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ARGONNE NATIONAL LABORATORY

Energy and Environmental Systems Division

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ANL/CNSV-TM-45

INDUSTRIAL COGENERATION CASE STUDY #1.

CELANESE FIBERS COMPANY
ROCK HILL, SOUTH CAROLINA

Prepared by

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for

Energy and Environmental Systems Division
Argonne National Laboratory
Under Contract 31-109-38-4834

September, 1979

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PREFACE

The project reported here was directed and conducted by James H. McElroy. Nirmal Kotamraju worked and consulted on all aspects of the project and provided particularly valuable service in his organization and management of the data development. Richard Peppin contributed and participated in the early stages of project development. Barbara Coates performed much of the data manipulation. Julie Drury and Leila Snyder typed the many drafts of the manuscript. Thanks are due Charles Leatham of Gilbert Commonwealth Engineers for his expert consultation on many of the technical aspects of cogeneration and to Jack G. Faucett for his consultation on the intricacies and complexities of interest, capital depreciation, inflation, and investment decision making.

Special thanks go to the people of Celanese -- Bruce Melaas, who initially authorized this case study; James Ragan, who coordinated initial contacts and plant visits; Guy Zazarra, manager of the Celriver utilities plant; and, in particular, Bill Norwood, Chief Engineer. Bill Norwood's sophisticated understanding of cogeneration and encyclopedic knowledge of the Celriver facility plus his enthusiastic support of this case study made him an invaluable project resource.

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1 INTRODUCTION AND BACKGROUND

Argonne National Laboratory, under the sponsorship of the Department of Energy's Office of Industrial Programs, has financed a project to do case studies of cogeneration at five industrial establishments. Six reports, one on each of the five individual case studies and a summary synthesis report, document the total case study project. This report covers the case study of the cogeneration operation at the Celanese Fibers Company plant at Rock Hill, South Carolina.

This chapter describes the objective of the project, the general methodology of site selection, and the selection of the subject Celanese plant in particular. The chapter concludes with a brief discussion of the case study methodology employed and the report organization used for documenting the results.

1.1 PROJECT OBJECTIVE

The Industrial Cogeneration Case Study Project, which this report partially documents, is part of an effort by the Department of Energy to improve understanding of cogeneration.

Much has recently been written and said about the energy saving potential of co-locating facilities that generate electric power with facilities that consume large quantities of lower grade process heat (which happens to be a by-product of power generation). By co-locating such facilities much of the by-product heat of electric generation that is traditionally thrown away (often as a thermal pollutant) can be used productively. If properly designed and operated such cogeneration operations can save large amounts of fuel and capital. (Capital savings are achieved through not having to provide equipment to convert the saved fuel into energy that is to be discarded.) While the theoretical potential of cogeneration is well known, little is generally known about the actual operation of functioning cogeneration facilities at establishments that use large amounts of process heat and power.

To fill this knowledge gap DOE/Argonne National Laboratory have commissioned two sets of cogeneration case studies. An earlier series of case studies explored cogeneration that takes place at a number of commercial and residential apartment facilities around the U.S. The case studies of this project explore cogeneration that takes place at five large industrial establishments located in five widely separated U.S. locations.

The earlier case studies were of relatively small scale cogeneration operations that primarily provided electricity and space conditioning energy for residential and nonindustrial (mostly commercial, residential apartments and service sector establishments) working spaces. With one exception all of these operations had electric power capacities of 5000 kW or less, most used diesel prime mover technology, and had requirements for relatively low grade by-product heat. They all operated on oil or natural gas and were of fairly recent (since 1960) vintage, and most of them were at best only marginal economic and energy saving successes and, at worst, total failures in both aspects.

In contrast the case studies of this project cover operations of much larger scale, 12,000 kWe, with large additional amounts of motive power cogenerated in some cases. The industrial cogeneration operations serve process heat needs that are much more diverse. For example, steam at more than three different enthalpies (temperature and pressure) is frequently needed by industrial establishments and the process heat usually needed must be of a much higher grade than that typically needed for space conditioning. Sometimes fairly high grade heat (400 psi superheated steam) is required.

The five establishments of this project all use steam turbine prime mover technology. Fuel use, on the other hand, is very diverse. All of these cogeneration operations are 30 or more years old, some dating back to the first two decades of this century, with long histories of incremental plant changes, additions, and refinements. Only one of the facilities (that at the Celanese plant, which is the subject of this report) even remotely resembles the originally designed and installed cogeneration operation, all the others have grown and evolved into operations quite different from those installed.

1.2 SITE SELECTION METHODOLOGY AND CRITERIA

For this study the Department of Energy was interested in cogeneration in five industries -- (1) food processing, (2) textiles, (3) pulp and paper, (4) chemicals, and (5) oil refining. In selecting sites for study, Jack Faucett Associates, (JFA) used a cogeneration data base they developed that identifies and categorizes most establishments where cogeneration takes place. From this array of establishments JFA selected from time to time some in each industrial category and began requesting their participation and cooperation in this case study project.

In general, sites ultimately selected were those that would provide the widest possible variety of information about the actual practice of industrial cogeneration in the U.S., particularly concerning such factors operating near the economic margin that can make the difference between successful and unsuccessful cogeneration operations. The case study candidates were not selected according to any scientific sampling principles. Rather, JFA's experience and knowledge gained in doing other case studies, especially one on cogeneration, and in developing and analyzing its cogeneration data base were used to select case study candidates.

1.2.1. Size of Electric Generation Plant

A prime objective of this study was to explore the economics of operating cogeneration plants. In that regard, the most interesting cogeneration operations are the plants with electric generation in the 10,000-30,000-kW range. As cogeneration candidates in the future, the smaller operations are less numerous and are expected in general to be less attractive; whereas the larger operations, being major beneficiaries of the economies of scale available from electric generation technology, are expected to be clearer winners. As to the very large operations, however, the number of

industrial applications where they are practical is small. For example, there are no large (greater than 30,000 kWe) cogeneration plants in the food and textile industries. The five industries studied constitute the bulk of U.S. manufacturing capacity and thus the bulk of the market for cogeneration, which lies in such medium-to-large-sized plants as those selected for this study.

1.2.2 Facility Location

Facility location was an important choice criteria for two reasons:

1. The overall project's usefulness is enhanced by case study experience provided from a large variety of geographical locations.
2. Selected individual establishments should be in locations that are generally attractive to industry -- out-of-the-way locations were avoided. For example, pulp and paper mills in remote and isolated locations in the States of Maine, Oregon, and Washington were not contacted. The participation of mills in Ohio, Tennessee, or Pennsylvania was preferred.

Additionally, it was desired to have sites located in as many different states and regulatory environments as possible. Facilities selected are in five states, New Jersey, South Carolina, Tennessee, Illinois, and California.

1.2.3 Facility Fuel Use

Case study candidates were chosen with major consideration given to the type of fuel used. The widest possible variety of fuel use was sought; the sites selected use petroleum, natural gas, coal, oil refinery by-product gas (refinery gas) and oil, and paper mill by-product black liquor. An aspect related to fuel used by these sites is the fuel-use mix of the electric utility that serves them.

In effect, onsite electric generation competes in part with the local electric utility since industrial plant managers typically have the choice of making power onsite or buying it from the local electric utility. To varying degrees, this decision has been made based on the comparative economies involved. Because a large part of the cost of purchased (as well as onsite-generated) power goes for fuel purchase, the kind of fuel used to generate utility-produced power is an important consideration. If the onsite cogeneration uses the more expensive oil and gas fuels and the electric utility uses the same, onsite cogeneration can be expected to be much more cost competitive with the purchased power option than would be the case if the relatively inexpensive coal and nuclear fuel generated the utility's power.

Fuel usage aspects for 1978 of the five onsite generating facilities selected for the entire case study project are:

1. The Celanese plant in South Carolina, the subject of this report, uses coal and competes with Duke Power Company whose baseload electric generation was 66% coal and 33% nuclear fueled.
2. The American Cyanamid plant in New Jersey uses oil and natural gas and competes with the Public Service Gas and Electric Company whose baseload electric generation was about 50% oil, 25% nuclear, and 25% coal fueled.
3. The Mead Paper plant in Tennessee uses purchased coal and by-product black liquor and competes with Appalachian Power Company whose baseload electric generation was nearly 100% coal fueled.
4. The AMOCO plant in Illinois uses natural gas, refinery gas, by product fuel oil, and residual fuel oil and competes with the Illinois Power Company whose baseload electric generation was more than 90% coal fueled.
5. The C&H Sugar plant in California uses oil and gas and competes with Pacific Gas and Electric Company whose baseload electric generation was 48% natural gas and 49% oil fueled, with the remaining 3% provided by geothermal energy.

1.2.4 Prime Mover Technology

Case study candidates were chosen with consideration given to the kind of engine that is the prime mover. Analysis, however, of JFA's cogeneration data base revealed that there was not much variety in the kind of technology used to power large cogeneration prime movers. One listing of large industrial cogeneration facilities showed that out of 380 facilities, 349 were steam turbine powered, 17 were internal combustion (diesel) powered, and fewer than 20 were gas turbine powered. The fact that all of the sites selected use steam turbine technology resulted because of limitations in the number of case studies performed plus the application of other important site selection criteria.

1.2.5 Motive Power Cogeneration

The most common perception of cogenerated power is of electric power. Technologically, however, there is no reason to limit the notion of cogeneration to electric power production. A more general and proper notion of cogeneration conceives of power in either mechanical or electrical terms. In selecting sites for this study, the primary focus was on onsite electric generation with recovery and use of by-product heat, but sites where significant motive power was generated were also sought for the project so that the relationship between motive power and electric power cogeneration could be explored. It turned out that although all the sites have some motive power generation, only the Celanese site, has a large quantity of it, nearly 10,000 kW.

1.2.6 Varied Institutional Environment in Which the Cogeneration Plant Existed

An initial criteria for case study site selection was varied institutional arrangements in which cogeneration existed. Sites of particular interest were those where cogenerators:

1. Sell excess electricity to the electric utility that serves their area;
2. Buy additional power above and beyond that they produce;
3. Wheel onsite generated power over electric utility lines to remotely located consumers; and
4. Are provided back-up demand capacity without a requirement for a minimum purchase of electricity.

While the objective of studying a variety of institutional arrangements in which cogeneration occurs was pursued, contacts with industrial cogeneration managers revealed that all the candidate sites reviewed were similar in that they all had connections with their local electric utility from whom they purchased additional power. None of the sites contacted were isolated from the grid; all purchased electricity in addition to making it; none had excess power they wanted to sell to the electric utility or wheel over the electric utility's lines. Other institutional arrangements were not found for this study.

1.3 SELECTION OF THE CELANESE CELRIVER PLANT

The Celriver fibers plant was selected as a representative textile industry plant for this study. The Celriver plant is not a traditional textile operation and, in some respects, is more similar to a chemical plant than to a textile mill. Nevertheless, it offered a number of important and unique advantages to the study project, in that it

1. has the largest cogeneration operation of all the plants studied in the case study project;
2. has more motive power cogeneration than any other case study site;
3. is the newest of all the sites studied;
4. has both condensing and noncondensing turbine generators that provided a superb opportunity to study and understand the relationship between condensing and noncondensing electric generation operation; and
5. is a coal fueled operation located in a section of the country that is rapidly industrializing.

1.4 A REPORT OVERVIEW

The remainder of this report explores cogeneration at Celanese's Celriver fibers plant located in Rock Hill, South Carolina. Chapter 2 describes the Celriver plant and discusses how its onsite electric generation evolved to its current state. Chapter 3 describes and discusses the cogeneration plant, and Chapter 4 provides an evaluation of the energy use and economics of the cogeneration operation. The evaluation is performed by comparing the economics and energy use characteristics of onsite cogenerated electric power with those of electric utility provided power that would have been provided in the absence of onsite generation.

2 CELANESE CELRIVER FIBERS PLANT

The Celanese Corporation is a large chemical and synthetic fibers company with industrial plants located primarily in eastern seaboard states. The Rock Hill, South Carolina, plant, called Celriver, manufactures acetate and triacetate yarn and staple plus acetate and triacetate polymer flakes for use by other Celanese plants and for outside sale. These materials are manufactured, using chemical engineering and textile processes, by a work force of 2200 people, and are made from wood pulp and chemical imports.

The Celriver Plant occupies 85 acres on an 1100-acre, Celanese-owned piece of rural land on the Catawba River in north central South Carolina, about thirty miles south of Charlotte, North Carolina. The plant was built in 1947 and 1948 and began fiber production in 1948. Since 1948 the plant has undergone a number of expansions that have increased its output by about 40%.

The plant is served by rail and truck transportation. Indoor working area occupies about 49 acres of floor space. Water for the plant is obtained from the Catawba River at a rate between 45 and 55 million gallons per day. Celriver has its own water purification and wastewater treatment plants for processing its water.

The plant consumes about 1000 tons of coal per day that provide heat, motive power, and electricity for plant operations. Celriver also purchases electric power from Duke Power Company. The difference between the electricity Celriver consumes and that which they make onsite is the amount of power purchased.

The nature of synthetic fiber manufacture requires many plant processes to continue on an uninterrupted basis; the plant operates 24 hours per day for 365 days a year, year in and year out. The two basic (and separate) processes of the plant -- (1) cellulose acetate flake manufacture and (2) filament extrusion -- never stop. If they ever do stop, it can take months to get the manufacturing processes properly going again. In addition, flammable liquids and explosive gases are used in the processes in such a way that outage of some equipment can very quickly result in the creation of a very dangerous flammable condition.

2.1 CELRIVER ENERGY OPERATIONS

Energy needs of the Celriver plant are supplied almost exclusively by coal and purchased electricity. In the past when inexpensive, interruptible natural gas was available, gas also provided a large amount of the fuel used during the summer months.

The plant is supplied with low sulfur coal from Virginia, Tennessee, and Kentucky via multi-car trains at single-car freight rates. (The 1000-ton-per-day consumption level at Celriver is not large enough to justify unit trains). The coal is stocked at the plant in a 100,000-ton coal pile and transported to the boiler coal pulverizers by conveyor.

The plant has six pulverized-coal boilers located in a central power plant. The boilers have an aggregate capacity of over 1.1 million lb of 600-psi, 725°F steam per hour. Steam generated in the powerhouse boilers, and used there to generate electricity, also is piped to major plant buildings to power turbine driven machines. The extraction and exhaust steam at 150, 50, and 25 psi is used to supply needed process heat for product manufacture.

Manufactured and purchased electricity is used primarily to drive electric motors. Steam turbine machine drives are used primarily for pumps, refrigeration units, and blowers, where reliability and continuity of power supply are essential and justify the higher cost and lower steam-to-power conversion efficiency typical of the small single stage turbines used to drive machines. (If the plant were built today, many of the steam turbine drives would be replaced with electric motors.)

2.2 ONSITE ELECTRIC GENERATION EVOLUTION

The Celriver plant was designed and built to be completely self sufficient with regard to electric energy. While Duke Power Company could have supplied the plant's needs, it was common practice at the time the plant was built for large industrial plants to generate their needed electricity onsite. The practice especially was true of continuous process chemical plants where reliability and continuity of power supply was particularly important and where large process heat needs provided the opportunity to cogenerate heat and power simultaneously.

The major influences on the decisions to cogenerate came from tradition (these kinds of plants at that time always cogenerated) and reliability of energy supply considerations (heat and power is so important to plant operation that these must be supplied internally to make sure the plant's needs can be satisfied).

When the Celriver plant was built, it was designed to have an ideal balance among needs for process steam. This balance was made fundamentally possible by the technology then employed in the plant's manufacturing processes that called for proportioned motive power (some supplied by steam engines and some supplied by electric motors) and process heat. (Such fine tuning is accomplished by adjusting the amounts of direct steam drive to the amounts of electric motor drive, as discussed in other parts of this report.)

This balancing resulted in the plant's supplying all of its electric energy and motive power needs while simultaneously exhausting from those electric and motive power turbines just enough heat to meet process heat needs. This nearly ideal balancing made it possible under normal operating conditions to minimize the use of the turbine generator condensers (condensers had to be provided for reliability purposes, since the plant had no external back-up electric supply). Thus, almost none of the heat of vaporization that is wasted in conventional separate power generation was disposed of unproductively in the early days of the plant's operation.

While a nearly ideal process-heat/mechanical-electric balance existed when the plant started operations, a plant trend toward increasing use of

electricity caused electric power needs to grow relatively faster than process heat needs.* Consequently, conventional electric generation (generation with condensing) began to grow. Thus, when the plant expanded in the early 1950s, instead of adding an extraction-noncondensing turbine generating set (which is all that would be needed if electric power and process heat needs were in balance), a new extraction-condensing unit was added.

The trend of electric needs growing relatively faster than process heat needs has continued up to the present time. From the 1940s up through the 1960s, the technology and economics of electric utility power supply improved at a rapid rate. Thus while electric power was getting more expensive to generate onsite (because of the relatively declining need for by-product process heat), purchased power from Duke Power was becoming less expensive and more reliable.

In the late 1950s the plant was approaching full utilization of its electric generation capacity (considering reserve needed to ensure reliability). At that time Celriver had 21,000 kW of electric generation capacity in four units -- one 5000-kW, noncondensing unit installed in 1948, two 5000-kW, extraction-condensing units also installed in 1948, and one 6000-kW extraction-condensing unit added in 1952. To meet its growing electric needs the plant needed to add either another turbine generator unit or to install a tie with Duke Power for backup and/or supply of part of its electric needs from offsite.

Onsite generation with condensing usage made sense when purchased power was less reliable and the needed generation capacity was already available anyway. However, it was clearly less sensible to expand onsite generation if new equipment purchase would be needed. When idle generating capacity is available, the cost of incremental power need not include payments to sunk-cost capital, and with the cost of fuel so low at that time power could be made more inexpensively. But in the absence of generating capacity, the cost of onsite incremental power must include expenses to provide needed new capital. Since the new capital needed would have to cover a boiler, as well as a turbine generator set, the costs of increasing electric generation were substantial.

These circumstances plus the fact that Celriver was generating a growing amount of power through use of condensing meant that to add a plant and equipment to increase onsite generation capacity, they would in

*The reasons for this trend at Celriver are not well understood. The plant needs process heat and mechanical energy. The fact that more and more mechanical energy is being provided by electric motors over direct driven steam engines is understood. However, what is unclear is why the earlier balance that existed between process heat and mechanical energy needs at Celriver has slowly but continuously changed, so that much more mechanical energy is consumed now, relative to process heat, than was the case in 1948 when the Celriver plant started operation. Perhaps the shift is a result of the fact that thermal efficiency is easier to improve than mechanical efficiency. Thus, the product is being made with less and less process heat while the mechanical energy needs remain unchanged. Perhaps fuel in the 1940s was so cheap to purchase and change to steam that little effort and few resources were used to reduce use.

effect begin competing with central station power production. It was clear that onsite generation with condensing could not be done at a cost less than that incurred through purchasing the power from Duke. Moreover, the reliability of purchased power had improved.

In consequence of these factors, a 15,000-kW tie was installed with Duke Power Company, and the purchase of incremental power was begun. Duke supplied all the power to the wastewater treatment plant and to the textile department on two buses that were separate from the main bus supplied from the onsite turbine generators. A paralleling tie with Duke was also made to the plant's main bus so that Duke Power could pick up any electric loads that exceeded what Celriver wanted to serve.

While the Duke Power tie was for 15,000 kW, actual draws were limited so as to keep demand charges as low as possible. Short duration peaking in electric demand was generally covered from onsite generators with the tie line use being minimized during surges.

As the plant's output continued to grow in the late 1950s and early 1960s and the absolute need for process steam rose, Celriver reduced the amount of onsite condensing and extracted more and more steam to meet process heat needs. At the same time, the need for electricity was growing faster than the need for steam, and the normal draw on Duke Power steadily accelerated relative to the increase in onsite power generation made possible by the growth in process heat needs.

In the mid-1960s growth in fiber output made it necessary to add a new steam generator, and planning began for installing another noncondensing turbine generator set. The new generator was installed in the late 1960s and began operation in the early 1970s.

A noncondensing turbine generator was chosen because it is much more thermally efficient than an extraction-condensing unit. This is so because at least 10% of all the steam that enters an extraction-condensing turbine must exhaust through the last stages and the condenser in order to keep the stages warm and prevent the turbine thermal warping that would occur if the first stages were warm and the last stages were allowed to cool.

In addition, the three extraction-condensing turbine generator units, plus the electric tie with Duke already available, offered all the capability needed to handle situations in which process steam and electric needs got badly out of balance and required steam and electric quantities that could not be provided with noncondensing units alone.

With fuel prices that existed before 1973-74, it was normally economical for the plant to use fully its onsite power generation equipment even though some portion was used with condensing, since the incremental cost of onsite generated electric power covered primarily the cost of fuel, which was very cheap at that time. Thus, the full energy saving benefits of cogeneration were sacrificed to economic efficiency.

However, this situation changed completely after the large 1973-74 fuel price rise. The increase in fuel prices, plus the relative inefficiency with which Celriver generated power with condensing, using about

15,000 Btu per kWh versus about 10,000 by Duke Power, made the incremental cost of onsite generated power with condensing greater than that of purchased power.

Thus, the 1973-74 fuel price rise began to force a change in the way Celriver governed its electric production. With fuel prices what they are, it is now desirable to generate electricity onsite up to the point where all process steam needs are just met. Additional generation requires exhausting steam to the condensers, which cannot be economically justified. Even so, in recent years, Celriver has found itself continually using condensing turbine generation units in such ways because the tie-line with Duke Power is now routinely fully used so that no back-up electric capacity is available. To back up electric loads reliably, two extracting-condensing turbine generator sets need to be run. Were it not for the reserve needs, only one unit would be operating. (While only 10% of the steam flow of an extraction exhaust turbine must pass to the condenser at full power, a much higher share of steam must flow to the condenser at lower power output. Consequently, two extraction-condensing units at half power send much more steam to their condensers than a single such unit operating at near full power.)

In the near future, Celriver will increase the size of its tie to Duke Power to obtain their backup, rather than through providing inefficient spinning reserve onsite.

3 COGENERATION AT CELRIVER

There are three outputs of the cogeneration system at Celriver. These are: (1) process steam generated to meet the thermal requirements of the industrial processes; (2) mechanical power required directly to drive certain machines throughout the plant; and (3) electricity generated as a by-product. (Approximately 60% of total electrical requirements are met through onsite electrical generation, with the other 40% being met through purchases from the Duke Power Company.)

The cogeneration system at Celriver is discussed in two sections. The first section provides a description of the equipment used for cogeneration and the manner by which process steam, mechanical power, and electricity are generated, along with the relationship among the outputs. The second section describes the performance and reliability of the cogeneration system in providing these outputs.

3.1 COGENERATION EQUIPMENT, PROCESSES AND OUTPUTS

In this section the equipment required for the generation of process steam, mechanical power, and electricity will be described along with the processes by which these outputs are generated.

3.1.1 Description of Equipment

A schematic of the cogeneration system is shown in Figure 3.1. The major components of the system are boilers, turbine generators (TGs), and steam driven turbines for the generation of mechanical power.

In addition to the above equipment, certain other steam driven machines (such as feedwater pumps, fans, etc.) are located in the powerhouse.

The cogeneration system consists of six coal fired boilers, five turbine generator sets, and more than 20 steam drives for plant machines. Boiler capacity is 1.1 million lb/hr and the total electrical generating capacity is 28,000 kW. The steam drives for plant machines have a total rated output of over 15,000 hp (not including the powerhouse auxiliaries, feedwater pumps, etc., with a total rated output of nearly 2000 hp).

All of the boilers generate steam at 600 psi and 725°F. They have been constructed for burning either coal or natural gas. (Natural gas was burned for a period in the 1960s and early 1970s when its price was lower than that of coal.) The six boilers provide the steam required to drive the TGs, steam machines, and powerhouse auxiliaries. The technical specifications of the boilers are provided in Table 3.1.

Two of the five TGs extract at 150 psi and exhaust at 50 psi (see Fig. 3.1). The other three extract at both 150 and 50 psi and also condense. Turbine generators #1 and #5 are run as much as possible, with the condensing turbines being used to supplement them. Table 3.2 shows the characteristics of the TGs.

The steam drives for the machines are used to provide mechanical power for refrigeration units and large blowers located outside the powerhouse. A description of their location, function, quantity, and horsepower is provided in Table 3.3. Nearly all of the steam driven machines are powered by 600-psi steam from the boilers and exhaust at 50 and 25 psi. Two steam drives power air-conditioners in the summer. However, since these units exhaust to condensers and do not provide process heat, the mechanical power generated cannot be categorized as cogeneration.

3.1.2 Description of the Cogeneration Processes

The cogeneration system at Celriver is designed to meet both the thermal demands of the industrial process and mechanical power requirements of certain steam driven machines. Electricity is generated as a by-product in the process. The generation of process steam is described first, followed by a description of the generation of mechanical power and electricity.

Process Steam. Process steam is required at 150, 50, and 25 psi. Steam is provided at 150 and 50 psi from the extraction and exhaust points of the turbine generators and at 50 and 25 psi from the exhausts of the steam driven machines. (See Fig. 3.1.) When the 600-psi steam generated by the boilers is passed through the TG sets and steam driven machines its pressure is reduced. It is then extracted at 150 psi and extracted/exhausted at 50 and 25 psi. The steam driven machines and TGs serve as pressure-reducing stations in the supply of process steam.

Mechanical Power. Mechanical power is required for certain steam driven machines located in the plant. Steam from the boilers enters these machines at 600 psi and leaves at 50 psi from some of them and at 25 psi from others. (See Table 3.3.) Steam exhausted from these machines provides part of the steam required for process. The 600-psi steam has a higher heat content than the steam at the lower pressures. The enthalpy (heat energy) of the steam is lowered by converting a portion of it into mechanical energy (horsepower). The mechanical energy is then used to drive the machines.

Electricity. The factors governing the production of electricity are more complex than those governing the production of process steam and mechanical power. Production processes establish the requirements for both process steam and mechanical power. The exhausts of the steam driven machines provide part of the process steam required at 50 psi and all of the process steam required at 25 psi. The remaining process steam (all of the 150- and part of the 50-psi steam) is provided by the extraction and exhaust points of the TGs. Electricity is generated as a by-product when the pressure of the steam generated by the boilers (600 psi) is reduced to the levels required for the process (150 and 50 psi).

The following factors determine the combination of TGs used to generate the by-product electricity.

- Turbine generators #1 and #5 are used as much as possible. These are noncondensing units and, therefore, provide the required 150- and 50-psi steam in the most energy effi-

cient way possible. (See Section 4.1 for a discussion of the efficiency of extraction-condensing turbines.)

- Two of the three remaining TGs (#s 2,3,4) provide the remainder of the 50-psi steam and all of the 150-psi steam with the third remaining as a reserve. These units are condensing units and, therefore, are not as energy-efficient as units #1 and #5. The required process steam can be generated by three TGs, but four units are used in order to provide a spinning reserve for electricity.

In addition, electricity is generated occasionally through condensing, which is done to reduce the demand peaks from the utility. Because of the steam-electric balance at Celriver only about 60% of the total electrical requirements are met through onsite generation. The remainder has to be purchased from the Duke Power Company. Under the billing system of the Duke Power Company, peak (maximum kilowatt) draw from the utility is a major cost determinant. Therefore, at those times when demand from the utility approaches a high level (relative to the average draw), electricity is generated onsite through condensing. The electricity generated onsite reduces the demand for purchased electricity, and therefore, reduces the peak draw from the utility. However, electrical generation for peak-shaving purposes amounts to only a small portion of the total.

3.2 PERFORMANCE AND RELIABILITY OF THE COGENERATION SYSTEM

The performance and the reliability of operation of the cogeneration system is presented in this section. The supply of process steam is covered first, followed by a discussion of the generation of mechanical power and electricity.

Process Steam. Process steam is required at 150, 50, and 25 psi. Steam is generated by the boilers and expanded through TGs and steam machine drives and extracted/exhausted to process. The reliability of the supply of process steam is thus dependent on the reliable operation of the boilers, TGs, and steam machine drives.

Boilers. There are six boilers at Celriver with individual generating capacities ranging from 150,000 to 266,000 and a total generating capacity of 1,116,000 lb/hr. Peak demand for process steam usually never exceeds 900,000 lb/hr. Thus, even with the largest boiler inactive Celriver is able to generate enough steam to meet their needs.

Turbine-Generators. There are five TGs at Celriver, with two being operated at full capacity most of the time and two more being operated at partial capacity. If necessary, process steam can be provided by only three of the five with the other two being used as a backup. Thus, the TGs can more than adequately meet the requirements for process steam.

Steam Driven Machines. Part of the process steam requirements are met by the exhausts of the steam driven machines. The machines are designed

in such a manner that several small machines collectively perform a single function. Steam turbines are generally reliable and, in addition, it is extremely unlikely that several of these would malfunction simultaneously. (While added reliability is obtained through the employment of several small machines, the use of such machines leads to inefficiencies in operation. These inefficiencies are discussed in the next section.)

Mechanical Power. The total rated output of the steam driven machines is approximately 15,000 hp or an equivalent of 11,250 kW. This output amounts to nearly 40% of onsite electric generating capacity. Steam from the exhausts of these machines satisfies requirements for part of the process steam, with the remainder being served by the exhausts of the TGs. For reasons discussed below, this method is not a maximally efficient one for generating mechanical power and process steam. A more efficient method would be to replace the existing machine steam drives either with more efficient steam drives or with electric motors, and to provide the process steam from the exhausts of the TGs. This move would result in additional electricity being generated with a given amount of process steam. The balance between process steam and electricity would thus be improved.

The steam turbines within the steam driven machines used at Celriver to provide mechanical power are generally single stage turbines. These are mechanically less efficient than multistage turbines in converting heat energy into mechanical energy. In other words, for every Btu of steam passed through a single stage turbine, a smaller percentage of the enthalpy in the steam will be converted to mechanical energy than if a multistage one were used. Consequently, a single stage turbine will require more steam to generate equal amounts of mechanical energy. Thus, the balance between steam and mechanical power is better for a multistage turbine. The requirements at the plant for mechanical power (including electricity, which is convertible into mechanical power) far exceed the mechanical power that is generated with the given requirements for process steam. If more mechanical power were generated with the same amount of steam (as would be the case if generated by multistage turbines), the system would have a better balance between process steam and mechanical power.

The inefficiency caused by single stage turbines can be eliminated if they are replaced by multistage ones or electric motors. If replaced by multistage turbines, less steam would exhaust into the process and thus more steam would pass through the exhausts of the TGs. More electricity would be generated than where single stage turbines are used because of the increased steam flow through the TGs. The steam to mechanical power (and, consequently, electricity) balance would thus be improved.

If the steam driven machines (which have single stage turbines) were replaced with electric motors, the process steam that had been previously supplied by the exhausts from the single stage steam turbines would now be provided by the exhausts of the TGs. Turbine generators typically have multistage turbines that generate more mechanical power (and, in turn, electricity) than single stage turbines for equal amounts of steam flow. The mechanical power required to supply electricity for the electric motors will be equal to the power previously generated by the single stage steam turbines. Once these requirements are satisfied, the excess mechanical power generated by the multistage TGs would be converted into electricity. An

increase in the quantity of electricity generated onsite would result in a corresponding decrease in the quantity of electricity purchased. The use of the multistage TGs in conjunction with electric motors also results in a more favorable steam to electricity balance.

While it is clear that multistage turbines would improve the steam to electricity balance at the plant, considerable costs are involved in the replacement of the single stage turbines either with multistage steam turbines or with electric motors. The former option would not be economical and is not under consideration, since replacement costs would be prohibitive because of the small size and large number of the steam driven machines. On the other hand, the cost of the installation of electric motors is not as high as the cost of the installations of the multistage turbines and this option is under study.

Electricity. Onsite electric generation provides approximately 60% of the total electrical requirements, with the remaining 40% being met through purchases from the Duke Power Company.

There are five TGs at the plant with individual generating capacities ranging from 5000-8000 kW and a total generating capacity of 29,000. In addition, up to about 15,000 kW can be purchased from the Duke Power Company. Thus, a maximum of 44,000 kW can be provided to the plant, and since peak electrical demand usually never exceeds 35,000, an ample supply of electricity is readily available. However, the onsite generating capacity of 29,000 kW cannot, in itself, meet the peak demand of the plant. In the event of an outage of the tie-line from the utility, certain operations will have to be curtailed to compensate for the shortfall.

The electrical system (both utility and onsite) has proved to be very reliable. There has been only a single major outage in which the plant was without power; the outage lasted 45 minutes. A quick response by maintenance personnel averted any major equipment repairs, and because of its short duration there was no reduction or delay in the output of the plant.

Fig. 3.1 Components of the Cogeneration System at Celriver

Table 3.1 Characteristics of Boilers at Celriver

<u>Boiler No.</u>	<u>No. 1</u>	<u>No. 2</u>	<u>No. 3</u>	<u>No. 4</u>	<u>No. 5</u>	<u>No. 6</u>
Manufacturer	Riley	Riley	Riley	Riley	Riley	Foster-Wheeler
Capacity (lb/hr)	150,000	150,000	200,000	200,000	200,000	266,000
Pressure (psi)	600	600	600	600	600	600
Temperature (°F)	725	725	725	725	725	725
Feedwater Temp. (°F)	315	315	315	315	315	315
Fuel Type	Coal	Coal	Coal	Coal	Coal	Coal
Date of First Use	1948	1948	1948	1952	1952	1965

Table 3.2 Characteristics of Celriver Turbine-Generator Sets

<u>Turbin-Generator No.</u>	<u>No. 1</u>	<u>No. 2</u>	<u>No. 3</u>	<u>No. 4</u>	<u>No. 5</u>
Manufacturer	Westinghouse	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Capacity (kW)	5,000	5,000	5,000	6,000	8,000
Date of First Use	1948	1948	1948	1952	1970
INLET (600 psi)					
Temperature (°F)	725	725	725	725	725
Flow Rate (lb/hr)	180,000	188,200	188,200	236,500	184,000
OUTLET (150 psi)					
Temperature (°F)	485	480	480	480	480
Flow Rate (lb/hr)	72,000	110,700	110,700	93,000	24,300
OUTLET (50 psi)					
Temperature (°F)	350	345	345	345	300
Flow Rate (lb/hr)	108,000	52,700	52,700	81,000	184,000
OUTLET (condenser)					
Temperature (°F)		82 ^a	82 ^a	82 ^a	
Flow Rate (lb/hr)		4,300 ^b	4,300 ^b	4,000 ^c	

^aSeasonal

^bMinimum

^cMaximum

Table 3.3 Summary of Steam-Driven Machines^a

<u>Location</u>	<u>Function</u>	<u>Steam Pressure</u>		<u>Quantity</u>	<u>Unit</u>	<u>Total</u>
		Inlet	Exhaust		Output	Output
		(psi)	(psi)		(horsepower)	(horsepower)
Solvent Recovery Plant	Blow Drying	600	25	10	870	8,700
Cellulose Acetate Plant	Refrigeration	600	50	6	402	2,412
		600	50	2	583	1,166
		600	50	2	669	1,338
		600	50	2	693	1,386
		600	50	1	493	493
						6,795
			Total	23		15,495

^aThe above does not include the powerhouse auxiliaries (feedwater pumps, etc.)

4 ECONOMIC AND ENERGY EFFICIENCY OF CELRIVER COGENERATION

In order to evaluate onsite electricity cogeneration at Celriver an analysis has been done comparing the economics and energy use characteristics of onsite electric generation with those prevailing if the electricity they made had been purchased from Duke Power Company.

The evaluation is presented in four sections. The first section identifies the costs and fuel usage associated with onsite electric generation for the 5-yr period from 1974 through 1978. The second, identifies the cost and fuel usage associated with the purchased power alternative. The third, makes a comparison of the cost and fuel usage of power produced onsite with those that would have occurred if the power had been purchased instead from Duke Power Company. The fourth section makes a second comparison between the economics of onsite generation and purchased power. The second comparison uses adjusted onsite cost figures to reflect approximate capital costs that would have to be charged to onsite generation if the capital equipment to produce it had been purchased in 1972 rather than when it actually was purchased.

4.1 ONSITE ELECTRIC GENERATION

Detailed month by month electric generation data was obtained from Celriver power plant accounting records. From this data cost and fuel usage associated with onsite generation of electricity was computed for each month of the five-year period -- 1974-1978.

4.1.1 Onsite Electric Generation, Fuel Usage

Table 4.1 contains yearly aggregate and average data that show onsite electric generation and its associated fuel usage. Column 2 shows the yearly electric energy output aggregating the output from all five TG sets. Although production declined from 1974 to 1975, since 1975 yearly electric output has steadily increased.

Two things were happening to cause this sequence of yearly kWh production.

1. The dip in electric production from 1974 to 1975 was most likely a result of higher fuel prices. While it was sensible to generate power onsite when fuel prices were low, it was no longer economical to do so. Consequently, Celriver cut back on power production associated with condensing and shifted this load to Duke Power after the large fuel price increase in 1973 and 1974.
2. The rising level of electric power production between 1975 and 1978 is primarily the result of a program to satisfy 150-psi process steam needs with 50-psi steam. Doing this enabled the plant to extract much more

topping electricity from the steam before sending it to process. About 95% of the enthalpy difference between 150- and 50-psi steam can be converted to electric power. Table 4.2 shows Celriver process steam production between 1974 and 1978 and clearly demonstrates that the composition of the mix changed a good deal, with more and more of the process steam needs being provided by 25- and 50-psi steam and less and less being provided by 150-psi steam.

Column 3 shows the average fuel-to-kWh heat rate for each of the five years. This heat rate shows how many fuel Btu it took to make one kWh of turbine generator output. There are three sources for the losses that make up the difference between the heat content of a kWh -- 3412 Btu -- and the fuel-to-kWh heat rates shown in the table.

1. Boiler losses; the Celriver boilers are highly efficient, well maintained and, regulated, with a fuel to steam efficiency of between 83 and 86%.
2. Turbine generator losses; noncondensing steam turbine generator systems of the type at Celriver typically have a steam to electric energy thermal efficiency of about 95%.
3. Condensing losses; Celriver has five TG sets. Two are extraction/back-pressure types that extract at 150 psi and exhaust at 50 psi. The remaining three TG sets extract and condense. They extract at 150 and 50 psi and exhaust to condensers that are maintained at a vacuum of about 1 psi (2 inches of mercury). The condenser losses are made up of two parts. One part results from the fact that any multistage extraction turbine must have at least 10% of its total steam flow at full power travel the full length of the turbine, which for condensing turbines means that 10% of total steam must be exhausted to the condenser. This passage must occur so that the whole turbine is maintained at temperatures within acceptable engineering limits. If the steam flowthrough requirement is not met, the thermal expansion stress caused by the large temperature difference between the turbine inlet, with flow, and the exhaust, without flow, would cause differential warping of turbine rotating and stationary parts, and, in turn, would result in rubbing that would soon destroy the turbine. Condensing for this purpose is solely a function of how much the condensing turbines are used and at what output level. The level of output is important because at less than full power relatively more steam must flow to the condenser to keep those last turbine stages warm than the 10% needed at full power. The other component of condensing that increases the TG heat rate is the condensing that takes place because turbine generator operators choose to exhaust more than 10%

10% of the total TG set flow to the condenser. This occurrence takes place when Celriver chooses to make more electric power than the minimum needed to satisfy required process steam needs that are served by steam extraction from the turbine.

Of the three sources of heat loss, losses from condensing are clearly the most serious. If Celriver used only its two back-pressure turbines and did not use its condensing turbines, the fuel-to-kWh heat rate would be about 4400 Btu per kWh. The minimum heat rate of the turbines that exhaust to condensers depends on the relative amount of steam that is extracted at the two extraction points. However, the minimum actual heat rates of the condensing turbines are estimated to be between 8000 and 9000 Btu per kWh. Thus, it is clear that even a 10% level of condensing has a very large impact on heat rate and cogeneration efficiency.

Since the large fuel price increase of 1973, it has become more expensive to make power through condensing than to buy it. When fuel prices were low, it was often economical to make all the electric power possible (even with condensing), rather than have extra generating capacity sitting idle. (This practice was feasible because the sunk cost of capital did not need to be charged to incremental power generation costs, which meant that the incremental cost of onsite generated power was almost exclusively made up of fuel costs.) Since 1973, Celriver has had to change its power generation practices to reduce, as much as possible, electric generation with condensing. This reduction has caused a shift in electric load from onsite to offsite. The power used to produce by condensing is now purchased from Duke. As can be seen from the heat rate trend from 1974 to 1978, this shifting of load to Duke has been successful in reducing the overall Celriver heat rate.

A new problem, however, has emerged. When the Celriver-Duke tie was made in the late 1950s, a line with a capacity of about 15,000 kW was installed. Since the line was installed, the draw on Duke Power has slowly increased to the point where it is now nearly fully used on a routine basis. This usage pattern has meant that Celriver's condensing TG sets are being used to cover some electric needs that could more economically be supplied by Duke. The extent of this practice is not great now, but as the plant's power needs grow, the situation will worsen. In consequence of this, Celriver is having a larger tie with Duke installed in the near future.

By 1977 Celriver had reduced their onsite generation heat rate about as much as they could. Even in 1978 their heat rate was about as low as it could be, given the level of electric production they had to maintain just to produce process steam. The plant has only 13,000 kW of noncondensing TG set capacity. Even if these units were run 100% of the time (which they nearly are) the extraction-condensing units must run at a minimum level of 4000-6000 kW just to make process steam. The heat rate data suggest that these units were operated so that they condensed about as little as they could. Hence, for 1977 and 1978 no more kWh was made than was needed for process steam for the plant configured as it is. To further reduce the heat rate will require that condensing be reduced, and this can be done only if a new non-condensing TG set is installed or one of the three existing extracting-condensing TG sets is modified to enable the condenser to be removed or bypassed.

Column 4 (of Table 4.1) shows the fuel consumption that was required for making electricity. The figures in this column are merely the product of the figures in Columns 2 and 3. The second part of Column 4 shows fuel consumption in physical units, tons of coal.

4.1.2 Onsite Electric Generation, Costs

Table 4.3 shows the costs of generating electricity onsite. The total cost was broken into three components and the cost of each component in current dollars was determined separately, following standard cost accounting principles.

4.1.2.1 Onsite Electric Generation, Fuel Costs

Table 4.4 shows the elements that went into calculating fuel costs. This table shows yearly aggregate data, but actual fuel cost data were determined monthly, because fuel prices, and sometimes the total fuel mix, changed monthly. However, even though the total fuel mix did change, the only fuel charged to electric generation was coal. (At times, very inexpensive natural gas was available on a limited basis.)

Coal was always the fuel charged to electric generation because it was always the incremental fuel. And coal would have been the only fuel consumption that would have changed if electric generation were not done onsite.

Columns 2 and 3 of Table 4.4 show the yearly onsite electric generation and associated fuel Btu consumption from Table 4.1. Column 4 shows the yearly average delivered price of coal developed from Celriver Power Plant monthly accounting records. Column 5 shows the yearly expenditure on coal for electric generation and is obtained by multiplying the figures in Column 3 by those in Column 4. Column 6 shows the cost of fuel per kWh (the Column 5 data divided by the Column 2 data).

A review of fuel and total cost data shows that:

1. Fuel expenditures represented 70% of the costs of onsite generation. Of the \$8.7 million expended on electric generation between 1974 and 1978, \$6 million was spent on coal. Fuel expenditures averaged approximately \$1.2 million per year.
2. Fuel costs declined from \$1.5 million in 1974 to \$1 million in 1976, then rose again to \$1.4 million in 1978. The variation in fuel costs is the result of variations in the kWh produced, the fuel-to-kWh heat rate, and the unit cost of coal. The reasons for the variation in energy consumption are discussed in the previous subsection.

4.1.2.2 Onsite Electric Generation, Operation and Maintenance Costs

Table 4.5 shows the operating and maintenance (O&M) costs for electric generation at Celriver.

The electric power plant is part of the total powerhouse operation. The cost data provided here is based on accounting data, put together to show the incremental cost of generating electricity. The powerhouse supervisors used judgment to estimate the additional costs that result from onsite generation. The great majority of powerhouse O&M costs would be incurred even if there were no onsite electric generation. For example, shift personnel monitoring electric sendout and switch gear would be needed whether or not there was onsite generation. Most of the steam sendout functions also would have to be operated and maintained, even without onsite generation. Hence, O&M cost data developed and provided by the plant show fairly modest costs.

The data for the year 1978 of Table 4.5 were drawn from accounting data. Similar data for prior years were not available. Consequently, after conferring with the powerhouse managers, it was decided that 1978 would be representative of a typical year with regard to O&M costs and that adequate estimates for each year back to 1974 would suffice. Therefore, the O&M data in the table for the years 1974 to 1977 are estimates based on actual 1978 data. The inflation index used to infer these O&M costs was the U.S. Department of Commerce GNP deflator series.

4.1.2.3 Onsite Electric Generation, Capital Costs

Table 4.6 shows the capital costs estimated by this project that are assignable to onsite electric generation.

Capital costs are conceptually and practically the most difficult of the costs to deal with for a number of reasons. Among these are:

1. It was difficult to obtain actual capital cost information from the case study sites. The desired capital cost information is the increment of capital costs associated with electric power production. Accounting records, however, are typically not kept in such a way as to facilitate separating out the cost of that gear solely associated with electric generation. In addition, the accounting records with data on costs of original plant construction and costs of original equipment components were frequently lost, in archives, or otherwise unavailable.
2. The electric generating plants on which capital cost information is wanted are seldom built at one time for a simply determined price. For example, the Celriver electric generating plant started out with three TG sets in 1948 (but probably purchased in 1946); another was added in 1952, and a fifth in the late 1960s. Further complicating matters is the fact that the last

TG set Celriver installed (before it was really needed) was a unit originally purchased by the Celanese Company for a European plant that was not built.

3. It is difficult to reconstruct how managers planned to pay for the generating plant capital. Were long-term low interest bonds issued when the plant was built and later when it was modified? Or, was financing of capital purchased covered some other way?
4. Capital investment can be entered into for multiple reasons. The investment can be made solely for the purpose of providing production potential or it can be made for speculative purposes as a hedge against inflation. Expectations and required rates of return vary, depending on the purpose of the investment and the alternative investment opportunities. With regard to the Celriver plant, it is difficult to know precisely what the alternative opportunities were for capital invested in onsite electric generation capability. However, conversations with its officials suggest that the electric plant was considered an integral part of the total operation and was not separately evaluated as an optional profit center that could or could not be provided, based on its own isolated productivity.
5. Different capital equipment has different economic life. Moreover, the way the firm keeps its accounting records plus its tax situation can have a large impact on the "bookkeeping" life relative to the economic life of capital equipment. For example, capital equipment is typically depreciated faster than actual productive value declines in order to obtain tax advantages. Also, a capital equipment purchase is typically required to pay for itself long before the end of the equipment's useful life.

It is difficult to deal with capital costs precisely. However, the fact that they represent a small part of the total onsite electric generation costs means that they can be determined through approximation and estimation methods without any danger of introducing major errors into the ultimate total of onsite generation costs.

To ascertain a capital cost estimate for the electric generation facility under study, this project used recent engineering estimates of what it would cost now to construct an equivalent plant. The cost figures were developed by an engineering firm experienced in cogeneration work and were developed in 1980 dollars. The incremental cost of an electric generation plant equivalent to Celriver is estimated to be \$14,085,000 in 1980 dollars.

The costs included in the estimate are only for the incremental facilities needed for electric generation. Thus, for example, very little

charge was included in the estimate for boiler capacity, since only a small amount of all the enthalpy added to steam in Celriver's boilers is converted to electric power and the incremental cost of larger boilers is small anyway.

After approximating the "new cost" of Celriver's electric generating plant a weighted "average" life of the electric generation equipment was calculated and estimated to be 25 years in 1978. This estimate provides a date of 1953 as the centroid of electric generation plant construction.

To obtain an approximate 1953 cost of the electric generation plant, the 1980 dollars of the plant construction cost estimate were deflated by the GNP deflator to 1953 dollars, upon the basis of which the plant could have been purchased in 1953 for about \$4.8 million.

The final capital cost estimate was determined using the \$4.8 million figure and assuming a 30-year average useful life of the electric generation equipment. Finance costs were ascertained, based on an approximate estimated 1953 corporate bond rate of 4%. Once electric generation capital costs in 1953 plus an approximate long-term interest rate and an average life of equipment were resolved, book capital costs were computed for Celriver's electric generation gear for the years 1974 to 1978.

4.2 PURCHASED POWER ALTERNATIVE

In order to compare the fuel consumption and cost of onsite electric generation with those of a purchased power alternative, directly comparable data must be developed for the purchased power alternative.

4.2.1 Purchased Power Alternative, Fuel Consumption

Table 4.7 shows purchased power fuel consumption and the data used to develop the consumption figures.

Column 2 shows the electric energy that was generated on site by Celriver (from Table 4.1).

Column 3 contains the Duke Power Company fuel-to-delivered kWh heat rate for its baseload plants. These heat rates were computed for each year from data in Duke Power's yearly annual reports to FERC (and earlier to FPC). The heat rates have been adjusted to reflect 7% energy losses that occur on Duke's system between the power plant and delivery to the customer. The heat rates for their baseload plants were chosen because the Celriver draw would have a relatively constant unchanging demand, and it is assumed that baseload capacity would have been provided by Duke Power to meet baseload type needs. This is a conservative assumption that would tend to narrow the Btu gap between onsite cogeneration and purchased power fuel consumption.

Column 4 shows the total quantity of fuel Btu that would have been consumed if Duke Power had supplied the electricity Celriver made.

Columns 4, 5 and 6 show the total Btu consumed divided proportionally among the three fuels consumed by Duke Power in their baseload plans for each year.

4.2.2 Purchased Power Alternative, Cost to Celriver

Under the purchased power alternative, Celriver would purchase all of its electricity now generated onsite from the Duke Power Company. The cost of electricity would then be the bill for equivalent purchases from Duke Power Company.

Celriver now meets its electricity requirements partly through onsite generation and partly through purchases from the Duke Power Company. Under the purchased power alternative it would purchase all of its electricity from the Duke Power Company. Therefore, the incremental cost of the alternative -- the cost of purchasing an amount equivalent to the quantity of electricity generated onsite -- is the difference between the cost of meeting total electricity consumption and the cost of electricity now being purchased.

Table 4.8 shows the annual aggregates of purchased power alternative costs for the electricity that was actually generated onsite with data that was used in computing the cost figures. Actual computations were made on a monthly basis since purchased electricity is priced on a monthly basis.

Columns 1 and 2 show the yearly onsite generation of electricity.

Column 3 shows actual purchases of electricity as listed on monthly Celriver accounting data.

Column 4 shows the total Celriver electric consumption and is the sum of data in Columns 2 and 3.

Column 5 is the total amount of money that would have to be charged for all the power used by Celriver had it been 100 percent purchased from Duke Power.

Column 6 is the actual charge for the actual power (as shown in Column 3) Celriver purchased from Duke Power.

Column 7 is the cost Celriver would have incurred if it had purchased from Duke Power the electricity they made. The Column 7 figures are the Column 5 numbers less the Column 6 numbers.

The Column 8 figures provide the unit cost per kWh and are determined by dividing Column 7 numbers by Column 2 numbers.

Except for the data of Column 5 - the purchased power cost of Celriver's total electric needs -- all the data of Table 4.8 were obtained from Celriver accounting records or were calculated from other data in the table.

The Column 5 data was calculated on a monthly basis for each of the five years, using the billing system and prices of Duke Power Company in effect at the time of the power consumption.

Monthly Electric Charge Computation

There are four major determinants of the monthly electric charge for larger power customers on the Duke Power system.

1. Peak demand - kW - (demand charges)
2. Energy consumed - kWh - (energy charges)
3. Fuel costs to Duke (fuel adjustment charges)
4. Special Duke power facilities needed to provide service

The demand charges are based on the maximum rate of electric power supply (i.e., maximum kW draw on the lines). Energy charges are based on the total kWh consumption. The fuel adjustment charge is based on the deviation of actual fuel costs from the fuel cost built into Duke Power's basic approved rates. Facilities charges are based on special facilities provided to the customer.

Communication with the power plant engineers revealed that Celriver's monthly peak (around 34,650 kW) demand for electric power for the last five years fluctuated very little. Even during times when the average electric demand changes a great deal the monthly peak kW demand will remain around 34,650 kW.

In ascertaining the monthly hypothetical electric bill for Celriver if all its electric power were purchased from Duke, monthly billing demand was assumed to be 34,650 kW. Energy charges were for the kWh actually consumed during that month. The fuel adjustment charges are also directly related to kWh consumption. Facilities charges, based on Celriver's judgment and experience, would be likely to be about \$1,000 per month.

With these inputs, plus actual known monthly kWh consumption, monthly hypothetical charges could be calculated for circumstances under which all of Celriver's power needs were provided for by Duke Power.

Column 5 of Table 4.8 contains the yearly aggregate of the hypothetical monthly bills computed for Celriver's purchase of all of its power from Duke for the 1974-1978 period.

4.3 ONSITE GENERATION COMPARED WITH PURCHASED POWER ALTERNATIVE

This section compares the fuel usage and costs associated with onsite electric generation through cogeneration with those associated with a hypothetical purchased power alternative. The following two subsections compare the (1) fuel usage and (2) costs as discussed and developed in Sections 4.1 and 4.2.

4.3.1 Onsite Generation Compared with Purchased Power Alternative, Fuel Usage

Table 4.9 combines the onsite generation fuel consumption data and the purchased power alternative fuel consumption data into one table, which also shows the fuel savings that Celriver achieved through electric energy cogeneration. As can be seen, cogeneration of electricity at Celriver has saved considerable amounts of energy relative to what would have been consumed if Celriver purchased all of its electricity. Total yearly savings varied between 458 billion Btu and 728 billion Btu of uranium, coal, and (a little) oil fuel. Over the five years analyzed, Celriver made its electric power for 4607 billion Btu of fuel, whereas if Duke Power had made the electricity it would have consumed 7515 billion Btu of fuel. Duke would have consumed 163% of what Celriver consumed. On the average, over the five years, it took Celriver 6408 Btu to make a kWh through cogeneration (conversion efficiency, 53%), while it took Duke Power 10,453 Btu on the average to make a kWh (conversion efficiency, 33%). On the other hand, had Celriver been able to eliminate condensing entirely from its electric generation, they could probably have reduced the fuel consumption per kWh to less than 4500 Btu (energy efficiency, 76%). But they would also have made fewer kWh.

It should be noted also that the fuel saved, based on the fuel usage mix of Duke Power's baseload plants, was nearly 75% nuclear fuel with the remaining savings nearly all coal. Duke Power uses very little oil in its baseload generating plants.

4.3.2 Onsite Generation Compared with Purchased Power Alternative, Costs

Table 4.10 combines the onsite generation total cost data from Table 4.3 with the purchased power alternative costs of Table 4.8 to facilitate direct comparison of the costs associated with the two ways Celriver could have obtained electricity for the 1974-1978 period. Table 4.10 also shows the cost savings to Celriver that came from cogenerated electricity.

From Table 4.10 it is clear that while purchased power was rising in price by a little more than 1.5 mills per year, onsite generated power was holding about constant in cost, especially after 1974. Thus, while onsite generated power was a little more costly than purchased power in 1974, the cost advantage of purchased power quickly disappeared after that and by 1978 was costing 1.5 times as much as onsite generation.

Earlier, in Section 4.1, fuel consumption for onsite electric generation was discussed, and it was explained that 1974 was probably an anomaly with respect to fuel consumption, since Celriver was still in the process of reducing electricity production with condensing to the 1973-1974 fuel price increases. This adjustment phase, coupled with the fact that fuel costs account for about 70% of onsite generation costs, explains why the year 1974 shows onsite generation as more costly than in other years.

A question arises about the profitability of the onsite generation facility. Earlier, in calculating the capital cost to be charged to onsite electric generation, conventional accounting principles were used and an interest rate for the finance portion of the capital costs was assigned

as if Celriver took out a long-term loan at the time the generation facility was built to obtain the money to pay for it at the then prevailing long-term interest rate.

There was no component in the capital charge for profit. Financing for the facility was assumed to be 100% debt. (This assumption is somewhat unrealistic, but it greatly simplifies discussion about capital costs.)

Profit on Celriver's investment in onsite electric generation facilities can reasonably be inferred to be approximated by the estimates shown in Column 7 of Table 4.10. In order to determine in a realistic and reasonable fashion the profit attributable to onsite electric generation, the rate of profit will be defined in constant dollars. This will eliminate the inflation factor, which greatly complicates discussion of profit. (Determining the relationship of interest, rates of return, depreciation, investment, profit and taxes to each other in a conceptually sound manner is very difficult in an inflationary economy.)

Table 4.11, Column 2, shows the remaining undepreciated capital of the Celriver onsite electric generation plant for the years 1974-1978 based on a 30-year life of equipment. Column 3 shows the savings of onsite generation in Column 7 of Table 4.10 expressed in 1973 dollars (as determined by using the Department of Commerce's Gross National Product Deflator data). Column 4 shows the constant dollar rate of return for the onsite electric generating equipment.

Column 4 shows a very rapid rise in rate of return. This rise is occurring because the capital base on which it is calculated is nearing the end of its life and for each year that goes by a big share of the capital is written off.

The next section will make an onsite electric generation purchased power alternative comparison, assuming Celriver's onsite generating facility was purchased in 1972. This will show much less relative change in the capital base on which rate of return is computed and there will be much more stability in the rate of return figures developed.

4.4 PURCHASED POWER ALTERNATIVE COMPARED WITH HYPOTHETICAL ONSITE GENERATION

An engineering costs estimate* was made to determine what the electric generation facility of the Celriver plant would cost if purchased recently. This work was done in order to assess the economics associated with the adoption of cogeneration from scratch by a plant like Celriver on a more current time basis than is possible on the basis of the actual facility with its initial construction having taken place in 1946-1947.

Using a 1972 date for construction and a 1974 date for operation, capital costs for a hypothetically new Celriver plant were determined for the years 1974-1978. These capital costs were calculated the same way as

*Gilbert Commonwealth Associates Engineers of Jackson, Michigan, provided the cost estimate.

were the original capital costs and are based on interest rates for long-term funds prevailing in 1972-1973 of about 7.5%. Table 4.12 shows what total onsite electric generation costs would be with this new capital cost. Table 4.13 shows the cost comparison of these modified capital cost figures with purchased power costs. As can be seen, the economics of the new plant are not as good as those with capital purchased in the early 1950s, but return is still positive in the later years. Table 4.14 shows the rate of return on the onsite generation investment in the same constant dollar fashion that the rate of return in the prior section was developed. Here again, as one would expect, the rate of return is not as favorable as for when the onsite equipment was purchased in the early 1950s, but it is still positive.

4.5 CONCLUSION

In conclusion, an important point must be made here. The economic evaluation of this chapter focuses on a comparison between onsite generated power and purchased power. Such a comparison is useful, but one must not lose sight of the possibility that for Celriver the benefits that come from increased reliability of power supply may be much more economically valuable than the savings in electric power costs.

Insofar as this is true, analysis here is of little use in understanding why Celanese chose to have an onsite electric generation facility at Celriver.

Table 4.1 Celriver Onsite Electric Generation - Fuel Consumption

Year	<u>On-Site</u>	<u>Fuel-to-Electricity</u>	<u>Fuel Consumption</u>	
	<u>Generation</u>	<u>Heat Rate</u>		
	(kWh, thous.)	(Btu/kWh)	(Btu's, Billions)	(Tons of Coal)
1974	143,225	7,283	1,043	42,869
1975	129,717	6,526	846	33,861
1976	135,645	6,541	887	35,021
1977	147,674	5,784	854	33,844
1978	162,694	6,003	977	38,701
Total				
1974-1978	718,955	6,408	4,607	184,296
Annual				
Average	143,791	6,408	921	36,859

^a At Celriver, coal is the incremental fuel for electric generation.

Table 4.2 Celriver Process Steam Production

Steam Flow in Thousands of Pounds Per Hour

Pressure of Process Steam

Year	25 and 50 psi	150 psi	Total
1974	416	268	684
1975	347	196	543
1976	403	129	532
1977	444	101	545
1978	478	136	614

Table 4.3 Celriver Onsite Electrical Generation - All Costs

Year	<u>On-Site Generation</u>	<u>On-Site Electrical Generation - Costs</u>				<u>Costs per unit of Electricity Generated</u>
	(kWh, thousands)	Fuel (dollars, thousands)	Operation and Maintenance (dollars, thousands)	Capital (dollars, thousands)	Total (dollars, thousands)	(mills/kWh)
1974	143,225	1,523	281	218	2,022	14.1
1975	129,717	1,037	308	211	1,556	12.0
1976	135,645	986	325	205	1,516	11.2
1977	147,674	1,058	347	199	1,604	10.9
1978	162,594	1,404	369	192	1,965	12.1
Totals 1974-1978	718,955	6,008	1,630	1025	8,663	12.0
Annual Average	143,791	1,202	326	205	1,733	12.0

Table 4.4 Onsite Electrical Generation Fuel Costs

	<u>On-Site</u> <u>Generation</u>	<u>Energy</u> <u>Consumption</u>	<u>Unit Cost</u> <u>of Fuel</u>	<u>Fuel</u> <u>Cost</u>	<u>Fuel Cost per</u> <u>Unit of Electricity</u>
Year	(kWh, thousands)	(Btu, Billions)	(\$ per Million Btu)	(dollars, thousands)	(mills/kWh)
1974	143,225	1,043	1.460	1,523	10.6
1975	129,717	846	1.226	1,037	8.0
1976	135,645	887	1.112	986	7.3
1977	147,674	854	1.239	1,058	7.2
1978	162,694	977	1.437	1,404	8.6
Total 1974-1978	718,955	4,607	1.304	6,008	8.4
Annual Average	143,791	921	1.304	1,202	8.4

Table 4.5 Onsite Electric Generation Operating and Maintenance Costs.

Year	<u>On-Site Generation</u>	<u>Operating Costs</u>		<u>Maintenance Costs</u>			<u>Total Costs</u>	<u>Unit Cost</u>
	(kwh, thousands)	Labor (dollars, thousands)	Materials (dollars, thousands)	Labor (dollars, thousands)	Materials (dollars, thousands)	Overhaul ^a (dollars, thousands)	(dollars, thousands)	(mills/kWh)
1974	143,225	191	5.3	20	8.4	57	281	2.0
1975	129,717	209	5.9	22	9.2	63	308	2.4
1976	135,645	220	6.2	23	9.7	66	325	2.4
1977	147,674	233	6.5	24	10.2	70	347	2.3
1978	162,694	250	7.0	26	11.0	75	369	2.3
Total 1974-1978	718,955	1,103	30.9	115	48.5	331	1,630	2.3
Annual Average	143,791	221	6.2	23	9.7	66	326	2.3

^aOne of the five turbine-generators is overhauled each year.

Table 4.6 Onsite Electrical Generation - Capital Costs

Year	On-Site Generation	Capital Costs			Capital Costs Per Unit of Electricity
	(kWh, thousands)	Annual Depreciation	Annual Interest	Total	(mills/kWh)
		(dollars, thousands)			
1974	143,225	160	58	218	1.5
1975	129,717	160	51	211	1.6
1976	135,645	160	45	205	1.5
1977	147,674	160	39	199	1.3
1978	162,694	160	32	192	1.2
Total 1974-1978	718,955	800	225	1025	1.4
Annual Average	143,791	160	45	205	1.4

Table 4.7 Purchased Power Alternative Fuel Consumption

Year	<u>On-Site</u> <u>Generation</u>	<u>Fuel-to-Electricity</u> <u>Heat Rate</u>	<u>Fuel</u> <u>Consumption</u>	<u>Fuel Type</u>		
	(kWh, thousands)	(Etu/kWh)	(Btus, billions)	Coal (Btus, billions)	Nuclear (Etus, billions)	Oil (Btus, billions)
1974	143,225	10,483	1,501	1,253	231	19
1975	129,717	10,488	1,360	837	524	-
1976	133,645	10,338	1,402	1,001	401	-
1977	147,647	10,455	1,544	1,115	433	6
1978	162,694	20,481	1,705	1,129	565	12
Total 1974-1978	718,955	10,453	7,515	5,334	2,143	38
Annual Average	143,791		1,503	1,067	429	8

Table 4.8 Purchased Power Alternative Costs

<u>Year</u>	<u>Electricity Consumption</u>			<u>Purchased</u>	<u>Cost of</u>	<u>Purchased Power Alternative</u>	
	<u>On-Site</u>	<u>Purchased</u>	<u>Total</u>	<u>Power Cost</u>	<u>Electricity</u>	<u>Total Cost</u>	<u>Unit Cost</u>
	<u>Generation</u>			<u>of Total</u>	<u>Actually</u>		
	<u>(kWh, thousands)</u>	<u>(kWh, thousands)</u>	<u>(kWh, thousands)</u>	<u>Electricity</u>	<u>Purchased</u>	<u>(dollars, thousands)</u>	<u>(mills/kWh)</u>
1974	143,225	121,707	264,932	3,143	1,522	1,621	11.3
1975	129,717	107,338	237,055	3,673	1,779	1,894	14.6
1976	135,645	123,630	259,275	4,278	2,066	2,212	16.3
1977	147,674	113,901	261,575	4,671	2,133	2,538	17.2
1978	162,694	110,800	273,494	5,468	2,266	3,202	19.7
Totals 1974-1978	718,955	577,376	1,296,331	21,233	9,766	11,467	15.9
Annual Average	143,791	115,475	259,266	4,247	1,953	2,293	15.9

Table 4.9 Fuel Consumption Comparison Celriver Onsite Generation vs Duke Power Company
Purchased Power Alternative

Year	<u>Electricity</u>	<u>On-Site</u>	<u>Purchased Power Alternative</u>				<u>Cogeneration Savings</u>			
	<u>Produced</u>	<u>Generation</u>	<u>Fuel Use</u>							
		<u>Fuel Use</u>								
	(kWh, thousands)	Coal (Btus, billions)	Coal (Btus, billions)	Nuclear	Oil (Btus, billions)	Total (Btus, billions)	Coal (Btus, billions)	Nuclear	Oil (Btus, billions)	Total (Btus, billions)
1974	143,225	1,043	1,253	231	19	1,503	210	231	19	458
1975	129,717	846	837	524	0	1,360	9	524	0	515
1976	135,645	887	1,001	401	0	1,402	114	401	0	515
1977	147,674	854	1,115	422	6	1,544	261	433	6	690
1978	162,694	977	1,129	565	12	1,706	152	565	12	728
Total 1974-1978	718,955	4,607	5,334	2,143	38	7,515	727	2,143	38	2,908
Annual Average	143,791	921	1,067	429	8	1,503	146	429	8	584

Table 4.10 Cost Comparison Celriver Onsite Generation vs Duke Power Company
Purchased Power Alternative

Year	<u>Electricity Produced</u>	<u>On-Site Generation Cost</u>		<u>Purchased Power Alternative Cost</u>		<u>Cogeneration Savings</u>	
	(kWh, thousands)	Total Cost (dollars, thousands)	Unit Cost (mills/ kWh)	Total Cost (dollars, thousands)	Unit Cost (mills/ kWh)	Total Cost (dollars, thousands)	Unit Cost (mills/ kWh)
1974	143,225	2,022	14.1	1,621	11.3	-402	-2.8
1975	129,717	1,556	12.0	1,894	14.6	339	2.6
1976	135,645	1,516	11.2	2,212	16.3	693	5.1
1977	147,674	1,604	10.9	2,538	17.2	934	6.3
1978	162,694	1,965	12.1	3,202	19.7	1,237	7.6
Total 1974-1978	718,955	8,663	12.0	11,467	15.9	2,804	3.9
Annual Average	143,791	1,733	12.0	2,293	15.9	560	3.9

Table 4.11 Rate of Return of Onsite Generation On
Undepreciated Value of Capital

Year	<u>Undepreciated Value of Capital</u>	<u>Savings due to On-Site Electric Generation</u>	<u>Constant Dollar Rate of Return</u>
	(thousands of 1953 dollars)	(thousands of 1953 dollars)	(per cent)
1974	1,440	-204	-14.2
1975	1,280	157	12.3
1976	1,120	305	27.2
1977	960	388	40.4
1978	800	479	59.9

Table 4.12 Onsite Electrical Generation Total Costs
(capital costs are for a new facility)

Year	<u>On-Site Generation</u>	<u>On-Site Electrical Generation - Costs</u>				<u>Costs per unit of Electricity Generated</u>
	(kWh, thousands)	Fuel (dollars, thousands)	Operation and Maintenance (dollars, thousands)	Capital ^a (dollars, thousands)	Total (dollars, thousands)	(mills/kWh)
1974	143,225	1,523	281	648	2,452	17.1
1975	129,717	1,037	308	632	1,977	15.2
1976	135,645	986	325	617	1,928	14.2
1977	147,674	1,058	347	602	2,007	13.6
1978	162,694	1,404	369	586	2,359	14.5
Totals 1974-1978	718,955	6,008	1,630	3,085	10,723	14.9
Annual Average	143,791	1,202	326	617	2,145	14.9

^aCapital Costs are for a hypothetical facility comparable to Celriver's with a centroid of construction in 1972 and where first year of operation is in 1974.

Table 4.13 Cost Comparison (new facility^a) Celriver Onsite Generation vs Duke Power Company
Purchased Power Alternative

Year	<u>Electricity Produced</u>	<u>On-Site Generation Cost</u>		<u>Purchased Power Alternative Cost</u>		<u>Cogeneration Savings</u>	
	(kWh, thousands)	Total Cost (dollars, thousands)	Unit Cost (mills/ kWh)	Total Cost (dollars, thousands)	Unit Cost (mills/ kWh)	Total Cost (dollars, thousands)	Unit Cost (mills/ kWh)
1974	143,225	2,452	17.1	1,621	11.3	-831	-5.8
1975	129,717	1,977	15.2	1,894	14.6	-83	-0.6
1976	135,645	1,928	14.2	2,212	16.3	284	2.1
1977	147,574	2,007	13.6	2,538	17.2	531	3.6
1978	162,394	2,353	14.5	3,202	19.7	843	5.2
Total 1974-1978	718,955	10,722	14.9	11,467	15.9	744	1.0
Annual Average	143,791	2,145	14.9	2,293	15.9	148	1.0

^aCapital costs are for a hypothetical facility comparable to Celriver's with a centroid of construction in 1972 and whose first year of operation is 1974.

Table 4.14 Rate of Return on Onsite Generation On Undepreciated Value of Capital (new facility)

Year	<u>Undepreciated Value of Capital</u>	<u>Savings due to On-Site Electric Generation</u>	<u>Constant Dollar Rate of Return</u>
	(thousands of 1972 dollars)	(thousands of 1972 dollars)	(per cent)
1974	5,716	-716	-12.5
1975	5,512	-65	-1.2
1976	5,308	212	4.0
1977	5,104	377	7.4
1978	4,900	555	11.3