned is the possibility that partnership debt will not qualify as a legal investment by certain classes of investors. This difficulty arises under some interpretations of provisions in the laws of certain states which generally define permissible investments for insurance companies, thrift institutions, fiduciaries and other classes of investors. For historical reasons these laws (e.g., N.Y. State Insurance Law, Sec. 81.2) speak only in terms of corporate obligations and ignore partnership obligations. This objection is normally overcome by forming a corporate borrower between the partnership and the lenders; the corporate borrower receives the loan proceeds and reloans them to the partnership

* Until 1977, certain types of corporations qualifying as "cost companies" served as tax pass-through entities. Their use was limited to certain mining activities.

on identical terms, pledging the partnership's note and other obligations as well as any collateral furnished by the partnership as collateral for the corporation's borrowing.

Considering next the regulatory effect of employing a project entity, as indicated earlier only the 1935 Act has jurisdictional features which would operate on the basis of the organizational structure employed. By resorting to a project entity, the participants are using a format which necessarily involves a holding company-subsidary company structural format.*

Where the "holding company" holds 10% or more of the outstanding voting securities of an "electric utility company" (which may encompass a project entity which owns or operates a cogeneration facility producing electric energy for sale), the holding company must apply for an exemption from the 1935 Act in order to avoid regulation. Such an exemption should be available where the applicant is primarily engaged or interested in one or more businesses other than the business of a public utility company and does not derive a material part of its income from its public utility subsidiaries. If a participating utility were to take a 10% or greater interest in a project entity cogenerating electricity for sale, the project entity may be classified as a subsidiary of the utility and the utility may be required to register as a holding company.** Such a result would bring the full weight of SEC regulation under the 1935 Act to bear upon both the participating utility and the project entity; for example, security issues by the project entity would require approval under the 1935 Act and contracts between members of a registered holding company system cannot be priced at more than "cost" (see Rules U-90 and U-91 under the 1935 Act). In addition, industrial companies owning or controlling 5% or more of the voting securities of the project entity become "affiliates" under the 1935 Act; this has a number of results, such as the requirement that SEC approval be obtained before an affiliate acquires, directly or indirectly, any security of any public utility company and the requirement that the affiliate maintain certain accounts and records. Thus, the applicability of the 1935 Act to a project entity which owns and operates cogeneration facilities concerns not only the participating public utility whose ownership in the entity gave rise to jurisdiction under the 1935 Act but also industrial participants whose ownership in the entity might otherwise not be subject to, or might qualify for an exemption from, the 1935 Act. Though Section 210 of the

* In this connection, the concept of "holding company" is not limited to corporate entities, but would cover partnership vehicles and joint ventures.

** The statute and rules in this regard are quite complex and counsel should be consulted if this result presents a significant risk.

Public Utility Regulatory Policies Act of 1978 contemplates exemption of qualified cogeneration facilities from regulation under the 1935 Act, until FERC promulgates implementing regulations it will be impossible to determine whether either or both the public utility and industrial owners of a project entity will be relieved of the regulatory burden borne by "holding companies" and/or "affiliates" under the 1935 Act.

If a project entity with suitable tax optimization characteristics can be employed as a vehicle for issuing debt without adversely impairing the credit raising capabilities of the entity's owners or subjecting them to undesired regulation, the advantages of financial leverage will be available to benefit evaluation of the project. To illustrate the impact of such leverage, assume that a \$450 million project has three participating partners, each responsible for one-third of the project. If each partner were to take an undivided interest in the project, each would be faced with raising \$150 million. Even if a partner were to borrow to fund all or a portion of its \$150 million commitment and were to secure the borrowing by placing a lien on its share of the project, such a borrowing would reduce that partner's ability to borrow for other purposes by an equivalent amount. Consequently, that participant would evaluate its potential investment in the project by measuring the return on its \$150 million needed to fund the project. If the project were expected to return \$18 million annually to each participant for 25 years in the form of cash distributions and/or savings in energy costs over the next best alternative source of energy and if a 20% investment tax credit and accelerated depreciation over a 22.5 year life were available, a discounted cash flow calculation would show an annual rate of return on investment for the project of about 10%, assuming no residual value.

If instead of an undivided interest approach, a project entity approach were employed using a partnership composed of subsidiaries of each of the same three corporate sponsors and if the partnership were to borrow \$300 million repayable in equal annual installments over 25 years at an annual interest rate of 9.5%, so that each corporate sponsor was required to fund only \$50 million initially, even after devoting a portion of its \$18 million annual share of the partnership's return to pay interest and principal on the partnership's debt, the remainder of the return together with the tax benefits will produce an annual rate of return of about 35% on the \$50 million commitment.

As the foregoing example illustrates, the magnitude of the improvement in return on investment which can be achieved by the application of leverage is such that it should be sufficient in many cases to move a project which does not qualify for investment when evaluated on a total capital cost basis up to the level of acceptability. Since most industrial

corporations today have a minimum annual return on investment criterion approximating 20%, the ability to employ financial leverage through the use of a project entity which can borrow without impairing its sponsors' own borrowing capacity is likely to be a significant, if not decisive, element in any decision to develop a multiparty cogeneration facility.

Combined Approaches

The requirements of a particular project may be such that no one of the foregoing approaches — sole ownership or multiparty ownership using either the undivided interest or project entity method — is satisfactory as applied by all of the potential participants to all of the project assets over all time phases of the project. It may nevertheless be possible to develop an organizational structure which satisfies the participants by combining one or more of these approaches in various ways. It is difficult to describe all of the possible combinations which may have to be developed to meet the exigencies of a particular situation. Indeed, the factual circumstances and the combination of the requirements of the potential participants in each project tend to be unique, to some extent, and therefore to require complex innovative responses rather than simple preconceived answers. There are, however, three principal ways of fragmenting a project and recombining it using a different approach for each segment. The project may be divided in terms of (1) the components of the equipment involved, (2) the participants involved and (3) the time phases (*i.e.*, the development and operating phases) of the project.

Different Methods for Different Equipment. A first possible means of combining various project organizational structures is to divide the equipment to be employed in the project into separate component groups and to adopt a different ownership option for each component group. A primary reason for using this approach would be to avoid the undesirable imposition of regulation upon industrial participants where a project is located in a state which would classify the generation and sale of electric energy as a public utility function subject to regulation but would not regulate the production and sale of steam. A financing structure may be employed in which the specific assets associated with steam production, principally boilers, burners and condensers, would be owned by the industrial companies, and possibly also by the utility, on an undivided interest basis or through a project entity, while the turbine generators and related transmission equipment specifically employed in connection with producing and dispatching electric energy would be owned by the utility on a sole ownership basis.

The owners of the steam assets would presumably sell to the utility the steam which they produce and which is to be used to drive the

electric generating turbines and might also repurchase from the utility the exhausted steam and/or condensed water remaining after electrical generation. This technique would require a precise segregation of the equipment based upon its jurisdictional significance and a sophisticated consideration of the ownership of facilities common to both steam and electric generation and an allocation of capital and operating costs associated with each function. Application of this approach would also require both careful legal scrutiny to confirm that it will achieve its regulatory objectives and consideration of whether undue operational problems are created by dividing ownership of assets which function together.

Assuming that these hurdles can be overcome, this approach not only may insulate industrials from public utility regulation and give the utility direct control over electric production but also may help the parties cope with some of the capital constraints discussed above, particularly the capital limitations of the typical utility. Turbine generators and related transmission equipment would normally represent less than 20% of the cost of a large scale cogeneration facility and may therefore be within the financial means of a utility which would not be able to finance an entire cogeneration facility. These assets should all be includible within the utility's rate base and therefore should be financeable within the utility's normal capital structure. Co-ownership through a project entity and the benefits of leverage would be available to the industrial participants but only in respect of assets which should be outside regulatory jurisdiction.

A variation on the foregoing structure is possible in the case of a utility which operates within a holding company structure. The utility could undertake ownership of the electric generating and transmission assets which are within the jurisdiction of federal and state regulators, while its parent holding company or a sister subsidiary of the holding company could participate with industrial companies in ownership of the steam generating assets which should be outside such jurisdiction. The parent holding company can use its own credit standing to support the financing of the non-jurisdictional steam generating assets without adversely affecting the credit standing of the utility. Although use of the parent's credit will have some bearing on its issuance of common equity in the future, the impact on the parent should be substantially the same as if its utility subsidiary had employed its own credit. This approach will, however, limit the use of the utility's credit and minimize the impact on the utility's own corporate financial statements. Since the utility is likely to be the principal issuer of debt and senior equity securities within the holding company system the net effect should be an increase in the leverage capacity of the system.

There may be other reasons apart from regulatory motivations for dividing project assets. Optimization of tax benefits may be enhanced by having certain participants or third parties who can employ such tax benefits own some but not all of the assets associated with the project. Such assets, which might for example include fuel handling and transportation equipment, may be owned and operated by one or more participants or third parties on bases which are different from the other project assets with charges being rendered for the services provided by those assets. Alternatively, such assets may be owned by an investor and leased to the entity which owns and operates the balance of the project.

Blending the Undivided Interest and Project Entity Approaches. A second means of organizing a project in a way which uses more than one of the foregoing approaches is to group the participants according to their financial characteristics and objectives and to allow each such group to select the structural option which it considers best for its members. The mechanics of this concept involve having one or more project entities (each of which would be owned by more than one participant) own an undivided interest in some or all of the assets employed in a project as a tenant-in-common with other project entities or individual participants.

This particular form of combination is likely to arise as a result of the actual or perceived incompatibility of potential participants with respect to securing financing for the project on a joint basis. Though willing to participate jointly in the project itself, one or more participants may find themselves unable to agree with all of the other participants on a common financing basis because of the disparity in their credit standings, differences in the constraints imposed by the respective credit agreements to which they are party, differing accounting standards to which they are subject or for any of a number of other reasons. A participant which is unable to accommodate itself to use of the project entity selected for financing purposes by the other participants may opt for its own undivided interest or the formation of another project entity, co-owned with participants of like mind. The existence of these groupings for financing purposes need not affect the underlying operating arrangements which the parties would have established were it not for such financing issues; such operating arrangements can be effectuated through agreements which are drawn (1) between the various tenants-in-common in respect of ownership and operation of the project, (2) between the various owners of each project entity in respect of governance of the project entity and (3) between the various participants as purchasers of project output and the owners and operators of the project.

The availability of the technique of providing for more than one ownership approach for a project can be useful in reconciling difficulties which arise in the formulation of a multiparty project. However, this technique adds complexity to the structuring of a project and also makes it more difficult to achieve the benefits of leverage discussed above by reducing the possibility of organizing a project entity which no single participant will control. To illustrate this latter difficulty, if three participants plan to form a project entity in which two participants each own 30% and the third owns 40% no one participant should be deemed to control the entity so that for financial reporting purposes under ARB No. 51 no participant should be required to consolidate the entity's accounts with its own on a line-by-line basis; consequently, no participant will have to consolidate the entity's borrowings with its own debt. If instead, one of the 30% participants chooses to take its interest as an undivided interest, the remaining two participants will not be able to form a project entity in which neither has a majority interest since the participant with the 40% share of the project will be left with a $\frac{4}{7}$ majority in the entity.

Different Methods for Different Phases of the Project. A third means of integrating various structural approaches into the organization of a single project is to adopt different methods for the developmental and operational phases of the project. This approach can be useful in reconciling the problem which the potential utility participant may have in financing the construction of a facility with the problem which the potential industrial participants may have in financing utility-type assets with an industrial-type capital structure.

The basis for this reconciliation can be that the industrials will bear the burden of construction financing with the utility assuming responsibility for permanent financing following completion of construction. This specific approach could be implemented in a number of ways. One simple way, which clearly illustrates the underlying economics, would be to have industrial participants own the facility during the construction phase and fund construction from their own resources, including funds they may borrow in their own names. Upon completion the facility would be sold to the utility which would thereafter operate it as sole owner and finance it with funds provided through its normal utility capital structure. The rates charged for the output of the project will reflect only the capital which the utility has employed from the commencement of its ownership. Compensation for the capital employed by the industrials during the construction period can either be included in the purchase price or, in effect, earned by the industrials over the operating period through lower charges for output.

There are two principal objections which most industrial companies will have to the foregoing arrangement, to each of which appropriate

responses can be made. The first objection is that most companies do not wish to finance the acquisition of assets by third parties. The answers to this objection are that though the utility will acquire ownership, the utility's capital cost associated with carrying that ownership will be less than that which the industrials would have incurred had they retained ownership and those savings in capital costs will benefit the industrials in the form of lower energy costs. Moreover, ownership of the assets is unimportant so long as their output is committed to the industrials and the industrials will have only a short term financial obligation while the utility will have a long term financial obligation in respect of assets which should benefit both the industrials and the utility.

A second objection is that the industrials, by taking ownership and providing financing during the construction period, bear the construction risk and should be rewarded for having borne that risk. This objection can be answered by identifying the long term energy savings to the industrials as the reward for having successfully incurred the construction risk. Alternatively, the industrials could be paid a higher price upon completion, in which event the industrials will have foregone some of their potential long term energy savings, or the utility could commit by contract to reimburse the industrials for some or all of the losses sustained by the industrials if the project is not successfully completed, in which event the industrials would not be bearing a construction risk but only a short term credit risk of the utility meeting its reimbursement obligation.

If the industrials are willing to support the construction financing of assets to be owned by a utility there are a variety of other ways the same basic financial effects can be achieved. For example, if no adverse regulatory constraints exist, ownership of construction might be vested in a subsidiary of the utility or a trust which the utility forms, thereby making tax benefits of ownership available to the utility during the construction period and avoiding any tax problems associated with sale of the project upon its completion. This entity might borrow up to the full cost of construction, including construction interest thereon, upon the strength of unconditional completion guarantees furnished by the industrial sponsors of the project. Upon completion of construction the utility could take title to the project and repay the construction borrowing through funding supplied by its conventional capital sources. The industrial customers may or may not be required to purchase output from the facility and/or to pay standby charges, depending on the business arrangements negotiated by the parties, but the utility should not require such commitments from the industrials in order to obtain financing on a

corporate basis once the project is completed and placed on an operating and earning basis along with all of its other operating utility plants.

Another similar approach to construction period financing would be to have the utility provide financing from its conventional capital sources for a portion of the cost of the project but have that conventional financing supplemented by payments from the industrials to provide the utility with an adequate return on its capital invested in construction work in progress. If such payments from the industrials were denominated as contributions in aid of construction they would not be taxable to the utility and smaller non-taxable payments in that form could yield the utility the same after-tax return as would larger taxable payments.

Even where a utility is not part of a cogeneration venture the participants may find reasons for varying the organizational and financial plans for the project as it moves from the development to the operating phase. A construction contractor may support construction financing with a guarantee or a turnkey contract but once construction is completed permanent financing may require other credit arrangements. Completion guarantees may be viewed by the sponsors providing them as dilutions of their borrowing capacities; after completion the opportunities for leveraging through use of a project entity may be enhanced. The sponsors may wish to vary the percentages of equity they are required to invest during the construction and operating phases and these may result in different arrangements applicable to the different phases. Any or all of these or other circumstances may justify use of an undivided interest approach during one phase but a project entity approach during the other phase.

Interrelating Various Combined Approaches. Not only is it possible to divide and recombine a project's structure in terms of the equipment, the participants and the time phases of the project, but it is possible to mix all of these elements to the extent necessary or desirable to achieve a structure which comes as close as possible to realizing the diverse objectives of all project participants. Thus, to illustrate this point, it is conceivable that, in a project involving three industrial participants and a utility, the industrial participants might assume the primary financial responsibility during the construction phase. Once construction was completed, the utility might acquire ownership of and finance the electric generating equipment while the steam generating equipment might be owned in undivided interests by one of the industrial participants and by a partnership owned in equal shares by the other two industrial participants. The equipment needed to transport and process fuel for the project might be owned by a passive investor and leased to a partnership consisting of all three industrial participants. Any number of variations of this nature may be feasible under appropriate circumstances.

CONCLUSION

At a time of increasing sensitivity to the rising costs of energy it would appear that the use of cogeneration in large scale multiparty applications offers significant opportunities to achieve substantial energy efficiencies. In order to capitalize on those opportunities it is necessary to organize the potential project participants in business arrangements which will satisfy their objectives with respect to economic benefits, risk bearing, management and control, financing and the use of financial leverage, tax optimization and regulation. There are three principal forms which those business arrangements can take — sole ownership, joint ownership of undivided interests and joint ownership of a project entity — and countless combinations and variations are possible. In short there is no lack of techniques to be considered to meet the requirements of the parties.

The prospect of utility-type regulation represents a troublesome obstacle to the formulation of acceptable arrangements; this difficulty hopefully will recede when exemptions from federal and state regulation to be provided under the authority of the Public Utility Regulatory Policies Act of 1978 are fully implemented. The hurdle which will remain is the magnitude of the task of securing the acquiescence of a number of potential participants, each with its own outlook and requirements, in the adoption of a plan for development and operation of a new cogeneration venture in which they will all participate. Any such plan, in order to accommodate all of the interests involved, may be extremely complex. Elements of such a plan which are necessary to satisfy some participants may inevitably conflict with the objectives of other participants, no matter how prodigious the efforts to reconcile such interests. Though prior experience in organizing such a venture will be a valuable requisite, each such project is likely to present unique requirements which will call for flexible and innovative responses.

In short, the formulation and effectuation of a new industrial cogeneration project involving multiple parties is a challenging undertaking. No matter how promising the rewards in terms of profitability and energy efficiency the difficulties are sufficiently substantial that there can be no assurance of success. However, we continue to believe that if adequate time, effort, skill and patience is brought to bear, and is leavened with a willingness to innovate and cooperate in order to bring about the desired

result, projects will come to fruition. We are confident that if success in that respect is achieved the resulting benefits — to the nation in energy savings and to the participants in profits and cost savings — will have amply justified the undertaking. We hope that this report will contribute to a wider understanding of what is required to accomplish this goal and will thereby serve to further the prospects of large scale multiparty cogeneration.