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COGENERATION INSTITUTIONAL STUDY IN THE GEISMAR, LA, AND ORANGE, TEXAS AREAS

WORK PERFORMED BY
STONE & WEBSTER MANAGEMENT CONSULTANTS, INC.
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FOR

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The objective of this report is to provide a better understanding of the institutional problems involved in the use of coal-fueled cogeneration. The viewpoints of industry, utilities, and government were probed extensively through indepth confidential interviews. To provide a real-life basis for this investigation two existing industrial sites in the Gulf Coast area were studied. The projected effects of the installation of coal-burning cogeneration plants supplying steam and electricity to several industries, replacing existing oil and gas burning boilers, were studied for each site.

This report has been prepared to provide insights into the overall institutional problem that will be useful at other locations. It covers the regulatory, economic, financial, engineering, operating, contractual, and corporate relations aspects of cogeneration. It concludes with suggestions for future action by the Federal government, state governments, industries, and utilities that should be helpful in removing the institutional constraints that are retarding cogeneration installations and the use of coal.

The installation of coal-burning community cogeneration plants to replace existing gas- and oil-burning boilers is unlikely at this time in areas similar to those studied because the large capital investments required in the early years pose a difficult problem. Such replacements will occur only if 1) the existing gas- or oil-burning boilers are old and in poor condition, requiring major expenditures, or 2) significant government subsidies or financial assistance are provided, or 3) the change to coal is mandated by the state or Federal government.

Where additional steam is needed to meet growth requirements, the installation of community cogeneration plants is more likely. The size of the plant will depend on the incremental steam requirement and its rate of

growth. Coal-burning plants will be given serious consideration for the larger installations and in areas where environmental problems are not overriding. Again, the portion of the existing gas- or oil-burning facilities to be replaced by such "growth requirement" plants generally will be small, unless special incentives are provided.

Table 1 provides a brief summary of the most significant problems in the application of coal-burning cogeneration plants and recommendations for removing some of these roadblocks.

Table 1
Summary of Problems and Recommendations
for Coal-Burning Community Cogeneration Plants

INTRODUCTION

INTRODUCTION

Relationship to Other Studies

This report summarizes the conclusions of a study made by Stone & Webster Management Consultants, Inc. of the business attractiveness and the institutional considerations involved in the installation of coal-burning community cogeneration plants in Geismar, Louisiana and Orange, Texas, to replace oil- or gas-fired boilers now in use. In this study we have defined a community cogeneration plant as a plant sequentially converting fuel into steam and electricity, thereby improving the overall efficiency of fuel use.

This study complements the engineering and technical studies of the same sites made by Stone & Webster Engineering Corporation and summarized in a companion report. While it has inevitably resulted in some redundancy, these reports have been written so that each can be read and understood without reference to the other.

The engineering study analyzed a number of different technological options with "typical" institutional arrangements and associated fixed charges. This institutional study has analyzed various institutional arrangements for one technical option: conventional coal-burning boilers which supply steam to turbine generators, with the back-pressure exhaust from the turbines supplying industrial steam needs. We believe, however, that much of the institutional information in this report will be useful for nuclear and other coal technologies that may be employed with cogeneration in the future.

We have also considered the legal opinions developed by counsel for Gulf States to provide a complete summary of all institutional problems.

Objectives

The major objective of this study is to provide all of the parties involved - the Federal government, the state governments, the industrial energy users, and the local utilities - with a better understanding of the institutional problems involved. Hopefully, such information will make possible policies and decisions to facilitate the installation of cogeneration plants where justified by long-range national benefits. This can only be done if adequate economic incentives exist. A number of these incentives are discussed in the report.

In performing this assignment, it gradually became apparent that an important role for Stone & Webster could be that of helping each of the various groups involved in a cogeneration project to understand the problems of the others. The industrial concerns had misconceptions concerning the role of government. Government groups did not clearly understand the problems of industrials and/or the utilities. The utilities did not understand how the industrial concerns or the government agencies viewed the situation.

In interviewing each of the groups involved in this study, we have not only tried to determine how they felt about each of the key issues and factors but also to communicate the views of the other parties. It may well be that the development of this "honest broker" role is the most important contribution of the assignment.

Basic Approach

The economic evaluation of cogeneration is a complex job, part technical, part institutional, and each specific case has to be worked out

individually. The approach used in this study was therefore one of analyzing the key factors, the key variables, and the effects of various incentives on the decision to install a community cogeneration plant. With this approach, it is hoped that the results will be of maximum use in connection with other potential future installations.

To insure the full input of information from all potential participants and to explore all potential means of solving the institutional problems associated with cogeneration, extensive interviews were conducted with the industrial concerns at each surrogate site, as well as with state officials and the utility involved. While the potential contents of the National Energy Act (NEA) obviously were of great concern, its uncertain status prevented adequate consideration at the time this report was prepared. This report is essentially based on present law but comments from time to time on the potential effect of the NEA.

Background

Our national energy policy requires a decrease in the use of gas and oil. Cogeneration provides a potential mechanism for achieving this goal since it makes possible a shift to other fuels while simultaneously reducing the amount of fuel needed through a more efficient process. The overall economics of cogeneration are usually improved by increasing the plant size, i.e., the "economies of scale." For this reason, quantitative evaluations have concentrated on the large coal-burning cogeneration plants covered in the comparison engineering study with special emphasis on "community plants" involving more than one industrial participant.

Industrial firms and the utility in Geismar, Louisiana and Orange, Texas have been investigating cogeneration possibilities for many years. These two specific areas, and the general vicinity of the Gulf Coast, have as much potential for use of cogeneration at existing industrial sites as any areas in the United States. The industrial companies are large steam and electricity users presently making heavy use of gas and oil in their boilers. Figures 1 and 2 show the geography and cogeneration plant arrangements developed in the engineering study of the two sites.

These companies are fully aware of their need to develop alternate energy strategies for both their existing plants and their future growth. As a result, they have been involved at their own expense in extensive studies involving significant contributions from their own staff and outside consultants. These studies have been made by individual companies and also jointly, by community groups. These industrial studies, as well as the local utility efforts, have not resulted in any firm commitments to cogeneration projects at these sites to date.

As we proceeded with our institutional investigations, it became obvious that we should make maximum use of the prior work that had been done by the industrial concerns and utilities on their own and focus on the reasons cogeneration was not being adopted as a solution to the energy problems of the area. This report has been prepared and organized accordingly.

Figure 2
Potential Cogeneration Plant Site
Orange

Scale:
One inch - 2,300 feet

COGENERATION FEASIBILITY STUDY
SITE PLAN-INTERCONNECTING
PIPING AND CABLING
ORANGE AREA - GSU/ERDA
COAL FIRED PLANT
STONE & WEBSTER ENGINEERING CORPORATION
CHERRY HILL, N.J.
DRAWING NUMBER 12977-EM-1D

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INDUSTRIAL INTERVIEWS

INDUSTRIAL INTERVIEWS

Interview Procedures

Appendices A and B present the detailed findings of our interviews for the Orange, Texas and Geismar, Louisiana sites, respectively. The information included in these appendices was based on extensive interviews with the personnel from each of the organizations involved. The responsibilities of those interviewed varied from company to company; interviewees included plant managers, representatives of the finance department, representatives of the law department, strategic planning officers, and the energy resources and fuel purchasing personnel. In most cases, two to five individuals from the company were present and provided information from a number of different departments in the organization. (The institutions and individuals interviewed are listed in the Acknowledgements section.)

To insure complete frankness and openness during the interviews, it was agreed that specific comments would not in any way be attributed to specific individuals or companies. Responses would be kept anonymous with companies involved identified only by a letter. This procedure led to considerable frankness and shed a great deal of light on the problems of executing community cogeneration projections in the areas studied.

The information obtained from each company shown in Appendices A and B has been reviewed by the company interviewed and each has agreed that its responses have been correctly presented.

In summarizing the information received in this report, we generally have made a combined presentation of the responses for both sites. In cases where there are significant differences between the responses obtained for each site, the information is presented separately.

Corporate Decision Process

Lead Time

In general, a cogeneration project will be initiated by the plant management or the operating division responsible for the plant. It will then proceed upward through the organization receiving review along the way by the financial department, the division or product group, senior management, the top corporate officials, and finally the Board of Directors. This entire procedure requires significant amounts of time with significant amounts of internal corporate review and discussion. It will usually be one to two years before a commitment to proceed with cogeneration is made. The companies involved believe that three to four years will be required for design and construction, resulting in a total elapsed time of five to seven years before cogeneration plants can be installed and begin to serve energy needs.

This long lead time presents a major problem in the installation of cogeneration. The industrial companies involved normally plan their business operations in detail for five years in the future with a rough look at ten and fifteen years ahead. They do not usually commit funds beyond the five-year detailed plan period. Cogeneration presents a significant problem with its long lead time because it will require them to commit capital funds beyond the period of planning for their normal product lines. It will require them to commit operating funds to a business operation of which they are not yet certain for a period more than 20 years in the future. Reductions in lead time for cogeneration, therefore, could be an important factor in its incorporation in the plans of these companies.

Attitude Toward New Technology

Because of these lead time problems, which are quite important in the decision-making process of the companies, very little consideration is being given to the newer technologies. Almost unanimously the companies are not interested in becoming involved with nuclear energy generation because of its long lead time and large unit sizes, which lead to backup problems. Other technologies that are not yet commercially available are given little serious consideration. Industry will not jeopardize the operation of a production plant through use of an unproven technology to provide the steam it needs.

Prerequisites

The majority of the companies will not make a firm commitment to participate in a cogeneration project until an agreement with all others involved has been reached and the basic contract terms - who is to do what, who is to pay what - have been settled. Neither will they make a firm commitment without having the necessary environmental approvals in hand. They are willing, however, to contribute funds for preliminary engineering and other studies of cogeneration up to perhaps a few percent of a project's cost prior to settlement of these contractual and environmental matters.

In general, the corporate decision process gives very heavy emphasis to the next five years and the impact on the competitive position of the operation during that period.

Key Factors in the Decision

Government Action

All companies interviewed stated that before making a decision concerning cogeneration they must have stable government rules. This is the single most important factor in their decision. All of the companies indicated that they could not see how they could become responsible even in part for a project costing several hundred million dollars without knowing the government regulations that will affect both the project and their future. The opinion of several is that the contents of the National Energy Act (NEA), and any subsidies or penalties included therein will be important in determining the timing of cogeneration. If the NEA is favorable, cogeneration will be installed sooner.

Companies are also concerned about the ratemaking policies of the various state utility commissions. If the commissions adopt rate schedules that unfairly penalize industry, such as inverted rates not justified by costs, the industrial companies will be given a much greater incentive to install cogeneration and even the less efficient condensing generation in order to protect themselves against commission actions they consider unreasonable.

Regulation and the Holding Company Act

There is unanimous agreement that the companies will not participate in any arrangement that is financially regulated by either state utility commissions or any of the branches of the Department of Energy (DOE) or the Securities and Exchange Commission (SEC). The filing requirements and other burdens of such financial regulation are seen as so odious that companies will refuse to participate in cogeneration in order to avoid them.

Companies are also very concerned about the Holding Company Act, which they believe could affect not only their activities in connection with a community cogeneration plant but all of their other corporate activities. Legal counsel for a number of companies has advised that they could be subject to the Holding Company Act under the law as it is now written and as the counsel has interpreted it. Several of the companies, therefore, will not participate until specific legislation has been passed to exempt community cogeneration projects and their participants from the Holding Company Act.

Economics

The general industrial opinion was that the economics of replacing existing energy supplies with cogeneration (retrofit) do not look good. Cogeneration economics improve considerably for use in supplying additional steam and electric needs.

The basic economic methodology used by industry in arriving at these conclusions is comparison of the cost of steam from a coal-burning cogeneration plant to the cost of steam from present boiler facilities based on converting the existing boilers from natural gas to oil. In determining the cost of steam from a cogeneration plant a credit is taken for the electricity produced based on projections of future electric rates for industrial plants in the Gulf States area.

This procedure for comparing new cogeneration installations with present facilities usually results in significantly higher energy costs from the installation of cogeneration. (Alternative economic evaluation procedures to overcome some of the inadequacies of this approach are suggested in the section titled Suggested Actions to Remove Major Constraints.)

There is little question that the sudden abandonment of a significant portion of the existing steam-producing plants in the companies interviewed would not be economical. Rather, cogeneration installations must be made recognizing the need to continue the useful life of a portion of the energy conversion facilities presently in use in the industrial complexes.

Cogeneration Organizational Arrangements

All the companies interviewed are willing, from a corporate policy basis, to participate in community cogeneration plants. At the Orange site, the first preference is to buy steam and electricity that have been produced by others. The industries would want to have some control of both the design and the operation of the plant that will supply their energy, however. At the Geismar site there were two distinct groups: one preferred industrial ownership and operation and the other preferred third party ownership.

Utility ownership and/or operation is acceptable to all industrial companies and preferred by most. The small companies are very concerned about the domination of the large industries. They feel that the large companies could control the design or operation of the cogeneration plant in such a manner as to achieve a competitive advantage over them. The small industrial companies, therefore, would prefer that a separate organization control the cogeneration plant.

The large industrial companies, however, are very concerned that an outside group or third party, or even the local utility, would not have sufficient incentive to do as good a job as the large companies would since

interruptions in steam supply would directly affect the operations and profits of the large industrial companies. Since they are "self insurers" of their losses from interruptions of their energy sources, they want to control the reliability of these sources.

From the viewpoint of organizational arrangements, it appears that there may be some practical limitations on the size of a cogeneration plant. The organizational, contractual, control, and decision-making problems will increase exponentially with the number of participants. These problems are increased by the technical difficulties encountered when a number of different steam pressures are involved. It may well be that a practical organizational limit for community cogeneration plants will be a maximum of three or four companies and two steam pressures.

Engineering and Operating Factors

Optimum Size and Participation

The optimum size for a cogeneration plant will depend on the balancing of the economies of scale with the complexities arising from the number of participants and steam pressures. The participants in a community cogeneration project will all want to have some voice in its design and operation. The larger companies indicated that they would want to be intimately involved with the various engineering details as the project proceeded in order to insure the reliability they desire. Plant size will also depend on the portion of the existing facilities that can economically be kept operating and the growth in energy needs.

Reliability

The steam supply provided by a cogeneration plant must be at least as reliable as the supply presently used in the industrial plants. The industrial concerns recognize that complete redundancy in the cogeneration plant will not be economically feasible and, therefore, it will be necessary to maintain some of the existing boiler equipment for peaking and backup service.

In most cases a shortage of steam due to breakdowns in a cogeneration plant would result in a loss of production in the industrial plants. In a few cases a sudden interruption in the steam supply could result in significant damage to equipment. An approach to the question of the reliability of steam supply on an overall community basis is suggested under the section titled Suggested Actions to Remove Major Constraints.

Use of Existing Steam-Producing Equipment

With the retention of existing boilers for backup and peaking service with a cogeneration installation, some companies would be operating their steam-producing equipment for the benefit of others. The companies that retain such existing boiler equipment and provide such service for the benefit of other members of the community most definitely wish to be compensated for providing this service. In a number of cases, existing boilers would be retained because they are necessary to burn waste products which cannot be disposed of in any other environmentally acceptable manner. The vast majority of companies will not abandon and remove their existing steam-producing equipment until cogeneration has proven itself reliable over a period of a year or two.

There is a strong indication that a necessary accompaniment or possible precursor to a cogeneration plant will be the establishment of a steam network to pool steam supply resources. Such an arrangement could be very beneficial from the viewpoints of both reliability and economics. (This is discussed under Suggested Actions to Remove Major Constraints.)

Most of the industrial plants have some slight capability to reduce steam loads in order to accommodate limitations in steam production capability caused by outages. These industrial plant steam curtailments will result in some loss of production. Compensation will be required where a production loss is taken by one company for the benefit of another company.

The amounts of condensate that could be returned to a cogeneration plant varies from 50% to 80%. In general, none of the industrial concerns will be able to provide make-up water for the cogeneration plant. In developing contractual arrangements for the cogeneration plant, these differentials in condensate return and possible make-up water supply will have to be considered.

Fuel

The use of coal as a fuel for a cogeneration plant is of great concern to the industrial concerns in both the Geismar and Orange areas. Plant operators who have no experience in the use of coal are concerned about the environmental problems that will result, including the functioning of scrubbers. Corporate staffs are concerned about future coal prices and transportation problems. Several companies even feel it may be desirable to design the cogeneration plant boilers with the capability to burn another fuel besides coal just as protection against the uncertainties of the future, such as transportation disruptions, coalminer strikes, or environmental lawsuits.

Overbuild Policy

At the Orange site, because of the very limited potential for future growth, there is general agreement that it is not necessary to build a cogeneration facility with any significant excess capacity to provide for future needs. The participants suggest that the cogeneration installation consist of modular units and that sufficient room be left for construction of additional units in the future, if and when they are needed.

At the Geismar site, there is considerable difference of opinion among the industrial companies, which have not been able to reach an agreement on how to provide for future needs. This apparently results because some companies expect a significant growth in future needs while others do not. The companies anticipating growth would like to see the cogeneration plant designed to provide for their future needs. Those anticipating no growth believe that incorporation of some overbuild in the cogeneration plant would unnecessarily and unfairly increase their costs, which will be based on some pro rata share of the total cogeneration plant costs. This question was one of the larger issues that ultimately resulted in the splitting up of the five potential participants in a community project at the Geismar site into two separate groups.

Design and Construction Responsibility

All participants feel that since the industrial concerns will be dependent upon the reliability of the supply from the cogeneration plant some mechanism that will allow them to participate in key design and construction policy decisions must be found. All recognize that this could present problems because of differences of viewpoints of the industrial concerns.

Operating Responsibility

All of the smaller companies are concerned about the domination of the operation by the large industrial companies. The larger companies feel that one of them should be responsible for the operation. Mechanisms will have to be developed so that such decisions as when the cogeneration plant will be shut down for maintenance, for example, can be resolved on a coordinated basis by all the participants. An intercompany committee is the most likely solution. All of the industrial companies strongly prefer that a profit-making arrangement be established covering the operation of the cogeneration plant such that rewards and penalties will accrue as appropriate to provide motivation to the operator.

In brief, the operating contract must provide sufficient incentives and controls to insure good operation while protecting the interests of all involved. The predominant view is that a third party or the local utility is preferable for this function.

Use of Existing Electrical Facilities

At the present time, most of the substation facilities supplying electric power to the existing industrials are owned by Gulf States Utilities. The industrial concerns, however, have the right to purchase these substation facilities if they so desire.

All industrial concerns feel strongly that it would not make economic sense to duplicate the existing substations and transmission facilities in the area to handle the electrical output of a cogeneration plant. Rather, they would like to see the existing electric facilities utilized for that purpose.

At the Geismar site a unique plan has been proposed by the industrial concerns. This would provide for location of the cogeneration plant adjacent to one of the large industries with the complete electrical output for the cogeneration plant feeding into the low voltage substation bus of that company. The other industrial participants would be credited for their share of the electrical output from the cogeneration plant through contractual and billing arrangements. They would also compensate the company receiving the cogeneration output for their equitable share of the appropriate utility backup charges when the cogeneration plant is out of service.

Labor and Union Considerations

In general, the companies do not see any special labor or union problems resulting from the installation of a cogeneration plant. They feel that after the cogeneration plant is started up the employees will decide if they wish to unionize. In their existing plants the only problem foreseen is that of providing an adequate labor supply for the existing boilers that are maintained on standby and would only operate intermittently for peaking or backup use.

Utility "Backup" Arrangement

All of the companies are concerned about what they consider to be excessive utility backup charges for a potential cogeneration plant. They strongly feel that a cogeneration facility should be connected to the utility grid and procedures that will lead to the operation of this cogeneration facility in the most economic manner should be established.

They would prefer to sit down with the utility and investigate the overall equities of the situation, developing separate contracts based on the costs and services to be provided instead of using backup rate schedules, which are determined in large measure by a local public utility commission.

Financial Considerations

Evaluation Process

All of the industrial companies interviewed use the discounted cash flow method of analysis to make their financial decisions. For cogeneration, they will look at an expected life of 20 to 30 years. Some will look at the after tax return, others will look at the before tax return. Most will compare the profitability of an investment in cogeneration with investments of the same capital in their own normal business. A significant factor for participants with relatively poor credit ratings will be the impact of their contribution of capital and the debt required with the cogeneration project on their ability to raise capital for other projects. All companies are interested in some form of "off balance sheet" financing, if this can be arranged.

All companies perform some form of financial sensitivity analysis. They investigate the effect of changes in future fuel and electricity costs, governmental energy and environmental policies, and their own market conditions. The biggest single uncertainty, however, and the one investigated most frequently, is the future variation in alternate fuel costs, particularly the price of coal vs. the price of oil. An important element in the future price of coal, in the opinion of most companies, will be the future cost of coal transportation.

The "hurdle" rate of return for most companies is in the range of 15% to 20% on the total project. In general, the required "hurdle" rate of return is similar to that expected on normal product lines.

If the project is to be highly leveraged, i.e., having a high ratio of debt to equity in the capital structure, the differing credit ratings (bond ratings) of the participants present a problem, particularly at the Geismar site. The companies whose debt securities have a high rating feel they will be subsidizing the companies whose debt securities have a low rating in the financing of a community cogeneration project.

It appears, therefore, that some mechanism for "cross industry" subsidization will be required with a community cogeneration plant. This subsidization must provide a mechanism for those with poorer credit ratings to compensate industrial concerns with better credit ratings for helping to raise the project capital at a lower cost.

Type of Joint Venture

Almost all companies prefer that someone else provide them with steam and electricity. Although they have a history of difficulties related to joint ventures, however, they would be willing to participate in a joint venture and are open concerning the type. None of the industrial companies saw any advantage to separate ownership for the steam and electric portion of the facilities. Several were quite concerned that such an arrangement could lead to less than optimum operation of the plant.

Take or Pay Contracts

All potential participants recognize the necessity for signing relatively long-term "take or pay" contracts for periods up to 20 years.

These contracts would provide that the industrials pay fixed charges and taxes for the cogeneration plant independently of the plant operation. All recognize that these contracts result in the use of participants' credit ratings to obtain financing. They also recognize that variable charges will have to cover fuel and operating costs. They feel, however, that the contribution of the existing facilities of the companies receiving the output of the cogeneration plant to the overall functioning of the project must be considered in determining the rate schedules.

Pricing Arrangements

Appendix D provides an illustration of the pricing arrangements for the Orange site. It presents a number of important factors that might be considered in determining the price for steam and electricity, including prices for steam at different temperatures and pressures, credit for the condensate returned and make-up water provided, and the handling of steam energy losses sustained in transmission.

Risk Opinion

Most of the companies consider community cogeneration to be about as risky as their normal lines of business. Some see it as less risky, while a few consider it more risky. The economics of a coal-burning cogeneration retrofit are very dependent on future fuel cost differentials which are risky to predict.

Those who consider cogeneration more risky also foresee the possibility of relatively low-cost coal gasification or liquefaction being developed sometime in the future to provide a fuel for use with their existing boilers. If this were to occur, a major investment in cogeneration could prove to be unwise.

Pollution Control Bonds

The use of tax-exempt pollution control bonds for cogeneration financing is looked on with favor by all companies. They would like to see as high a percentage of the capital as possible financed through this method. The justification for the use of pollution control bonds for a cogeneration plant would be the reduction in air pollution resulting from the use of a lower total amount of fuel than is currently used by the existing independent steam and electricity production methods.

Payments During the Construction Period

All companies would prefer not to make any payments during the period of construction for the cogeneration plant. All would prefer to pay only on receipt of the steam and electric output of the plant. However, some would be willing to make contributions during the construction period if the return on their contributions is sufficiently great to make them financially desirable.

Construction Cost Overruns

All companies recognize that construction cost overruns are a possibility on a major project such as the design and construction of a cogeneration plant. They also recognize that the users of the output of the cogeneration plant will have to bear these costs. One company indicated it would not agree to participate in a cogeneration plant until 40% to 60% of the engineering design is completed and costs are relatively assured. A number of other companies felt strongly that the contractor who will build the cogeneration plant must share some of the risk through an incentive construction contract.

Inflation

All companies include inflation in their financial and economic projections. The forecast prices they determine are to be in terms of actual dollars in the year expended. Many perform sensitivity analyses in which they look at various inflationary rates in making their financial projections.

UTILITY INTERVIEWS

UTILITY INTERVIEWS

The electric utility in both the Geismar and Orange areas is Gulf States Utilities (GSU). In order to provide an opportunity for Gulf States to comment on a number of the key issues in connection with cogeneration, we interviewed the officials for Gulf States listed in the Acknowledgement section. The specific questions asked of Gulf States and their responses are summarized in this section.

Basic Philosophy

GSU is willing to participate in and cooperate with community cogeneration projects on any reasonable basis, including ownership and operation. GSU's load is predominantly industrial. All levels of the corporation, from the chief executive down, recognize the importance of the economic welfare of the industrial concerns in their territory. They believe that low-cost energy must be supplied to these industries. They see the advantages to GSU of the satellite load even if they do not supply the industrials. If it came to a choice of an industrial plant installing its own cogeneration and ceasing to buy electricity from GSU or moving out of the area to some other location, GSU would most definitely prefer the installation of customer-owned cogeneration facilities.

Contractual Dealings with a Cogeneration Plant Owned by Others

Gulf States indicated that it would be willing to buy the excess electrical output, if any exists, from a cogeneration plant installed in its service territory and owned and operated by others, unless this electricity costs more than electricity produced by GSU's alternate methods of

generation. Gulf States would not credit the cogeneration plant with any capacity value if it had no voice in scheduling its operation.

At the present time, Gulf States is buying and selling electrical capacity and energy from and to other utilities in the region. A significant difference is seen in buying and selling energy from and to a cogeneration plant, however, since such a plant would not be regulated. Therefore, dealings with a cogeneration plant would have to be on a somewhat different basis than dealings with neighboring utilities. The neighboring utilities are considered to be significantly more reliable because of their size and because of Gulf States' past experience of participation in utility grid operations. Also, since the utilities are regulated, the prices they charge for electric capacity and energy and the general nature of the contractual terms are the result of considerable past evolution and government approval.

Capacity Requirements to Back Up Cogeneration Plants

Electric utilities, including GSU, make probability calculations to determine how much generating capacity is required to meet a specified reliability criteria. GSU would be willing to analyze its total generating reserve capacity with and without several cogeneration plants in its territory to determine the additional reserves required to provide backup for the cogeneration plants. This approach would allow the establishment of backup charges based on the equities of the situation.

Generation Economic Evaluation Procedures

Present predictions are that the future costs of electricity from additional generating capacity to be installed by GSU will be several times

higher than the future costs of electricity from generating capacity presently installed on the GSU system. This means that incremental electricity costs for GSU will be considerably higher than average costs.

In evaluating alternate possible additional types of generating capacity, GSU compares the total cost (capital plus operating) per kilowatt-hour for the various alternates over the life of the plant. The "total system revenue requirements" technique, which we believe to be superior, is not always used by GSU to compare alternate expansion strategies.

GSU has a severe problem because it feels that the rate policies adopted by the Louisiana Commission do not provide sufficient revenue to raise the capital needed to build the plants that are most economical.

GSU has made a number of different load projections for its future electric peak demands and sales based on various possible cogeneration developments in its service territory. For each of these projections, GSU has developed alternate capacity programs. Financial forecasts have been made for each load growth and capacity scenario to determine the possible long-term effects of various cogeneration developments.

Summary

GSU is willing to sit down with the industrials interested in cogeneration to study the future of industrial energy needs along with its own expansion needs, and to develop jointly the most economic program for meeting these needs. If savings are possible through cogeneration plants, some equitable procedure for splitting these savings would be developed.

STATE GOVERNMENT INTERVIEWS

STATE GOVERNMENT INTERVIEWS

Interviews with government officials were conducted in Louisiana, the state in which the Geismar site is located, and in Texas, the location of the Orange site. Two interviews were conducted in each state: one with representatives of the natural resources, commerce, and industry departments, and the other with representatives of the public utilities Commission. The individuals interviewed are listed in the Acknowledgements.

Findings

The natural resources and industrial people are generally concerned with the conservation of energy and the welfare of industry in the state. The public utility regulatory people are concerned with regulation and pricing of energy sales by utilities. The findings of these interviews are summarized in Tables 2 and 3.

Possible Action by State Governments

The state governments can take the following major steps to encourage the use of cogeneration.

1. Clarify environmental protection requirements.

Particularly important are the "offsets" that will be required in existing air pollution sources to compensate for the addition of the cogeneration plants in these areas, which are presently classified as nonattainment areas. The necessary field survey work should be initiated as soon as feasible.

2. Determine in advance the basic regulatory policies concerning cogeneration plants. The determination of such policies and their publication should clarify many uncertainties for industrials and utilities who are presently considering cogeneration installations.
3. Alleviate utility financial problems arising from participation in cogeneration projects. The step suggested in both Louisiana and Texas is the inclusion in the rate base of construction work in progress (CWIP) for the utility owned portion of the electrical facilities of the cogeneration plants.

It is also highly desirable that all Federal policies be treated and implemented on a consistent basis among the various states. Such equality in interpretation is essential in order to avoid undesirable differences between state policies toward the use of coal and cogeneration.

Table 2

Comments Concerning Cogeneration

State Utility Commissions

<u>Topic</u>	<u>Texas</u>	<u>Louisiana</u>
Cogeneration study status	No specific studies of cogeneration have been made in Texas as yet. A grant has been provided for a one-year study of the institutional problems concerned with cogeneration. The study should be completed about 1979.	The Louisiana Public Service Commission has made no comprehensive investigation of cogeneration to date. Efforts have been confined principally to discussion of regulatory matters with the lawyers representing the various industries and the utilities.
Impact of Cogeneration on utilities	<p>The Commission staff recognizes that the installation of cogeneration by industry could result in a change in utility growth patterns and load factors causing an increase in the rates for residential and commercial customers.</p> <p>Because of utility problems in capital through an increase in rates, industrial ownership of cogeneration facilities is generally favored.</p>	<p>The Commission staff is aware of the possible impact of industrial cogeneration installations on utility growth and load factors. It recognizes that the loss of base industrial load would probably result in the need for rate increases for residential and commercial loads. It would like to see cogeneration developed to limit such adverse effects.</p> <p>The Commission is very concerned about the utilities' future needs for capital. It sees cogeneration, with part ownership by the industrial companies, as a possible mechanism for significant reduction of these future capital needs.</p>

Table 2 (Continued)

Comments Concerning Cogeneration

State Utility Commissions

<u>Topic</u>	<u>Texas</u>	<u>Louisiana</u>
Utility commission regulation	<p>Utility participation in cogeneration requires a Certificate of Convenience and Necessity from the PUC. Such a Certificate has been provided for the Celanese/Southwestern Public Service project.</p> <p>Utility Commission regulation is expected to apply as follows:</p> <ol style="list-style-type: none">1. Steam Price No regulation for any of the possible forms of ownership.2. Electric Price Utility Ownership: Regulation will apply only to the electrical portion, not the steam portion. Industrial Ownership: Regulation will not be involved, provided the electricity produced is sold only to the industrial owners. Third Party Ownership will probably involve regulation as a utility by the Commission	<p>Individual contracts involved in the ownership, operation and so on, of cogeneration plants will probably not have to be reviewed and approved by the Commission. The overall prudence of the agreements entered into by the utility will be reviewed as a part of future rate investigations.</p> <p>No matter who owns the plant, prices for the sale of excess steam to nonowners will not be regulated. Sales of excess electricity to non-owners will be regulated. Only the portion of the plant producing such excess electricity will be considered. If the utility purchases steam from a cogenerated project, this would be treated in a manner similar to the purchase of fuels in determining the fuel adjustment under the utility energy clause.</p> <p>Industrial community cogeneration plants selling electricity only to the industrial owners will not be regulated. They will not, however, have the power of eminent domain. The above criteria will also apply to third party ownership.</p>

Table 2 (Continued)

Comments Concerning Cogeneration

State Utility Commissions

<u>Topic</u>	<u>Texas</u>	<u>Louisiana</u>
State and local taxes	<p>The following are the local and state taxes involved in a cogeneration project.</p> <ol style="list-style-type: none">1. Ad valorem average taxes of 4% or 5% will be levied by the local municipalities.2. Gross Receipts taxes of 1/6 of 1% will be applied to the electric revenues.3. No franchise or state income taxes will be involved in an industrial community-owned plant. The State has just eliminated a 4% state sales tax on electric utility sales.	<p>There are no state taxes applicable to cogeneration in Louisiana. Municipalities will collect the franchise taxes.</p>
State incentives	<p>Possible future state actions to help foster cogeneration include the following items.</p> <p>Clearly defined written guidelines approved by the Commission specifying their policies toward cogeneration and indicating the specific aspects of such projects that will fall under their regulation.</p>	<p>One possibility is that the utility will be allowed to include in rate base the CWIP for cogeneration plants and be allowed to earn thereon. Industrial rates only would be adjusted to cover the earnings on this CWIP. Such an arrangement would result in lower industrial rates later, reflecting the omission of AFDUC from the book capital costs for the cogeneration plants since the cost of money during the construction period will have been paid by the industrials already.</p>

Table 2 (Continued)

Comments Concerning Cogeneration

State Utility Commissions

<u>Topic</u>	<u>Texas</u>	<u>Louisiana</u>
State incentives (Continued)	<p>Permission for utilities to put CWIP in the rate base for cogeneration projects.</p> <p>The Texas Public Utility Commission will not hold up a Certificate of Convenience and Necessity because other state departments have not yet reviewed the overall plan. The general concept is that each department in the State would furnish the permits required for a cogeneration project as independently and expeditiously as possible.</p>	<p>Stable state rules and policies pertaining to regulation of cogeneration are desirable. These can only be developed in Louisiana through a public hearing, which may be given consideration in the future. The availability of such rules in writing should clear the air concerning the position of the Louisiana Commission with respect to the regulation and control of cogeneration projects.</p> <p>The state has an Energy Task Force which at present has an informal interdepartmental coordination role.</p>

Table 3

Comments Concerning Cogeneration

State Government Department of Natural Resources
and Department of Industry

<u>Topic</u>	<u>Texas</u>	<u>Louisiana</u>
Cogeneration study status	<p>The responsibility for all cogeneration studies falls to the Public Utility Commission, which presently has a grant for investigating the institutional problems related to cogeneration. The Texas Industrial Commission is responsible for assisting industry in conserving energy and for all on-site generation. The Texas Industrial Commission also sponsors seminars, conferences, and so on, to assist industry in saving energy. Because it is a nonregulatory commission, the Industrial Commission usually obtains excellent cooperation from industry.</p> <p>An innovative energy search center has also been established which will provide information in all energy areas, including cogeneration, at no cost upon request from Texas' industries.</p>	<p>Many studies concerning the potential for cogeneration and the problems associated with the use of coal and lignite as fuel have been made by the State of Louisiana. The resulting reports are available for use by industry and are listed in Appendix H.</p>
Use of fuels other than coal for cogeneration	<p>Docket 600 calls for gradual reduction in the use of gas as a boiler fuel. Recently the requirements for Docket 600 have been eased and further easing is likely. In the long run, however, coal and lignite are the best fuels for cogeneration. There is still considerable concern about the wisdom of shipping Texas gas to the northern part of the country and shipping coal from the northern part of the country to Texas since this is costly and wastes energy.</p>	<p>No state regulations exist requiring industry to shift from gas to coal. In the long run, the best way to use Louisiana gas is as a feedstock for process industries. The use of Louisiana gas as a boiler fuel in other states, when such use is not approved in Louisiana, would put Louisiana industry at a disadvantage. The switching from gas to coal therefore, will have to be done on a national basis in order to treat all regions of the country equally.</p>

Table 3 (Continued)

Comments Concerning Cogeneration

State Government Department of Natural Resources
and Department of Industry

<u>Topic</u>	<u>Texas</u>	<u>Louisiana</u>
State action to encourage coal cogeneration	No specific action has been taken except for the educational courses and the institutional study which has been funded as indicated above.	No action has been taken except for the publication of reports listed in Appendix H.
Role of cogeneration	<p align="center">-</p> <p>The present EPA environmental air quality goals cannot be attained even if all industrial operations in Texas cease. The Orange site is a "nonattainment" area. The addition of a cogeneration plant in the Orange area will probably require "offsets" in the contribution of other existing plants in the area. In order to be sure what specific "offsets" will have to be, a one-year monitoring survey of air quality will be required. Such a survey will have to be arranged by the owners of the new cogeneration plant. The final decision in this matter will rest with the Texas Air Quality Control Board, which is willing to give preliminary opinions on air quality problems to prospective industries.</p>	<p>Cogeneration using coal should be employed for new plants as it is economic. The use of oil for such new plants does not appear to be the right long-range answer. For existing plants, conversion to cogeneration will occur in general only as the result of governmental decree or order.</p> <p>The Geismar location is in a "nonattainment" area. A complete study will be made of all industries in the Geismar area and their respective contributions to air pollution. Also required will be an investigation of what can be done to reduce the existing contributions. The State feels that money for such surveys will have to come from the Federal government. Based on such surveys, potential cogeneration plant owners can determine what will have to be done to reduce existing contributions and what will be the likely cost. (It was discovered subsequent to the interviews that the industries in the Geismar area have hired a consultant to make such a study at their own expense.)</p> <p>Some environmental concerns exist regarding the effects of coal terminating facilities</p>

Table 3 (Continued)

Comments Concerning Cogeneration

State Government Department of Natural Resources
and Department of Industry

<u>Topic</u>	<u>Texas</u>	<u>Louisiana</u>
Environmental problems (Continued)		presently under construction and the additional facilities required in the future. Of particular concern is water leaching out of the coal piles. No siting authorities exist in Louisiana and none are foreseen for the future. A Coastal Zone Management Agency which may become involved with certain cogeneration projects has been created, however.
Industry concern with the stability of rules	The state government recognizes the need for stable rules. It wants adjacent states to interpret Federal rules in the same manner as it does.	Stability of regulations is a difficult problem.
Advice for Washington	Develop stable rules and leave them alone for a while. Insure similar interpretation of rules by all states.	Let states solve their own problems. Take the advice of the states more frequently. Provide more funds to the states for technical assistance, particularly for the investigation of problems five years or more in the future. Reduce the amount of time required to obtain Federal assistance funds. Presently, more time than is allowed to do the work covered by them.

METHODS OF PRODUCT PRICING

METHODS OF PRODUCT PRICING

The allocation of costs in a plant that produces two products simultaneously, using common facilities, is not a science but an art. A number of different approaches giving differing answers can be used. Appendices A and B demonstrate that decisions to participate in cogeneration schemes will reflect individual considerations of steam economics, regulatory constraints, and participant equity. Cost-of-service, market value, and incremental cost measures will ultimately be taken into account during these evaluations. Where different corporate entities are involved, the final resolution will be established through negotiations.

Cogeneration fits the above description. A simple method for allocating costs is explained in this section.

Capital Cost Allocation

For capital investment, assume that the turbine generator is the sole portion of the plant used for the generation of electricity, with the balance of the plant installed solely for the production of steam. While this is an oversimplification, it is generally acceptable to most industrial concerns and utilities. This approach will result in capital costs for coal-burning boiler plants split at approximately 15% for electricity and 85% for steam.

Operating Cost Allocation

Operating costs can be split a number of ways. One approach is based on the assumption that the purpose of the cogeneration plant is primarily to supply steam, with electricity as a by-product. With this approach, the

value of the electricity produced is estimated and credited to reduce the plant operating costs since the electric bill for the industrial company will be reduced by this amount. The balance of the operating costs, therefore, is charged to steam. This approach is simple and works well when only one steam pressure is involved.

More than One Steam Pressure

When more than one steam pressure is involved, the energy in a pound of steam at lower pressure is less than the energy in a pound of steam at higher pressure. In this situation, it becomes necessary to allocate costs on the basis of the amounts of energy contained in the steam at two different pressures. A suggested approach is to determine the minimum and maximum justifiable prices for electricity and the various types of steam using a number of different allocation procedures. Within these minimum and maximum values, final prices can be negotiated and agreed upon.

Appendix C provides brief descriptions of the cogeneration plants at the Orange and Geismar sites which were the basis of this study. Appendix D illustrates a number of approaches to cost allocation using data for the Orange site.

LEGAL AND TAX QUESTIONS

LEGAL AND TAX QUESTIONS

The key regulatory and tax considerations in connection with cogeneration plants at the Geismar, Louisiana and Orange, Texas site, owned by a separate entity, have been investigated for Gulf States Utilities by legal counsel. This material, which is based on the existing laws as of August 1978, has been summarized by Benny Hughes, Esq., of the law firm Orgain, Bell & Tucker, and is reproduced below.

REGULATION BY THE STATE UTILITY COMMISSION

General:

The proposed cogeneration entity would be subject to regulation by the state regulatory authorities as a public utility, and sales of electricity would be regulated, but sales of steam would not.

Exceptions:

- (1) In Texas, there is an exemption for "self use," but the exemption does not appear to apply to the proposed cogeneration entity owned by and supplying electricity to several parties.
- (2) In Louisiana: (a) if the electricity is sold by the entity only to the owners, the sales would not be regulated except incidentally, through regulation of the utility's purchase of power not purchased directly by the industrial customers, (b) sales of electricity produced by a separate unit dedicated primarily for steam production are exempt even if made by a utility.

Comments:

If regulation of the entity as a utility is a deterrent to desirable development of cogeneration projects, present exceptions to regulation which are based on the absence of sales to others would have to be expanded to allow for sales to the various participants. If the customers are sophisticated industrial consumers who participate voluntarily in the project and in control of its operations, the customary need for regulation would be absent.

REGULATION BY THE FEDERAL ENERGY
REGULATORY COMMISSION

General:

The retail sales of electricity and steam by the cogeneration entity to its owners would not be subject to regulation by this Commission under the Federal Power Act.

Exceptions:

If any electricity is sold wholesale to a utility in interstate commerce, as a co-owner or otherwise, such sale would be subject to regulation and would cause the cogeneration entity to be treated as a public utility subject to regulation under the Federal Power Act.

Comments:

Such regulation would extend beyond the sale to such activities as financings, record keeping, and transactions with the owners (at least through regulation of allocation of costs). If the public interest requires that these charges for wholesale electricity from cogeneration entities be regulated, the most efficient regulation would appear to be to retain limited regulation on the wholesale sale alone and to release the cogeneration entity from full regulation as a public utility. If regulation is left solely to regulation of the purchasing utility's cost of purchased power, the public interest in the rates and financial integrity of the utility could be disserved since the utility would bear the risk of loss between the negotiated purchase prices and the purchase cost allowed upon regulation of the utility's rates.

REGULATION BY THE SEC

General:

The cogeneration entity owning the generating facilities would constitute an electric utility company and would subject 10% or more owners thereof to regulation as public utility holding companies under the Public Utility Holding Company Act of 1935, unless an exemption applies.

Exeptions:

- (1) Exemptions may be available for particular projects which are small, or for the use of a single owner-user, or in which the investors are intrastate in character. Present exemptions do not appear available for the larger, multi-

party projects under consideration; however, the no-action letter dated June 26, 1978, attached to the detailed report indicates that favorable attention may be given by the staff to exemption application for jointly-owned cogeneration projects.

- (2) Under certain circumstances, if the cogeneration entity is limited to ownership of the steam facility only and the local utility owns the generator and sells the associated electric energy, the cogeneration participants may avoid regulation as holding companies.

Comments:

Since regulation under this Act is not compatible with the businesses of nonutility participants in such projects, and since the burden of such regulation based solely on participation in such projects by local utilities is probably not acceptable, existing exemption from this regulation should be expanded by statute or published regulations to allow for participation, even by local utilities, in such cogeneration projects.

CERTAIN TAXES INVOLVED

General:

1. A corporate cogeneration entity would be subject to state franchise taxes, but partnership or joint venture entities would not.

Exception - a non-profit corporate entity would not be subject to such tax in Louisiana, but probably would be in Texas because of the nature of its business.

2. Cogeneration facilities would be subject to ad valorem taxes.

Exception - a ten-year exemption in Louisiana would probably be available.

3. A gross receipts tax for sales by the entity of electricity (not steam) within an incorporated city would be due in Texas, but Texas has no income tax. Louisiana does not have a gross receipts tax, but does have an income tax which would be borne either by the corporate cogeneration entity or by the corporate owners of a non-corporate cogeneration entity.

4. The retail sales by the cogeneration entity of electricity and steam to participants for certain industrial uses and wholesale sales of electricity to a utility would be exempt from sales tax in Texas and Louisiana.

Exception - in Texas, the exemption would not apply to electricity sold for commercial or residential purposes (as defined) or to sales of steam for purposes other than manufacturing, processing, or fabrication.

Appendix G provides additional information that has been made available by Mr. Hughes.

Possible Future Developments

The above information is based on the applicable laws as they existed in August of 1978. The National Energy Act (NEA) contains significant modifications to encourage both the use of coal and cogeneration. This Federal legislation, which provides objectives and overall guidelines, will subsequently require the regulatory agencies involved to issue specific rules. This rulemaking procedure is expected to take about one year after the legislation is passed. Since the NEA was passed in October of 1978, the rules which industry desires to have before proceeding with cogeneration will not be available until the fall of 1979.

ALTERNATIVE FINANCIAL APPROACHES

ALTERNATIVE FINANCIAL APPROACHES

Alternative Corporate Structures and Ownership

A number of different ownership arrangements are possible for a community cogeneration plant: it could be owned by the utility alone, by the industrials which it will supply, by a third party, or by any combination of the above. The ownership could be accomplished through a partnership arrangement, a joint venture, or wholly-owned subsidiaries. The arrangement that is best will depend on legal, tax, and business factors which require more detailed investigations beyond the scope of this study. (A companion study being made by Kidder-Peabody and Company should provide additional information.)

Another concept for the use of cogeneration calls for new industrial parks centered around a cogeneration (and possibly a coal gasification) complex. The energy complex would provide a low-cost efficient energy source to newly constructed industrial plants. While such "cogeneration parks" have obvious advantages, they need to be viewed in the overall national context. They will reduce the growth in our needs for oil and gas to be used in new installations. They will not reduce existing needs for oil and gas unless they also result in abandonment of production plants in existing industrial areas. Such abandonments could involve significant economic penalties.

The location of coal-burning cogeneration parks away from existing urban areas could result in an increase in urban unemployment and urban financial problems if it causes the relocation of industry. If the energy parks are

located in existing industrial areas this effect will be eliminated. The economic penalties from premature abandonment of existing boilers could also be lessened if operation of this equipment is combined for peaking and back-up purposes.

Some proponents of such energy/industrial parks propose that they be built by government agencies such as municipalities or regional authorities. Such agencies would be able to issue tax-exempt bonds and thereby would have a lower cost of money, reducing financing costs considerably. Real estate tax exemptions may also be possible. While such subsidies could provide additional incentives for cogeneration, it should be recognized that any subsidies would have to be made up through increases of taxes in other sectors of the economy or the country.

In order to provide an indication of the effect of such a low cost of money, our financial evaluations include the effect of an appropriately low interest rate typical of municipal debt costs.

Alternate Financing Arrangements

Conventional Financing

Conventional financing, either by the utility, the industrials, third parties, or a tax-exempt government agency, is one possibility. Because of the security offered through long-term agreements to buy steam and electricity from the project with large and stable industrial concerns, a heavily leveraged financial structure is possible with private ownership. Debt ratios of 75% and possibly even higher are considered feasible.

Leveraged Lease

Another financing alternate might be the use of a leveraged lease. This can have certain advantages when used and structured properly. It involves a lessor, equity participants, and lenders of nonrecourse debt. The lessor can claim all tax benefits. (A separate report by Kidder-Peabody and Company provides more information on this financing method.)

Contractual Requirements

In order to make the financing of a community-owned cogeneration plant feasible as described above, a long-term contract with the consumers of its steam and electricity production is essential. This contract will have to provide that the consuming industries be responsible for the interest on the debt, sinking fund obligations, and the taxes involved in the project - i.e., the fixed costs. Essentially, the project will be financed by the owners banking heavily on the credit ratings of the consuming industries. Steam and electric energy costs from the plant will also have to include an automatic adjustment clause covering changes in fuel price and other operating expenses. A long-term contract covering an assured and economical coal supply will also be necessary.

Risks to Owners and Customers

The risk to the owners of such a plant consist primarily of a significant reduction in the requirements of the consuming industry. While their fixed costs will still be covered, the amount of revenue available to cover the equity portion of the financing for the plant could be

considerably less than expected. On the other hand, the customers of the plant are taking risks, particularly a long-term shut-down of the plant because of mechanical failures, fuel shortages, or labor problems. During such periods, they will still be paying the fixed charges on the plant but will not receive any energy and undoubtedly will be forced to drastically curtail their normal production operations.

Utility Participation

Utility participation in such a project on an equity basis could have some advantages. Although it would increase the likelihood of regulatory complications, it would decrease the cost of capital if a lower cost of money results.

Effect of Different Credit Ratings of Participants

With a number of participants in the ownership of a cogeneration plant, some recognition of their different credit ratings may be required. The participants who have the better bond ratings can finance at a lower cost than the participants whose bond rating is poorer. Some mechanism for cross-industry subsidization to cover this difference in credit rating will be needed in certain cases. One approach is to calculate the cost of money to each participant at its normal financing cost and then compare this with the company's pro rata cost under the cogeneration financing arrangement. Adjustments could then be made to compensate for the differences between companies through a number of mechanisms, preferably through the fixed charges to be paid.

Taxes (Other than Income)

Taxes on a community cogeneration plant may be of three types: franchise, sales, or ad valorem (property). The applicability of these various taxes has been reviewed with the state regulatory commission staffs as summarized in the section of this report covering regulatory interviews and has been investigated by legal counsel as summarized in the section covering legal and tax questions and in Appendix G.

The tax assumptions that have been used in the various financial calculations included in this report are indicated in Appendix E.

Government Incentives

A number of government incentives affecting the economics of cogeneration have been investigated. Among these are various investment tax credit rates, shorter lives for tax depreciation, and lower income tax rates. A range of returns on equity and different debt ratios and interest rates have also been considered.

Effects of Key Variables

A "base case" was calculated for both the Orange and Geismar sites. Table 4 shows the assumptions used for these base cases and Appendix E illustrates the step-by-step calculation procedures used. This procedure was also used to obtain the various other financial and economic results presented in this report.

A breakdown of steam costs for each site by major components is given in Table 5. This shows the most significant components in the cost of steam

Table 4
Key Assumptions Used in Financial Calculations
for Base Cases

Return on Equity	20%
Long-term Debt Ratio	75%
Financing During Construction Period	100% debt
Long-term Debt Life	25 years
Income Tax Rate	
Federal	46%
Texas	0%
Louisiana	8%
Taxes Other than Income	2%
Investment Tax Credit	10%
All Tax Benefits During Construction Period Can be Consolidated and Used on Current Basis	
Operating Life	30 years
Tax Depreciation Life	22.5 years
Property Tax	Starts with construction for Orange Starts 10 years after in-service date for Geismar
Cost of Debt	9%
Sinking Fund	1/25 of debt retired each year - no lag
Construction Cost Escalation	7%
Fuel	Alabama Coal
Fuel Escalation	6%/year
O&M Cost Escalation	6%/year
Working Capital	60 days of fuel 45 days of other O&M
Working Capital Escalation	6%/year
Electricity Credited at Project Rates (see Appendix E)	
Construction Period	6 years
Annual Steam Production	
Orange	17,305,380,000 pounds
Geismar	46,042,560,000 pounds
Annual Electricity Production	
Orange	1,171,562,400 kw hours
Geismar	2,776,744,800 kw hours
Capital Costs (book costs, including interest during construction, overheads and escalation)	
Orange	\$ 485,077,000
Geismar	\$1,134,429,000

Table 5

Steam Costs by Components
(Dollars per thousand pounds)

	<u>Orange</u>		<u>Geismar</u>	
	<u>1985</u>	<u>2000</u>	<u>1985</u>	<u>2000</u>
Fuel	\$3.17	\$ 7.59	\$3.17	\$ 7.59
Operation and Maintenance	.83	1.98	.83	1.98
Taxes Other than Income	.56	.56	-	.49
Working Capital Increase	.04	.09	.03	.07
Retirement of Debt	.84	.84	.74	.74
Interest	1.89	.76	1.66	.67
Income Taxes	(.45)	.74	(.41)	.47
Return of Equity and Earnings	<u>.70</u>	<u>.60</u>	<u>.72</u>	<u>.30</u>
Subtotal	<u>7.58</u>	<u>13.16</u>	<u>6.74</u>	<u>12.31</u>
Credit for Electricity	<u>(2.48)</u>	<u>(6.86)</u>	<u>(2.21)</u>	<u>(6.11)</u>
Revenue Required	<u>\$5.10</u>	<u>\$6.30</u>	<u>\$4.53</u>	<u>\$6.20</u>

are fuel, debt service, and credit for electricity. The differences between the costs for the Orange and Geismar sites are discussed later.

To determine the effect of changes in key assumptions, variations in key parameters were made as shown in Table 6. The cost of steam has been used as the measure to determine the effect of changes.

In general, the price of steam in the first year of operation has been compared. While two different steam pressures will be provided by the cogeneration plants, steam prices are given on a total volume of steam basis for ease of comparison. Methods for developing prices for steam at two different pressures are given in Appendix D. These, and other simplifying assumptions that have been used, are adequate for comparison of variations in key parameters. A review of the recommendations on economic study methods given in the section of this report on "Suggested Actions to Remove Major Constraints" is suggested before further study of specific installations is made.

The variation of steam costs over time for both the Orange and Geismar sites is shown in Figure 3. This figure and Table 5 show a higher initial cost and a lower long-range cost for steam at the Orange site. This is the result of higher initial capital cost per 1,000 pounds of steam produced and higher state taxes at the Orange site. Orange also has a higher ratio of electric energy to steam output than Geismar. With the forecasted increase in electric energy rates (based on a forecast by Gulf States Utilities), the increasing credit for the electricity generated keeps the cost of steam from rising as fast in the future at the Orange site as at the Geismar site. Geismar has a higher average steam pressure; an average energy content of

Table 6
Summary of Cases Analyzed

<u>Description</u>	<u>Variations</u>
Base Case - Orange Site	-
Base Case - Geismar Site	-
Orange Site	Return on equity at 10%, 12.5%, 15%, and 17.5%. (Base Case - 20%)
Orange Site	Financed with 20% and 100% equity. (Base Case - 25% equity)
Orange Site	Lag of sinking fund payments of one year and two years. (Base Case - no lag)
Orange Site	Cost of debt at 6%, 8%, and 10%. (Base Case - 9%)
Orange Site	Investment tax credit at 12% and 20%. (Base Case - 10%)
Orange Site	Tax depreciation life at 12 years and 16 years. (Base Case - 22.5 years)
Orange Site	Property tax starts with in-service date. (Base Case - Start with construction)
Orange Site	Operating life of 25 years. (Base Case - 30 years)
Orange Site	Construction period of 5 years. (Base Case - 6 years)
Orange Site	Value of purchased power. Estimates increased and decreased 20%.
Orange Site	Price of coal. Estimates increased and decreased 20%.

1330 Btu per pound compared to the Orange average energy content of 1305 Btu per pound, which means a slightly faster increase in costs at Geismar as fuel costs rise.

The industries involved at both sites have been reluctant to disclose their present costs for steam for competitive reasons. However, a range of present steam costs of from \$2 to \$4 per 1,000 pounds has been indicated. Since steam at different temperatures and pressures has a different heat content per pound, direct comparison of steam costs is not feasible. It is certain, however, that steam costs from existing industrial facilities will increase with time as a result of the increase in prices of oil and gas. Figure 4 illustrates the potential increase in steam cost based on the future estimate of increases in oil prices of 7% per year used in the companion engineering report. A comparison of future steam costs for oil firing of existing boilers with cogeneration plants show that unit steam costs will be comparable about five years after installation of the coal-fired cogeneration plant. This analysis is oversimplified because it does not include write-off and tax effects for premature retirement of the existing boilers. It does demonstrate, however, the relative "inflation proof" characteristics of coal fired cogeneration. While cogeneration involves a considerable initial capital outlay, these dollars will not escalate with time as will the fuel costs for less capital intensive alternates. Figure 5 shows the relative increase in steam costs versus costs for coal and electricity and also demonstrates the advantages of coal-fired cogeneration in a period of escalating oil costs.

First year steam costs for the two sites for various returns on equity are the following.

<u>Return on Equity</u>	<u>Steam Cost</u>	
	<u>Orange</u>	<u>Geismar</u>
	(Dollars per thousand pounds)	
10%	4.45	4.03
12.5%	4.62	4.15
15%	4.79	4.28
17.5%	4.94	4.40
20%	5.10	4.53
Δ 20% - 10%	0.65	0.50

Figures 6 and 7 show the effect of debt ratio and return on equity on the cost of steam at the Orange site. They show that highly-leveraged financing will be very beneficial and, if this is achieved, increased return on equity will have a minor effect on steam costs.

The base case has assumed that a sinking fund covering the debt portion of the project financing will be established and 1/25 of the debt will be retired each year. An alternative is a delay in the refunding of this debt. Figure 8 shows the effect on unit steam costs of one- and two-year delays, with total refunding being made over 24- and 23-year periods, respectively.

A number of small variations in federal income tax rates were investigated. The effect on steam costs were small since the value of the tax credits in the early years increased and tended to offset higher income taxes in the later years.

The effect of variation in the cost of debt money is shown in Figure 9.

Figure 10 shows the effect of variations in investment tax credit rates. Increases of 2% and 10% in the present rate have been considered. As can be seen, such increases would significantly reduce the price of steam.

The effect of shorter tax depreciation lives is shown in Figure 11. The present asset guideline class for industrial steam and electric generation has a period of 28 years and a lower limit of 22.5 years. Tax lives of 16 years and 12 years have been considered. Such shorter lives would substantially benefit the cash flow for the project.

Figure 12 shows the effect of different state and local taxing policies. Texas taxes property while it is under construction, while Louisiana generally allows a 10-year moratorium on such taxes as an incentive. Both of these methods have been considered, as well as the assumption that such taxes start at the in-service date of the plant.

Cogeneration plants will have their output tied directly to a geographic location. The steam they produce cannot be transmitted more than a few miles. An obvious question is, "What if the useful operating life of the plant is less than the anticipated 30 years?" The effect of an assumed operating life of 25 years instead of 30 years changes first year steam costs less than one cent per thousand pounds.

Because of the amount of capital required for these projects, the extent of the construction period during which this capital is invested but not earning any return is of concern. Figure 13 shows that the effect of a one year reduction in this construction lead time can be very important.

Variations in the credits assumed for the electricity produced will also affect steam prices significantly, as follows.

<u>Value of Electricity</u>	First Year Steam Costs <u>Orange</u> (Dollars per thousand pounds)
Base Case	\$5.10
Base Case plus 20%	4.60
Base Case minus 20%	5.60

Similarly, the costs of coal for use as fuel will affect steam costs as follows.

<u>Cost of Coal</u>	First Year Steam Costs <u>Orange</u> (Dollars per thousand pounds)
Base Case	\$5.10
Base Case plus 20%	5.73
Base Case minus 20%	4.47

A comparison of the relative effects of changes in the above parameters is given in Table 7.

Conclusions

The above analysis leads to the following conclusions.

1. Cogeneration energy costs will increase significantly less rapidly than fuel costs in the future.
2. The economics for cogeneration can be improved most by steps to achieve the following.
 - a. A greater investment tax credit.
 - b. Faster depreciation for tax purposes.

Table 7
Relative Effects of Changes in
Key Assumptions

Orange

<u>Key Variable</u>	<u>Change in Variable</u>	Change in First Year Steam Cost ⁽¹⁾ (Dollars per thousand pounds)
Debt Ratio	Increase from 75% to 80%	-.32
Return on Equity	Decrease from 20% to 17.5%	-.16
Lag in Sinking Fund Payments	Delay of one year	-.16
Cost of Debt	Decrease from 9% to 8%	-.20
Investment Tax Credit	Increase from 10% to 20%	-.90
Tax Depreciation Life	Decrease from 22.5 to 16 years	-.35
	16 to 12 years	-.29
Property Taxes	During construction to in service	-.10
	In service to 10-year moratorium	-.27
Construction Period	One Year Reduction	-.22
Vale of Purchased Power	+20%	-.50
	-20%	+.50
Price of Coal	+20%	+.63
	-20%	-.63

Note:

(1) All other variables at "base case" value.

Figure 3
Orange and Geismar Cogeneration Process

Steam Costs
1985 to 2000

Figure 4
Orange Coal Cogeneration Plant
Comparison of Escalated Costs
Steam from Oil Using Existing Boilers
Vs. Steam from Coal Using Cogeneration

Figure 5
Comparative Effects
of Cost Escalation on
Electricity, Coal, and Steam Costs

Figure 6
Orange Coal Cogeneration Plant
Effect of Financing on Cost of Steam

Figure 7
Orange Coal Cogeneration Plant
Effect of Debt Ratio on Cost of Steam

Figure 8
Orange Coal Cogeneration Plant
Effect of Lag in Sinking Fund Payments

Figure 9
Orange Coal Cogeneration Plant
Steam Cost Sensitivity
to Debt Cost

Figure 10
Orange Coal Cogeneration Plant
Steam Cost Sensitivity
to Investment Tax Credit

Figure 11
Orange Coal Cogeneration Plant
Steam Cost Sensitivity
to Tax Depreciation Life

Figure 12
Orange Coal Cogeneration Plant
Steam Cost Sensitivity
to Initiation of Property Tax Payments

Figure 13
Orange Coal Cogeneration Plant
Steam Cost Sensitivity
to Construction Lead Time

SUGGESTED ACTION TO REMOVE MAJOR CONSTRAINTS

SUGGESTED ACTIONS TO REMOVE MAJOR CONSTRAINTS

There are a number of technical, economic, regulatory, and institutional constraints on the use of cogeneration plants. Some of these constraints are real, resulting from the inherent nature of the systems involved and their costs. Others are the result of man-made rules, decisions, policies, and attitudes, i.e., artificial constraints.

The economic and institutional barriers to the use of cogeneration are precisely those that constrain the industrial use of coal. If the Federal government's policy is to induce conversion to coal, then some of the following recommendations should be considered.

It is quite evident that cogeneration will not descend in one fell swoop and take over the supply of steam and electricity to industries. Rather, cogeneration will evolve over a period of time on a step-by-step basis. The evolution will include continued utilization of existing energy sources in the industrial plants for some time. The initial capital requirements and financial difficulties that accompany the replacement of adequate and properly functioning existing energy sources prevent wholesale conversion to coal and cogeneration and mandate an evolutionary conversion program.

A weakness frequently exists in the techniques being used both by industry and the utilities for evaluating the economics of cogeneration since they compare the costs for new cogeneration plants with the costs of energy produced by existing plants. This procedure is valid in a nongrowth situation, but it can lead to incorrect decisions in growth situations. To ensure economically and conservationally sound utilization of our nation's resources, it is particularly important that both industry and the utilities

compare the cost of cogeneration with the cost of alternate facilities that would have to be installed in the future to meet their increased needs, and that such comparisons be made over a long period of time, i.e. twenty to thirty years. This can best be done through cooperative industry-utility studies, particularly when steam needs of industrial plants are not growing while regional needs for electricity are growing.

Each of the three principal groups interested in cogeneration - government, utilities, and industry can take certain steps to remove some of the artificial constraints. The material that follows provides an outline of the specific actions that each group can take to accomplish this.

Federal Government Actions

In order to achieve a national reduction in the use of oil and gas through increased use of cogeneration, a large number of possible actions are available to the Federal government, including doing nothing at the present time and "letting nature take its course." There is danger that the Federal government might take actions that fail to let the free market work in the cogeneration decision-making process, thus retarding the use of cogeneration.

As a result of our investigations, we have compiled a list of possible Federal government actions which merit serious consideration. These suggestions are listed in what we believe to be the order of their importance.

1. Establishment of stable rules covering cogeneration and the use of coal. An early interpretation of the application of the NEA for various types of cogeneration projects is vital.

2. Exempt cogeneration from all Federal and state financial regulation. This will also allow the free market to work in the financing, rate, and contract areas. Any arrangements a regulated utility may have with a cogeneration company can be adequately reviewed as part of the normal utility rate review process.
3. Specifically exempt companies participating in a cogeneration project from the Holding Company Act.
4. Clarify existing environmental rules, particularly the "offsets" that will be required before a cogeneration plant will be allowed in an area presently classified as a nonattainment area.
5. Simplify and stabilize environmental rules so that changes which could significantly affect a cogeneration plant's operational ability or cost are not made while it is being constructed. Such stability is particularly important in the industrial decision making process since it will result in "equality of treatment" for various cogeneration plants which may be installed at different times. The possibility of future changes in environmental rules, either in the form of relaxation or increased severity, tends to prevent industrial commitment to cogeneration plants.
6. Increase the investment tax credit presently allowed for cogeneration facilities from 10% to at least 20%. (It

should be recognized that such a tax subsidy will inherently require a compensating tax increase somewhere else).

7. Allow a faster write-off for tax purposes for steam producing equipment prematurely retired because of the installation of a cogeneration plant. Similarly, allow a faster write-off for tax purposes on the cogeneration facilities themselves.
8. Allow, without tax or other penalty, the continued use of oil (or in special cases, gas) for existing boilers retained as part of an overall steam supply system with a cogeneration plant. Also allow the addition of new, temporary oil-burning "package boilers" to cover periods between module additions to the cogeneration plant. This should allow continued use of existing equipment for peaking and backup services while improving the economy of cogeneration and the use of coal.
9. Establish rules clarifying which portion of a cogeneration plant will be eligible for funding through the use of pollution control bonds.
10. "Honest brokers" should be used as appropriate in various regions of the country to help solve the institutional and business problem involved in community cogeneration plants.

State Government Actions

Complementing Federal government action, a number of steps by state governments are desirable.

1. Clarify environmental requirements.
2. Establish in advance the basic regulatory policies that will apply to cogeneration.
3. Consider allowing CWIP for cogeneration plants owned by utilities to be put in "rate base."
4. Local states and communities should delay property taxes on cogeneration installations until the savings from the plants have begun to accrue to the owners.

Industry Actions

The industrial concerns located in the areas where community cogeneration plants are feasible should, as a first step, investigate the possibility of "pooling" their existing steam sources through the establishment of a thermal energy network that includes condensate return (see Figure 14). This investigation should include an analysis of the costs and benefits from the adoption of incremental cost dispatch of steam and an arrangement for buying and selling existing steam reserve capacity.

The possibility of reducing the number of steam pressures used should also be investigated. This study should look at what could be done initially and over a period of time to reduce overall community steam generating and transmission costs, with all participants sharing in such cost reductions.

FIGURE 14
POOLING OF PRESENT STEAM FACILITIES
ILLUSTRATION OF CONCEPT

An essential ingredient of such a thermal energy network study is the collection of availability data for the existing equipment and hourly steam use data. This information would be used to make a detailed reliability analysis. Production cost simulation based on incremental costs would also be desirable. The use of incremental costs will result in the economic analysis being based on minimization of overall costs and comparison of the "out-of-pocket" costs for each participant for the various alternatives, rather than an analysis of average costs. (Techniques and computed programs used by the electric utilities for many years could be applied to these purposes.)

While these suggestions require the exchange between industrials of data and cost information heretofore considered proprietary, the potential savings from the procedures should help to overcome reluctance on the part of individual industrial concerns. A qualified consulting firm may be in the best position to coordinate such an investigation.

After determination of the costs and savings of a community approach to the use of existing steam facilities, the future needs of the group should be investigated. Of particular importance would be a study to investigate a number of possible alternate cogeneration additions. A number of steam supplies, such as 200,000 pounds per hour, 500,000 pounds per hour, and 1,000,000 pounds per hour for the cogeneration modules should be checked to determine the optimum size. Also, a number of possible locations for the cogeneration installations should be investigated. The smaller modules will lend themselves to dispersed installation at various points along the thermal energy network. Such an arrangement would have as an important

advantage the ability for each plant to control and operate a significant portion of its own steam supply. Also, contractual problems could be appreciably decreased by such a dispersed steam source arrangement.

To determine the best arrangements for fuel, the possibility of a joint community arrangement for coal and its transportation, storage, and handling should be investigated. One possibility would be a jointly owned coal supply company or coal terminating facilities.

In these investigations of alternate expansion patterns, overall system reliability calculations should be made based on the operation of existing and newly installed facilities in a coordinated manner. Also, economic evaluations should be based on incremental cost dispatch to determine which of the existing facilities should be operated for peaking service or backup for each alternate cogeneration program. In all of this work a total system long-range approach should be used in order to determine the overall optimum energy operation from the viewpoint of the steam needs of the industrials.

Also, as part of this analysis, possible mechanisms for curtailing steam use by specific industrial concerns during equipment outages or failures should be investigated. One approach would be for each company to indicate the compensation it would require for reducing its steam take below its needs for each company based on the incremental value for its lost production. An industrial group using this mechanism should be able to reach an equitable arrangement.

Utilities Actions

In their review of the economics of cogeneration, the utilities should not make the mistake of analyzing a cogeneration project by itself, without

considering its effect on the rest of their business. Rather, they should compare their future total system costs with cogeneration plants to their total costs with the other alternate capacity additions possible on their system.

In their reliability analyses to determine their own reserve requirements and the reserve requirements to back up cogeneration plants owned by others, the utilities should analyze all cogeneration plants as a group, rather than individually.

Joint Utility - Industry Actions

After the industrial companies have studied their alternate expansion patterns and determined the ones preferable for steam supply, they should meet jointly with the utilities, which have determined their optimum expansion pattern for an electric supply viewpoint. A review of the programs for the two groups should indicate whether a joint study would be desirable to determine the best answer from the total energy viewpoint, i.e., the industrial plus the utility viewpoints and the steam plus electricity viewpoints. This joint study would involve the comparison of the electrical capacity added through cogeneration with the electric capacity that would otherwise be installed by the utility. The study would indicate not only the optimum electric and steam development program but could provide the basic information required for a utility/industrial ownership and contractual arrangement to equitably split the benefits received from coordination. Even if a joint project does not materialize, the study could be used as a basis for establishing actual electric backup costs to the industries. Obviously, such a joint study approach will involve complexities

and problems, mainly because of the number of participants and their differences in viewpoint. However, these problems may be justified if the resulting savings are of sufficient magnitude. Because of the many expected differences of viewpoint between the participants, the use of consulting services will probably be desirable in this work.

Conclusion

Even though clear stable government rules are presently lacking, many of the steps suggested for industries and the utilities can be taken at this time. Such action should put them in a good position to decide the extent of their participation when government rules become available.

The steps recommended should contribute to the removal of artificial constraints to the use of cogeneration and the establishment of a spirit of cooperation between industry, government, and the utilities. The economic welfare and sound competitive position of industry is of vital concern to all.

APPENDIX A

Summary of Industrial Interviews
Orange, Texas

	COMPANY A	COMPANY B	COMPANY C	COMPANY D	CONSENSUS OF REPLIES														
1) Corporate Decision Process																			
a) Sequence	<p>Sponsoring operating location puts together facts, makes economic evaluation, and initiates normal approval process.</p> <p>Decision will be an overall corporate decision in which overall corporate welfare governs.</p> <p>Departments involved are:</p> <ul style="list-style-type: none">Plant Management.Division Management.Corporate Energy Resources Department.Financial Department (Review of Economics).Top Executive Level.Board of Directors. <p>A major problem is reluctance of plant managements to shift to coal with which they have no experience in a large multi-company situation. Overall corporate "instructions" may be required to achieve shift.</p> <p>Procedure will be the same if company does project on own or is part of a community project.</p>	<p>Department or plant recognizes need: capacity, new product, cost saving.</p> <p>Engineering Department makes investment estimate. Operating and Finance Departments make overall economic analysis.</p> <p>Proposed project included in "Construction Forecast" for financial planning purposes.</p> <p>Project justification provided by Operating Department.</p> <p>Final decision on major projects made by Executive and Financial Committees, both of which report to the Board of Directors.</p> <p>Approval Sequence:</p> <ul style="list-style-type: none">Departments Involved—Division LevelDepartments Involved—General Management LevelExecutive CommitteeFinance Committee	<p>Initiative for cogeneration must be taken at the operating plant. Must be justified locally—economically.</p> <p>Put in Corporate Budget which is five-year plan for capital expenditures (six months to one year before evaluation).</p> <p>Operating group involved makes economic evaluation jointly with Divisional group.</p> <p>Sequence:</p> <ul style="list-style-type: none">Operating Plant and Divisional RecommendationDivisional V. P.Group V. P. (Review by "controller" group)Group President (Review for competitive position)Corp. President and Chairman (Review by Corporation Controller)(Corporate Planning Department will review for coordination with other corporate activities)	<p>Local Plant Management.</p> <p>↓</p> <p>Division President</p> <p>↓</p> <p>Group President</p> <p>↓</p> <p>Executive Committee</p> <p>↓</p> <p>Board of Directors</p>	<p>Plant Management</p> <p>↓</p> <p>Division Management</p> <p>↓</p> <p>Financial Department</p> <p>↓</p> <p>Top Executive Level</p> <p>↓</p> <p>Board of Directors</p>														
b) Time Required	<p>About two years will be required in the decision making process.</p>	<p>Study phase—twelve months</p> <p>General approval—twelve months</p> <p>Detailed design and construction estimate—15 months</p> <p>Intercompany contract negotiations and construction—36 months</p> <p>Multi-company approach would add twelve months during these steps.</p>	<p>Plant reviews—two years</p> <p>Corporate review—one year</p> <p>Permit—one year</p> <p>Design and construction—three or more years</p> <p>Total seven or more years until cogeneration plant can be in operation.</p> <p>Firm commitment to a cogeneration plant will not be made until <u>all permits</u> have been obtained.</p>	<table><tr><td>Plant and division study</td><td>1 to 2 years</td></tr><tr><td>Design and construction</td><td>3 to 4 years</td></tr><tr><td>Total</td><td>4 to 6 years</td></tr></table> <p>Only limited expenditures will be approved until all environmental permits have been obtained.</p>	Plant and division study	1 to 2 years	Design and construction	3 to 4 years	Total	4 to 6 years	<table><tr><td>Plant study</td><td>1 to 2 years</td></tr><tr><td>Corporate review</td><td>1 year</td></tr><tr><td>Design and construction</td><td>3 to 4 years</td></tr><tr><td>Total</td><td>5 to 7 years</td></tr></table> <p>No major expenditures until all permits have been received.</p>	Plant study	1 to 2 years	Corporate review	1 year	Design and construction	3 to 4 years	Total	5 to 7 years
Plant and division study	1 to 2 years																		
Design and construction	3 to 4 years																		
Total	4 to 6 years																		
Plant study	1 to 2 years																		
Corporate review	1 year																		
Design and construction	3 to 4 years																		
Total	5 to 7 years																		
2) Key Factors in Decision																			
a) Government Action	<p>NEA provisions will be important factor.</p> <p>No decision will be made until:</p> <ul style="list-style-type: none">Gas supply is curtailed, orGovernment orders halt in use of gas, orEconomics become more favorable.	<p>Waiting to see NEA provisions.</p>	<p>Waiting for guidance from National Energy Act. Will not spend any money for cogeneration until ordered to change fuel or until economics justify project.</p> <p>Already spending money to change from gas to oil as ordered by Texas Docket 600.</p>	<p>Have established Corporate Energy Policy Committee to follow National Energy Act developments and decide on resulting corporate action plan.</p>	<p>Outcome of the National Energy Act.</p>														
b) Regulation	<p>Not willing to be part of any arrangement which will be regulated.</p>	<p>Not willing to be part of any arrangement which will be regulated.</p>	<p>Do not want to be part of a regulated industry. Feel cogeneration plant should feed utility grid if desirable without causing regulation.</p>	<p>Do not want to be involved in a plant or organization that is regulated.</p>	<p>Companies do not want to be part of any arrangement that is regulated.</p>														
c) Holding Company Act	<p>Does not want to fall under Holding Company Act. Would want cogeneration specifically exempted.</p>	<p>Want to be exempted.</p>	<p>Want cogeneration to be exempted.</p>	<p>Do not want to come under its jurisdiction.</p>	<p>They want to be exempted from Holding Company Act.</p>														
d) Economics	<p>Believe best economics for cogeneration is for new plants. Retrofitting into existing plants will be difficult to justify economically.</p>	<p>Requires much study. Major investment, must offer reasonable return.</p>	<p>Have been making own study with local utility and a consultant. Results will be critical to corporate decision.</p> <p>Can build "product" plant for less cost than that of cogeneration plant to supply "product" plant with steam and electricity.</p>	<p>Management wants cogeneration to cost less than present costs.</p> <p>Results show cogeneration not economic compared to present costs.</p> <p>Willing to participate in joint economic study with local utility evaluating energy system expansion alternatives to a combined basis.</p> <p>Future economic competitiveness of products produced by plant is in doubt.</p>	<p>Better for new plants. Difficult for cogeneration to cost less than present steam supply for existing plants.</p>														
e) "Insurance" Value of Shift to Coal	<p>Puts little value on better assurance of an energy supply to plant since uncertainties with cogeneration balance uncertainties with other energy sources.</p>	<p>Put little value on better assurance of an energy supply from shift to coal. Their plant requires oil and gas as a chemical feedstock. Plant operation cannot be isolated from oil availability by conversion to coal.</p>	<p>See little insurance for coal cogeneration.</p>	<p>Of minor importance.</p>	<p>Little value in insurance of coal cogeneration. Will still require oil and gas as feedstock for product plant operations.</p>														
3) Cogeneration Organizational Arrangements																			
a) Industrial Community Ownership	<p>Suggest three-step procedure:</p> <ol style="list-style-type: none">Study phase—Each company to provide one representative to make preliminary analysis.Establish an interim organization to do detailed feasibility study.Establish a separate new company to do design, construction, and operation.	<p>Willing to participate.</p> <p>They presently buy steam and sell steam. Completely open on organizational structure.</p> <p>Willing to have someone else take over responsibility for their energy supply if adequate controls are provided. If others own it, this company would want right to review designs, operating procedures, etc.</p>	<p>Acceptable, but would prefer to put money in producing corporate products. More comfortable using talents in own business.</p> <p>Will require top corporate approval.</p> <p>Cannot tolerate domination in decisions by larger industrial plants in the area.</p>	<p>Willing to participate but prefer others provide steam and electric supply for their operations.</p>	<p>First preference is for others to produce steam and electricity for their use. However, they would want same say in organization, design and operation. Willing to participate if necessary.</p>														
b) Utility Ownership	<p>This is an acceptable arrangement.</p> <p>This company would not want to participate in a joint ownership arrangement with utility if it would result in regulation.</p>	<p>Acceptable.</p>	<p>Preferable. Would prefer to buy steam and electricity from a reliable supplier than to produce themselves.</p>	<p>Prefer purchasing all steam and electric needs from others.</p>	<p>This arrangement would be acceptable. They would prefer buying steam and electric from others.</p>														
c) Third Party Ownership	<p>Acceptable and probably preferable.</p>	<p>Acceptable.</p>	<p>Preferable.</p>	<p>Acceptable if price is competitive.</p>	<p>Acceptable and preferable.</p>														

Summary of Industrial Interviews
Orange, Texas

	COMPANY A	COMPANY B	COMPANY C	COMPANY D	CONSENSUS OF REPLIES
4) Financial Considerations					
a) Financial Evaluation Process	Use discounted cash flow method of analysis year by year for expected life of plant. Include inflation and escalation in cash flow analysis. Favor "off balance sheet" financing even though accounting rules will require showing on a capitalized basis. Assume expected life of cogeneration plant the same as that of the existing product plant. Obsolescence of product is the only reason plants will cease operation. "Payback" period is not a primary criteria in financial evaluations. Not interested in getting into cogeneration business and supplying steam and electricity for others. Only interested in own needs.	Use IMR (Investor's Method Return) basis for evaluation for 20 years (equivalent to discounted cash flow analysis). Look at projects based on 100% equity investment, then examine effects of leveraging off-balance sheet financing, etc. Economic evaluations made by comparing profitability of cogeneration investment with putting capital into chemical business. Projects compete with each other. Rate of return is most important but not only criteria. Not interested in getting into cogeneration business other than to supply own needs. Willing to put up its "pro rata" share of capital in a cogeneration project. Assuming 20-year life for cogeneration in evaluation.	Use discounted cash flow method of analysis year by year for life of plant. Will calculate for 25- or 30-year period. Return compared with other alternatives along with DCF for any large capital project such as cogeneration. All three economic indicators are evaluated. NPU and payback period are calculated. Inflation included in calculations. Favor "off-balance sheet" financing.	Use discounted cash flow method of analysis, year by year, for both expected economic and book lives of plant. Look primarily at after tax return on total investment without leveraging. Project would have to compete for capital with regular product lines. Off-balance sheet financing has not been a significant factor in economic evaluations. Assume economic life of cogeneration plant at the Orange site would be short, due to uncertainty of certain product lines. Could have major retirements there within five years. Payback period has not been an important economic indicator. Not interested in getting into cogeneration business to supply others.	1) Use discounted cash flow method of analysis. 2) Expected life 20-30 years. 3) Most favor or at least look at "Off Balance Sheet" financing. 4) Payback period not an important economic indicator. 5) Companies would have to check profitability of investment in cogeneration with investment in own business. 6) Companies only interested in supplying own steam needs. 7) Economic life of cogeneration could be short due to uncertainty of product lines for one company.
b) Sensitivity Analyses	Would check changes in key assumptions in doing economic and financial evaluations. Particularly alternate fuels and electrical costs.	Largest risk in cogeneration project is possible error in projecting future delivered fuel prices, and need and costs for scrubbers. Changes in government energy, environmental policies.	Analyze effect of changes in key variables, particularly effect of changes in fuel costs and cost overruns for construction of cogeneration plant.	Concerned about the many uncertainties confronting business at present. Rapid changes in technology, markets and fuel costs.	Would perform sensitivity analysis on changes in fuel and electric costs, government energy and environmental policies and technical and market conditions for product.
c) "Hurdle" Rate of Return	15% to 18% return required on total capital after taxes.	Projects begin to look attractive if IMR return on 100% equity basis is 15% or higher. 15% rate not rigid—depends on other investment opportunities available, overall capital constraints, etc. Corporate policy is to accept a slightly lower return on projects which save energy, if otherwise justified.	13% return (DCF) after taxes required as a minimum based on entire project being funded by equity. Projected rate of return is compared with risks.	Starting point for a new business investment is a 14.5% after tax return on a 100% equity basis. Have lower starting points for capacity additions and projects that result in cost savings.	Projects begin to look attractive when return is 13% to 15% after taxes on 100% equity funding.
d) Type of Joint Venture	Would prefer some other responsible group take on job of providing them with steam and electricity. Do not like separate ownership of steam and electric facilities	Completely open on type of joint venture to be set up. Willing to have another responsible group take over responsibility for supply of their steam and electricity. See no advantage for separate steam and electric companies except to avoid regulation.	Open on type of joint venture. Do not like separate steam and electric companies. Inefficient from operating viewpoint.	Would prefer to have a utility provide their steam and electricity requirements. Might invest in a community project if the economics were favorable. Separate ownership of steam and electric facilities does not sound too good.	<u>Companies prefer others to produce steam and electricity</u> , and are open on the types of joint venture; they would invest if the economics were favorable. <u>See no advantage to separate steam and electric ownership of cogeneration facilities.</u>
e) Take or Pay Contracts	Would sign 20-year "take or pay" contract.	Term of contract open for negotiation. Will depend on benefits.	Willing to sign take or pay contract. Product plant usually runs at full capacity for entire year.	Would consider a long-term contract at Orange plant only on part of the present consumption. Would only sign for ten years at other old plants.	Some would be willing to sign take or pay contract for 20-year period, others will only sign short term contracts.
f) Pricing Arrangements	Want steam priced based on operation of cogeneration plant at 80% of maximum capacity. Willing to pay fixed charges and quantity charges. Suggest quantity charges be on a "Btu" basis.	Steam and electrical pricing complex, need to reflect cost, investment and backup factors. Want each participant in community cogeneration project to pay own share of fixed charges based on commitment when project authorized unless agreement reached between increasing and decreasing member companies.	Fixed charges should be based on capital investment and other fixed expenditures. Variable charges should be based on fuel and operating costs.	Fuel steam and electricity probably could be priced on a "Btu" basis. Higher cost steam should be sold at a premium.	Pricing structure should have a fixed charge. Fixed charge should be based on capital investment and other fixed costs. Variable charges should be based on fuel and operating costs. Steam should be purchased on a Btu basis.
g) "Risk" Opinion	See cogeneration as a normal business risk.	See investment in cogeneration plant as slightly less risky than investment in normal product plants. If market for product disappears, cogeneration plant might be useable for other purposes.	Cogeneration is not part of normal business line. Technology of cogeneration as proposed is <u>dated</u> and may be surpassed in near future.	Cogeneration is now seen as a new business type of risk.	Some see cogeneration as more risky than normal business risks, some less risky.
h) Use of "Pollution Control" Bonds	Willing to consider for financing.	Acceptable if feasible.	Desirable.	Have used where feasible.	Acceptable.
i) Payments During Construction Period	Not willing to make any payments until energy is received from the cogeneration plant if owned by others. If a consortium of which they are a part owns they prefer to contribute equity rather than advanced payments.	Would be willing to consider making some payments during the construction period if the return would be sufficient. (They have done so in the past.)	Would take a long hard look at this if someone else owns the plant before agreeing to make such payments.	Questionable that they would make advance payments during the construction period. Might consider if economics were attractive.	Doubtful that any advanced payments during construction would be made. Some might consider payments if the economics were very attractive.
j) Treatment of Construction Cost Overruns	Feel "take or pay" contracts will have to include cost overruns in the basis for pricing. This is one of the risks that will be investigated in sensitivity analysis.	Will not sign a contract for a community cogeneration project until 40% to 60% of engineering design is completed to provide good assurance on costs. Cost overruns will have to be borne by the participants in one way or another, thus emphasis must be placed on obtaining realistic bids before contracts are signed.	Would have to be borne by steam and electric consumers under take or pay contracts.	Would have to be covered in the contract with the steam and electric customers.	Cost overruns would have to be covered by the "take or pay" contracts. One company will not agree to participate until 40%-60% of engineering design is complete and costs relatively assured.
k) Inflation	Included in all financial and economic projections. They use actual expected cash prices and costs.	Included in all financial and economic projections. They use forecast prices and costs in current dollars.	Included in all financial and economic projections. Fuel escalation estimates and sales price escalation estimates developed by other sources in company.	Include inflation factors in their financial evaluation process.	All companies include inflation financial and economic projections. Forecast prices and costs are in "current" dollars.

Summary of Industrial Interviews
Orange, Texas

	<u>COMPANY A</u>	<u>COMPANY B</u>	<u>COMPANY C</u>	<u>COMPANY D</u>	<u>CONSENSUS OF REPLIES</u>
5) Engineering and Operating Factors					
a) Participation in a Community Cogeneration Project	Willing to participate.	Willing to participate provided they will still have a strong voice in determining designs and operation procedures to assure cost and continuity objectives are attained.	Willing to participate reluctantly. Look favorably on consideration of a nuclear cogeneration plant.	Willing to participate.	Willing to participate. Would want voice in design and operation.
b) Changes in Future Needs	Can foresee no great change at the Orange, Texas site at this time.	See no major increase in steam needs in next ten years. Expect to reduce present steam requirements slightly through increased plant investments to use heat presently wasted. Capacity released should provide for some future growth. Operating departments make forecasts of future needs. Purchasing department responsible for procuring fuel needs on a corporate basis.	See no major change in present needs. Reducing steam used by existing processes in order to provide for future increased needs.	Steam and electricity needs are likely to decrease. Steam needs could go to 20% of present needs in three or four years.	No increase, probably reduction in total steam needs at Orange site through conservation, more efficient use, and some decline in product markets.
c) Reliability Required	Concerned about reliability of steam and electric supply from cogeneration plant. Desire that cogeneration plant be designed to meet their maximum steam needs at 85% of its capacity. Major problem on loss of steam and electrical supply would be damage to equipment and lost business.	As good as present arrangement. Need steam sources with high reliability. Believe provision of complete standby in the cogeneration plant will be too expensive.	Supply as reliable as present supply. Sufficient steam capacity should be provided so 98% of load can be supplied.	As good as present system. Can tolerate very infrequent shutdowns.	Highly reliable source required, at least as reliable as present system. Complete standby capacity in cogeneration plant not feasible.
d) Disposition of Existing Boilers	Would need two existing boilers on "hot standby" and retain all other boilers on "cold standby" with a four-hour start-up time. Would want compensation for these boilers if other companies benefit from them.	Would continue operation of some of existing boilers since these burn own wastes which would be difficult to dispose of any other way. This could provide backup up to 20% of their steam needs. Would want compensation for these boilers if other companies benefit.	If cogeneration plant steam supply is considered sufficiently reliable, existing boilers will be put in "cold standby," except for one which will be operated at partial load to burn waste gases from plant. Willing to use "cold standby" boilers to help backup cogeneration plant. Want compensation for use of these boilers for this purpose. Final decision on disposition of existing boilers would be made after few years of operating experience with cogeneration plant.	Want to discontinue operation of their existing boilers. Do not want to keep any boilers on "cold standby." Willing to pay for "backup" services from existing boilers in other industrial plants. Will not abandon existing boilers until they have at least six months operating experience with cogeneration plant.	Except where boilers are used to burn waste products, boilers for the most part would be put on "cold standby." If boilers would be used as backup for cogeneration facility, companies want to be compensated. Companies would abandon boilers only after cogeneration has sufficiently proven itself.
e) Industrial Plant Load Curtailment	Can cut back on load 10% to 20% in emergencies without damage to equipment. Can reduce further by starting up boilers in "cold standby."	Little possibility of curtailing plant demand, load on steam plant could be reduced by increasing the output of the boilers retained in the plant.	Have some curtailable load but this should not be counted on for normal contingencies. Prefer to reserve ability to curtail load for emergency situations that may occur. Willing to curtail use of steam through operation of cold standby boilers.	Can reduce load (reluctantly) by reducing production.	Industrial steam load could be curtailed very little, if at all. Steam load on cogeneration plant can be reduced by starting up boilers on "cold standby."
f) Use of Existing Makeup Water Capability	Requires investigation. Existing water treatment probably not adequate for high pressure boilers.	Could send some "makeup" water to the cogeneration plant. Would have to be demineralized before it could be used. Economics need study.	No makeup water can be provided. Condensate will be returned.	Can return part of the condensate.	For the most part, no makeup water can be provided. Some companies can return some condensate. Further investigation and economic study is required.
g) Fuel Considerations	Use of coal would be difficult for plant operators to accept. Would continue to need some oil and/or gas as a fuel for standby boilers.	Major question is future prices and need for scrubbers.	Concerned about coal transportation system and its adequacy to provide needed coal supply.	Would seriously consider cogeneration if required to convert existing operation from oil to coal.	Concerned about plant operators reluctance to use coal, future prices, transportation problems, and need for scrubbers.
h) Lead Times	See major problem in new plants because of difference in lead times between product plants (three years) and cogeneration plants (six years). Some temporary steam supply arrangement will be essential. Suggest use of "exempt" oil fired boilers for this purpose, with these boilers providing backup steam supply after cogeneration plant is in service.	An important problem for new plants since cogeneration lead time is much greater than lead times for new product plants.	Concerned about long lead time for cogeneration.	Cogeneration lead time presents a major problem in view of future uncertainties faced by product plant.	Long cogeneration plant lead times are major impediment to use of cogeneration; product plant lead times are considerably shorter. Companies will not commit to an energy supply prior to product plant commitment.
i) Overbuild Policy	See no need for overbuilding capacity to provide for possible future steam use increases. Willing to provide some condensing capacity to provide excess electricity to local utility grid initially and could be used to provide additional process steam if needed later.	Would not overbuild. Would leave room (land) for future expansion if feasible.	See no need to overbuild. Prefer modular cogeneration plant design.	See no need for overbuild in cogeneration plant.	Companies see no need to overbuild for possible future needs. Would leave room for future expansion of modular units is preferred.
j) Design and Construction Responsibility	See no special problem with community cogeneration project.	Would want to be involved to insure reliability and adequacy.	Want a voice in cogeneration plant design, i.e., capacity. Most economical balance of electrical and steam, etc.	See no special problems with a community cogeneration plant.	Some companies would want to be closely involved in design to insure economics and reliability.

Summary of Industrial Interviews
Orange, Texas

	COMPANY A	COMPANY B	COMPANY C	COMPANY D	CONSENSUS OF REPLIES
k) Operating Responsibility	See no operating problems. Operating staff should handle coordination of steam supply equipment maintenance schedules both in plants and cogenerating station. Utility operation acceptable unless it leads to regulation.	Would want to be involved to insure reliability and adequacy. See problems in coordinating maintenance outage schedules between plants supplied by a community cogeneration project. Require steam pressures to be controlled to within 1%. Good working relationship between all participants is essential.	Concerned about management and operation of cogeneration plant, particularly the domination of the larger industrials in operating decisions. Prefer local utility be hired as operating agent even if ownership is by industrials. Concerned about provisions for adding additional steam customers later. Variations in steam temperature and pressure must be very small.	See problems in scheduling "shutdowns" for maintenance on a coordinated basis. Do not like separate electric and steam ownership. See major operating problems resulting.	Maintenance and shutdown of unit would have to be coordinated among all participants. Some concern over domination of operation by larger industrials. Need close pressure and temperature control.
l) Use of Existing Electrical Substation and Transmission Facilities	Existing electrical substation and transmission facilities should be used to deliver electrical output of the cogeneration plant. Industrial plant can purchase substation from utility if it desires.	Some substations are owned by the utility and some by the company. Believe existing substations should be used to handle output of cogeneration plant to the extent possible.	Existing substations and transmission <u>should be</u> used to deliver output of cogeneration plant. Would prefer utilities agree to "wheel" electricity from cogeneration plant to industrial plants. Duplication would be a <u>ridiculous</u> overbuild.	Must be used instead of building new facilities.	Existing substation and transmission facilities should be utilized. Industrials could purchase substations if they desire.
m) Labor and Union Considerations	See no problems, advantages or disadvantages with a "community" cogeneration plant. Could be a problem in staffing in-house "standby" boilers.		Product plant is nonunion. Do not wish union interference. If after start-up employees wish to organize, it is their choice and should not be <u>mandated</u> initially.	No problems foreseen.	No problems foreseen except staffing of in-house "standby" boiler equipment. Employees' choice to unionize after startup of cogeneration plant.
n) Utility "Backup" Arrangements	A major impediment to cogeneration is the cost of utility "breakdown" service. Suggest utility work out special contractual arrangements to cover based on probabilities, diversities of needs, and actual utility costs.	Would have to develop reasonable backup arrangement with utilities.	Vital that cogeneration plant should feed utility grid if and when desirable <u>without</u> penalty.	Concerned about excessive charges for electric "backup" service.	Concerned about excessive backup charges. Facility should be connected to grid and operated in most economic manner. Prefer separate contracts based on cost/benefits to standard roles.
6) Suggested Future Action					
a) By Government	Exempt cogeneration plants from regulation and the Holding Company Act. Exempt oil and/or gas used in "backup" or standby boilers from "use tax." Allow installation of new boilers designed only for oil firing during first few years of operation at new product plant sites for which a cogeneration plant is being installed. Exempt oil used in such boilers from "use tax." Provide economic incentive including investment tax credit. Exempt utility subsidiary that own and/or operate a facility from regulation.	Approval of: <ul style="list-style-type: none">• Fast tax writeoff for investment withdrawn prematurely because of installation of cogeneration plant.• More investment tax credit.• Accelerated depreciation of new investment. Exemption from: <ul style="list-style-type: none">• Regulation.• Environmental requirements for scrubbers if low S coal used. Intervene in state hearings when helpful. Don't penalize those who are going to cogeneration compared to those who are not. Guarantee of contracted steam supply which cannot be jeopardized by expansion of the service area.	Provide government energy policy to guide decisions. Exempt cogeneration plants from utility regulation. Exempt cogeneration plants from present restraints. Simplify permit problems, particularly environmental. Allow use of oil or gas in backup boilers without use tax penalty. Simplify procedures for arranging with local utility for backup service, use of present substation and transmission facilities, and wheeling. Government subsidies not looked on too favorably—prefer to see marketplace provide solutions. Let the free market work.	To cover long-term risks involved in cogeneration. Industry could cover risks in the first few years with government guaranteeing costs from the fifth year on. Believe government subsidies needed to prove in cogeneration economically. Particularly suggest: <ul style="list-style-type: none">• Investment tax credits• Lift 50% ceiling on investment tax credits which can be used.• Allow use of existing and potential future taxes on other fuels to be used to build cogeneration plants.• Allow fast tax write-off for prematurely retired steam facilities.• Allow tax depreciation of construction work in progress on cogeneration plants to offset long lead time problems.• Delay local property taxes on cogeneration plants.	Companies would like to see: <ol style="list-style-type: none">1) Exemption of facility from regulation and Holding Company Act.2) Reduction of environmental requirements.3) Exempt backup fuels from Use Tax if committed to cogeneration. Economic incentives in the form of Investment Tax Credits accelerated depreciation, and lifting 50% ceiling on rise of investment tax credits. Fast write-offs for prematurely retired steam facilities. Government guarantee covering long-term risks. Delay property taxes on cogeneration facilities.4) Stable Government Energy Policy to guide decisions.5) Let free market work more.
b) By Utilities	Establish special contractual arrangements with cogeneration plant owners for coordinated operations rather than use conventional "backup" rates. Contract should recognize diversity in backup requirements for several cogeneration plants during utility system emergencies through curtailment of load on utility system.	Development of some procedure for keeping backup costs reasonable, including consideration of diversity of needs for cogeneration plants. Perhaps cogeneration plant should buy supplemental and backup electricity from the utility for distribution and billing to the industrial plants.	Work with industrial concerns to develop overall economic solutions and equitable pricing arrangement.	Build cogeneration plants as needed by industry.	<ol style="list-style-type: none">1) Utilities should work with industrial concerns to develop economic solutions. Build and operate cogeneration plants needed by industry.2) Special utility-industrial contracts should be negotiated for "backup" rather than standard rates.
c) By Industry	Agree on "Full Coordination" operating approach for cogeneration plant, including operation of existing boiler facilities in individual plants and coordination of operations with needs of local facilities. Agree on compensation procedures when an industry or industries maintain and/or operate standby equipment for the benefit of other industries or the local utility.	Maintain present open-minded position.	Develop a community cogeneration institutional arrangement so that smaller industrials are not dominated by the larger industrials.		<ol style="list-style-type: none">1) Develop arrangements that are fair to all participants no matter what size.2) Coordinate operation of industrial boiler facilities with cogeneration plant operation.3) Agree on compensation for industries that maintain backup boiler facilities and standby equipment.

APPENDIX B

Summary of Industrial Interviews
Geismar, Louisiana

	COMPANY E	COMPANY F	COMPANY G	COMPANY H	COMPANY I	CONSENSUS OF REPLIES
1) Corporate Decision Process						
a) Sequence	<p>Economic analyses initiated in Energy Management Section</p> <p>In Corporate Headquarters</p> <p>↓</p> <p>Project Review Committee</p> <p>↓</p> <p>Engineering and Planning Committee</p> <p>↓</p> <p>Top Executive Level</p> <p>↓</p> <p>Board of Directors</p> <p>Business planning done on a five-year cycle. Future <u>energy</u> needs decided by business group. Energy and feedstocks group decide on <u>fuel</u> to be used.</p>	<p>Major concerns in decision are "on stream" availability and domination of the larger companies. Company has a Corporate Energy Department.</p> <p>Sequence:</p> <p>Economic Analysis initiated by Operating Division Engineers working with Corporate Energy Department.</p> <p>↓</p> <p>Approval of Division President (checks to see if compatible with future).</p> <p>↓</p> <p>Corporate Management Committee</p> <p>↓</p> <p>Executive Committee of Board</p> <p>↓</p> <p>Board of Directors</p>	<p>Business Center Recommendations</p> <p>↓</p> <p>Product Team Group</p> <p>↓</p> <p>Executive Vice President and President</p> <p>↓</p> <p>Board of Directors</p> <p>Preliminary "spade" work can be done without Board approval, up to several million dollars worth. Contract and basic principles would have to be outlined before board approval.</p>	<p>Anyone can come up with a project. Economic analyses are made initially by engineers. More detailed calculations are made in accounting. Projects that appear attractive at division level go to corporate office for a decision. At corporate level everyone in management, including the Board of Directors, can get involved.</p> <p>Authority sequence:</p> <ul style="list-style-type: none">• Vice President (division)• President (division)• Executive Vice President (corporate)• President (corporate)• Board of Directors	<p>Economic analyses can be indicated at all levels. Investment requests are reviewed by financial and engineering staffs. Final commitment would require approval by the Board of Directors.</p>	<p>Operating Division or Product Group or Energy Management Group.</p> <p>↓</p> <p>Division Management</p> <p>↓</p> <p>Division Senior Management</p> <p>↓</p> <p>Corporate Top Management</p> <p>↓</p> <p>Board of Directors</p>
b) Time Required	<p>Corporate approval process will require about twelve months.</p>	<p>Corporate procedures depend on amount of capital</p> <ul style="list-style-type: none">• Four months for growth or lowering of costs• Much longer—if cost increases results <p>Have hired consultant jointly with neighboring companies to make a study.</p> <p>Desire an operating agreement with other companies prior to final commitment. Could take several years to agree.</p>	<p>Normal internal corporate decision process on projects is three to six months.</p> <p>Decision process for a community cogeneration project could take up to five years because of complexities involving multi-company negotiations.</p>	<p>Can move fast on a project, as decision process is not very formal. Will do attractive projects that are not in the budget. Can get verbal approval for initial expenditures.</p> <p>Can make a decision in two to six months.</p> <p>Target date for coal fired cogeneration would be to have first boiler operating in mid-1982.</p>	<p>Corporate approval two months—one year</p> <p>Total time until operation four—six years</p> <p>Operating agreement with other companies desired before making final decision.</p>	
2) Key Factors in Decision						
a) Government Action	<p>Government subsidies will determine when cogeneration is installed. Expect to put in cogeneration sooner or later. Larger subsidies will cause it to be sooner. Inverted electrical rates, or other rate measures penalizing industrials would spur use of cogeneration. Would even put in own condensing generation if this occurs.</p>	<p>Want stability in rules. Can't make plans with rules frequently changing.</p> <p>Want "equality of treatment" with competitors; don't allow one installation without scrubbers and require scrubbers on the next.</p>	<p>Will cautiously assess the risk in taking action if government regulations are uncertain.</p>	<p>National Energy Act provisions will be important.</p> <p>Would want cogeneration to be exempted.</p>	<p>The uncertainty of government laws and regulation are an impediment to projects of this kind.</p>	<p>1) Want stable government rules. Will take no action until National Energy Act passes.</p> <p>2) Government subsidies will determine timing.</p> <p>3) Measures such as inverted electrical rates penalizing industrials would spur cogeneration.</p>
b) Regulation	<p>Not willing to be regulated.</p>	<p>Will not participate in a regulated project.</p>	<p>Do not want to be part of a regulated project.</p> <p>Find commission decisions can be highly political. Would only consider if some major offsetting advantage resulted.</p>	<p>Would want no part of a regulated project. Regulators want to look at other company operations. Can become very costly.</p>	<p>Would want to avoid participation in any project that would bring in any further regulatory authority.</p>	<p>Companies want no part of regulated project.</p>
c) Holding Company Act	<p>Should be modified to exclude cogeneration projects. Believe present act would put all participants under jurisdiction if utility involved in project.</p>	<p>Do not want to be involved.</p>	<p>Do not want to come under jurisdiction.</p>	<p>Would want cogeneration to be exempted.</p>		<p>Act should be modified to exclude cogeneration plants.</p>
d) Economics	<p>Studies show use of low Sulphur Wyoming Coal most economic, even with scrubbers.</p>	<p>Cannot afford to convert existing operation. Capital required to convert to coal comparable to present total capital investment in plant.</p> <p>Will consider cogeneration for growth in needs.</p> <p>Have made economic evaluations on both five-company bases and two-company bases for comparison purposes.</p>	<p>Will use cogeneration to provide for future expansion. Uneconomical to abandon existing steam plant. Replacement of existing steam capacity would occur only if cogeneration costs lower than present costs.</p>	<p>Consider best cogeneration economics to be in expansion facilities. Think economy of scale is in coal transportation handling, and coal contracts, rather than boilers.</p>	<p>Compare energy costs with various supply alternatives.</p>	<p>Cogeneration would be considered for plant expansion.</p> <p>For the most part, it would be uneconomical to abandon existing steam facilities to install cogeneration.</p>
e) "Insurance" Value of Shift to Coal	<p>Economics more important.</p>	<p>Looking at all future possibilities including nuclear, mine mouth coal, etc.</p>	<p>A broader resource base affords "insurance" against supply interruptions. The fundamental question, however, is the "cost of insurance" versus the risk of not having it. We believe the risk will become increasingly high as we approach the 1990's.</p>	<p>See no real great value to better assurance of an energy supply from shift to coal. Feel nuclear was a golden opportunity that has been thrown away.</p>		<p>See little insurance value of coal cogeneration. The economics are more important.</p>
3) Cogeneration Organizational Arrangements						
a) Industrial Community Ownership	<p>Very interested in the community concept. See big advantages in the economy of scale.</p> <p>Prefer a joint venture with a few companies, with one company to operate the plant for the group.</p> <p>Prefer not to sell any of electrical output to utility.</p>	<p>Not in favor.</p> <p>Prefer a separate profit making company to own—not the industrial consumers of the cogeneration plant.</p>	<p>Do not want to be in the energy conversion business unless essential to basic business.</p> <p>Where jointly owned cogeneration facilities are planned, we would want a degree of management and operating control sufficient to protect the dependent manufacturing plants for which the cogeneration plant provides support.</p>	<p>Would consider participating in a joint venture, however, normally tend to avoid joint ventures.</p> <p>Open as to organizational structure. Feel should be as small and streamlined as possible. Probably better to have one of users operate.</p>	<p>Would desire either an independent utility or an industry owned utility.</p>	<p>Some in favor of industrially owned cogeneration plant, others not in favor.</p> <p>Companies not in favor prefer to have a separate organization and operate the plant.</p> <p>All in favor of small number of participants.</p> <p>Problems grow as number of participants grow.</p>
b) Utility Ownership	<p>Do not favor.</p> <p>Believe "motivation" will not be as great as industrial ownership.</p>	<p>Preferred to industrial community ownership.</p>	<p>Prefer to buy from utility if it results in a lower cost than producing energy themselves.</p> <p>Would prefer a negotiated demand and energy contract. Could result in greater problem in achieving an acceptable design.</p>	<p>Acceptable if reliability and economies are good and there is no regulatory threat.</p>	<p>Acceptable.</p>	<p>Most companies prefer to have the local utility operate the cogeneration plant if it is cheaper.</p>
c) Third Party Ownership	<p>Acceptable, but not preferred.</p>	<p>Preferred to industrial community ownership.</p>	<p>Could result in a greater problem in achieving an acceptable design.</p> <p>Want assurance that performance will be good.</p>	<p>Acceptable if economies are good and have confidence in their ability to perform.</p>	<p>Acceptable.</p>	<p>Acceptable if economies and performance is good. Will result in greater design problems.</p>

Summary of Industrial Interviews
Geismar, Louisiana

	COMPANY E	COMPANY F	COMPANY G	COMPANY H	COMPANY I	CONSENSUS OF REPLIES
4) Financial Considerations						
a) Financial Evaluation Process	<p>Use discounted cash flow approach to project evaluation, by years, over the life of the plant.</p> <p>After tax returns on investment or present values compared with alternatives. Look at cogeneration as highly leveraged with 10% to 20% equity. Chemical projects are compared on a 100% equity basis.</p> <p>No strong interest in off-balance sheet financing. Do not like cogeneration financing interfering with ability to borrow for chemical business. Utility investments are operating necessities which do not, in themselves, add to our chemical business. The advent of coal and cogeneration make utility investment greater than gas and oil and therefore, a still larger capital drain. The by-product power recovery, generally, is an economically attractive addition to a coal-fired steam plant.</p> <p>Would use the tax life of 22.5 years in evaluating a cogeneration project.</p> <p>Payback period as compared to alternate fuels (e.g., oil) is calculated to establish the advantage of coal once the coal investment decision is made.</p> <p>Not interested in getting into cogeneration business to supply others, investment too high, and it is not our business.</p>	<p>Use discounted cash flow method of analysis, year by year, for life of the project.</p> <p>Look at return after taxes on total assets without leveraging. Off-balance sheet financing of no great value. It would be counted against credit rating.</p> <p>Cogeneration project would be analyzed for ten years to judge investment. Would look beyond ten years, but question ability to estimate impact of inflation for that long a period. Would look at five years in a lot of detail.</p> <p>Payback period is important in certain high risk deals but not necessarily in a cogeneration project.</p> <p>Not interested in getting into cogeneration as a basic business. Are starved for capital in basic business.</p>	<p>Normally use discounted cash flow method of analysis, by years, for the life of the project.</p> <p>Look at investment on nonleveraged and leveraged basis. Look at before tax and after tax returns on both total capital and equity.</p> <p>The importance of high leverage on any project varies from year to year depending on a company's cash flow and financial objectives. Low cost of capital is desirable if consistent with maintaining the desired corporate financial integrity.</p> <p>Consider value of money or earning power of capital invested. Other factors considered such as market strategies.</p> <p>Compare alternatives of going along, a community group, or a third party owner-operator.</p> <p>Off-balance sheet financing is a consideration.</p> <p>The IRS guidelines for chemical plant investment permit nine-year tax depreciation. Economic evaluations span differing time periods depending upon the type of chemical product involved, but typically a range of 10-15 years is used.</p> <p>Payback period is of some importance. Depends on how critical cash flow is at the time.</p> <p>Not interested in getting into cogeneration business to supply others. Looking for lowest cost steam.</p> <p>See a problem with joint industry ownership because of different credit rating of participants.</p>	<p>Don't use refined financial evaluation approaches.</p> <p>Most regular projects have been short lived.</p> <p>Generally look at before tax return on total investment including working capital, by years until investment is paid back.</p> <p>Cogeneration would be a long-term investment and would be looked at on a leveraged basis after taxes, year by year for its service life or a number of years.</p> <p>Would consider effect on company's loan ability.</p> <p>Off-balance sheet financing is a very important consideration.</p> <p>Would probably use 20 years in evaluating a cogeneration project.</p> <p>Payback period is important in regular business, not so much for cogeneration.</p> <p>Not interested in cogeneration as a business investment to supply others.</p>	<p>Discounted cash flow method used to evaluate energy alternatives based on 15% return.</p> <p>Returns are calculated on a nonleveraged basis.</p> <p>With an equity position, analysis would cover the entire life of the project.</p> <p>With no equity position, the analysis would cover a ten-year period.</p> <p>Off-balance sheet financing would be considered.</p>	<p>1) Use discounted cash flow analysis.</p> <p>2) Most use 20-30 life in evaluating project.</p> <p>3) Some interested in off-balance sheet financing, others are not.</p> <p>4) Payback period not important for cogeneration.</p> <p>5) Some concern on effect of cogeneration in getting capital for other projects.</p> <p>6) Not interested in cogeneration as a basic business.</p> <p>7) Some look at after tax return, others look at before tax return on total investment.</p>
b) Sensitivity Analyses	<p>Uneasy about working with a product (coal) where they have no experience, moving it over great distances, future transportation costs and fly ash and sludge disposal. Will Eastern or Western coal escalate faster?</p>	<p>Concerned about effect of future inflation on costs, particularly fuel.</p>	<p>Vary key parameters in studies.</p>	<p>Concerns include regulation, environmental requirements, coal handling and working in joint ventures. Question how fast government will force conversion to coal and where country is headed in its energy needs.</p>	<p>Cost of supply; fuel.</p>	<p>Concern over fuel cost escalation, coal transportation and handling, government requirement.</p>
c) "Hurdle" Rate of Return	<p>Not sure of proper hurdle rate for cogeneration. Third party owners would need to make a profit. Think a return of 10% or 15% on equity would be reasonable with solid take or pay contracts.</p>	<p>If their capital, would look for same return after taxes, as in their regular business. Prefer not to reveal this rate. Think utility should take a lower return on equity. Should only participate in profit to extent they participate in risk. Feel take or pay contracts makes the users primarily responsible.</p>	<p>Somewhere between 10% and 20% on total capital. Would look for same return on cogeneration as for the product lines it serves.</p>	<p>Normally a 20% annual return before taxes on total investment. Cogeneration would be looked at primarily versus alternatives. Might have no cash equity investment.</p>	<p>Assuming an equity position, a hurdle rate of return of 15% is required.</p>	<p>Required hurdle of return (10%-20%). Probably around 15% based on 100% equity.</p> <p>Looking for some rate of return as for product lines.</p> <p>Utilities should accept slightly lower return on equity because of "take or pay" contracts.</p>
d) Type of Joint Venture	<p>Strongly favor community cogeneration no matter what form of ownership. Appreciate economies of scale with coal. Regulatory area very critical. Under current environment (regulatory), difficult to justify risks of a partnership with a utility. Have seen what regulatory process can do to business when it becomes very political.</p> <p>Cogeneration must be removed from any jurisdiction.</p>	<p>Think best approach would be a third party owner-operator selling steam.</p> <p>Participate in many joint ventures and they are a nightmare. Strongest company wants to dominate. The more partners the more complicated.</p> <p>Would participate in community cogeneration fixed in size. Each increment of expansion has to be a new deal. Might do with one partner who they are comfortable with.</p> <p>Different bond ratings of companies present a problem. Don't think lower credit rated companies should pay higher share of interest. They contribute to overall economy of scale.</p> <p>Separate steam and electric ownership is interesting. Don't want utility portion under a commission. Won't deal with utility regulatory commissions, life is too short.</p> <p>Utility proposals to date involve no real equity contribution by utility. Do not feel that equity made available by investment tax credits involves sharing in risks.</p>	<p>Would be willing to join a community cogeneration project provided the economic and operating factors were favorable. Additional requirements more likely to go on a community basis. Very reluctant to put entire steam load in someone else's hands. Defining how to expand a community project is a problem. Compatibility of participants a very important factor.</p> <p>Want to know what happens when cogeneration plant is fully depreciated. Third party could have valuable facility. Appears there would be an advantage in steam users' ownership.</p> <p>In a perfect world they would own and operate, have 100% control. What does third party bring to table?</p> <p>See separate steam and electric ownership as a complication in operating the cogeneration facility and in avoiding adverse regulatory impact.</p> <p>Consider built-in incentives for all participants to perform as vital.</p>	<p>Considering a joint venture community cogeneration project for expansion of steam facilities to be owned by the steam users. Might include utility company in ownership with options to buy them out at any time.</p> <p>Tough trying to reach agreement in joint ventures. Companies have different standards, return requirements, timing needs and philosophy. Each additional company makes the problem worse.</p> <p>Terms for expanding cogeneration project can be tremendous problem. Should be determined ahead of time.</p> <p>See large companies way of going costing a lot of time and expense. We also like to be in control of our energy requirements.</p> <p>Might prefer getting together on coal and going own way on steam.</p> <p>Would purchase energy requirements from an outside source with good economics and an assured supply.</p>	<p>All willing to participate in joint venture but most prefer a third party as owner.</p> <p>Have had difficulties in past with joint venture agreements.</p>	
e) Take or Pay Contracts	<p>Would consider life of project (22.5 years) for a take or pay contract.</p>	<p>Would sign take or pay contracts that supported economic results. If sign take or pay contract would want to fully review financing plans and arrangements of the owners.</p>	<p>Would negotiate on twenty-year contracts. Would compare conversion results with present steam cost, if not mandated.</p>	<p>Would consider a take or pay contract to cover the fixed charges of the project. Same guarantee as if we did the project ourselves.</p>		<p>Companies would consider take or pay contracts to cover fixed charges for as much as twenty years.</p>
f) Pricing Arrangements	<p>Feel pricing should have both commodity and fixed charge components.</p> <p>Fixed charge to cover interest on debt, amortization taxes, operating labor.</p> <p>Variable charges to cover return on equity, fuel.</p> <p>Steam Intensive Operation: Steam should get credit for condensate and power. Probably use utility's industrial rates for pricing electric power.</p> <p>Power Intensive Operation could require a variety of approaches.</p>	<p>Steam should be priced on a demand charge and commodity charge basis.</p> <p>Electric power should be based on utility rates.</p> <p>Some compensation need for contributions made by existing plants of participants.</p>	<p>Prefer some form of incentive contract (see 5-k).</p> <p>Would have both a demand charge and a commodity charge for steam.</p> <p>Electric charge would follow power company marginal prices.</p> <p>Fixed steam charges on capital to include:</p> <ul style="list-style-type: none">• Interest on debt.• Amortization.• Taxes.• Return on Equity Negotiable. <p>Commodity steam charge to include:</p> <ul style="list-style-type: none">• Fuel.• Operation and Maintenance. <p>Oppose heat balance allocation approach except to determine prices for steam at different pressures. Prefer a combination entropy-enthalpy method for pricing so as not to bias the heat energy versus the electrical/mechanical energy tradeoffs.</p> <p>A major problem is pricing to cover excess capacity provided for one company's incremental growth.</p> <p>Want compensation for use by others of capacity in present boiler plant as project reserve or spare.</p>	<p>Pricing must be flexible and fair to all parties.</p> <p>There should be credits for condensate and electric generation. Electric generation could be sold to biggest user based on utilities' rates.</p> <p>Need two-part charge, one for the steam used and the other to cover fixed charges.</p> <p>Might need a minimum or penalty for those who take more or less than budgeted.</p>	<p>Steam costs and customer obligations should relate to different categories of charges; i.e., variable, semi-variable and capital related.</p>	<p>Pricing should have both a commodity and fixed charge components. Compensation should be given for existing facilities that would be used as a backup as well as credit for condensate and makeup water returned.</p>

Summary of Industrial Interviews
Geismar, Louisiana

	COMPANY E	COMPANY F	COMPANY G	COMPANY H	COMPANY I	CONSENSUS OF REPLIES
g) "Risk" Opinion	Feel risk factor for cogeneration is lower than for normal business. Use of scrubbers would increase the risk.	See cogeneration as a normal business risk for them.	Fuel cogeneration would have some risk factor as the product lines in the plants it serves. Third party should have a return on his equity, if he has any. This could be negotiated.	See steam and electric as necessary costs of doing business. Main objective is keeping a good plant site fully utilized. Plan to expand operations at Geismar and expect utilities to be there forever.	Risks should be shared by both owners and customers on a negotiated basis relating to the financial exposure of each.	See cogeneration as normal or less than normal business risk.
h) Use of "Pollution Control" Bonds	Would use pollution control bonds in part if feasible.	Pollution control bonds would be very acceptable.	Use pollution control bonds where applicable.	Use pollution control bonds where possible.		Pollution control bonds should be used where possible.
i) Payments During Construction Period	Generally not too happy to contribute front end money. Would evaluate on a discounted cash flow basis.	Wouldn't make payments ahead of time.	Would negotiate on interest payments during the construction period.	Would consider payments during the construction period if economically justified.		Most not happy contributing money during construction. Some would consider if economically justified.
j) Treatment of Construction Cost Overruns	Feel overruns would push up cost of steam. Dubious about getting fixed basis contracts. However, there are a lot of hungry contractors waiting for the big boom.	Wouldn't want a "no risk" fixed price. Feel have to pay share of overruns.	Would expect step-up provisions in construction contracts for overruns. Would like contractor to share some of the risk and have some incentive to perform.	Feel would have to pay for construction overruns one way or another. Would ride herd on contractors.		Companies feel they should pay their share of cost overruns. Contractor should share some of the risk as an incentive to perform.
k) Inflation	Use inflation factors for various components of cost. Look at projected fuel costs closely.	Do studies two ways, (1) make best guess on inflation factors and (2) then look at in constant dollars. Then look at sensitivity in price.	Use various inflation estimates in financial projections. Call them current dollars.	Would probably look at in present dollars and also assuming different rates of inflation. Anticipating the future accurately has become tougher in recent years.		Sensitivity analysis should be performed on different inflationary rates. Various rates should be used in financial projections.
5) Engineering and Operating Factors						
a) Participation in a Community Cogeneration Project	Very interested. See big advantages in economy of scale.	Willing to participate if size is fixed and number of participants is limited. Too many different steam pressures needed by companies at Geismar presents a major problem. Suggest a maximum of two steam pressures from cogeneration plant. See major problem with a 20% participant maintaining any control. Major problem is putting together an operating agreement. Want this done first prior to decision to participate.	Willing to participate. See separate steam and electric ownership as complicating operations.	Willing to participate.	Willing to participate depending on relative costs, obligations, and contractual agreements.	Companies willing to participate. Some see economies of scale. Others see increasing institutional complexity with size and number of participants. Domination by major users could be a problem. Operating agreement would have to be reached before some companies would agree to participate. Maximum of two steam pressures from a cogeneration plant suggested as limit.
b) Changes in Future Needs	Will require fully coordinated planning and operation. Suggest penalties for changes in steam usage adversely affecting other participants. Suggest contract provide terms and conditions covering future expansion in project. See potential problems if only one company wants expansion.	Any future expansion must be a completely new deal. Do not even want to mention future expansion provision in initial contract.	A major problem is how to expand for future needs. Suggest "modular" approach with addition of standard increments from time to time.	Expect sustained growth at the Geismar site.	Original agreements should have foresight so as to not restrict long-term planning and independent decision making.	Companies see provision for future needs as a major problem. "Modular" approach could be the answer. Each expansion would have to be a new deal.
c) Reliability Required	Same as presently existing—have six boilers, five can carry peak loads. Would support a reliability evaluation of steam supply on a community basis including existing boilers plus cogeneration plant. Carry business interruption insurance to cover lost production for loss of steam supply.	Same as present.	Concerned with reliability of high pressure boilers. A complete shutdown of steam supply could require a week or two for restart of operations. Would like to see a "loss of production" penalty paid if steam supply is interrupted but see no way to achieve.	Would like same as presently exists. Have maintained a 97% to 98% load factor. Told 90% is best that can be expected from cogeneration plant. Production facilities are operated as near 100% as possible. Biggest problem in event of a complete shutdown would be loss of production. No major equipment damage would be expected.	Same reliability as with present facilities. However, they could sacrifice some reliability for cogeneration supply by converting existing boiler to standby. Steam pressure should be maintained in range of (+5%, -0%); temperature (+25°F, -0°F). Steam loss not critical other than to the cycling life of high temperature equipment such as reformers.	Companies want same reliability as they now have. Biggest problem would be in loss of production and start-up time. Damage to high pressure steam turbines at one plant would be possible. Suggested reliability analysis of entire system: cogeneration plant plus existing boilers that will be retained.
d) Disposition of Existing Boilers	Expect to continue full operation of present boilers to maintain existing steam supply. Oldest boiler less than 18 years old. Cogeneration will provide for growth in steam needs. Cannot afford to replace old boiler house. Suggest as a first step, the construction of a steam network to tie together existing steam plants in a "pooled" operation. Steam network to serve later as distribution system for cogeneration plant.	Compensation desired if existing boilers utilized by project.	Would continue operation of some of existing steam capacity. Will use existing plant for peaking purposes with cogeneration plant providing for base load needs.	Don't want to abandon present facilities. Would keep as backup for some period of time. Keeping warm would depend on confidence in coal plant. Would expect compensation if community project benefited from them.	Existing boilers would be kept as "standby" initially. Standby oil fired boilers could be maintained to cover outages.	For the most part companies would continue using all or part of their existing facilities. Some would use cogeneration steam for expansion retaining existing boilers for peaking services. First step would be establishment of a steam network to pool existing steam supplies improving reliability and economics. Compensation required if existing boilers would be used as backup.
e) Industrial Plant Load Curtailment	Loads can be curtailed somewhat without damage to equipment but with loss of production.	Can curtail steam load somewhat with loss of production.	Can curtail steam load 5% to 10% provided some warning is given.	Would cut back on production in an emergency loss of a significant part of cogeneration. Would use present facilities.		Most companies can be curtailed some small amount with less of production.
f) Use of Existing Makeup Water Capability	About 50% of condensate will be returned. No makeup water can be supplied to cogeneration.	Condensate return will present a problem.	Condensate will be returned. Makeup will have to come from Mississippi River. Demineralizers will be needed.	Would return 80% of condensate. Can provide makeup water. Economics should be looked at.		Most can return some portion of (50% to 80%) condensate. Most cannot supply makeup water.
g) Fuel Considerations	Feel future boilers should be designed for more than one fuel. Concerned about potential strip mining reclamation cost of \$5 per ton.	See problems of handling coal as horrendous. See real problems in future with coal handling.	Want to use oil as "peaking" or "flexible" fuel. Propose to use oil as a standby fuel to cover extended interruptions in coal supply.	Concerned about coal contracts, transportation, and handling.		Very concerned about coal transportation and handling. Some companies feel boilers should be designed to burn more than one fuel.
h) Lead Times	Not interested in nuclear because of long lead times compared to five-year planning cycle.	Long lead time for cogeneration a problem.	A problem to complete cogeneration plant in time to meet business expansion needs.	Cogeneration lead times are greater than lead times for product plant expansion.		Companies concerned about longer lead times than for product plant expansion.

Summary of Industrial Interviews
Geismar, Louisiana

	COMPANY E	COMPANY F	COMPANY G	COMPANY H	COMPANY I	CONSENSUS OF REPLIES
i) Overbuild Policy	Should be agreed to among participants. A major problem at this site.	Very concerned about who will pay for capacity in excess of initial needs.	Presents a major problem between potential participants.	See no need for overbuild in cogeneration plant. Are more concerned with over spending.	Lack of foresight in initial operating agreements' could restrict long-term flexibility and independent decision making by users. Proper planning is required.	Provision of extra capacity for future growth is a major problem. Companies cannot agree on how initial excess will be paid for nor how future expansion will be approved and paid for.
j) Design and Construction Responsibility	Presently have a community group organized as follows: <div><div>Steering Committee</div><div><div>Engineering Committee</div><div>Legal Committee</div><div>Financial Committee</div><div>Public Relations Committee</div><div>Operating Committee</div><div>Environmental Committee</div></div></div>	Should be responsibility of owners of cogeneration facility.	Reliability problems require all participants to be intimately involved in approving designs.	See no special problem with community cogeneration project. It is a boiler plant, not an untested process.		Companies feel all participants should get involved in design to assume reliability.
k) Operating Responsibility	Prefer one member to be responsible for operating of community plant. Would prefer an industrial operator rather than utility because motivation to maintain steam supply would be greater. Suggest an "Operating Committee" of all participants to provide operating policy. Desire compensation for changes in operation by one company for benefit of group.	Separate operating company an absolute necessity. Prefer a profit making arrangement. Should be easier to set up than a nonprofit approach. See no operating problems with separate companies, one steam, one electric.	Where jointly owned cogeneration facilities are planned, would want a degree of management and operating control sufficient to protect the dependent manufacturing plants for which the cogeneration plant provides support.	See no unusual operating problems. Believe a user operator would be cheaper. Would try to schedule product plant maintenance to fit cogeneration.	Cogeneration facility would not be held liable; however current business interruption insurance would have to be modified.	Some prefer that one industrial company should operate facility. Others feel such an arrangement is not acceptable. All prefer a profit making arrangement with incentives to perform built into contract.
l) Use of Existing Electrical Substation and Transmission Facilities	Propose entire electrical output of cogeneration plant go to one company via low voltage lines. This company would compensate other companies involved accordingly.	Will not use existing utility facilities. All electrical output of cogeneration plant to go to one company. Will feed low voltage side of this existing substation.	Prefer supplying electrical output to owner users reducing take from utility system. (Believe this will help avoid regulation.)	Should use existing facilities where possible. Some substations are owned by the utility and some by the companies. Plan to feed all electricity to the largest user.		Most want to use existing facilities whenever possible. All want electrical output to go to one company preferably largest user with others receiving appropriate energy credit and paying appropriate share of backup charges.
m) Labor and Union Considerations	No problem.	Have nonunion process plant. Would prefer nonunion cogeneration plant.	Concerned that cogeneration plant be operated during possible strikes. Need an operating plan for the cogeneration facility which is consistent with the operating plan for the manufacturing facilities which it serves.	Some of potential users have unions and some do not. No special labor problems foreseen.	The disposition of personnel in existing steam plant is not a consideration at this time.	No special labor problem foreseen.
n) Utility "Backup" Arrangements	Steam loads will vary considerably causing wide variations in electrical output. Power requirements from the utility will vary greatly. Want emergency backup at reasonable price.	Other participants in project expected to pay share of "backup" costs to one company which receives cogeneration electrical output.	Utility would supply electrical peaking and backup needs.	A reasonable backup arrangement should be developed. Perhaps pay for only when available.	Would use existing boilers as backup for cogeneration plant. Would want compensation if used as backup.	Reasonable backup arrangements should be developed jointly with utility. (See 5-1 above.)
6) Suggested Future Action						
a) By Government	Want "equality of impact." Don't want to see competitors given an advantage through government action. Suggest results of government environmental studies in the area be made available to all companies to clarify potential environmental effect of cogeneration. Pass national energy act clarifying cogeneration situation. Very concerned about future actions of commissions.	30% investment tax credit. No regulation. Let electricity flow to utility and be wheeled by utility. Logical environmental rules now.	Desire 30% investment tax credit. Increase ability to use investment tax credit from 50% to 90%. Allow accelerated amortization for tax purposes (half normal period). Exempt cogeneration from all Federal and state regulation, including Utility Holding Company Act. Provide stability in rules. Proposed energy bill would expire in 1982. Time limit is too short for this to be of value. See no need for loan incentives. Believe caution is warranted when considering best available control technology requirements in Clean Air Act amendments. Cost effectiveness must be weighed with environmental considerations particularly in attainment areas.	Exempt cogeneration plants from regulation. Provide greater tax incentives, such as a larger investment tax credit. Simpler and more rational environmental requirements. Scrubbers for low sulphur coal made no economic sense. Negative incentives, such as the proposed users' tax on oil and gas, usually produce false economics. Think this route leads to everyone losing in the long run. Need a clear energy act. Would get there better and faster if there was less government action and interference.	Government should provide stability in laws and regulations. Allow business to control its costs and options by avoiding further regulation.	1) Exempt cogeneration from Federal and state regulation and Holding Company Act. 2) Simple and more rational environmental requirements. 3) Increase investment tax credit. 4) Provide stable rules. Proposed NEA will expire in 1982. Too short on time for decisions. 5) Cogeneration might develop faster with less government action and interference. 6) Equality of impact—do not let competition get edge due to cogeneration.
b) By Utilities	Reasonable backup rates:	Call attention to government and public that if utilities lose industrial load, residential and commercial rates will have to rise.	Stay with "cost of service" basis for electric rates. Inverted rates will drive industry to put in own condensing generation. Such a movement on the part of industry would be destructive to utilities, industry, and the nation as a whole since it is economically wasteful and energy inefficient.	Develop reasonable backup rates for cogeneration projects. Cooperate with industrials in working out cogeneration problems. Instead of 1,000+ Mw generating plants, locate next to steam uses and install 100 to 500 Mw plants (or whatever is required for steam); sell electricity <u>and steam</u> at more than double the efficiency. Use gas turbine generators/waste heat boiler systems where appropriate.		1) Cooperate with industrials to work out cogeneration problems. 2) Determine back up and peaking service charges based on costs. 3) Develop reasonable backup rates.
c) By Industry	Reach agreement on ground rules for future expansion.	Less domination by larger companies.	Form compatible groups that can work out the inter-company problems involved.	Cooperate with utilities in working out cogeneration.		1) Reach agreement on procedures for expansion and operation so that large companies do not dominate. 2) Form groups that can work out problems. 3) Cooperate with utilities.

Cogeneration Plant Descriptions

The coal-burning cogeneration plants at both Geismar and Orange are sized to provide the projected 1985 steam requirements. It has been assumed that the industrial users will expand and maintain their facilities as needed to provide backup. A description of the facilities to be provided in each plant is given below. A one-line diagram of the Orange plant is shown on Page 7 of Appendix D.

Coal-Fired Plant at Orange, Texas

The steam required for export and internal use will be generated in two 50% capacity boilers each rated at 1,800,000 pounds per hour at 2415 psia and 1000° Fahrenheit. The related feedwater system includes two half-size deaerators, three 50% feedwater pumps, and two 50% strings of feedwater heaters arranged in parallel.

Three noncondensing steam turbine generators are used to generate a total of 185.3 Mw (gross). Two units utilize a throttle pressure of 2415 psia and exhaust at 640 psia and 290 psia, respectively, to provide steam for export and feedwater heating. The third turbine operates on a throttle pressure of 290 psia and exhausts at 45 psia to the deaerator.

The coal handling system contains the equipment to receive, store, and deliver coal to the boiler house silos. Two separate ash handling systems are utilized for the bottom ash and fly ash. A hydraulic system is used for bottom ash. Fly ash is handled pneumatically.

Each boiler is equipped with a precipitator selected to comply with state and federal regulations. Also, each boiler has a scrubbing system for SO_2 control consisting of the demister/absorber, limestone storage and handling, slurry tanks, thickener, miscellaneous pumps, tanks, piping and ductwork, and a sludge handling system.

The water treatment system consists of clarifiers, sand gravity filters, cation exchangers, vacuum degasifiers, anion exchangers, mixed-bed exchangers, and mixed-bed polishing units. The wastewater system provided complies with the new source performance standards and handles the water treatment wastes, steam plant wastes, and storm drainage.

The electrical system includes the necessary transformers and distribution system to allow integration of the cogenerated power with the present GSU supply at each of the user's plants.

Coal-Fired Plant at Geismer, Louisiana

The steam required for export and internal use will be generated in two 50% capacity boilers, each rated at 4,700,000 pounds per hour at 2415 psia and 1000° Fahrenheit. The related feedwater system includes two half-size deaerators, three 50% feedwater pumps, and two strings (one for each boiler) of three closed feedwater heaters arranged in parallel.

Four noncondensing steam turbine generators are used to generate a total of 448.8 Mw (gross). All units have a throttle pressure of 2415 psia. Two exhaust at 690 psia, one exhausts at 290 psia, and one exhausts at 45 psia. This steam is for both export and feedwater heating. The latter unit has controlled extraction to provide the required 970-psia export steam.

Other equipment is the same as at the Orange site.

APPENDIX D

ILLUSTRATION OF ALLOCATION PROCEDURES AND
PRICING ARRANGEMENTS FOR ORANGE, TEXAS SITE

COST ALLOCATION

Introduction

Costs of service are widely considered an appropriate basis for the establishment of electric utility energy pricing, and while an industrial cogeneration plant is not specifically a utility operation, the costs of producing the electricity cannot reasonably be overlooked in the establishment of cogeneration steam pricing that will provide adequate revenues on an equitable basis.

As will be discussed in the description of the development of the per unit energy cost allocations, the methods chosen for cost allocation can vary significantly from one location to another. However, there would appear to be maximum and minimum limits to the operating costs that can be assigned reasonably to the by-product electricity produced by the plant's operation. These limits are set out as two options in the costing analysis which follows. These two options may be equated to the general costing principles of value of service and incremental costs, respectively, by considering for the measure of "value" some competitive source of electrical energy, and for "incremental cost" only the heat expense associated with the extracted steam to produce the electric energy in the turbine.

This approach was followed in this case because the plant sizing and utilization was principally designed for the satisfaction of the companies' steam load requirements. Electricity, while a jointly produced product, was considered to be a valuable by-product. The general allocation method

following from this reasoning is to separate the incremental costs added to the project by providing electric generating capability. The allocations used in the following example are illustrative of the overall approach but do not reflect all the detailed analysis that would be employed to calculate the steam - only costs from the joint product plant. For example, boiler capital costs in this analysis have been considered as totally steam product related. This is a simplification since certain incremental boiler costs which result from the higher boiler pressure dictated by electric power production are not charged to the electricity cost. For purpose of illustrating the alternate allocation methods it is not necessary to include such refinements in this analysis.

For instance, the development of the "value" measure for electricity costs can be undertaken by analysis of the costs of producing electricity in a highly efficient sole-purpose generating plant. The type of plant, operating conditions, and other factors that would determine alternative costs should be considered based on feasible alternatives for the situation involved. Differences in turbine steam rates and condensor facilities are among the factors to be reviewed.

An alternative measure aligned with the market value of service basis for the costing of the electricity product would be the cost of this energy if supplied by the local utility company. In using this approach it should be noted, however, that utility rate costs are usually rolled-in average costs encompassing all the existing production plants and therefore do not truly represent in themselves useful measures of the cost of adding new energy sources to the system. The establishment of the value of electrical

output on this basis is also a form of cost allocation, in that all residual operating costs (those not adequately covered by the electric revenues) are allocated to the steam sendout. The economic comparisons shown in the engineering report have adopted this approach to represent the costs allocable to the electric energy product.

The cost allocation approach has been reviewed in general terms and for the specific costs of the proposed coal-fired plant at the Orange, Texas site. The results of the cost allocation analysis for this sample site are summarized in the following sections of this appendix.

Plant Cost Allocation

General Method

The method utilized for the allocation of plant capital costs assumes as a basic premise that the primary purpose of the plant is the production of steam.

Electrical generating, and equipment associated therewith, is viewed as being additional to the basic plant. Where jointly used facilities such as offices, warehouses, and control equipment are encountered, capital costs are split based on an estimate of the "extra" cost incurred by providing electrical service.

This approach to capital cost allocation provides one possible division of cost along the lines of two separately run businesses at the same location. Portions of physical plant facilities are not divided between the joint products (steam and electricity). Instead, each item is considered as applicable to either steam or electricity. If such a simplistic, 100% assignment is not practical, then the electrical cost is the amount that is incurred in excess of what would be necessary for a "steam only" operation.

With the determination made in this manner, it is practical to have ownership by different parties at the steam and electric production facilities.

Orange Site Plant Costs

The estimated production plant capital costs for the coal-fired plant at the Orange, Texas site have been reviewed on the basis outlined above. A portion of the yardwork, office, and warehouse costs is estimated to be due to the electric generation at the site. The balance of the cost associated with the electrical generation represents the turbogenerator system. This includes all the equipment, both mechanical and electrical, from the generator turbine to the distribution transformers and lines in the station yard: accessory equipment, such as the controls and the lube oil system, is assigned to the electric function as it pertains to the operation of the turbogenerator system. The numerical results of this analysis are shown on the following schedule. Approximately 85% of the total direct costs are found to be associated with steam production and 15% with electricity production through an item-by-item review of plant equipment accounts as summarized on page 5 of this appendix. Indirect plant costs are assignable to the steam and electric categories at the same rate as direct plant costs. Therefore, the overall breakdown of production plant costs remains 85% for steam and 15% for electricity.

Distribution plant costs for steam and condensate piping are totally assignable to the steam product cost, and electric substation and distribution facilities are totally assignable to the electricity product costs.

The table on the following page sets forth the allocated plant costs for a coal-fired plant at the Orange, Texas site. This table sets out the estimated direct costs for the Alabama coal-fired plant in January 1978 dollars.

Distributable and indirect costs and an allowance for indeterminates would proportionately increase the figures presented. For the example presented these costs are estimated to be 45.2% of the direct costs, based upon the cost estimate for the Alabama coal-fired plant at Orange.

Operating Expense Allocation

Operation and Maintenance Expense

The principle cost of cogeneration plant operation is fuel, and this expense is incurred as a function of the Btu of energy produced. The proposed method of allocation of O&M costs is outlined in a sample calculation for the coal-fired plant at the Orange, Texas site, in the section titled Allocation of Plant Heat Input. The basic approach utilized is allocation of fuel costs on the basis of the heat sent out in the energy to the customers. The heat cycle flow diagram is shown on page 8 of this appendix.

Because two types of energy, electricity and steam, are jointly produced in the plant, there is some controversy as to the proper sharing of the joint costs, such as auxiliary power and feedwater heating, which consume portions of the Btu produced, and the joint savings over separate production of each product. The cost allocation method outlined in the sample calculations presents two extremes of the possible sharing of these joint costs with reference to the electricity, as it is considered to be the by-product item. The maximum fuel cost allocation for the electric energy, which is by consequence the minimum cost allocation for the steam sendout, is developed

PROPOSED PLANT ALLOCATION
COAL-FIRED, ORANGE, TEXAS

FPC Account Number	Plant Items	Plant Costs			Allocation Ratios	
		Total	Steam	Electric	Steam	Electric
		-- (Thousands of Dollars)--			-- (Percent)--	
	Production Plant					
310	Land and Land Rights					
	Yard Work	\$ 7,184	\$ 5,747	\$ 1,437	80. %	20. %
311	Structures and Improvements					
	Waste Treatment	868	868	-	100.	-
	Turbine Building	2,493	-	2,493	-	100
	Screenwell Structure	526	526	-	100.	-
	Office and Shops	261	157	104	60.	40.
	Warehouse and Miscellaneous	207	103	104	50.	50.
	Boiler Structure	5,949	5,949	-	100.	-
312	Boiler Plant Equipment					
	Water Treatment	1,000	1,000	-	100.	-
	Boiler Plant Equipment	112,756	112,756	-	100.	-
	Coal Handling	22,277	22,277	-	100.	-
	Fuel Oil	-	-	-	-	-
314	Turbogenerator Units					
	T/6 Unit	19,574	-	19,574	-	100.
315	Accessory Electric Equipment					
	Accessory Equipment	12,025	10,822	1,203	90.	10.
316	Miscellaneous Power Plant Equipment					
	Miscellaneous Equipment	1,898	1,518	380	80.	20.
	Total Production Plant	<u>187,018</u>	<u>161,723</u>	<u>25,295</u>	<u>86.5</u>	<u>13.5</u>
	Distribution Plant					
	Steam and Condition Piping	10,303	10,303	-	100.0	
	Electric Distribution	<u>4,209</u>	<u>-</u>	<u>4,209</u>	<u>-</u>	<u>100.0</u>
	Total Distribution Plant	<u>14,512</u>	<u>10,303</u>	<u>4,209</u>	<u>71.0</u>	<u>29.0</u>
	Total Plant	<u>\$201,530</u>	<u>\$172,026</u>	<u>\$29,504</u>	<u>85.4</u>	<u>14.6</u>

by considering the costs that would be incurred in a highly efficient central power station used solely for generating electricity. The other extreme, the minimum cost allocation to electricity, is developed by assignment of cost for only the incremental Btu directly utilized to generate the electricity in the turbine, exclusive of all auxiliaries. The range between these minimum and maximum values for fuel cost allocation is open to individual judgment as to the proper allocation of joint costs, and consequently could vary from one situation to another. These extreme cost limits, however, seem to be definitive.

The balance of the O&M expense includes plant operating and maintenance labor and associated materials. A description of the suggested method of allocation of these is given by major expense account in the following tables. An underlying principle is the proposition that the steam plant is the primary object of the operations, and therefore is principally responsible for any unavoidable common expenses.

<u>FPC</u> <u>Account</u> <u>Number</u>	<u>Account</u> <u>Description</u>	<u>Basis for</u> <u>Allocation</u>
Operation		
500	Supervision and Engineering	100% Steam
501	Fuel	Btu Basis
502	Steam Expenses	Btu Basis
505	Electric Expenses	100% Electric
506	Miscellaneous Steam Power Expenses	100% Steam
Maintenance		
510	Supervision and Engineering	100% Steam
511	Structures	Plant Basis
512	Boiler Plant	Btu Basis
513	Electric Plant	100% Electric
514	Miscellaneous Steam Plant	100% Steam

The O&M (excluding fuel) cost estimates developed for the coal-fired plant at the Orange, Texas site were made on a overall basis of cents per million Btu. A breakdown of this is not available by account; therefore the appropriate allocation of this cost is a "Btu Basis."

The "Btu Basis" factors for cost allocation are taken from the figures utilized in the sample "Allocation of Plant Heat Input" calculations.

<u>Service</u>	<u>Heat Allocation Factors</u>	
	<u>Option 1</u> <u>(Maximum Electric)</u>	<u>Option 2</u> <u>(Minimum Electric)</u>
Electric	48.8%	18.5%
Steam		
650 psia	34.4	54.8
290 psia	16.8	26.7

The application of these factors to allocate costs of O&M based on expected 1985 cost levels would be as follows.

Total Heat Input [lb/hr = pounds per hour (of steam)] :

3,441,382 lb/hr x 7,884 hrs x (1,461.2-493.2)

Btu/lb x $\frac{1}{.86}$ = 30,539,000 x 10⁶ Btu

Fuel Cost

30,539 x 10⁹ Btu x \$1.77/10⁶ Btu = \$54,054,000

Other O&M Expense

30,539 x 10⁹ Btu x \$0.462/10⁶ Btu = 14,109,000

Total O&M

\$68,163,000

<u>Allocation Operating Costs (O&M)</u>	<u>Cost per Unit Sendout (1985)</u>	
	<u>Option 1</u> <u>(Maximum Electric)</u>	<u>Option 2</u> <u>(Minimum Electric)</u>
	<u>----- (Dollars) -----</u>	
Electricity (185,300 Kw)	\$.0228/Kwh	\$.0086/Kwh
Steam		
640 psia		
(1,450,000 pounds per hour)	2.05/1,000 pounds	3.27/1,000 pounds
290 psia		
(745,000 pounds per hour)	1.95/1,000 pounds	3.10/1,000 pounds

One approach commonly employed to resolve the differences between the possible allocation of costs is to equally divide the "savings" resulting from cogeneration of electricity between the products. Under any such scheme, however, the allocation for fuel would necessarily be decided on a monthly basis reflecting actual operating conditions rather than the idealized full-load conditions assumed in the foregoing example.

Allocation of Plant Heat Input

Input was allocated using the following assumptions, method, and calculations.

1. Steam heat balance per S&WEC (Drawing No. 12977-EP-2E).
2. 1985 Fuel Cost = \$1.77 per million Btu for eastern coal.
3. Steam service sendout at 640 psia and 190 psia.
4. Estimated obtainable heat rate for independent total electric generation = 9,000 Btu/kwh.

Method

Fuel costs are allocated to the steam sendout and net electrical sendout on the basis of the Btu included. Two calculations are presented to obtain the minimum and the maximum costs which could be attributed to electrical output. The difference in these is the extent to which the heat "savings" due to cogeneration of electricity with steam service are credited toward the cost of steam sendout and the costs of plant auxiliaries are charged to the generation of electricity.

Calculations

Heat used for steam sendout:

1.	640 psia of sendout		
	1,450,000 psia x (1,326.6-36.0) Btu/lb	=	1,871.4 x 10 ⁶ Btu/hr
2.	290 psia of sendout		
	745,000 lb/hr x (1,263.1-36.0) Btu/lb	=	914.2
	Total Steam		<u>2,785.6</u> x 10 ⁶ Btu/hr

Heat used for electric generation:

1.	19 Mw unit		
	496,206 lb/hr x (1,263.1-1,135.6) Btu/lb	=	63.3 x 10 ⁶ Btu/hr
2.	70 Mw unit		
	1,772,967 lb/hr x (1,461.2-1,326.6) Btu/lb	=	238.6
3.	97 Mw unit		
	1,668,415 lb/hr x (1,461.2-1,263.1) Btu/lb	=	330.5
	Total Electric		<u>632.4</u> x 10 ⁶ Btu/hr

Total Heat Used: 3,418.0 x 10⁶ Btu/hr

Heat required for electric generation alone:

185,300 Kw x 9,000 Btu/kwh 1,667.7 x 10⁶ Btu/hr

"Savings" by cogeneration (credit to steam):

(1,667.7 - 632.4) 10⁶ Btu/hr 1,035.3 x 10⁶ Btu/hr

Heat allocation (Minimum Electric Allocation):

1.	Total heat supplied		
	3,441,382 lb/hr x (1,461.2-480.0) Btu/lb	=	3,376.7 x 10 ⁶ Btu/hr
2.	Heat used for electric generation		632.4 x 10 ⁶ Btu/hr
3.	Allocation for cogeneration "savings"		
	to steam sendout	=	0.
4.	Balance of heat:		
	Allocation to steam sendout	=	2,744.3 x 10 ⁶ Btu/hr

Heat allocation (Maximum Electric Allocation):

1.	Total heat supplied	=	3,376.7 x 10 ⁶ Btu/hr
2.	Heat used for electric generation	=	632.4
3.	Allocation of cogeneration "savings"		
	to steam sendout	=	1,035.3
4.	Balance of heat:		
	Allocation to steam sendout	=	1,663.6 x 10 ⁶ Btu/hr

Heat allocation factors:

1.	<u>Minimum</u> electric allocation		
a.	Total heat required	=	3,418.0 x 10 ⁶ Btu/hr
b.	Electric generation allocation of heat used	=	632.4
c.	Steam sendout allocation balance of heat	=	2,785.6
d.	Steam @ 640 psia of allocation heat used	=	1,871.4
e.	Steam @ 290 psia of allocation heat used	=	914.2
	Total Steam	=	<u>2,785.6</u> x 10 ⁶ Btu/hr

Allocation factors (Minimum Electric)

	<u>10⁶ Btu/hr</u>	<u>Percent of Total</u>
Steam - 640 psia	1,871.4	54.8%
290 psia	914.2	26.7
Electric	632.4	18.5
Total	<u>3,418.0</u>	<u>100.0%</u>

Maximum electric allocation

- a. Total heat required = 3,418.0 x 10⁶ Btu/hr
- b. Electric generation allocation
Heat used = 632.4
Charged for "savings" 1,035.3
Total Electric 1,677.7
- c. Steam sendout allocation $\frac{1,667.7}{1,750.3} \times 10^6 \text{ Btu/hr}$
- d. Allocation of steam @ 640 psia of
 $1,871.4 \times 10^6 \text{ Btu/hr} \times \left[1 - \frac{(1,035.3)}{(2,785.6)} \right] = 1,175.9$
- e. Allocation of steam @ 290 psia of
 $914.2 \times 10^6 \text{ Btu/hr} \times \left[1 - \frac{(1,035.3)}{(2,785.6)} \right] = 574.4$
- Total Steam $\frac{1,750.3}{1,750.3} \times 10^6 \text{ Btu/hr}$

Allocation factors (Maximum Electric)

	<u>10⁶ Btu/hr</u>	<u>Percent of Total</u>
Steam - 640 psia	1,175.9	34.4%
290 psia	574.4	16.8
Electric	1,667.7	48.8
Total	<u>3,418.0</u>	<u>100.0%</u>

Plant Fixed Charges

The balance of the cogeneration plant operating expenses would be for items such as depreciation, ad valorem taxes, income taxes, and return on investment. These items may be grouped as the "fixed charges" for the operation. These costs are generally apportioned in cost allocation analysis on an investment basis.

In the example for the Orange, Texas site, the return cost has been combined with other plant-related "fixed charges" and shown as a single cost item. The allocation of this item, which includes depreciation, taxes, and

return, would be done on the basis of the relative amounts of plant assigned to the electric and steam products.

Based upon the plant cost allocation for this example the allocation of cost is 14.6% to electric and 85.4% to steam. Within the overall steam amount of this cost a portion is assignable to the 640 psia service sendout and the balance to the 290 psia sendout. This apportionment may be made on the basis of the steam Btu sendouts. The proportions of Btu sendout of steam service are 67.2% at 640 psia and 32.8% at 290 psia.

Based upon these foregoing percentages for allocation, the levelized fixed charge costs for the Orange site coal-fired example would be the following.

	Percent of Total	Fixed Charges Allocated Amount(1)	Amount per Unit(2)
		(Thousands of Dollars)	
Electric	14.6%	\$10,638	\$.0073/Kwh
Steam - 640 psia	57.4	41,822	3.66/1,000 pounds
290 psia	<u>28.0</u>	<u>20,401</u>	3.47/1,000 pounds
Total	<u>100.0%</u>	<u>\$72,861(1)</u>	

Notes:

(1) Table 6-4, Cogeneration Feasibility Study, SWEC

(2) Based on 90% load factor.

This example uses a single levelized fixed charge for simplicity. This approach results in uniform fixed charges for the life of the plant. A similar procedure can be used based on the discounted cash flow approach outlined in Appendix E, Examples of Financial Calculations, in which net plant capital costs for each year can be determined. This approach will result in different fixed charges each year.

Summary of Cost Allocation

The results of the foregoing cost allocations for the Orange, Texas site are summarized in the following table.

	<u>Dollars per Unit Sendout (1985)</u>	
	<u>Option 1</u> <u>Maximum Electric</u> <u>Allocation</u>	<u>Option 2</u> <u>Minimum Electric</u> <u>Allocation</u>
Electricity	\$.0301/Kwh	\$.0159/Kwh
Steam		
640 psia	5.71/1,000 pounds	6.93/1,000 pounds
290 psia	2.05/1,000 pounds	3.27/1,000 pounds

These costs (1985 cost levels with levelized fixed charges) are stated on the basis of a 90% plant load factor, and are based upon the sendout quantities from the plant. Operation at a lower load factor and distribution losses, etc., would increase the necessary sales price accordingly at the customer's delivery point.

PRICING ARRANGEMENTS

Credit for Electrical Production

The development of an allocation of costs to the steam and electric plant products, with the establishment of pricing based upon these principles, provides in itself a recognition of electrical production value in the billing to the steam customers. Appropriate accounting categories could be established, if desired, to accumulate monthly the allocated electrical operating costs and revenues received from sales. The net profit (or loss) associated with the electric sales transaction would then be assignable to the entities that provided the associated electric capital investment, in proportion to the share provided.

An alternative separate accounting method is to establish a method of crediting steam customers for revenues received from sales of electricity less the cost of fuel. Under this method no underlying allocations of capital cost to steam and electric products would be made. The basic steam service charge would be initially higher to cover the "fixed costs" associated with the electrical facilities, but this would be offset in turn by the subsequent credits from electric rates.

To develop the credit methodology it appears reasonable to assume that lower pressure steam service should receive more credit per pound of steam than the higher pressure steam, due to the differences in energy potential of the product. A method to establish this differential is illustrated by the following example for the Orange, Texas site (refer to Heat Cycle Flow Diagram).

Power Products by Export Steam:

at 640 psia:

$$69.92 \text{ Mw} \times \left(\frac{1,450,000}{1,772,967} \right) \text{ lb/hr} = 57.18 \text{ Mw}$$

$$57.18 \text{ Mw} \div 1,450,000 \text{ lb/hr} = \underline{39.4} \text{ Kwh/10}^3 \text{ lbs (export)}$$

at 290 psia:

$$96.34 \text{ Mw} \times \left(\frac{745,000}{1,668,415} \right) = 43.24 \text{ Mw}$$

$$43.24 \text{ Mw} \div 745,000 = \underline{58.0} \text{ Kwh/10}^3 \text{ lbs (export)}$$

Balance of Power Produced:

$$185.3 \text{ Mw} - 57.18 = 43.24 = \underline{84.88} \text{ Mw}$$

Power Allocations to Export Steam:

At 640 psia:

$$84.88 \text{ Mw} \times \left(\frac{1,450,000}{2,195,000} \right) \text{ lb/hr} + 57.18 \text{ Mw} = 113.25 \text{ Mw}$$

$$113.25 \text{ Mw} \div 1,450,000 \text{ lb/hr} = \underline{78.1} \text{ Kwh/10}^3 \text{ lb (export)}$$

$$\begin{aligned} \text{At 290 psia:} \\ 84.88 \text{ Mw} \times \left(\frac{745,000}{2,195,000} \right) \text{ lb/hr} + 43.24 \text{ Mw} = 72.05 \text{ Mw} \end{aligned}$$

$$72.05 \text{ Mw} + 745,000 \text{ lb/hr} = \underline{\underline{96.7 \text{ Kwh}/10^3 \text{ lb}}}$$

Credit Ratios:

The credit for net electric revenues could be applied on a per pound basis to steam sales in relation to the ratios of electric energy produced, as calculated above. This procedure would recognize both the thermodynamics of the cycle and the steam flow conditions.

Use of Existing Facilities

It is probable that most of the cogeneration steam customers could retain all or a portion of their existing steam generation equipment. This capacity would therefore be available to supplement and/or back up the supply from the central cogeneration plant, thereby enhancing the capabilities of the project to the benefit of all customers.

In order to have such facilities maintained and available for use when required, it would be necessary to compensate the cooperating individuals for their costs and as an inducement to participate.

The pricing of such compensation for maintenance of existing boiler capacity in a usable condition for the cogeneration systems use would probably require a fixed payment for the capacity plus a variable payment for the operating expense as and if use occurs. The fixed portion of the compensation should be a negotiated price for each installation. Some of the factors to be considered would include age and condition of equipment, output capability, start-up time, and the benefits provided to others on the system. A maximum value for the fixed capacity payment would be set by the

fixed costs of the central cogeneration plant. A minimum value would be established by review of the exact embedded costs involved in each location.

The variable portion of backup compensation would be intended to offset the incremental expense incurred. These payments would vary for each customer supplying backup, as their facilities are not similar and have different operating characteristics. The basis for each would be a determination of the incremental costs involved in maintaining standby steam capabilities for the sole use of the cogeneration system and operating costs incurred while producing steam for the cogeneration system's benefit.

Based upon the exact characteristics of the facilities the customers are willing to offer to back up the cogeneration system, a determination must be made as to which should be kept as "hot standby" and which should remain in cold reserve. Compensation payments for these could vary, as "hot standby" is potentially of greater value.

Curtailments of Service

During the operation of the cogeneration plant it is anticipated that circumstances will arise whereby the capacity of the total system to supply the entire customer steam requirements may be temporarily limited. This may be caused by necessary periodic maintenance and by unanticipated forced equipment outages.

Reductions in customer demands to meet limited available capacity could be made on a proportionate, customer-by-customer basis. If certain customers cannot proportionately reduce their demands and other customers can take their place, however, a compensation for excess curtailment would be necessary.

The compensation for "excess curtailment" could be established on several bases. One approach would be to fix the compensation as a proportionate reduction in the monthly steam billing to the curtailed customer(s) and a proportionate increase to the customer(s) with nonreduced service. This approach, which would essentially transfer a portion of the monthly fixed charge payments of one customer to another, could be considered the "minimum" pricing appropriate for curtailed service.

Another approach would be to preestablish for each industry a compensation per 1,000 pounds of steam based upon the value of lost production. Such values would necessarily have to be established by the steam customers. Customers receiving continuous full service at times of system curtailments would be assessed these costs and customers curtailing use would receive compensation.

An additional pricing consideration for curtailed service could be the extent of advance notice to the party curtailed. Curtailment on short notice, such as with one hour or less advance warning, is considered more costly to the customers in terms of potential value of lost production and is more valuable to the cogeneration system as it represents a greater degree of emergency relief. This suggests that curtailments on short notice should receive higher compensation than those on a more scheduled basis. The differentiation in compensation could be determined by compensation for short-term notice curtailments at the rate established for the value of lost production, while compensating for other curtailments at a rate more closely aligned with steam production costs.

Disposition of Distribution Losses

The cogeneration plant will send out steam at several established distribution pressures. Based upon these pressures a certain Btu content per pound of steam is puting to the distribution system. Since all customers are not immediately adjacent to the cogeneration plant, a certain amount of heat (Btu per pound) will be lost in the distribution mains. An approximate value for this loss is 10%, which could vary with the actual system layout.

To equitably provide service to the various steam customers by accounting for the distribution system losses, a Btu basis for billings would be preferable. Measurement of inlet pressure and temperature as well as quantity would provide the necessary billing determinants by customer. The correction to the rates for steam sendout for delivered Btu could be made as a billing adjustment which is calculated monthly based on actual operating results. The adjustment to billings would reflect the difference between the actual experienced losses per Btu sendout and the assumed conditions as included in the basic monthly use charge.

An alternative approach to the assessment of lost sales would be to apportion losses on the pounds of steam sold. While simpler than a Btu basis, this approach could be less desirable as it presumes that all customers are receiving steam at similar pressure and temperature conditions, which could be inaccurate for the more remote consumers. Whether or not the inaccuracies of this approach would be significant would have to be determined by evaluating each actual system's layout.

Return of Steam Condensate

The steam distribution system is to be arranged such that the steam condensate may be returned to the central plant. Within the plant the returned water will be treated by filters and demineralizers.

The costs for steam to be billed each customer would include the assumption that each customer is to return a condensate quantity equal (at least) to the pounds of steam taken. This requirement could be met with city, reservoir, or condensate water furnished to the central plant by the customer. The amount supplied by each customer could be monitored by condensate flow metering.

If a customer is deficient in its return of water, a charge based on raw water supply costs at the central plant could be added to the monthly bill for service.

With sufficient metering and quality review, the costs of water treatment could also be assessed to the customers, based upon the deviations in the quality of the condensate returned from preset standards. Such a refinement however, would, be difficult to administer with multiple customers, and therefore it is suggested that the costs of water treatment be assessed equally as a cost of steam service to all customers.

Automatic Adjustment Clauses

The pricing of steam from the cogeneration plant will be initially established upon certain estimated costs and operating conditions. Included in the proposed product prices will be assumed per-unit costs of raw materials such as fuel, power, water, etc., and estimated plant operating efficiency factors. As actual operating experience is gained and costs of

materials change over time, an adjustment in product prices will inevitably be required.

Automatic adjustment clauses as generally utilized by the utility industry are appropriate vehicles for the pass-through of certain increased operating expenses to the customers. These clauses measure actual per unit cost experience against the established base prices and provide for upward (and downward) adjustments in customer billings to reflect cost changes. The period over which the actual cost experience is measured can vary from the most recent month to the latest twelve months or a future period. The cost measurement period is usually selected so as to reflect cost changes as promptly as possible to assist cash flow, but also to moderate seasonal or abnormal monthly swings which may be nonrecurring.

APPENDIX E

Examples of Financial Calculations

The purpose of this appendix is to illustrate the discounted cash flow method used in making the economic and financial calculations.

It has been assumed for the purposes of these calculations that the project will be a nonutility type of entity whose owners can consolidate and use on a current basis their share of the initial income tax deductions. It has been further assumed that overheads such as property taxes and interest during the construction period will be capitalized for book purposes and expensed for income tax purposes. The project has been given credit for such tax savings in the analysis.

The computations have been made year by year for the estimated life of the project and are stated in current dollars. The estimated construction expenditures, operating expenses, and fuel inventory requirements were prepared by Stone & Webster Engineering Corporation. We have also used the various escalation factors and electric power values indicated in their report.

The following tables cover the two base cases for the Orange and Geismar sites as well as an alternate (100% equity) case for Orange.

Table E-1 shows the construction costs of the Orange project in 1978 dollars and also in current dollars after escalation at an annual rate of 7%.

Table E-2 is a calculation of the cash requirements during the construction period on a construction loan basis for the Orange project. This assumes that the loans would be replaced with long-term debt and equity at the end of the construction period. An investment tax credit of 10% has been used throughout the period. Construction work in progress is subject to ad valorem taxes in Texas and these taxes have been calculated at an assumed annual rate of 2%. The interest on the construction loans has been

calculated at an annual rate of 9%. An income tax rate of 46% has been used to calculate the cash savings on the property taxes and interest. The table also shows the annual and cumulative book cost of the project. Of particular interest is the comparison between book cost and cash requirements for the project.

Table E-3 is a discounted cash flow for the Orange project based on the use of construction loans and long-term debt financing. Working capital has been provided equal to 60 days of fuel supply and 45 days of other operating expenses. Long-term debt equal to 75% of the book cost of the plant has been issued at the end of the construction period. It has been assumed that this debt would have a 25 year, equal annual sinking fund payment and an annual interest rate of 9%. The cash equity investment was calculated as follows.

Total Construction Loans	\$410,390,000
Working Capital	<u>10,377,000</u>
Total Cash Requirements	420,767,000
Long-term Debt	<u>363,808,000</u>
Cash Equity Investment	<u>\$ 56,959,000</u>

The total revenues shown produce an average annual return on equity of 20%. An automatic adjustment clause covering changes in fuel and other operating expenses has been assumed. The electric revenues are based on the 1977 average industrial rate in the area of 16.5 mills per kilowatt hour escalated at 11% a year to 1985 and at 7% each year thereafter. Steam revenues are the difference between total revenues and electric revenues. Fuel costs and other operating expenses have been escalated at annual rates of 6%. Taxes other than income taxes have been provided at 2% of the original book cost. Tax depreciation has been calculated on a 22.5-year life using a double declining balance method switching to sum of the years

digits in the third year. A 46% rate has been used for computing income taxes and working capital has been escalated at 6% a year. It has been assumed that, except for the land, the plant will have no residual value at the end of its estimated 30-year operating life. The land has been recaptured net of tax assuming an annual appreciation in value of 7%. The working capital also has been recaptured.

Table E-4 shows the year by year costs for steam per 1,000 pounds and for electric per kilowatt hour reflected by the revenues shown in Table E-3.

Table E-5 is a calculation of the cash requirements during the construction period on a 100% equity basis for the Orange project. The method and assumptions are the same as those used in Table E-2, except that loans and interest are not considered.

Table E-6 is a discounted cash flow for the Orange project on a 100% equity basis. This method is commonly used by industrial companies for evaluating investment alternatives. It assumes that all cash requirements will be provided by equity capital. The other assumptions used in this computation are the same as in Table E-3.

Tables E-7, E-8, E-9 and E-10 show the construction costs, cash requirements, a discounted cash flow, and summary of unit costs for the Geismar project assuming the use of construction loans and long-term debt financing. Except for the income tax rate and the treatment of property taxes, the assumptions are the same as used in tables E-1, E-2, E-3, and E-4 for the Orange project. Louisiana has an 8% state income tax. This state tax and the Federal tax are mutually deductible so an effective income tax rate of .484% has been used in the Geismar calculations. A ten-year moratorium on property taxes is generally available in Louisiana and has been assumed in this case.

Table E-1

ORANGE COGENERATION PROJECT
CONSTRUCTION COST
ALABAMA COAL

<u>Year</u>	<u>SWEC</u> <u>(1978</u> <u>dollars)</u>	<u>Land</u> <u>(1978</u> <u>dollars)</u>	<u>Connections</u> <u>(1978</u> <u>dollars)</u>	<u>Balance</u>	<u>Escalation</u> <u>7% per Year</u>	<u>Total</u>
				-(Thousands of Dollars)-		
1979	\$ 4,390	\$2,000		\$ 6,390	\$ 447	\$ 6,837
1980	7,310			7,310	1,059	8,369
1981	13,170			13,170	2,964	16,134
1982	81,930			81,930	25,463	107,393
1983	105,350			105,350	42,409	147,759
1984	<u>80,470</u>		<u>\$3,000</u>	<u>83,470</u>	<u>41,796</u>	<u>125,266</u>
Total	<u>\$292,620</u>	<u>\$2,000</u>	<u>\$3,000</u>	<u>\$297,620</u>	<u>\$114,138</u>	<u>\$411,758</u>

Table E-2

ORANGE COGENERATION PROJECT
CONSTRUCTION PERIOD
ALABAMA COAL - CONSTRUCTION LOAN BASIS

<u>Year</u>	<u>Construction Costs</u>	<u>Investment Tax Credit</u>	<u>Property Taxes</u>	<u>Tax Savings on Property Taxes</u>	<u>Balance</u> (Thousands of Dollars)	<u>Interest</u> (Thousands of Dollars)	<u>Tax Savings on Interest</u>	<u>Loan Requirements</u>	<u>Plant Cost per Books</u>	
									<u>Annual</u>	<u>Cumulative</u>
1979	\$ 6,837 ⁽¹⁾	\$ (470)	\$ 68	\$ (31)	\$ 6,404	\$ 288	\$ (132)	\$ 6,560	\$ 7,193	\$ 7,193
1980	8,369	(837)	228	(105)	7,655	935	(430)	8,160	9,532	16,725
1981	16,134	(1,613)	496	(228)	14,789	1,990	(915)	15,864	18,620	35,345
1982	107,393	(10,739)	1,781	(819)	97,616	7,145	(3,287)	101,474	116,319	151,664
1983	147,759	(14,776)	4,511	(2,075)	135,419	17,979	(8,270)	145,128	170,249	321,913
1984	125,266	(12,527)	7,691	(3,538)	116,892	30,207	(13,895)	133,204	163,164	485,077
Total	<u>\$411,758</u>	<u>\$(40,962)</u>	<u>\$14,775</u>	<u>\$(6,796)</u>	<u>\$378,775</u>	<u>\$58,544</u>	<u>\$(26,929)</u>	<u>\$410,390</u>		

Note:

(1) Includes cost of land -- \$2,140,000.

Table E-3
ORANGE COGENERATION PROJECT
CASH FLOW
ALABAMA COAL - 75% DEBT BASIS

Year	Steam Revenues	Electric Revenues	Total Revenues	Fuel Expenses	Other Operating Expenses	Taxes Other than Income	Tax Depreciation	Interest	Income Taxes	Capital Cost	Investment Tax Credit	Working Capital - Net	Debt	Net Cash Flow	Discounted at 20%
(Thousands of Dollars)															
1979						\$ (68)		\$ (288)	\$ 163	\$ (6,837)	\$ 470		\$ 6,560		
1980						(228)		(935)	535	(8,369)	837		8,160		
1981						(496)		(1,990)	1,143	(16,134)	1,613		15,864		
1982						(1,781)		(7,145)	4,106	(107,393)	10,739		101,474		
1983						(4,511)		(17,979)	10,345	(147,759)	14,776		145,128		
1984						(7,691)		(30,207)	17,433	(125,266)	12,527	\$(10,377)	86,622	\$(56,959)	\$(19,075)
1985	\$ 88,192	\$ 42,996	\$ 131,188	\$ (54,791)	\$ (14,301)	(9,702)	\$ (36,410)	(32,743)	7,709			(623)	(14,552)	12,185	3,401
1986	89,327	46,006	135,333	(58,078)	(15,159)	(9,702)	(33,174)	(31,433)	5,618			(660)	(14,552)	11,367	2,644
1987	90,502	49,226	139,728	(61,563)	(16,069)	(9,702)	(31,613)	(30,123)	4,297			(699)	(14,552)	11,317	2,193
1988	91,714	52,672	144,386	(65,257)	(17,033)	(9,702)	(30,071)	(28,814)	2,986			(742)	(14,552)	11,272	1,820
1989	92,964	56,359	149,323	(69,172)	(18,055)	(9,702)	(28,529)	(27,504)	1,674			(786)	(14,552)	11,226	1,511
1990	94,253	60,304	154,557	(73,323)	(19,138)	(9,702)	(26,987)	(26,194)	362			(833)	(14,552)	11,177	1,254
1991	95,579	64,525	160,104	(77,722)	(20,286)	(9,702)	(25,445)	(24,885)	(949)			(833)	(14,552)	11,125	1,040
1992	96,942	69,042	165,984	(82,385)	(21,503)	(9,702)	(23,903)	(23,575)	2,261			(936)	(14,552)	11,070	862
1993	98,344	73,875	172,219	(87,329)	(22,794)	(9,702)	(22,361)	(22,265)	(3,573)			(993)	(14,552)	11,011	715
1994	99,779	79,046	178,825	(92,568)	(24,261)	(9,702)	(20,818)	(20,956)	(4,885)			(1,052)	(14,552)	10,949	592
1995	101,249	84,580	185,829	(98,122)	(25,611)	(9,702)	(19,276)	(19,646)	(6,197)			(1,115)	(14,552)	10,884	491
1996	102,754	90,500	193,254	(104,010)	(27,148)	(9,702)	(17,734)	(18,336)	(7,509)			(1,182)	(14,552)	10,815	406
1997	104,287	96,835	201,122	(110,250)	(28,776)	(9,702)	(16,192)	(17,027)	(8,821)			(1,252)	(14,552)	10,742	336
1998	105,850	103,614	209,464	(116,865)	(30,503)	(9,702)	(14,650)	(15,717)	(10,132)			(1,328)	(14,552)	10,665	278
1999	107,439	110,867	218,306	(123,877)	(32,333)	(9,702)	(13,108)	(14,407)	(11,444)			(1,408)	(14,552)	10,583	230
2000	109,052	118,627	227,679	(131,310)	(34,273)	(9,702)	(11,566)	(13,098)	(12,756)			(1,492)	(14,552)	10,496	190
2001	110,683	126,931	237,614	(139,188)	(36,330)	(9,702)	(10,024)	(11,788)	(14,068)			(1,582)	(14,552)	10,404	157
2002	112,329	135,816	248,145	(147,540)	(38,509)	(9,702)	(8,482)	(10,478)	(15,380)			(1,676)	(14,552)	10,308	130
2003	113,984	145,324	259,308	(156,392)	(40,820)	(9,702)	(6,939)	(9,168)	(16,692)			(1,778)	(14,552)	10,204	107
2004	115,645	155,496	271,141	(165,776)	(43,269)	(9,702)	(5,397)	(7,859)	(18,003)			(1,883)	(14,552)	10,097	88
2005	117,302	166,381	283,683	(175,722)	(45,865)	(9,702)	(3,855)	(6,549)	(19,315)			(1,997)	(14,522)	9,981	73
2006	118,950	178,028	296,978	(186,265)	(48,617)	(9,702)	(2,313)	(5,239)	(20,627)			(2,117)	(14,522)	9,859	60
2007	120,581	190,490	311,071	(197,441)	(51,534)	(9,702)	(771)	(3,930)	(21,939)			(2,244)	(14,552)	9,729	49
2008	122,186	203,824	326,010	(209,288)	(54,626)	(9,702)		(2,620)	(22,896)			(2,378)	(14,552)	9,948	42
2009	123,754	218,091	341,845	(221,845)	(57,904)	(9,702)		(1,310)	(23,499)			(2,521)	(14,560)	10,504	37
2010	125,272	233,358	358,630	(235,156)	(61,378)	(9,702)			(24,101)			(2,672)		25,621	75
2011	126,729	249,693	376,422	(249,265)	(65,061)	(9,702)			(24,101)			(2,832)		25,461	62
2012	128,110	267,171	395,281	(264,221)	(68,964)	(9,702)			(24,101)			(3,003)		25,290	51
2013	129,399	285,873	415,272	(280,074)	(73,102)	(9,702)			(24,101)			(3,183)		25,110	43
2014	130,578	305,885	436,463	(296,879)	(77,488)	(9,702)			(24,101)	14,186		56,227		98,706	138
Total	\$3,263,729	\$4,061,435	\$7,325,164	\$(4,331,674)	\$(1,130,610)	\$(305,835)	\$(409,618)	\$(484,208)	\$(305,080)	\$(397,572)	\$40,962	\$ -0-	\$ -0-	\$411,147	\$ -0-

Table E-4

ORANGE COGENERATION PROJECT
ANNUAL STEAM AND ELECTRIC PRICES
ALABAMA COAL - 75% DEBT BASIS

<u>Year</u>	<u>Steam</u> (Dollars per thousand pounds)	<u>Electric</u> (Mills per Kwh)
1985	5.10	36.7
1986	5.16	39.3
1987	5.23	42.0
1988	5.30	45.0
1989	5.37	48.1
1990	5.45	51.5
1991	5.52	55.1
1992	5.60	58.9
1993	5.68	63.1
1994	5.77	67.5
1995	5.85	72.2
1996	5.94	77.3
1997	6.03	82.7
1998	6.12	88.4
1999	6.21	94.6
2000	6.30	101.3
2001	6.40	108.3
2002	6.49	115.9
2003	6.59	124.0
2004	6.68	132.7
2005	6.78	142.0
2006	6.87	152.0
2007	6.97	162.6
2008	7.06	174.0
2009	7.15	186.2
2010	7.24	199.2
2011	7.32	213.1
2012	7.40	228.1
2013	7.48	244.0
2014	7.55	261.1

Annual Production -

Steam: 17,305,380,000 pounds.
Electric: 1,171,562,400 kilowatt hours.

Table E-5

ORANGE COGENERATION PROJECT
CONSTRUCTION PERIOD
ALABAMA COAL - 100% EQUITY BASIS

Year	Construction Costs	Investment Tax Credit	Property Taxes	Tax Savings on Property Taxes	Cash Requirements	Plant Cost per Books	
						Annual	Cumulative
						(Thousands of Dollars)	
1979	\$ 6,837	\$ (470)	\$ 68	\$ (31)	\$ 6,404	\$ 6,905	\$ 6,905
1980	8,369	(837)	222	(102)	7,652	8,591	15,496
1981	16,134	(1,613)	471	(217)	14,775	16,605	32,101
1982	107,393	(10,739)	1,716	(789)	97,581	109,109	141,210
1983	147,759	(14,776)	4,302	(1,979)	135,306	152,061	293,271
1984	125,266	(12,527)	7,118	(3,274)	116,583	132,384	425,655
Total	\$411,758	\$(40,962)	\$13,897	\$(6,392)	\$378,301		

Note:

(1) Includes cost of land -- \$2,140,000

Table E-6
ORANGE COGENERATION PROJECT
CASH FLOW
ALABAMA COAL - 100% EQUITY BASIS

Year	Steam Revenues	Electric Revenues	Total Revenues	Fuel Expenses	Other Oper. Expenses	Taxes Other than Income	Tax Depreciation	Income Taxes	Capital Costs	Investment Tax Credit	Working Capital-Net	Net Cash Flow	Discounted at 20%
-(Thousands of Dollars)-													
1979						\$ (68)		\$ 31	\$(6,837)	\$ 470		\$ (6,404)	\$ (5,337)
1980						(222)		102	(8,369)	837		(7,652)	(5,314)
1981						(471)		217	(16,134)	1,613		(14,775)	(8,550)
1982						(1,716)		789	(107,393)	10,739		(97,581)	(47,059)
1983						(4,302)		1,979	(147,759)	14,776		(135,306)	(54,376)
1984						(7,118)		3,274	(125,266)	12,527	\$(10,377)	(126,960)	(42,519)
1985	\$ 193,864	\$ 42,996	\$ 236,860	\$ (54,791)	\$ (14,301)	(8,513)	\$ (36,410)	(56,509)			(623)	102,123	28,501
1986	194,999	46,006	241,005	(58,078)	(15,159)	(8,513)	(33,174)	(57,997)			(660)	100,598	23,396
1987	196,174	49,226	245,400	(61,563)	(16,069)	(8,513)	(31,613)	(58,715)			(699)	99,841	19,350
1988	197,386	52,672	250,058	(65,257)	(17,033)	(8,513)	(30,071)	(59,425)			(742)	99,088	16,003
1989	198,636	56,359	254,995	(69,172)	(18,055)	(8,513)	(28,529)	(60,134)			(786)	98,335	13,235
1990	199,925	60,304	260,229	(73,323)	(19,138)	(8,513)	(26,987)	(60,843)			(833)	97,579	10,944
1991	201,251	64,525	265,776	(77,722)	(20,286)	(8,513)	(25,445)	(61,553)			(883)	96,819	9,049
1992	202,614	69,042	271,656	(82,385)	(21,503)	(8,513)	(23,903)	(62,262)			(936)	96,057	7,482
1993	204,016	73,825	277,891	(87,329)	(22,794)	(8,513)	(22,361)	(62,971)			(933)	95,291	6,185
1994	205,451	79,046	284,497	(92,568)	(24,161)	(8,513)	(20,818)	(63,681)			(1,052)	94,522	5,113
1995	206,921	84,580	291,501	(98,122)	(25,611)	(8,513)	(19,276)	(64,390)			(1,115)	93,750	4,226
1996	208,426	90,500	298,926	(104,010)	(27,148)	(8,513)	(17,734)	(65,100)			(1,182)	92,973	3,492
1997	209,959	96,835	306,794	(110,250)	(28,776)	(8,513)	(16,192)	(65,809)			(1,252)	92,194	2,886
1998	211,522	103,614	315,136	(116,805)	(30,503)	(8,513)	(14,650)	(66,518)			(1,328)	91,409	2,384
1999	213,111	110,867	323,978	(123,877)	(32,333)	(8,513)	(13,108)	(67,228)			(1,408)	90,619	1,970
2000	214,724	118,627	333,351	(131,310)	(34,273)	(8,513)	(11,566)	(67,937)			(1,492)	89,826	1,627
2001	216,355	126,931	343,286	(139,188)	(36,330)	(8,513)	(10,024)	(68,446)			(1,582)	89,027	1,344
2002	218,001	135,816	353,817	(147,540)	(38,509)	(8,513)	(8,482)	(69,356)			(1,676)	88,223	1,110
2003	219,656	145,324	364,980	(156,392)	(40,820)	(8,513)	(6,939)	(70,065)			(1,778)	87,412	916
2004	221,317	155,496	376,813	(165,776)	(43,269)	(8,513)	(5,397)	(70,775)			(1,883)	86,597	756
2005	222,974	166,381	389,355	(175,722)	(45,865)	(8,513)	(3,855)	(71,484)			(1,997)	85,774	624
2006	224,622	178,028	402,650	(186,265)	(48,617)	(8,513)	(2,313)	(72,193)			(2,117)	84,945	515
2007	226,253	190,490	416,743	(197,441)	(51,534)	(8,513)	(771)	(72,903)			(2,244)	84,108	425
2008	227,858	203,824	431,682	(209,288)	(54,626)	(8,513)		(73,257)			(2,378)	83,620	352
2009	229,426	218,091	447,517	(221,845)	(57,904)	(8,513)		(73,257)			(2,521)	83,477	293
2010	230,944	233,358	464,302	(235,156)	(61,378)	(8,513)		(73,257)			(2,672)	83,326	244
2011	232,401	249,693	482,094	(249,265)	(65,061)	(8,513)		(73,257)			(2,832)	83,166	203
2012	233,782	267,171	500,953	(264,221)	(68,964)	(8,513)		(73,257)			(3,003)	82,995	169
2013	235,071	285,873	520,944	(280,074)	(73,102)	(8,513)		(73,257)			(3,183)	82,815	140
2014	236,250	305,885	542,135	(296,879)	(77,488)	(8,513)		(73,257)	14,186		56,227	156,411	221
Total	\$6,433,889	\$4,061,435	\$10,495,324	\$(4,331,674)	\$(1,130,610)	\$(269,287)	\$(409,618)	\$(2,002,901)	\$(397,572)	\$40,962	\$ -0-	\$2,404,242	\$ -0-

Table E-7
GEISMAR COGENERATION PROJECT
CONSTRUCTION COST
ALABAMA COAL

<u>Year</u>	<u>S & W Enger.</u> <u>1978 dollars</u>	<u>Land</u> <u>1978 dollars</u>	<u>Connections</u> <u>1978 dollars</u>	<u>Balance</u>	<u>Escalation</u> <u>(7% per Yr.)</u>	<u>Total</u>
			(Thousands of Dollars)			
1979	\$ 10,700	\$3,000		\$ 13,700	\$ 959	\$ 14,659
1980	17,840			17,840	2,585	20,425
1981	32,110			32,110	7,226	39,336
1982	199,780			199,780	62,090	261,870
1983	256,850			256,850	103,395	360,245
1984	<u>196,211</u>		<u>\$3,000</u>	<u>199,211</u>	<u>99,757</u>	<u>298,962</u>
Total	<u>\$713,491</u>	<u>\$3,000</u>	<u>\$3,000</u>	<u>\$719,491</u>	<u>\$276,006</u>	<u>\$995,497</u>

Table E-8

GEISMAR COGENERATION PROJECT
CONSTRUCTION PERIOD
ALABAMA COAL-CONSTRUCTION LOAN BASIS

Year	Construction Costs	Investment Tax Credit	Balance	Interest	Tax Savings on Interest	Loan Requirements	Plant Cost per Books	
							Annual	Cumulative
							(Thousands of Dollars)	
1979	\$ 14,659(1)	\$ (1,145)	\$ 13,514	\$ 608	\$ (294)	\$ 13,828	\$ 15,267	\$ 15,267
1980	20,425	(2,043)	18,382	2,072	(1,003)	19,451	22,497	37,764
1981	39,336	(3,934)	35,402	4,588	(2,221)	37,769	43,924	81,688
1982	261,870	(26,187)	235,683	17,000	(8,228)	244,455	278,870	360,558
1983	360,245	(36,024)	324,221	42,985	(20,805)	346,401	403,230	763,788
1984	298,962	(29,896)	269,066	71,679	(34,693)	306,052	370,641	1,134,429
Total	<u>\$995,497</u>	<u>\$(99,229)</u>	<u>\$896,268</u>	<u>\$138,932</u>	<u>\$(67,244)</u>	<u>\$967,956</u>		

Note:

(1) Land included at \$3,210,000.

Table E-9
GEISMAR COGENERATION PROJECT
CASH FLOW
ALABAMA COAL - 75% DEBT BASIS

Year	Steam Revenues	Electric Revenues	Total Revenues	Fuel Expenses	Other Operating Expenses	Taxes Other than Income	Tax Depreciation (Thousands of Dollars)	Interest	Income Taxes	Capital Costs	Investment Tax Credit	Working Capital - Net	Debit	Net Cash Flow	Discounted at 20%
1979								\$ (608)	\$ 294	\$ (14,659)	\$ 1,145		\$ 13,828		
1980								(2,072)	1,003	(20,425)	2,043		19,451		
1981								(4,588)	2,221	(39,336)	3,934		37,769		
1982								(17,000)	8,228	(261,870)	26,187		244,455		
1983								(42,985)	20,805	(360,245)	36,024		346,401		
1984								(71,679)	34,693	(298,962)	29,896	\$ (23,783)	188,918	\$(140,917)	\$(47,193)
1985	\$ 208,362	\$ 101,907	\$ 310,269	\$ (145,704)	\$ (38,031)		\$ (88,489)	(76,574)	18,648			(1,427)	(34,033)	33,148	3,251
1986	212,253	109,040	321,293	(154,446)	(40,313)		(80,623)	(73,511)	13,358			(1,513)	(34,033)	30,835	7,172
1987	216,306	116,673	332,979	(163,713)	(42,732)		(76,829)	(70,448)	10,040			(1,603)	(34,033)	30,490	5,909
1988	220,526	124,840	345,366	(173,536)	(45,296)		(73,082)	(67,385)	6,744			(1,699)	(34,033)	30,161	4,871
1989	224,916	133,579	358,495	(183,948)	(48,013)		(69,334)	(64,322)	3,447			(1,802)	(34,033)	29,824	4,014
1990	229,483	142,930	372,413	(194,985)	(50,894)		(65,586)	(61,259)	151			(1,910)	(34,033)	29,483	3,307
1991	234,231	152,935	387,166	(206,684)	(53,948)		(61,838)	(58,196)	(3,146)			(2,024)	(34,033)	29,135	2,723
1992	239,164	163,640	402,804	(219,085)	(57,185)		(58,091)	(55,133)	(6,442)			(2,145)	(34,033)	28,781	2,242
1993	244,285	175,095	419,380	(232,230)	(60,616)		(54,343)	(52,070)	(9,739)			(2,225)	(34,033)	28,417	1,844
1994	249,599	187,352	436,951	(246,164)	(64,253)		(50,595)	(49,007)	(13,035)			(2,411)	(34,033)	28,048	1,517
1995	255,110	200,466	455,576	(260,934)	(68,108)	\$ (22,689)	(46,847)	(45,944)	(5,350)			(2,555)	(34,033)	15,963	720
1996	260,819	214,499	475,318	(276,590)	(72,194)	(22,689)	(43,099)	(42,881)	(8,647)			(2,709)	(34,033)	15,575	585
1997	266,731	229,514	496,245	(293,185)	(76,526)	(22,689)	(39,352)	(39,818)	(11,943)			(2,871)	(34,033)	15,180	475
1998	272,847	245,580	518,427	(310,776)	(81,117)	(22,689)	(35,604)	(36,755)	(15,239)			(3,044)	(34,033)	14,774	385
1999	279,170	262,771	541,941	(329,423)	(85,984)	(22,689)	(31,856)	(33,692)	(18,536)			(3,226)	(34,033)	14,358	312
2000	285,701	281,165	566,866	(349,188)	(91,144)	(22,689)	(28,108)	(30,629)	(21,832)			(3,420)	(34,033)	13,931	252
2001	292,439	300,846	593,285	(370,139)	(96,612)	(22,689)	(24,361)	(27,566)	(25,128)			(3,625)	(34,033)	13,493	204
2002	299,386	321,905	621,291	(392,348)	(102,409)	(22,689)	(20,613)	(24,503)	(28,425)			(3,843)	(34,033)	13,041	164
2003	306,537	344,439	650,976	(415,889)	(108,553)	(22,689)	(16,865)	(21,441)	(31,721)			(4,073)	(34,033)	12,577	132
2004	313,894	368,549	682,443	(440,842)	(115,067)	(22,689)	(13,117)	(18,378)	(35,017)			(4,317)	(34,033)	12,100	106
2005	321,449	394,348	715,797	(467,292)	(121,971)	(22,689)	(9,369)	(15,315)	(38,314)			(4,577)	(34,033)	11,606	84
2006	329,201	421,952	751,153	(495,330)	(129,289)	(22,689)	(5,622)	(12,252)	(41,610)			(4,851)	(34,033)	11,099	67
2007	337,141	451,489	788,630	(525,050)	(137,046)	(22,689)	(1,874)	(9,189)	(44,906)			(5,142)	(34,033)	10,575	53
2008	345,263	483,093	828,356	(556,553)	(145,269)	(22,689)		(6,126)	(47,296)			(5,451)	(34,033)	10,939	46
2009	353,555	516,910	870,465	(589,946)	(153,985)	(22,689)		(3,063)	(48,778)			(5,778)	(34,030)	12,196	43
2010	362,008	553,093	915,101	(625,343)	(163,224)	(22,689)			(50,261)			(6,124)		47,460	139
2011	370,605	591,810	962,415	(662,863)	(173,018)	(22,689)			(50,261)			(6,492)		47,092	115
2012	379,331	633,237	1,012,568	(702,635)	(183,399)	(22,689)			(50,261)			(6,881)		46,703	95
2013	388,167	677,563	1,065,730	(744,793)	(194,403)	(22,689)			(50,261)			(7,295)		46,289	78
2014	397,089	724,993	1,122,082	(789,481)	(206,067)	(22,689)			(50,261)	21,279		128,866		203,729	288
Total	\$8,695,568	\$9,626,213	\$18,321,781	\$(11,519,095)	\$(3,006,666)	\$(453,780)	\$(995,497)	\$(1,134,389)	\$(586,777)	\$(974,218)	\$99,229	\$ -0-	\$ -0-	\$ 746,085	\$ -0-

Table E-10

GEISMAR COGENERATION PROJECT
ANNUAL STEAM AND ELECTRIC PRICES
ALABAMA COAL - 75% DEBT BASIS

<u>Year</u>	<u>Steam</u> (Dollars per thousand pounds)	<u>Electric</u> (Mills per Kwh)
1985	\$4.53	36.7
1986	4.61	39.3
1987	4.70	42.0
1988	4.79	45.0
1989	4.88	48.1
1990	4.98	51.5
1991	5.09	55.1
1992	5.19	58.9
1993	5.31	63.1
1994	5.42	67.5
1995	5.54	72.2
1996	5.66	77.3
1997	5.79	82.7
1998	5.93	88.4
1999	6.06	94.6
2000	6.21	101.3
2001	6.35	108.3
2002	6.50	115.9
2003	6.66	124.0
2004	6.82	132.7
2005	6.98	142.0
2006	7.15	152.0
2007	7.32	162.6
2008	7.50	174.0
2009	7.68	186.2
2010	7.86	199.2
2011	8.05	213.1
2012	8.24	228.1
2013	8.43	244.0
2014	8.62	261.1

Annual Production:

Steam 46,042,560,000 pounds.

Electric 2,776,744,800 kilowatt hours.

APPENDIX F

SUMMARY OF PRICING PROCEDURES FOR
A FEW EXISTING COGENERATION FACILITIES

To provide some insight into the development of a pricing structure for the sale of process steam and electrical energy from the proposed cogeneration plant, we have reviewed the pricing formulas of two major existing cogeneration projects.

Public Service Electric and Gas Company (PSE&G)/Exxon

Public Service Electric and Gas Company currently supplies the Exxon Company's Bayway oil refinery with approximately 2.4 million pounds per hour of high (730 psi) and low (142 psi) pressure steam in exchange for certain quantities of fuel oil, water and money. All process steam for the refinery is supplied by the Linden station which is capable of burning a high viscosity residual fuel oil. Under the terms of the contract, 1.6 million Btu of this fuel are supplied for every 1,000 pounds of steam delivered. However, actual fuel flow is limited to the amount of fuel being consumed in those boilers generating the process steam. In addition, 1.1 pounds of water are returned for each pound of steam delivered. This water can be reservoir water, city water, or condensate, although returned water above 1.55 million pounds per hour of steam flow must be condensate.

Monetary remuneration for the steam is based on a monthly service charge which decreases as the monthly steam load factor approaches 78% on the high pressure system and 65% on the low pressure circuit. In addition, there is a quantity charge for each 1,000 pounds of steam delivered, up to the contract maximums.

Gulf States Utilities (GSU)/Exxon-Ethyl

Gulf States Utilities operates under a similar type of cogeneration agreement with the Exxon Company and Ethyl Company refineries near Baton Rouge from the utilities' Louisiana Station. In the agreement GSU provides both process steam and electrical energy in return for natural gas or fuel oil and money. The refineries do not return any water or condensate to the utility. The utility provides up to 2.4 million pounds per hour and 450,000 pounds per hour of 135 psig steam to the Exxon and Ethyl refineries, respectively. In return it receives primarily natural gas at the exchange rate of 1.6 million Btu of fuel per 1,000 pounds of steam. When natural gas is unavailable, the contracts provide for a return of low sulfur oil at the same exchange rate. GSU can limit the quantity of fuel oil returned so as to ensure safe and reliable operation of the power plant.

Under proposed rate structures presently being negotiated with the oil companies, GSU will implement a rate schedule composed primarily of a monthly service charge to cover the fixed cost components of the power plant operating costs and a small commodity charge to cover variable costs. In addition, the refineries will receive a credit on their monthly electric bills based on their respective process steam consumptions during that billing period. GSU will compute the theoretical amount of electric energy generated by the process steam and deduct this amount from the refineries' monthly electric energy consumption. The difference will then be priced as per applicable approved rate tariffs.

APPENDIX G

EXERPTS FROM GULF STATES' COUNSEL'S LEGAL OPINIONS

State Utility Regulation

A. Texas (extracted from opinions of Orgain, Bell & Tucker)

1. Sale of Electricity

In general, the pricing of the sale of electricity in Texas would be subject to regulation by the Public Utility Commission of Texas (PUCT) or by the municipality within which the sale is made. Section 3(c)(4) exempts from the definition of "public utility" any person, partnership, joint venture, or corporation which is not otherwise a public utility and which furnishes electric service only to itself and is not resold or used by others. No published rules or cases have yet been found which indicate how the word "itself" will be interpreted. There is thus a risk that sales by a cogeneration entity to the entities owning it might not qualify for this exemption. In any event, if any sales are made by the cogeneration entity to others, the entity would be a public utility and its sales -- presumably all sales -- would be subject to regulation.

As a public utility, the cogeneration entity would be subject to full regulation under the Public Utility Regulatory Act. All corporations owning 5% or more of the voting securities of the cogeneration entity would be deemed "affiliates". Depending upon whether the sales are made within municipalities and whether or not the municipality had released its powers of regulation, sales by the cogeneration entity would be subject to regulation

by either the PUCT or the municipality within which the sale is made. Under the Act, the regulation of the rates by either the PUCT or the municipality would be based upon the same regulatory criteria, and if initial regulation is by the municipality, appellate jurisdiction would lie with the PUCT. The rates would be required to be fair, just and reasonable. In rate proceedings, payment to affiliated interest for services or property or interest would not be allowed except to the extent found reasonable. Rates would not be permitted to grant any unreasonable preference or advantage. As a public utility, the cogeneration entity would be subject to all of the other regulation provided by such act, including certification of facilities, record-keeping and accounting treatment, reports on relations with affiliated interests, sale, lease, or acquisition of operating units, et cetera.

2. Sale of Steam

There is no present Texas governmental price regulation for the sale of manufactured steam other than such regulation as might be applied to discriminatory pricing under Texas antitrust laws.

As a secondary regulation of the price of steam, however, the State of Texas does provide for regulation of rates for the supply of water. Initial pricing of the supply of water would probably be by contract between the cogeneration entity and a river authority or other water supply authority. The Texas Water Rights Commission has regulatory authority to fix reasonable rates for the furnishing of water. Judicial review of Commission rate-setting can be obtained under the Water Code. The price of underground

water does not appear to be directly regulated, but conservation laws could operate to limit its availability.

One proposal has been to separate the ownership of the steam facilities from the generating facilities. It is arguable whether or not the steam facilities could be classified as jurisdictional "facilities" under the Texas Public Utility Regulatory Act. No clear precedent has been found. Even if the entity owning the steam facilities were found to be a public utility under such Act by reason of its ownership of jurisdictional facilities, the only consequence would probably be accounting and report requirements imposed on the entity since the Act does not presently purport to regulate steam sales. If the local utility owned a portion of such entity, the likelihood of the facilities being held jurisdictional would be increased.

Whether the local utility owns an interest in the steam entity or not, the use or purchase and resale of the steam or operation of the steam facility would be subject to review in the rate proceedings of the electric utility. It must be considered as at least a possibility that rates would be set on a basis which would allocate the utility's profit attributable to the steam to the utility's electric ratepayers. The odds are the greatest that this would be done if the local utility owned an interest in the steam entity and the least if the utility owned no interest in the steam entity, paid such entity a fair price for the steam, and made its profit from its fee for operating the steam facilities.

B. Louisiana (extracted from opinions of Taylor, Porter, Brooks & Phillips)

1. When the entire cogeneration plant project is owned by and its output sold to its owners (who are not utilities), there would be no regulation of rates and/or service in Louisiana.

2. If some of the plant output is sold to the local utility, in the opinion of Taylor, Porter, Brooks & Phillips there could be some incidental regulation, in the sense that the Louisiana Public Service Commission could make a determination as to whether or not the terms and conditions of the steam, electricity, etc. sale to the local utility would be in the public interest. Otherwise, there would be no regulation.

3. If a new subsidiary is formed by the local electric utility which will handle the entire project from inception through operation, and if the utility subsidiary's business is completely isolated from its utility business, then such subsidiary would not, in the opinion of Taylor, Porter, Brooks & Phillips, be subject to Louisiana Public Service Commission jurisdiction. The greater the relationship between the subsidiary's business and the utility's other business, the greater the likelihood of regulation by the Louisiana Public Service Commission. These opinions would also apply if the utility owned only a part interest in the project.

4. If the local electric utility owns and operates the project, and if the project is completely isolated from its utility business, then such project would not, in the opinion of Taylor, Porter, Brooks & Phillips, be subject to Louisiana Public Service Commission jurisdiction. The greater the relationship between the project and the utility's other business, the

greater would be the likelihood of regulation by the Louisiana Public Service Commission.

5. If the project is owned by third parties, completely separate from the consuming industrial plants or the local utility, it is possible that the Louisiana Public Service Commission may take the position that the cogeneration organization selling to industries would constitute a public utility. However, this is not likely in the opinion of Taylor, Porter, Brooks & Phillips.

6. These preliminary opinions concerning regulation by the Louisiana Public Service Commission are based in large part on the case of Gulf States Utilities Company vs. Louisiana Public Service Commission, 222 La 132, 62 So2d 250 (1952). In this case, the Louisiana Supreme Court excluded from the rate consideration income derived by Gulf States Utilities from the sale of steam and electricity to Ethyl Corporation through specially designed steam turbine generating equipment. These generators were fueled by burnable waste residues from the Esso Refinery in Baton Rouge.

Regulation by the Federal Energy Regulatory Commission

A. If the cogeneration plant sells electric energy to consuming industries solely for their own direct consumption, such sales would not be subject to regulation presently under the Federal Power Act by the Federal Energy Regulatory Commission (FERC). This would be true whether the cogeneration plant was a corporation, joint venture, or a partnership owned by the participating industries, or whether the sale was made directly by an electric utility, or a subsidiary owned in whole or in part by the utility

or by third parties. The Federal Power Act purports to regulate the sale of electric energy at wholesale in interstate commerce, which is defined to mean the sale of electric energy to any person for resale.

B. If the cogeneration plant should sell some of its output to a local utility, such sale would be subject to regulation by the FERC under the Federal Power Act if the sale is to a local utility for resale. This regulation over the sale at wholesale to another utility would exist even though the entity owning the cogeneration plant did not own any interstate transmission facilities. If the entity owning the cogeneration plant only owns the facility used for generation and for local distribution or transmission in intrastate commerce and does not own facilities for the transmission of energy in interstate commerce, then the FERC will not have jurisdiction over such facilities or the cogeneration entity under the Federal Power Act. However, if the entity makes a jurisdictional sale as described above, it will be deemed to be a public utility under the Federal Power Act and subject to regulation as such under the Federal Power Act.

C. The prices and terms of sale would be subject to regulation under Sections 205 and 206 of the Federal Power Act, which in general require them to be just and reasonable and not unduly preferential or discriminatory. Plant, revenues, and expenses would be allocated between jurisdictional and non-jurisdictional sales of steam and electricity would certainly raise difficult cost-of-service issues.

D. Once the cogeneration entity becomes characterized as a public utility by reason of jurisdictional sales or ownership of jurisdictional

facilities, it would be subject to other regulation under the Federal Power Act, including but not limited to the keeping of records and accounts, disposition of property, mergers and consolidations, acquisition of securities of public utilities, issuance of securities, et cetera.

E. There is no present direct federal regulation for the rate of manufactured steam other than as might be applied to discriminatory or illegal pricing under federal antitrust laws.

Regulation by the Securities and Exchange Commission

A. The proposed basic case would be for the cogeneration facility as a whole to be owned by some combination of the local utility and the consuming industrial customers. A stated assumption is that the investors would not want to be subject to Public Utility Holding Company regulation. Whether the cogeneration entity is a corporation, partnership, association, joint stock company, business trust, or merely an organized group, whether incorporated or not, since it owns or operates facilities used for the generation of electric energy for sale, the cogeneration entity would constitute an electric utility company under the Public Utility Holding Company Act, and unless (1) the form of undivided ownership is not considered to constitute a "company" under Section 2(a)(2) or (2) it is exempt under Section 2(a)(3), or (3) the investors owning 10% or more of the voting securities of the cogeneration entity are exempt under Section 2(a)(7)(B) or under Section 3(a) of the Act, the investors would be subject to regulation under such Act as holding companies.

Although SEC staff members informally indicate that simple undivided

ownership is not considered to be a "company" under the Act, we have found no clear published authority to such effect and believe that in most, if not all, cases the complexity of cogeneration projects will necessitate a degree of "organization" that will cause them to fall within the definition of a "company" under the Act.

For the investor to qualify for an exemption from the Public Utility Holding Company Act, at least one of the following conditions must be satisfied:

1. The cogeneration entity is primarily engaged in one or more businesses other than the utility business and by reason of the small amount of electric energy sold by the cogeneration entity, it is not necessary in the public interest or for the protection of investors or consumers that such entity be considered an electric utility company for purposes of the Act. Regulation Section 250.7 provides that if the gross sales of electric energy do not exceed \$100,000 per year, the cogeneration entity would not be deemed an electric utility company. Beyond this amount, a determination by the SEC as to whether or not the public interest is served would be necessary. Even the stated limit is probably of little comfort during this period of high inflation. Also, even assuming that the business of selling steam would be treated as another business, there would be the continuing fact issue of if the steam business

was the primary business. Also, if the local utility were a substantial investor, there is a strong probability that the cogeneration entity would not be considered as being primarily in a non-utility business.

2. The cogeneration entity is one operating within a single state and substantially all of its outstanding securities are owned directly or indirectly by another company to which such entity sells or furnishes electric energy which it generates; such other company uses and does not resell such electric energy, is engaged primarily in manufacturing, and is not controlled by any other company; and by reason of the small amount of electric energy sold or furnished by such entity to other persons, the SEC determines that it is not necessary in the public interest or for the protection of investors or consumers that the entity be considered an electric utility company. This requirement does not fit with the proposed plan for multiple ownership of the cogeneration entity and further would require a periodic judgment by the SEC of public interest.
3. The SEC declares that the investor is not a holding company upon a finding by it that the investor does not directly control the cogenerating entity, is not an intermediary company through which such control is exercised, and does

not directly or indirectly exercise such a controlling influence over the management or policies of the cogeneration entity as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the investor be subject to the Act. Again, this finding would hinge upon fact determinations and could vary from time to time over the life of the cogeneration unit.

4. The investor and cogeneration entity (assuming that the investor realizes a material part of its income -- 2% of net income may be material! -- through the cogeneration investment) are predominantly intrastate in character and carry on their business substantially in a single state in which the investor and the cogeneration entity are organized. This basis for exemption would only be available in limited circumstances in which the investors were predominantly in business in the state of the cogeneration project and were all incorporated in such state. The exemption may be denied if the SEC finds it detrimental to the public interest or interest of investors or consumers.
5. The investor is predominantly a public utility company whose operations as such do not extend beyond the state in which it is organized and states contiguous thereto. The exemption may be denied if the SEC finds it detrimental to

the public interest or interest of investors or consumers.

6. The investor is only incidentally a public utility holding company, being primarily engaged or interested in one or more businesses other than the business of an electric or gas utility company and the investor does not derive any material part of its income from utility subsidiaries, or if it does derive a material part of its income from utility subsidiaries, only if such investor owned substantially all the outstanding securities of the subsidiary utility companies. The fact issue of whether or not the investor was only "incidentally" a holding company and whether or not it derived or did not derive a "material" part of its income from the cogeneration operation (assuming no other utility operations are involved), would be subject to periodic determination by the SEC and could vary over a period of time. Even beyond this, the exemption apparently only applies if a single investor is involved. The exemption may be denied if the SEC finds it detrimental to the public interest or interest of investors or consumers.

Other bases for exemption exist but are too remote to be of general interest in this analysis.

Based upon the exemptions described above, it is reasonable to assume that counsel for potential investors would advise the investors that deter-

minations could be made either initially or at some later date to the effect that the investor was a holding company subject to the Act and that, even if originally exempted, no absolute assurance could be given that the investor would be free of such regulation for the life of the project. If this risk is acceptable to a potential investor, it would at least be reasonable to anticipate that a potential investor would want as much initial assurance of its position as is reasonably available. Starting with a prospect or two which at least appear to meet one of the exemption criterion, the SEC could be approached informally for a reaction and, if appropriate, an exemption filing or proceeding could be initiated. (Note: see no-action letter to Gulf States Utilities Company dated June 26, 1978, for indication of favorable attitude of SEC staff toward exemption.) Since it must be anticipated, however, that many potential investors will not find this risk of initial and continued exemption acceptable and if one of the purposes of this research project is to determine on a practical level if this form of cogeneration project is available for general application, legislative relief from the Public Utility Holding Company Act may have to be obtained or published regulations assuring the exemption for this type of project issued by the SEC.

B. Other proposals would be to exclude the local utility as an owner or to change the type of investor, i.e. industrial customers vs. vendors, insurance companies, etc. The comments made in A above would apply here also.

C. An additional proposal was offered for preliminary consideration.

In an effort to accommodate the utility industry's interest in new types of financing, a regulation was adopted by the SEC which exempts certain entities from being considered as electric utility companies and, in turn, the owners thereof from being considered as public utility holding companies. Under this regulation if the cogeneration entity owned the cogeneration facilities, it would not be deemed an electric utility company if

- (a) the facility is leased under a net lease to the local utility and the facility is to be employed by the local utility in its operations; and
- (b) the cogeneration entity is owned only by companies engaged primarily in businesses other than the public utility business; and
- (c) the terms of the lease have been approved by a regulatory authority having jurisdiction over the local utility's rates; and
- (d) the lease is for over fifteen years; and
- (e) the rent does not include any amount based directly or indirectly on revenues or income of the local utility.

In the situation in which you have outside passive investors involved, this exemption could be used as a vehicle for the investors to own and finance a cogeneration entity. The business problem created would be (1) whether the economics of the lease to the local utility could be designed to include enough return for the investors without producing a cost too high for the utility to justify and (2) whether the economics of the sale of

steam and power by the utility to the industrial customer could be designed to be acceptable to the utility and the customer. If fuel and financing were supplied by the industrial customers, the rates for sale of steam and power by the utility to such customers could be designed on a unit sale basis giving appropriate credit to the customer for the fuel and financing provided. A no-action letter should be sought with respect to application of this exemption to a given case to determine if the SEC staff would take the position that the rate credits given as an integral part of the leasing transaction would be considered as in effect tying the rent indirectly to the utility's revenues. We have found no published interpretation of this point. However, the release proposing the regulation stated that the purpose of the requirement was to prevent any profit sharing on the theory that this would assure that the investor was only a passive owner of the utility assets. Based on this stated purpose, it may well be that the SEC would not grant the exemptions under this regulation if the industrial customer were an investor in the cogeneration entity.

The retail sale of electricity by the cogeneration entity, including the credits involved therein, would be subject to regulation in Texas, the steam sale not. (See above). In Louisiana, it is indicated above that the combined sale would not be subject to regulation. To satisfy the requirement for exemption under the Holding Company Act regulation, however, any commission having jurisdiction over rates of the utility would have to review and approve the lease. The Texas commission probably has the necessary jurisdiction and authority to approve such a lease if it determines the

transaction is in the public interest (Section 68). The FERC could also probably consider and approve the lease as a security under Section 204 of the Federal Power Act.

D. Another proposal would be for several investors to own the steam producing facilities and the local utility to own the electric generating equipment. The investors may include the industrial customers, contractors, vendors, financial institutions and the local utility.

It is not clear that use of separate ownership of the steam facilities would gain any non-regulatory advantages. Section 2(a)(3) of the Public Utility Holding Company Act defines "electric utility company" as a company owning or operating "facilities used for the generation. . . of electric energy for sale. . ." The word "facilities" has been held in similar context to be "a widely inclusive term, embracing anything which aids or makes easier the performance. . . involved in the business of a person or corporation." The term has been viewed broadly by the SEC staff also, but the staff has ruled that fuel storage facilities and general purpose computers are not "facilities" for such purpose. Obviously there could be a question raised about the steam producing facilities. We have found no direct precedent other than the no-action letter issued by the SEC staff to Gulf States Utilities Company on June 26, 1978. However, should the steam facilities now or later be determined by the SEC and/or courts to be "facilities" for purposes of Section 2(a)(3) or should the particular project not conform in substance to the project covered by such no-action letter, then the entity owning the steam facilities would be considered an electric

utility and 10% or more equity owners of it as holding companies, subject to qualification for an exemption as discussed above.

In pursuit of this matter, attached as exhibits are copies of letters requesting a no-action letter on such a proposal and the SEC response thereto.

If the local utility owns its interest in the generating equipment outright, no holding company issue is created with respect thereto. If the generating equipment is owned through a subsidiary of the local utility, and operations are conducted on a local basis within the state of the local utility's operations, presumably the utility could obtain an exemption from the Holding Company Act under Section 3(a)(2) and avoid additional regulation through such exemption.

Certain State Taxes and Fees

A. In Texas

The form of business entity through which cogeneration operations are conducted in the State of Texas will govern the taxes, fees and charges payable by the cogeneration organization. In reviewing this issue, we have presumed that the cogeneration entity will be formed under Texas law and that all of its facilities will be located in Orange County, Texas, for the sole purpose of making electric and steam sales within that county. In addition, since the focus of this question is on taxes, fees and charges payable in Texas, we have not considered those taxes, fees and charges which may be payable by the cogeneration organization at the federal level.

Accordingly, subject to the foregoing limitations, our preliminary

review indicates that the following taxes, charges and fees would be payable by the cogeneration entity in Texas.

1. Corporate Organization

If the cogeneration entity were formed as a general purpose domestic corporation under the Texas Business Corporation Act, a filing fee of \$100 would be required to be paid to the Office of the Secretary of State for the State of Texas in order to obtain a certificate of incorporation. No further taxes would be levied or charges would be made by the State with regard to the incorporation, nor at this time would any State income taxes be imposed upon the organization's income subsequent to formation since the State of Texas does not presently tax personal or corporate income.

Following its formation as a domestic corporation, the cogeneration organization would be required to pay franchise taxes imposed by Arts. 12.01 et seq. of Tex. Tax. Gen. In Texas, franchise taxes are payable annually by June 15 of each year for the 12-month period commencing May 1. Subject to a minimum annual tax of \$55, the franchise taxes are calculated on the basis of \$4.25 per \$1,000 of (i) the stated capital, surplus and undivided profits of the corporation or (ii) the assessed value of the corporation's property in the State, whichever is greater. Under Ruling No. 026.02.12.019 issued by the Comptroller of Public Accounts of the State of Texas, for a newly organized corporation the minimum franchise tax is payable within 45 days after the end of the month in which the corporation is organized.

Under the provisions of Arts. 7145 et seq. of Tex. Rev. Civ. Sta. Ann., the cogeneration entity as a domestic corporation would be required to pay

ad valorem property taxes on all property, real, personal or mixed, owned by the corporation within the State of Texas. Although intangible assets (such as accounts receivable or contract rights) come within the literal scope of Arts. 7145 et seq., assets of that type customarily are not taxed for ad valorem tax purposes in Texas. During calendar year 1976, the following ad valorem taxes were assessed in Orange, Texas:

<u>Authority</u>	<u>Tax Rate Per \$1,000 of Assessed Value</u>	<u>Ratio of Assessment to Market Value</u>
County & State	\$19.10/\$1,000	25%
City	\$18.20/\$1,000	50%
School District	\$12.30/\$1,000	100%

In Texas, unlike in many other states, properties subject to ad valorem taxes are appraised and valued by each taxing authority rather than through a centralized board.

Pursuant to Art. 11.03 of Tex. Tax. Gen., the cogeneration organization may be required to pay a gross receipts tax on a quarterly basis to the Comptroller of Public Accounts of the State of Texas. By its terms, Art. 11.03 applies only to the gross receipts of a gas, electric light, power or water works or plant located within an incorporated town or city and used for the sale of gas, electricity or water in that town or city. As construed in Texas, Art. 11.03 covers a company's gross receipts from the sale of gas, electricity or water made within an incorporated city or town to two or more customers (Opin. of Att'y. Gen. No. V-1084) even though the generating plant or works may be situated outside the city or town limits (El Paso Electric Co. v. Calvert, 385 S.W. 2d 542 (Tex. Civ. App. - Austin 1965, writ ref'd., n.r.e.)). If a company purchases the gas, water or

electricity for resale and if the wholesaler pays the gross receipts tax on the wholesale proceeds, then any receipts on resale are subject to tax only to the extent that the resale receipts exceed the wholesale receipts (Opin. of Att'y Gen. No. C-47). In towns having a population of 10,000 or more persons (such as Orange), the present gross receipts tax is imposed at the rate of 1.997% of those receipts arising from sales made within the town itself.

Accordingly, if the cogeneration entity were to come within the scope of Art. 11.03 by virtue of its sales of electricity in the City of Orange, the gross receipts tax would be payable on its receipts from electric sales. However, a similar receipts tax would not be payable on the organization's steam sales in that those sales would be outside the coverage of Art. 11.03*

In Texas, a limited sales and use tax is imposed by Arts. 20.01 et seq. of Tex. Tax. Gen. on all retail sale of taxable items or services. The sales tax is paid by the purchaser at the time of sale and is remitted by the retailer to the Comptroller of Public Accounts of the State of Texas on a monthly basis (if monthly tax proceeds exceed \$750) or on a quarterly basis (if monthly tax proceeds are less than \$750). Sales of taxable items at the wholesale level are exempted from sales and use taxation until resold at retail. At the present time, the rate of sales taxation in Orange, Texas is 5% of the selling price of the taxable item, consisting of 4% to be retained

*Since Art. 11.03 makes specific reference only to sales of water, we have been informally advised by the Comptroller of Public Accounts of the State of Texas that such Article has no application to steam sales.

by the State of Texas and 1% to be remitted to the City of Orange in accordance with Art. 1066c of Tex. Rev. Civ. Sta. Ann.

Under Art. 20.04(R) of Tex. Tax. Gen. and Comptroller Ruling No. 026.02.20.015, a sale of electricity by the cogeneration entity would be exempted from all sales and use taxes to the extent that the sale is made for any use other than residential or commercial use. As defined by statute, commercial use does not include use by persons engaged in (i) processing and manufacturing tangible personal property for sale as tangible personal property, (ii) exploration for or production and transportation of a material extracted from the earth, (iii) agricultural operations, (iv) electrical processes such as electroplating, or (v) printing of newspapers. In addition to the foregoing, pursuant to Art. 20.04(E) of Tex. Tax. Gen. any sale of steam by the cogeneration entity would also be exempted from all sales and use taxes to the extent that the sale is made to a person for use during any phase of a manufacturing, processing or fabricating operation involving tangible personal property that is ultimately to be sold at retail.

As a result of the foregoing, retail sales of electricity or steam by the cogeneration entity would be subjected to sales and use taxation unless the use to which the electricity or steam will be put by the purchaser comes within one of the exemptions described above.

If classified as a public utility engaged in sales of electricity regulated by the Texas Public Utilities Commission, the cogeneration entity would be required to pay an annual assessment imposed by Sections 78 et seq. of Art. 1446c of Tex. Rev. Civ. Stat. Ann. This annual assessment would be payable to the Commission on or before August 31 of each year unless paid

quarterly at the option of the cogeneration entity and would be calculated on the basis of 1/6 of 1% of the entity's gross receipts from rates charged to its ultimate consumers of electricity in Texas. As now drafted, Art. 1446C would not impose a similar assessment on the receipts of the cogeneration entity from its sales of steam.

Under the authority of Art. 1436a of Tex. Rev. Civ. Stat. Ann. the cogeneration entity would be permitted to erect, construct and maintain without the payment of any fee or charge its electric distribution and transmission lines along state and county roads located outside the limits of an incorporated town or city. However, to the extent that the entity's electric transmission and distribution lines (as well as its facilities for steam distribution) would be situated along public roads within the city limits of Orange, the entity (if qualified) would become subject to two taxes imposed by the City. The first of these taxes would be a street rental charge imposed at the rate of 2% of the entity's gross receipts from sales of electricity and steam to residential, commercial, industrial and municipal customers. The second of these taxes would be a franchise fee payable to the City for issuance of a franchise authorizing the entity to make steam and electric sales in the City. This fee is imposed at the rate of 4% of gross receipts from sales of steam and electricity to residential and commercial customers only, and the entity would receive a credit against this fee to the extent that the entity pays a street rental charge on receipts from sales made to customers in those two classifications.

With regard to the sales of steam generated by cogeneration entity, two

Texas statutes would apply to the entity's steam operations. First, Art.

6.068 of the Texas Water Code provides that a fee of \$1.00 per horsepower of generating equipment is payable to the Texas Water Rights Commission by each operator of a steam generating plant using State water for such purpose.

Second, Art. 5221c of Tex. Rev. Civ. Stat. Ann. provides that an annual per boiler fee not to exceed \$15.00 is payable each year to the Commissioner of the Bureau of Labor Statistics for the inspection of each boiler used to generate steam.

2. Joint Venture

If the cogeneration entity were to be a joint venture of the participating industries as co-tenants or co-owners, all of the taxes, fees and charges described in 1. above would be payable by the joint venture other than for (i) incorporation filing fees payable to the Secretary of State for the State of Texas and (ii) franchise taxes imposed by Arts. 12.01 et seq. of Tex. Tax. Gen. In the event of formation of the joint venture, however, the provisions of Art. 1435a of Tex. Rev. Civ. Stat. Ann. would then govern the liability of each participating industry for the payment of any fees, taxes and charges arising out of the generation, transmission, sale and distribution of electric energy. Under the authority of Art. 1435a, each participating industry would be liable for the payment of such fees, taxes and charges incident to the venture's electric operations only to the extent of its undivided interest in the venture, and no participant would be liable for payment of any taxes, fees and charges as to which another participant would have primary liability. As now drafted, the provisions of Art. 1435a

would not apply to the joint venture's steam operations, and accordingly each participant would be jointly and severally liable for the payment of all fees, taxes and charges arising in connection with those steam operations.

3. Partnership

If the cogeneration entity were formed as a partnership consisting of the participating industries, all of the taxes, fees and charges described in 1. above would be payable by the partnership other than for (i) incorporation filing fees payable to the Secretary of State for the State of Texas and (ii) franchise taxes imposed by Arts. 12.01 et seq. of Tex. Tax. Gen. Although Art. 1435a providing for several liability as to payment of taxes, fees and charges by joint ventures does not expressly state that it is applicable to partnerships, the provisions of such Article should apply to the partnership if each participant remains a co-owner of the partnership facilities.

If the partnership were formed as a limited partnership under the Texas Limited Partnership Act, the partnership would be required to pay to the Secretary of State for the State of Texas a filing fee equal to 1/2 of 1% of the total contributions made or required to be made to the partnership incident to formation. However, in no event would the filing fee exceed the sum of \$2,500 or be less than the sum of \$100.

4. Subsidiary Corporation

If the cogeneration entity were formed as a subsidiary corporation of a local investor-owned electric utility company, all of the taxes, fees and

charges described in 1. above would be payable by the subsidiary corporation.

5. Direct Ownership by Utility

If the cogeneration entity were formed within and operated by a local investor-owned electric utility company, all of the taxes, fees and charges described in 1. above would be payable by the utility other than for the incorporation filing fees payable to the Secretary of State for the State of Texas.

6. Partial Ownership by Utility and Participating Industries

If the cogeneration entity were partially formed within and operated by a local investor-owned electric utility and partially owned and operated by the participating industries, a joint venture would be established between the utility and the industries. In that event, all of the taxes, fees and charges described in 1. above (other than incorporation filing fees and franchise taxes) would be payable subject to the provisions for several liability contained in Art. 1435a.

7. Third Party Ownership

If the cogeneration entity were formed within and operated by an unrelated third party or parties, the fees, taxes and charges described in 1. through 5. above would be payable by the third party or parties depending upon the form of business entity through which the cogeneration operations were to be conducted. In that event, no taxes, charges and fees would be payable by the participating industries other than for taxes required to be included by the third party or parties in the sales price of electricity and steam not otherwise exempted from such taxation.

8. Non-profit Organization

The State of Texas has enacted two statutes of general application governing the formation of non-profit corporations and associations. The first of these statutes is Art. 1396-1.01 of Tex. Rev. Stat. Ann., and is commonly known as the Texas Non-Profit Corporation Act. To be incorporated under this Act, the corporation must be formed and operated on a basis whereby no dividends are paid, and no part of the income is distributed, to the members, directors or officers of the corporation (other than for compensation payable to such persons in reasonable amounts). The second of these statutes is Art. 1396-50.01 of Tex. Rev. Civ. Stat. Ann., and is commonly known as the Texas Cooperative Association Act. Under this Act, a cooperative association may be formed for the purpose of providing any type of property, commodity, good or service for the primary and mutual benefit of the association. However, the Act expressly states that the members of the association may only be natural persons, other cooperative associations, or non-profit corporations. As a result, since neither the participating industries nor any local investor-owned electric utility involved in the cogeneration project could qualify for membership in the association, we have not considered the regulatory and tax effects of formation of a cooperative association.

On the basis of our briefing and research, it is our opinion that the formation of the cogeneration entity under the Texas Non-Profit Corporation Act would have the following tax effects in Texas.

If the cogeneration entity were formed as a non-profit corporation, the

corporation would be required to pay all of the taxes, fees and charges payable by the domestic corporation described in 1. above, except that the incorporation filing fee would be reduced to \$25. Although certain of the taxing statutes described in 1. above (such as the statutes pertaining to franchise taxes and sales taxes) do provide tax exemptions, none of these exemptions would be available to the corporation due to the nature of its business. Because of the absence of tax advantages resulting from operation as a non-profit corporation, it appears that formation of the cogeneration entity as a non-profit corporation may not be warranted, particularly in light of the strict limitations on corporate dividends and income distribution applicable to corporations of that type.

B. In Louisiana

1. The sale of steam, electricity and gas are exempt from Louisiana sales taxes. The corporation would be subject to Louisiana Corporate Income and Corporated Franchise Tax and would also have to pay an occupational license tax.

2. If the cogeneration company was organized as a non-profit corporation, it would not be subject to Louisiana Income tax because, by definition, it would not be permitted to earn income. It would also not be subject to the Louisiana Corporation Franchise Tax. Otherwise, it would be subject to the same taxes as noted above.

3. If the cogeneration organization were in the form of a joint venture or partnership, it would not be subject to Louisiana Corporation Income and Franchise Taxes. A joint venture is treated as a partnership

under Louisiana law. Net partnership income would be taxed to the partners.

4. The cogeneration organization would be subject to Louisiana ad valorem taxes. However, to the extent that new facilities were constructed these facilities probably could obtain a ten-year ad valorem tax exemption.

DIVISION OF
CORPORATE REGULATION

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Appendix G
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June 26, 1978

Benny Hughes, Esquire
Orgain, Bell & Tucker
Beaumont Savings Building
Beaumont, Texas 77701

Re: Gulf States Utilities Company ("Gulf States")
File No. 132-3

Dear Mr. Hughes:

I am responding to your letters of April 20, 1978, and May 11, 1978, concerning a proposal by Gulf States to organize a subsidiary to own and operate steam production facilities. You state that the new subsidiary will be a joint venture company to be owned in various percentages exceeding 10% by Gulf States and unspecified industrial customers. The steam produced by this subsidiary will be sold to the industrial owners for various industrial uses. Initially, however, the steam will pass through an electric generator, which is to be owned and operated separately by Gulf States or some other company. In one project you describe, the investment in steam plant will be approximately \$122 million, while Gulf States' investment in the generation equipment will be about \$8.6 million. You state that income from electric sales will constitute only 10 to 20% of the combined income from steam and electric sales.

In concur in your conclusion that, under the circumstances described in your letters, an entity organized to own steam production facilities will not become an "electric utility company," as defined in Section 2(a)(3) of the Public Utility Holding Company Act of 1935 ("Act"), even though some or all of the steam is applied first to generate incidental power. Accordingly, Gulf States and the industrial co-owners of the steam subsidiary will not become "holding companies" under Section 2(a)(7) of the Act.

I must emphasize that, in reaching this conclusion, I do not consider the separate ownership of the boiler and electric generating facilities as controlling. A boiler installed by an electric company to produce steam for the generation of power is an integral part of its

Benny Hughes, Esquire
Page Two

electric utility facilities, and the simple act of separating ownership of the boiler would not alter its character as a statutory "facility," within the meaning of Section 2(a)(3). In the project you have described, however, the steam plant has been designed primarily to produce steam for use as such by industrial consumers. The generation of a relatively small amount of power as a by-product will not change the essential nonutility function of the boiler.

I am satisfied that, if the entity owning the steam plant also owned the generator and related equipment, it would be an appropriate case for an application for exemption by order under Section 2(a)(3). However, since the entity Gulf States proposes to organize will neither own nor operate the generating equipment itself, and as the steam producing facilities will be employed primarily for other purposes, an application under Section 2(a)(3) is unnecessary.

Sincerely,

A handwritten signature in cursive script, appearing to read "Aaron Levy".

Aaron Levy
Director

APPENDIX H

REPORTS CONCERNING THE USE OF COAL AND COGENERATION
PREPARED BY THE STATE OF LOUISIANA

Beckers, Thomas F., and Weaver, Robert E. C. Coal Use in Louisiana - A Second Reconstruction. State of Louisiana Department of Natural Resources, Research and Development Division, 1978.

Henry, James M., Landrum, T. C., Beckers, Thomas F., and Weaver, Robert E. C. Opportunities for Cogeneration in Louisiana's Chemical Strip - An Economic Assessment. State of Louisiana Department of Natural Resources, Baton Rouge, 1977.

Moffatt, Joseph F., Rense, William C., and Gaulden, C. F. Transportation and Distribution Problems of Coal Utilization in Louisiana. State of Louisiana Department of Natural Resources, Office of Conservation, Division of Natural Resources and Energy, 1977.

_____, Transportation of Coal and Lignite in Louisiana State of Louisiana Department of Natural Resources, Baton Rouge, 1978.

Roland, Harry L., Jr., Jenkins, George M., and Pope, David E., Lignite, Evaluation of Near-Surface Deposits in Northwest Louisiana. State of Louisiana Department of Conservation Louisiana Geological Survey, Mineral Resources Bulletin No. 2 Baton Rouge, 1976.

APPENDIX C