ABSTRACT

Cogeneration feasibility studies were conducted for eleven state agencies of Texas. A net present value (NPV) analysis was used to evaluate candidate cogeneration systems and select the optimum system. CELCAP, an hour-by-hour cogeneration analysis computer program was used to determine the costs used in the NPV analysis. The results of the studies showed that the state could save over $6,000,000 per year in reduced utility bills. Different methods of analyzing the economic performance of a cogeneration system are presented for comparison. Other implications of the study are also discussed.

INTRODUCTION

The utility bills for the State of Texas exceeded $200,000,000 in FY '83. In a study conducted by the Energy Management Group of the Mechanical Engineering Department at Texas A&M for the Public Utility Commission of Texas (PUC), it was determined that cogeneration could possibly save the state millions of dollars per year in reduced utility bills. They suggested that a detailed feasibility study of cogeneration be conducted on several of the larger state agencies.

The PUC approved the study and awarded the contract to the Energy Management Group. Economic analyses of cogeneration were performed for eleven state agencies. Recommendations including the type and size of cogeneration system were made for each agency.

This paper outlines some available economic analyses and discusses in detail the economic analysis chosen for this study. It also describes the computer program used in the analysis and outlines the results of this study. Finally, some implications of the study are presented.

ECONOMIC ANALYSIS METHODS

Several methods are used by companies and governments to evaluate the economics of candidate projects. The three most popular methods are:

1. Simple payback
2. Net present value
3. Internal rate of return

The method of evaluation selected should be able to take into account the time value of money, rank the projects in order of economic attractiveness, and give the results in a meaningful unit of measurement.

Simple payback determines the time required for a project to recover its initial investment. It is calculated by dividing the project's initial investment by the expected profits (or savings) per unit time (usually in years):

$$PB = \frac{I}{A}$$

where:

PB = Simple payback (years)
I = Investment ($) 
A = Profit or savings per unit time ($/year)

Simple payback does provide the results in a meaningful scale. It emphasizes the importance of time but not the time value of money. Also, it is not a recommended method of ranking projects, but it can still be used as a first order selection criterion.

The net present value (NPV) method determines the present value of the future costs and revenues of a project minus its initial investment:

$$NPV = \sum_{n=0}^{N} \frac{A_n - C_n}{F_n} - I$$

where:

NPV = Net present value ($)
N = Number of time periods (project life in years)
A = Revenues for each time period n ($)
C = Expenses for each time period n ($)
F = Present value factor and is based on the discount (interest) rate for each period n (dimensionless)
I = Initial Investment ($)

The net present value method meets all of the criteria suggested in the opening paragraph of this section. It gives results in dollars, takes into account the time value of money using the present value factor, and can be used to reliably rank projects.

The internal rate of return (IRR) is defined as the interest rate paid on the time-varying uncollected balances of an investment, such that the final investment balance is zero at the end of the proposed project. In other words, the IRR is determined by solving for the discount (interest) rate which makes the NPV equal to zero for a certain time period.

The IRR satisfies two of the criteria for economic evaluation, that is it takes into account the
Consider two mutually exclusive projects, A and B. Project A requires an investment of one dollar and will have a net profit of one dollar per year. Project B requires an investment of two dollars and will have a net profit of one dollar and fifty cents per year. Both projects have four year lives, and the company’s discount rate is five percent. Therefore, correct application of the IRR method also yields correct results.

For example, assume that in the previous example ten more projects like A and five more projects like B. Obviously, project A is now more attractive than B, but the NPV and the IRR methods would also prove this, i.e., for a fixed budget, the portfolio which maximizes the IRR will also maximize the NPV.

Since no fixed amount of money was specified for cogeneration opportunities at the eleven state agencies, and all monies could be raised at the same discount rate, the NPV method was chosen for evaluating cogeneration candidates. In the presentation of results, however, simple payback was given due to its wide acceptance and use.

**ECONOMIC ANALYSIS FOR STATE AGENCIES**

For each state agency, the analysis that was used was based on annual costs and savings associated with each candidate cogeneration system. The following were identified as the primary economic factors:

1. Electricity cost before cogeneration (the base case) and after cogeneration
2. Fuel (natural gas in this study) costs before and after cogeneration
3. Power plant operating and maintenance (O&M) cost before and after cogeneration
4. Initial investment
5. Discount rate
6. Differential escalation rates for the cost of electricity and fuel
7. Standby power charges

The next step was to develop an equation for calculating the NPV which incorporated the above variables.

\[
NPV = (EB+CA)x(1+(r/100)^h+D/100)^{-h}
\]

where:

- \( NPV \) = Net present value ($)
- \( EB \) = Annual electricity cost before cogeneration ($) + Annual fuel cost after cogeneration ($) + Differential escalation rate for the cost of electricity (escalation rate above inflation rate) (decimal)
- \( CA \) = Annual electricity cost after cogeneration ($) + Annual fuel cost after cogeneration ($) + Differential escalation rate for the cost of gas (decimal)
- \( D \) = Differential escalation rate for the cost of gas (decimal)
- \( h \) = Life of project (years)
- \( SPC \) = Annual standby power charge
- \( I \) = Initial investment

Since state agencies are not taxed entities a before-tax analysis was required. Differential escalation rates were considered only for gas and electricity; it was assumed that O&M cost and stand-
were constructed based on utility bills and hourly back pressure steam turbines, and automatic steam cycles’ energy management systems. For those not having prime movers such as, gas turbines, diesel engines, the cogeneration computer simulation program was required by CELCAP:

CELCAP was run to model the base case. The following is a list of input information for electricity, fuel (natural gas), and operating and maintenance (O&M). CE

The monthly costs and consumptions of electricity and fuel were then compared with actual utility bills. The profiles were then altered for a particular system in the CELCAP generated information did not agree well with the billing information.

Using the same demand profiles, various sizes and types of cogeneration systems were analyzed. CELCAP shows control mode options with each cogeneration system:

1. Engine run at peak electrical output
2. Engine follows electrical load (demand) up to their capacity
3. Engine follows steam load (demand) up to their capacity

The annual costs of the best control mode were now used in the NPV equation. CELCAP does have the capability of a life cycle cost economic analysis, but the NPV analysis external to the main program proved to be more flexible and less time-consuming.

The standby power charge is often neglected in many cogeneration economic analyses, but in most cases can significantly affect the profitability of cogeneration. Standby power is the capacity that the utility must have in the event the cogeneration facility experiences an unscheduled outage. Many current utility tariffs structure the charge for standby power for cogenerators the same as the demand charge. In other words, as long as the cogeneration system has no unscheduled outage, the cogenera-

The life cycle cost (LCC) analysis is a type of NPV analysis which determines the total cost of a project in today’s dollars. The LCC’s for the alternative, including the “do nothing” case, are compared and the one with the lowest LCC is selected.
maximum standby power charge every year. The project's 20 year life, therefore, incurring the differential escalation rates for the cost of electricity and natural gas would vary from zero to 4%, the city and natural gas would vary from zero to 4%. A differential escalation rate, also called a real escalation rate, is the percentage increase in the cost of electricity and natural gas over a period of time. In this analysis, it was assumed that the differential escalation rates for electricity and natural gas were: (1) 2% and 0%, (2) 2% and 2%, (3) 4% and 2%, and (4) 2% and 2%, respectively.

Since the fuel charge in the electrical rate structure is primarily responsible for the escalation of electricity costs, it was assumed that the standby power charge would not escalate relative to the general inflation rate. It was also assumed that O&M costs would not escalate relative to the general inflation rate. At this point all values in the NPV analysis have been explained. The NPV equation can now be solved.

**COGENERATION FEASIBILITY STUDIES**

Cogeneration feasibility studies, incorporating the described NPV analysis, were undertaken for eleven state agencies: two hospitals, eight universities, and the capital complex in Austin. The completed studies were submitted to the Public Utility Commissioner (PUC) of Texas.

An important restraint in the analysis was the fact that state agencies, unless otherwise authorized, cannot sell electricity. Agencies authorized to sell power are utility authorities, e.g., the Lower Colorado River Authority (LCRA). As a result of this restriction, a cogeneration facility could not benefit from the sale of power, but the restrictions also result in the economic feasibility of cogeneration being based on the demands of the agency only and not a function of the byproduct rate. A summary of the findings available at this writing is shown in Table 1. It can be seen that the potential savings from cogeneration at state agencies is significant.

### Table 1: Economic Summary of Cogeneration

<table>
<thead>
<tr>
<th>Agency</th>
<th>Electrical Power Cost (kW)</th>
<th>Natural Gas Cost (kW)</th>
<th>Simple Payback (Years)</th>
<th>Electrical Cost Escalation Rate</th>
<th>Natural Gas Cost Escalation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texas State University</td>
<td>4,900,000</td>
<td>300,000</td>
<td>8.0</td>
<td>2%</td>
<td>0%</td>
</tr>
<tr>
<td>Austin Hospital</td>
<td>2,000,000</td>
<td>500,000</td>
<td>11.0</td>
<td>2%</td>
<td>0%</td>
</tr>
<tr>
<td>University of Houston</td>
<td>600,000</td>
<td>100,000</td>
<td>15.0</td>
<td>4%</td>
<td>2%</td>
</tr>
<tr>
<td>Texas A&amp;M University</td>
<td>1,500,000</td>
<td>250,000</td>
<td>18.0</td>
<td>4%</td>
<td>2%</td>
</tr>
<tr>
<td>Texas Tech University</td>
<td>2,000,000</td>
<td>1,000,000</td>
<td>22.0</td>
<td>4%</td>
<td>4%</td>
</tr>
<tr>
<td>State Capitol Complex</td>
<td>1,200,000</td>
<td>200,000</td>
<td>24.0</td>
<td>4%</td>
<td>4%</td>
</tr>
<tr>
<td>University of Texas</td>
<td>1,500,000</td>
<td>250,000</td>
<td>27.0</td>
<td>4%</td>
<td>4%</td>
</tr>
<tr>
<td>Total</td>
<td>23,225</td>
<td>8,800</td>
<td>30.1</td>
<td>4%</td>
<td>4%</td>
</tr>
</tbody>
</table>

Notes:
- The standby power charge was assumed to be negligible.
- DT = Diesel Engine
- DE = Diesel Engine Without Interconnection Switchgear
- G/L = Gas Turbine
- CHP = Combined Heat and Power
- SC = Standby Power Charge
- *The results were not explained in the original text.
An important implication that results from the installation of a base-load cogeneration system is the fact that the cost of electricity purchased on a kilowatt-hour basis from the utility would go up. In other words, the price of electricity displaced by the cogeneration system is actually lower than the average price of electricity bought before cogeneration. To illustrate, consider the following typical electrical demand profile:

\[
\text{ELEC} = (\text{KWH} \times \text{E} + \text{KWH} \times \text{FA} + \text{PD} \times \text{DC})/\text{KWH}
\]

where:

- \(\text{ELEC}\) = average cost of electricity (\$/kwh)
- \(\text{KWH}\) = electrical energy consumed (kwh)
- \(\text{E}\) = energy charge (\$/kwh)
- \(\text{FA}\) = fuel adjustment charge (\$/kwh)
- \(\text{PD}\) = peak demand (kW)
- \(\text{DC}\) = demand charge (\$/kW)

Simplification gives:

\[
\text{ELEC} = \text{E} + \text{FA} + (\text{PD} \times \text{DC})/\text{AD} \times \text{HR}
\]

where:

- \(\text{AD}\) = the average demand for the period (kW)
- \(\text{HR}\) = time in period (hrs)

Substituting:

\[
\text{ELEC} = \text{E} + \text{FA} + (\text{PD} \times \text{DC})/(\text{AD} \times \text{HR})
\]

Therefore, it can be seen that the electricity cost is a function of the ratio of PD to AD for any given rate structure. Now assume that a base-load system is installed at the site and carries the load as indicated:

It can be seen from comparing PD2 and AD2 with PD and AD that the ratio of peak demand to average demand goes up as more of the base electricity demand is carried by the cogeneration system, and hence the price of electricity goes up. An hour-by-hour analysis, like that used in CELCAP, can take into account the changing average price of electricity and in part prevent the savings from being overstated.

From the study it also became clear that the standby power charge was extremely important. As shown in the table of results, the standby power charge for a single unscheduled outage can greatly reduce or erase any savings from cogeneration for a full year.

Although the NPV is sensitive to the differential escalation rates for fuel and electricity, the optimum cogeneration system is not a strong function of differential escalation rates. In other words, the optimum cogeneration system is virtually independent of the differential escalation rates, but the actual dollar value of the system is a strong function of the differential escalation rates.

**SUMMARY**

Cogeneration feasibility studies have been completed for seven of the eleven selected state agencies. The results indicate that Texas could install a total of 33MW of cogenerated electrical capacity for $23.3-million and subsequently save over $5-million per year in reduced utility bills.

A net present value (NPV) analysis was used as the primary selection criterion. It was chosen because it can reliably rank alternatives, take into account the time value of money, and give results in a meaningful unit of measure. Also, it can easily be used to analyze an alternative's sensitivity to differential escalation rates and standby power charges.

An hour-by-hour cogeneration analysis program called CELCAP was used for calculating the annual costs used in the NPV analysis. The importance of an hour-by-hour analysis was shown by the fact that...
It can take into account the increasing average price of electricity due to the demand charge and installation and operation of a cogeneration facility.

REFERENCES