A COMPUTER SIMULATION MODEL FOR EXAMINING COGENERATION ALTERNATIVES

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ABSTRACT

The purpose of this paper is to describe a computer simulation model that was used to analyze the technical and economic aspects of specific cogeneration applications. The model was coded in the APL language and runs on the Scientific Time Sharing System.

The model was used to help provide a quantitative assessment of the potential market for industrial cogeneration equipment in the near-term future. This assessment was developed from costs and technical parameters derived from a detailed analysis of five generic cogeneration cases.

I. INTRODUCTION

In the past several years, energy conservation has received increasing attention in industrial equipment decisions. One scheme that can provide a significant reduction in overall energy use for the same production capability is cogeneration. A cogeneration plant is a power plant that produces both electricity and useful thermal energy (usually pressurized steam) in a more fuel efficient manner than if the electricity and thermal energy were produced separately. This power production method has been used by both the electric utilities and industry for many years. For all practical purposes, it has been phased out in the electric utilities as ever larger generation plants have been located far from industrial centers. It has also been declining in use in industry for the last 15 years. In the past, the decreasing price of electric power, the high reliability of electric utility supply, and the relatively low fuel costs have contributed to this decline. However, with recent increases in both electricity and fuel prices, coupled with emphasis on energy conservation, an entirely new perspective is presented.

The major cogeneration issues may be categorized as technical, economic, environmental, regulatory, and institutional [1, 2].

The technical issues involve the specific manner in which the steam is used in the process, the properties of the steam required, and the amount used at particular locations in the total plant layout. For example:

- high pressure steam intended for mechanical drives (> 500 psig)
- unsuitable low pressure steam used for heating and cooking (< 400 psig)
- low steam flow rates
- rapid load fluctuations for steam and electric power
- small and isolated plants
- availability of fuel

The economic issues [3, 5] involve the standard considerations in any capital budgeting decision in addition to some peculiar to cogeneration. For example:

- the high level of required capital
- ROI for cogeneration versus competing projects
- business expertise in other areas
- non-desirability of converting variable cost to a fixed one
- lower reliability than electric utility or else high standby costs
- National Energy Plan Incentives
  - investment tax credits
  - oil and gas tax savings in future
  - priorities on available gas and oil

The environmental air pollution requirements on sulfur emissions and the general policy of nondegradation in particular areas preclude the development of cogeneration regardless of technical or economic attractiveness.

There is also a concern that generation of electric power might bring the industrial concern under increased regulation of local and state authorities (i.e., the Public Service Commissions).

In some cases, there are also institutional constraints in which the industries' position is that electric power is not part of their business and will not be involved regardless of the economics.

Recent discussion [4] has also centered on the possible increased role of electric utilities in selling steam to industrials. While this is a form of cogeneration, we have not analyzed this potential market in this study. Our general belief is that this would require an "energy park" location of industrials and electric utility generation. While some interest in this arrangement is currently being expressed, the future site plans for most utilities are remote from industrial centers, and we estimate minimal impact in the period of this study (1978 - 1985).

Additional concern has been expressed regarding the technical and economic problems involved in either selling excess industrial power back to the utility or wheeling it to other industrials. Our general analysis indicates that it is unlikely that self-generation will exceed in-plant needs except possibly in the petroleum industry. While some single plants will have excess capacity, this will not be the main market thrust. The problem of getting a fair value for this excess power will place additional uncertainty on the capital budgeting decision.

This paper first presents the economic criteria used in evaluating a particular cogeneration investment. Then the various technical options (e.g., topping turbine, combustion turbine, combined cycle, etc.) that may be simulated using the computer model are discussed. A comparison of generic industrial cogeneration cases is presented to show how the model is applied.

II. ANALYSIS OF THE COGENERATION INVESTMENT

To provide some general guidelines on what incremental investment might be supported, some general investment conditions were analyzed and the results displayed in Figure 1. In this figure, the allowable incremental investment in electric power as a function of industrial electricity price with net payback or internal rate of return for the project as a parameter is shown. This functional relationship is analytically derived in the Appendix A. Substituting the investment parameters shown in Figure 1 in the analytical expression developed in the Appendix results in the explicit functional relationships shown. The conversion of net payback period to discounted cash flow (internal) rate of return is accomplished using the graph in Figure 2. This relationship is also derived in the Appendix and is evaluated in Figure 2 for three annual savings escalation conditions. The investment in Figure 1 ($/KW) is incremental, meaning the additional investment in steam and electric power generation over the base investment in steam equipment needed to supply the process.

Examination of Figure 1 shows that with industrial electricity prices near 1.7¢/KWH (1974 national average) not much investment in power generation equipment was justified. However, with the recent average prices near 3¢ per KWH

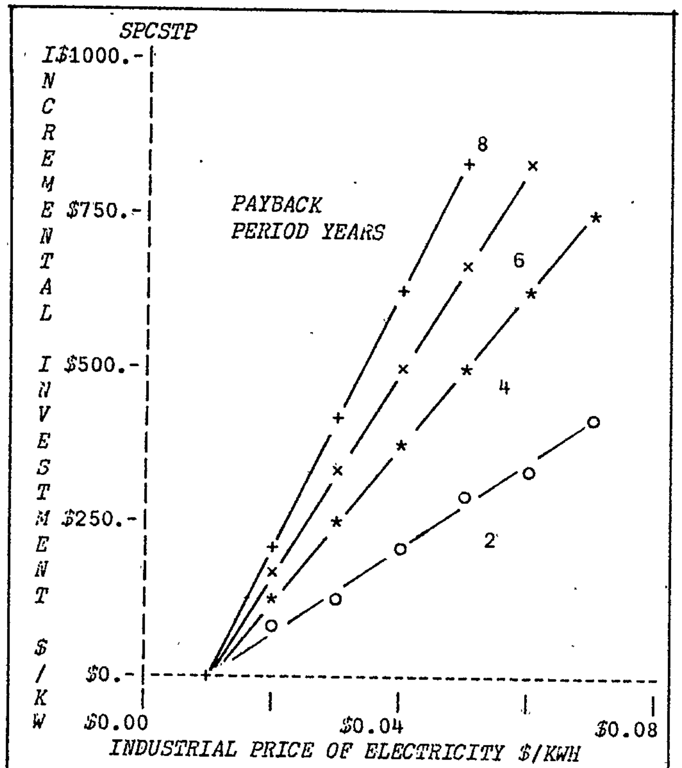


FIGURE 1. ALLOWABLE COGENERATION INVESTMENT VS INDUSTRIAL PRICE OF ELECTRICITY FOR INDICATED PAYBACK PERIOD AND INVESTMENT PARAMETERS GIVEN.
FCP=4500 BTU/KWH
FCST=$2.20/10E6 BTUS
CF=85 %, OMR= 4 %, TR=48 %
ITCR=10 %

(4 and 5¢/KWH in some regions), an entirely new perspective is presented.

The investment data presented in Figures 1 and 2 for the "general investment" are calculated in the computer simulation model for the specific cogeneration option under investigation. In addition, the yearly net cash flow and its specific components are presented.

III. COGENERATION SIMULATION OPTIONS

A schematic diagram for the industrial cogeneration computer simulation model is shown in Figure 3. In the lower right-hand corner, a decision table is presented which shows the settings of conceptual switches and values for model options. These options are briefly listed in the upper left-hand corner of Figure 3 and in more detail in Table 1.

For the particular option being simulated, data concerning the process heat requirements, electrical requirements, fuel properties, and desired steam conditions are input to the model.

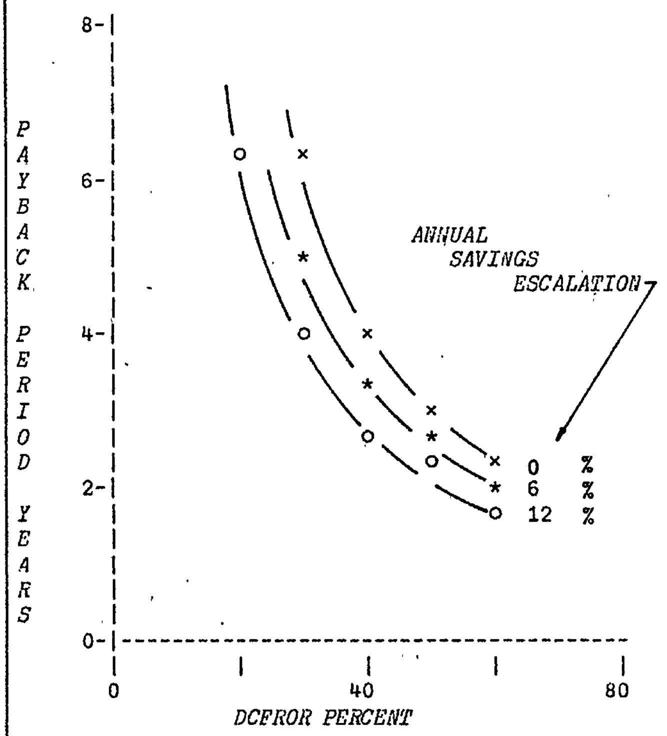


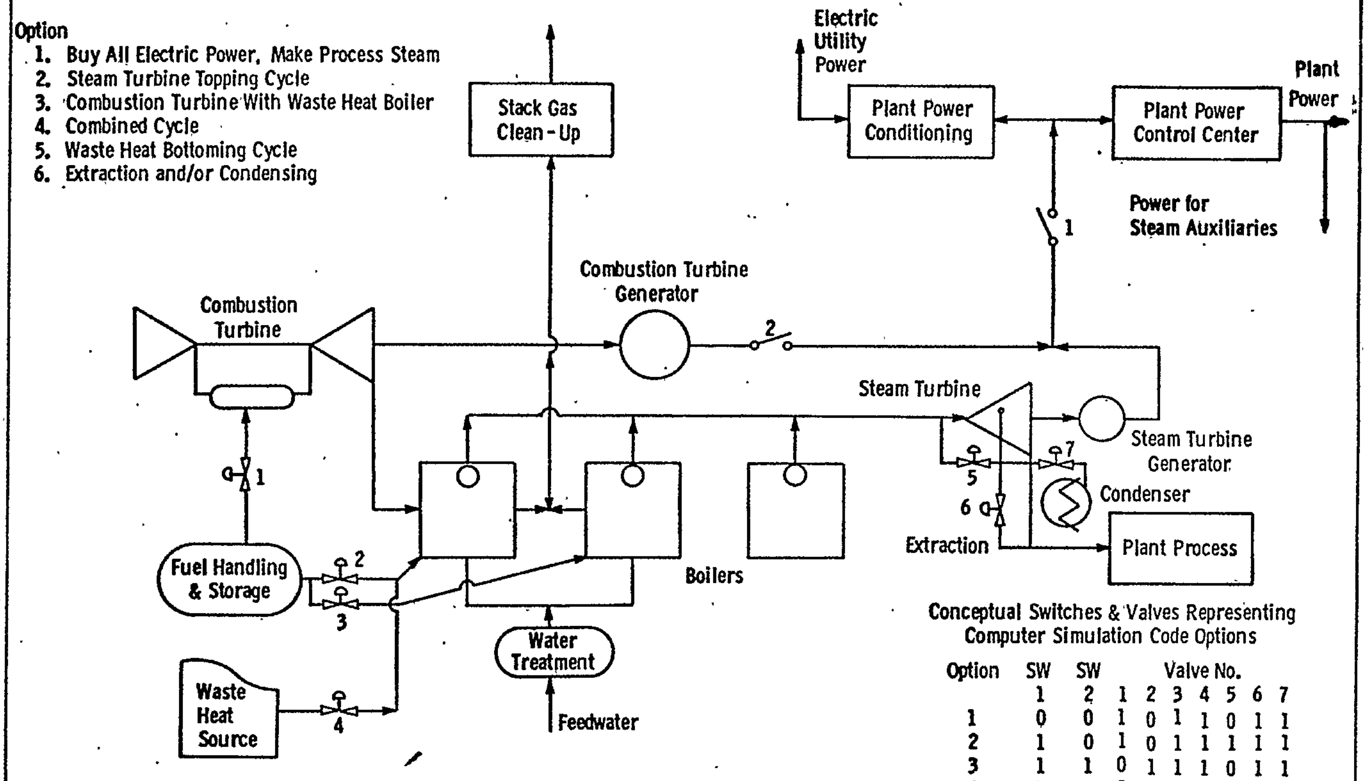
FIGURE 2. PAYBACK PERIOD VS. DISCOUNTED CASH FLOW RATE OF RETURN FOR VARIOUS SAVINGS ESCALATION RATES.

A basic heat and mass balance is performed by the simulation model using fundamental thermodynamics to arrive at a steady-state process description. Then using steady-state pressures, temperatures, mass flows, and electric power flows embedded functional relationships are used to both size and cost the system components. The total investment is calculated by summing the cost of all components. The cash flows resulting from the potential investment are then calculated on an annual basis over the period of interest for the project. The internal rate of return and the net payback period for the project are calculated as a comparative figure of merit for the investment.

Table 1

Description of Computer Simulation Code Options

- Option 1 – Purchase Power
  All electrical requirements are met by the utility. All process heat requirements are met by the customer-owned equipment.
- Option 2 – Steam Turbine Topping
  All or part of the electrical requirements are met by the customer-owned steam turbine generators. Purchased power may or may not be utilized. All process steam requirements are met by the customer-owned equipment.



Conceptual Switches & Valves Representing Computer Simulation Code Options

Option	SW 1	SW 2	Valve No. 1	2	3	4	5	6	7
1	0	0	1	0	1	1	0	1	1
2	1	0	1	0	1	1	1	1	1
3	1	1	0	1	1	1	0	1	1
4	1	1	0	1	0	1	1	1	1
5	1	0	1	1	1	0	1	1	1
6	1	0	1	0	1	1	1	0	0

1 = Closed   0 = Open

Fig. 3 — Schematic diagram for the industrial cogeneration computer simulation model

- Option 3 – Combustion Turbine Topping
  All or part of the electrical requirements are met by customer-owned combustion turbine generators. Purchased power may or may not be utilized. All process steam requirements are met by customer-owned equipment.
- Option 4 – Combined Cycle
  All or part of the electrical requirements are met by customer-owned combustion and steam turbine generators. Purchased power may or may not be utilized. All process steam requirements are met by customer-owned equipment.
- Option 5 – Bottoming Cycle
  All or part of the electrical requirements are met by customer-owned steam turbine generators. Purchased power may or may not be utilized. All heat for generation is supplied by the process. Steam may or may not be shipped to the process and, if so, is supplied by customer-owned equipment.
- Option 6 – Extraction and/or Condensing
  Same as Option 1 except for the multiple configuration of the turbine.

The simulation options are now each discussed in more detail. A single example demonstrating the simulation model will be used in explaining each option. The process details for this example are summarized in Table 2.

Table 2

Cogeneration Example for Simulation Options

- Option 1 – Buy All Electric Power, Make Process Steam
  Flow to process 50 psig @ 135,000 #/hr
  Boiler pressure 200 psig, temperature 300 °F
  #6 oil as fuel
  Electric power required 60,000 KW
- Option 2 – Topping Turbine
  Flow to process 50 psig @ 135,000 #/hr
  Boiler pressure 900 psig, temperature 825 °F
  #6 oil as fuel
  Steam turbine throttle conditions 850 psig 825 °F
  Electric power required 60,000 KW
- Option 3 – Combustion Turbine with Waste Heat Boiler
  Flow to process 50 psig @ 135,000 #/hr
  Turbine inlet temperature 800 °F
  Turbine pressure ratio 10
  #2 distillate oil fuel
  Electric power required 60,000 KW
- Option 4 – Combined Cycle (Combustion Turbine with Back Pressure Steam Turbine)
  Flow to process 50 psig @ 135,000 #/hr
  #2 distillate oil fuel
  Electric power required 60,000 KW

SIMULATION OPTION 1: BUY ALL ELECTRIC POWER, MAKE PROCESS STEAM

This option is the base case against which the cogeneration cases (Options 2 through 6) are compared. It is assumed that an expansion in basic plant capacity requires added steam capacity. The investment question then is should just steam capacity be purchased or should a cogeneration system be installed to make both steam and electricity? This option investigates the investment and cash flow for just steam expansion. The net cash flow is simply the negative of the cost of electric power shown in Figure 4.

SIMULATION OPTION 2: STEAM TURBINE TOPPING CYCLE

The calculations performed in the steam topping option of the computer simulation model are as follows. Essentially, a fundamental heat balance is performed to establish the steady state operating point of the system. Based on steady state operation, installed costs are estimated for major system components. These costs are then aggregated to obtain total system costs and a discounted cash flow analysis is performed for the necessary investment.

For the application using a back pressure steam turbine, the calculations begin with defined values for steam turbine inlet temperature, pressure, and the desired exhaust pressure (determined by process requirements). Sets of curves similar to those shown in Figure 5 are approximated in the model for four specific inlet pressures: 1500, 1200, 900, 600 psig. The theoretical steam rate is estimated from these curves and an actual steam rate is calculated by dividing by the turbine generator efficiency (Figure 6). The electrical power from the turbine generator is then calculated by dividing the steam mass flow through the turbine by the actual steam rate (see Appendix B).

FIGURE 4

OPTION 1 – FLOW OF FUNDS

Year	Cost of Electric Power*
1	$ 13,436,000
2	14,340,140
3	15,343,949
4	16,418,026
5	17,567,288
6	18,796,998
7	20,112,788
8	21,520,683
9	23,027,131
10	24,639,031
11	26,363,762

*Based on total purchase of 60 MW, 85% capacity factor at 3¢/KWH in year 1 escalating at 7% annually.

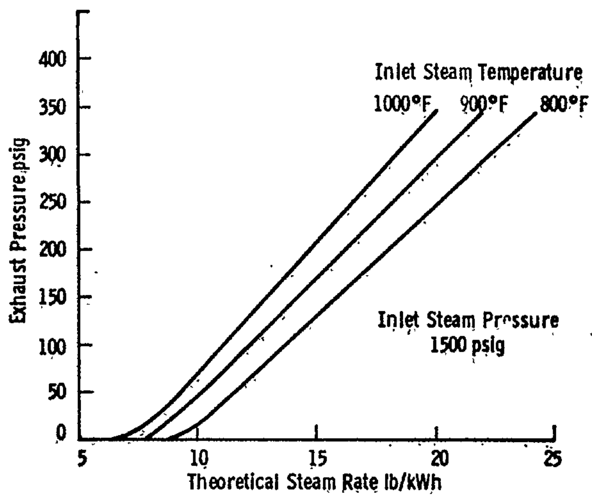


Fig. 5 — Example of curves for approximating theoretical steam rates in simulation model

The computer simulation model contains functions which approximate the Mollier steam diagram in the superheat region. These functions are used to estimate the inlet enthalpy of the turbine knowing the pressure and temperature. The exhaust enthalpy is calculated by subtracting the enthalpy drop across the turbine from the inlet enthalpy. Knowing the exhaust pressure and enthalpy, these functions are again used to estimate the exhaust temperature of the steam. If this temperature is above the upper limit for the process, a desuperheater calculation is performed. The amount of water that must be sprayed into the superheated steam to bring the temperature under the upper limit is calculated on an energy basis. Having performed these calculations, the pressures, temperatures, and mass flows are now known for all points in the plant, and component sizes and costs are then estimated from an embedded set of functional relationships shown in Appendix B.

The output of the simulation model (for the example in Table 2) is shown in Figure 7 and a system diagram is shown in Figure 9. The components of cash flow related to the investment are again calculated using the equations in Appendix A.

SIMULATION OPTION 3: COMBUSTION TURBINE WITH WASTE HEAT BOILER

The combustion turbine calculations use isentropic Brayton cycle relationships to calculate ideal temperatures and pressures. Efficiencies for the turbine and compressor are then introduced, and temperatures and pressures are corrected to actual values using these efficiencies. The equations are given in Appendix B.

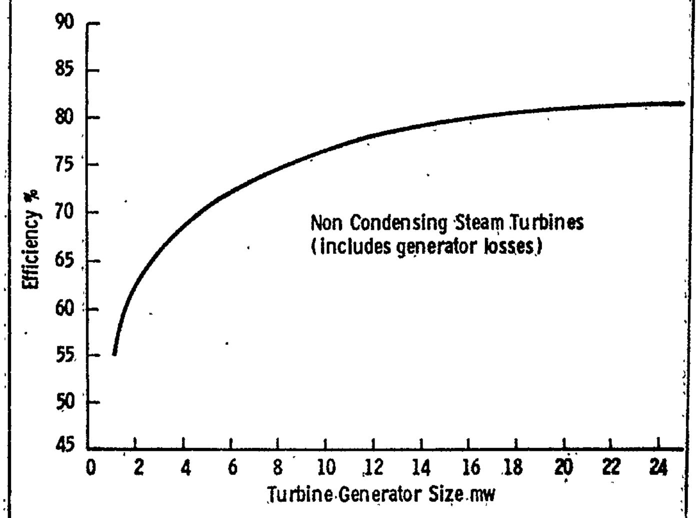


Fig. 6 — Turbine generator efficiency versus size

FIGURE 7. COGENERATION INVESTMENT SIMULATION
OPTION:STEAM TURBINE TOPPING CYCLE

FLOW OF FUNDS

YEAR	VALUE OF PWR.	FUEL COST	OPER.+MAIN.	AUXILIARIES
1	$2,010,000.00	$593,000.00	$123,000.00	$69,000.00
2	$2,150,700.00	$628,580.00	$127,920.00	$73,830.00
3	$2,301,249.00	$666,294.80	$133,036.80	$78,998.10
4	$2,462,336.43	$706,272.49	$138,358.27	$84,527.97
5	$2,634,699.98	$748,648.84	$143,892.60	$90,444.92
6	$2,819,128.98	$793,567.77	$149,648.31	$96,776.07
7	$3,016,468.01	$841,181.83	$155,634.24	$103,550.39
8	$3,227,620.77	$891,652.74	$161,859.61	$110,798.92
9	$3,453,554.22	$945,151.91	$168,333.99	$118,554.85
10	$3,695,303.02	$1,001,861.02	$175,067.35	$126,853.69
11	$3,953,974.23	$1,061,972.68	$182,070.05	$135,733.44

YEAR	DEPREC.	TAXES	INV. TAX CRED.	NET CASH FLOW
1	$102,478.26	$336,230.43	$235,700.00	$901,247.83
2	$102,478.26	$620,026.43	$0.00	$802,821.83
3	$102,478.26	$671,730.79	$0.00	$853,666.77
4	$102,478.26	$727,309.16	$0.00	$908,346.81
5	$102,478.26	$787,046.53	$0.00	$967,145.34
6	$102,478.26	$851,248.63	$0.00	$1,030,366.47
7	$102,478.26	$920,243.36	$0.00	$1,098,336.44
8	$102,478.26	$994,382.47	$0.00	$1,171,405.28
9	$102,478.26	$1,074,043.23	$0.00	$1,249,948.51
10	$102,478.26	$1,159,630.26	$0.00	$1,334,368.95
11	$102,478.26	$1,251,577.55	$0.00	$1,425,098.76

PAYBACK PERIOD 2.38
INTERNAL RATE OF RETURN 46.3

TOTAL STEAM GENERATION COSTS $ 3,274,000.00
INCREMENTAL INVESTMENT TOTAL $ 2,357,000.00
STEAM GENERATING EQUIP. $ 127,000.00
STEAM TURBINE GEN. $ 2,533,000.00
POWER COND CREDIT $ 303,000.00
BOILER PRESSURE,PSIG 900.00
STEAM TURBINE PRESSURES:INLET,EXHAUST:PSIA 850.00 65.00
EFFICIENCY OF TURBINE GENERATOR 0.80
GROSS ELECTRIC POWER PRODUCED,KW 9,000.00 0.00
FIRST STAGE 9,000.00
SECOND STAGE 0.00
ELECTRIC POWER FOR AUXILARIES,KW 460.00
STEAM TURBINE ENTHALPY:INLET,EXTRACTION,EXHAUST:BTUS/LBM 1,412.00 1,180.00
STEAM TURBINE TEMPERATURES:INLET,EXHAUST:OF 850.00 300.00
TEMPERATURE OF PROCESS STEAM,OF 300.00
PRESSURE OF THE PROCESS STEAM,PSIG 50.00
TOTAL PROCESS FLOW,LBSM/HR 135,000.00
FLOW THROUGH 2ND STG TO PROC. OR COND.,LBSM/HR 0.00
COST OF ELECTRIC PWR. $/KWH $ 0.03
ELECTRIC POWER AT BASE RATE VALUE,KW 9,000.00

COGENERATION SIMULATION ... Continued

The electric power rating, pressure ratio, atmospheric temperature, and combustion turbine firing temperature are defined input variables. Using the pressure ratio and the ideal Brayton cycle relationships, the temperature into the combustor and at the exhaust of the combustion turbine expander is calculated. The efficiency values for the compressor and the expander are used with the ideal temperatures to calculate the net work performed by the turbine. The total mass flow needed through the expander is then calculated by dividing the electric power rating of the unit by the net work. The temperatures are then recalculated to actual values based on this actual mass flow.

The heat recovery steam generator calculations begin with the temperature, pressure, and flow required at the process. First, the steam mass flow that can be generated based on combustion turbine exhaust temperatures, a minimum pinch point of 40°F, and minimum differential temperatures (exhaust gas to steam or water) of 50°F is calculated. An iterative procedure is then used to correct the steam flow to the desired value. If higher flow values are needed, then supplemental firing of combustion turbine exhaust is initiated. If lower values are needed, stack gas exhaust temperatures are elevated.

The generic example used in demonstrating the first two options is again run here for Option 3. (Figure 10). The output is demonstrated in Figure 8.

SIMULATION OPTIONS 4, 5, 6: COMBINED CYCLE, WASTE HEAT BOTTOMING CYCLE, EXTRACTION AND/OR CONDENSING

These options essentially involve combinations of the system calculations discussed in the preceding sections. While the calculations are identical to those shown in Appendix B, considerable bookkeeping is required in the model so that the temperatures, pressures, and flow from one part of the system are consistent with all the others on a first and second law thermodynamic basis.

The generic example used in previous sections is used to demonstrate the output for Option 4 and the summarized results are given in Table 3.

Table 3

Comparison of the Cogeneration Options for the Generic Examples (1000 $)

	Option 1	Option 2	Option 3	Option 4
Total investment	$ 4952	$ 7309	$ 9363	$12082
steam generating equipment	3147	3274	-	498
steam turbine generator system	-	2533	-	2533
power conditioning	1805	1502	1050	738
combustion turbine system	-	-	4759	4759
heat recovery steam generator	-	-	3554	3554
Annual operating costs	16557	15332	14789	13568
fuel	2932	3525	6633	7288
operation and maintenance	189	312	322	416
purchase power	13436	11495	7834	5864
Fuel chargeable to power (Btu/KWH)	0	4111	5520	5235
DCFROR	-	46.3%	40%	32%
Total specific cost	-	$ 812/KW	$ 375/KW	$ 355/KW
Incremental specific cost	0	262/KW	176/KW	210/KW
Savings in Annual Operating Costs	0	1225	1768	2989

- = not applicable to that option

FIGURE 8. COGENERATION INVESTMENT SIMULATION
OPTION: COMBUSTION TURBINE WITH WASTE HEAT BOILER

FLOW OF FUNDS

YEAR	VALUE OF PWR.	FUEL COST	OPER.+MAIN.	AUXILIARIES
1	$5,584,000.00	$3,701,000.00	$133,000.00	$18,000.00
2	$5,974,880.00	$3,923,060.00	$138,320.00	$18,720.00
3	$6,393,121.60	$4,158,443.60	$143,852.80	$19,468.80
4	$6,840,640.11	$4,407,950.22	$149,606.91	$20,247.55
5	$7,319,484.92	$4,672,427.23	$155,591.19	$21,057.45
6	$7,831,848.86	$4,952,772.86	$161,814.84	$21,899.75
7	$8,380,078.28	$5,249,939.23	$168,287.43	$22,775.74
8	$8,966,683.76	$5,564,935.59	$175,018.93	$23,686.77
9	$9,594,351.63	$5,898,831.72	$182,019.68	$24,634.24
10	$10,265,956.24	$6,252,761.63	$189,300.47	$25,619.61
11	$10,984,573.18	$6,627,927.32	$196,872.49	$26,644.40

YEAR	DEPREC.	TAXES	INV. TAX CRED.	NET CASH FLOW
1	$191,782.61	$306,844.35	$441,100.00	$1,615,938.26
2	$191,782.61	$826,424.35	$0.00	$1,260,138.26
3	$191,782.61	$911,540.44	$0.00	$1,351,598.56
4	$191,782.61	$1,003,824.18	$0.00	$1,450,793.86
5	$191,782.61	$1,103,848.27	$0.00	$1,558,343.39
6	$191,782.61	$1,212,229.71	$0.00	$1,674,914.31
7	$191,782.61	$1,329,633.13	$0.00	$1,801,225.36
8	$191,782.61	$1,456,774.39	$0.00	$1,938,050.70
9	$191,782.61	$1,594,424.45	$0.00	$2,086,224.13
10	$191,782.61	$1,743,413.54	$0.00	$2,246,643.60
11	$191,782.61	$1,904,635.56	$0.00	$2,420,276.01

PAYBACK PERIOD 2.73
INTERNAL RATE OF RETURN 40.3

TOTAL INVESTMENT	$4,411,000.00
COMBUSTION TURB. SYS.	$4,759,000.00
HEAT RECOV. STEAM G.	$3,554,000.00
STEAM GEN. EQUIP.	3,147,000.00
PWR. CONDITIONG EQUIP.	755,000.00

COMBUSTION TURBINE PRESSURE RATIO	10.00
COMBUST. CHAMB. AIR INLET TEMP.,OF	60.00
COMBUSTION TURBINE INLET TEMP.,OF	1,800.00
COMBUSTION TURBINE EXHAUST TEMP.,OF	950.24
COMBUSTION TURBINE AFTER BURN TEMP.	950.24
COMBUSTION TURBINE FLOW,LBSM/HR	982,894.85
WASTE HEAT INPUT,LBSM/HR	982,894.85
WASTE HEAT TEMPERATURE,OF	950.24
STACK TEMPERATURE,OF	251.18
PINCH POINT,OF	54.00
PROCESS STEAM FLOW,LBSM/HR	135,000.00
TEMPERATURE OF PROCESS STEAM,OF	300.00
PRESSURE OF PROCESS STEAM,PSIG	50.00
COMBUSTION TURBINE ELECTRIC POWER ,KW	25,000.00
ELECTRIC POWER FOR AUXILIARIES,KW	220.00
COST OF ELECTRIC POWER,$/KWH	$ 0.03

IV. COMPARISON OF THE INDUSTRIAL COGENERATION OPTIONS

Data from each of the computer simulation runs for the generic example are shown in Table 3.

An examination of the data in Table 3 for the four options shows that steam turbine topping yields the highest return on invested capital. These cases deliver the same thermal process power and are therefore compared on that basis. The steam turbine topping also requires the maximum investment on a per kilowatt basis. The electric power produced increases from a low of 9 MW in Option 2 to a high of 34 MW in Option 4, essentially requiring more equipment and investment in each case.

The returns on investment in all cases are attractive because one is trading off the higher equipment costs of the smaller industrial plant with the lower fuel chargeable to power rate.

Even though the combustion turbine and heat recovery steam generator look attractive (Option 3) from the DCFROR, one must remember that high grade distillate oil or gas is required presently to fire this equipment. Most industrials are currently trying to reduce their consumption of gas and oil (and are strongly urged to through government rhetoric), and might be hesitant to choose this alternative. Using coal economically is essentially restricted to the steam turbine topping applications for this time period.

The returns on investment are attractive in many cases, but the capital investment is large and the investment is in a business not closely related, in most cases, with the primary business.

If one considers using coal as the fuel for Option 2, then almost twice the capital investment would be required for the same electric power production. The return for coal firing is usually below that for oil firing and might require additional tax or investment credits to encourage this approach.

In all options shown, the electric power produced is valued at the price the industrial is presently paying for electricity. In other words, the power produced is never greater than the actual plant need. This results in getting maximum value for the power produced and maximum return on investment. If electric power greater than need is produced, then the value of this excess power is extremely uncertain in today's electric utility-industry environment. Taking a pessimistic approach and valuing this power at electric utility energy or even bus bar costs makes the industrial plant unattractive even for small amounts of excess power.

V. CONCLUSIONS

The computer simulation model presented here can be an effective tool in examining industrial cogeneration alternatives. The model would be properly applied in the very preliminary stages of an investigation to determine a more detailed study plan. Then detailed equipment and construction cost studies would follow.

VI. REFERENCES

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APPENDIX A DERIVATION OF DISCOUNTED CASH FLOW RATE OF RETURN, PAYBACK PERIOD, AND ALLOWABLE INVESTMENT FOR COGENERATION SYSTEMS

The gross savings (before taxes) for year i is

$$GS_i = S_i - FC_i - OM_i - DEP_i \tag{A1}$$

where

GS_i = gross savings for year i

S_i = savings on purchase of electricity for year i

FC_i = incremental fuel costs for year i

OM_i = incremental operating and maintenance costs for year i

DEP_i = incremental depreciation for year i

The net savings (after taxes) for year i is

$$NS_i = GS_i - TAX_i \tag{A2}$$

where

NS_i = net savings for year i

TAX_i = local, state, and federal income tax on gross savings for year i

The net cash flow for year i is

$$NCF_i = NS_i + DEP_i \tag{A3}$$

The taxes are calculated from

$$TAX_i = TR \times GS_i - ITCR \times C_o \tag{A4}$$

where TR is the effective industrial tax rate

$ITCR$ = investment tax credit rate

Using straight line depreciation yields (A5)

$$DEP_i = C_o/L$$

where C_o = incremental capital investment

L = life of the investment for tax purposes

The DCFROR, r is defined as that rate of return which equates the present worth of the net yearly cash flows to the incremental capital investment

$$C_o = \sum_{i=1}^{N} \frac{1}{(1+r)^i} NCF_i \tag{A6}$$

The net savings in year i may be related to the savings in the first year of operation by

$$NS_i = NS_1(1+g)^{i-1} \tag{A7}$$

where

g = annual growth rate of gross savings

The gross payback period is defined as the ratio of capital investment to the gross annual savings (before taxes) plus depreciation and is given by

$$GPB = \frac{C_o}{GS_1 + DEP_1} \tag{A8}$$

The payback period is taken as the ratio of the capital investment to the net annual savings (after taxes) and is given by

$$PB = \frac{C_o}{NS_1 + DEP_1} \qquad (A9)$$

Using (A2) and (A5) in (A3) and substituting the result into (A6) yields

$$C_o = \sum_{i=1}^{N} \frac{1}{(1+r)^i} \left[NS_1(1+g)^{i-1} + \frac{C_o}{L}\right] \qquad (A10)$$

Solving (A10) for NS_1 and substituting into (A9) yields

$$PB = \frac{1}{\dfrac{\left[1 - \dfrac{1}{L} \displaystyle\sum_{i=1}^{N} \dfrac{1}{(1+r)^i}\right]}{\displaystyle\sum_{i=1}^{N} \dfrac{(1+g)^{i-1}}{(1+r)^i}} + \dfrac{1}{L}} \qquad (A11)$$

Summing the series in (A11) yields a closed form expression

$$PB = \frac{\dfrac{1}{(1+g)} \left[\dfrac{1-(1+r_o)^{-N}}{r_o}\right]}{1 - \dfrac{1}{L}\left[\dfrac{1-(1+r)^{-N}}{r}\right] + \dfrac{1}{L(1+g)}\left[\dfrac{1-(1+r_o)^{-N}}{r_o}\right]} \qquad (A12)$$

where $r_o \triangleq \dfrac{r-g}{1+g}$

Equation (A12) is used to plot the PB versus r relationship for different savings growth rates g.

An expression for the allowable investment versus electric power cost for different PB may be derived in the following manner.

The savings are defined by

$$S_1 = CAP \times 8760 \times CF \times EPR \qquad (A13)$$

where
- CAP = capacity of the cogeneration plant KW
- CF = capacity factor
- EPR = electric power price per KWH to the industrial

The fuel costs are expressed by

$$FC_1 = FCP \times FCST \times CAP \times 8760 \times CF \qquad (A14)$$

where
- FCP = fuel chargeable to power
- FCST = fuel cost

The operation and maintenance costs are related to the capital investment by

$$OM_1 = OMR \times C_o \qquad (A15)$$

where

OMR = operation and maintenance rate

Substituting (A13), (A14), and (A15) into (A9) and rearranging yields

$$\frac{C_o}{} = \frac{(1-TR) \times PB \times 8760 \times CF \times (EPR-FCP \times FCST)}{\{1 + PB\,[(1-TR)\,OMR - \frac{TR}{L} - ITCR]\}} \qquad (A16)$$

Equation (A16) was used to plot the specific (\$/KW) allowable investment versus electric power price for various net payback periods shown in Figure 1.

APPENDIX B EQUATIONS USED IN THE SIMULATION MODEL OPTIONS 2, 3, 4, AND 5

STEAM TOPPING TURBINE CALCULATIONS:

The following relationship is used in the model to calculate any one of enthalpy, temperature, or pressure given the other two values.

$$h_g = S(T)p_b + h_o \qquad (B1)$$

where

h_g = superheated steam enthalpy, $S(T)$ = matrix of values for different temperatures, h_o vector of "ordinate" enthalpy values, and p_b = steam pressure. The electric power, P_e, from the topping turbine generator is given by

$$P_e = \dot{w}_s E_{fft}/TSR \qquad (B2)$$

where

$\dot{w}_s$ = steam mass flow rate
E_{fft} = efficiency of turbine generator
TSR = theoretical steam rate

The enthalpy of the exhaust steam from the topping turbine, h_{exh}, is calculated from

$$h_{exh} = h_g - P_m/\dot{w}_s \qquad (B3)$$

where

h_g = enthalpy of steam into turbine, and P_m = mechanical power produced by the turbine.

The temperature of the exhaust steam is calculated by using h_{exh} in (B1) and solving inversely for T_{exh}, the steam exhaust temperature.

The rate of fuel flow to the boiler, f_r, is approximated with

$$f_r = (h_g - h_f)\dot{w}_s \qquad (B4)$$

where h_f = saturated feedwater inlet enthalpy.

The costs of the steam turbine, STBC, and the incremental costs of the boiler are approximated from the following:

$$STBC = 581.156\ (P_e/1000)^{.67} \quad (B5)$$

The boiler costs, BC, to supply steam at pressures at temperatures in the neighborhood of the generic example are approximated by

$$BC = 2.45 \times 10^6 (p_b/100)^{.02} (\dot{w}_s/1 \times 10^5)^{.85} \quad (B6)$$

The base and scale coefficients are selected and changed by the model for different pressure and flow ranges.

COMBUSTION TURBINE CALCULATIONS:
The calculations used for the combustion turbine follow Brayton cycle relationships.

The ideal turbine compressor work, W_c, is given by

$$W_c = c_{pa}(T_{c1} - T_a) \quad (B7)$$

where c_{pa} = specific heat for air, T_{c1} = temperature into the combustor, and T_a = the air inlet temperature.

The temperature ratio between combustion turbine inlet, T_{CBIN}, and that out, T_R, is given by

$$\frac{T_{CBIN}}{T_R} = \left(\frac{P_C}{P_R}\right)^{\frac{\gamma-1}{\gamma}} \quad (B8)$$

The ideal turbine expansion work, W_t, is calculated from

$$W_t = c_{pv}(T_{CBIN} - T_R) \quad (B9)$$

where c_{pv} = specific heat of combustion products, and T_R = temperature of combustion products rejected from turbine.

The net actual shaft work performed by the combustion turbine is given by

$$W_{net} = E_{fft}\, W_t - W_c/E_{ffc} \quad (B10)$$

where E_{fft} and E_{ffc} are the actual efficiencies of the turbine and compressor, respectively.

The actual combustor inlet temperatures and turbine reject temperatures are calculated from (B7) and (B9) using the actual turbine work ($W_{ta} = E_{fft} \times W_t$) and compressor work ($W_{ca} = W_c/E_{ffc}$).

WASTE HEAT BOILER CALCULATIONS:
The flow of combustion products to the waste heat boiler, $\dot{w}_{cg}$, is approximated by

$$\dot{w}_{cg} = P_{mc}/E_{fft}\, W_{NET} \quad (B11)$$

where P_{mc} = combustion turbine mechanical power.

The steam flow, $\dot{w}_s$, out of the waste heat boiler is calculated using energy balance and second law thermodynamics by

$$\dot{w}_s = (\dot{w}_{cg} c_{pv}(T_R - T_{ws} - T_{pp}))/(h_g - h_w) \quad (B12)$$

where T_{ws} = temperature of saturated water inlet, T_{pp} pinch point temperature of waste heat boiler, and h_w = enthalpy of inlet feedwater.

Since water enters at conditions of saturation, the stack temperature, T_{STK}, is calculated from

$$T_{STK} = T_{pp} + T_{ws} \quad (B13)$$

For a desired steam flow $\dot{w}_s$, equations (B12) and (B13) are iteratively solved for increasing pinch point temperature, T_{pp}, with the constraint

$$250°F < T_{STK} \text{ and } T_w < T_{STK} \quad (B14)$$

where T_w = saturated feedwater temperature

The cost for the combustion turbine generator system, CTCST, is approximated for turbines near the size of the generic case by

$$CTCST = (190\ \frac{\$}{KW})\ P_{ec} \quad (B15)$$

where P_{ec} = electric power out of the turbine

The waste heat boiler costs, WHBCST, are calculated from

$$WHBCST = 2.754 \times 10^6 (p_b/100)^{.02} (\dot{w}_s/1 \times 10^5)^{.85} \quad (B16)$$

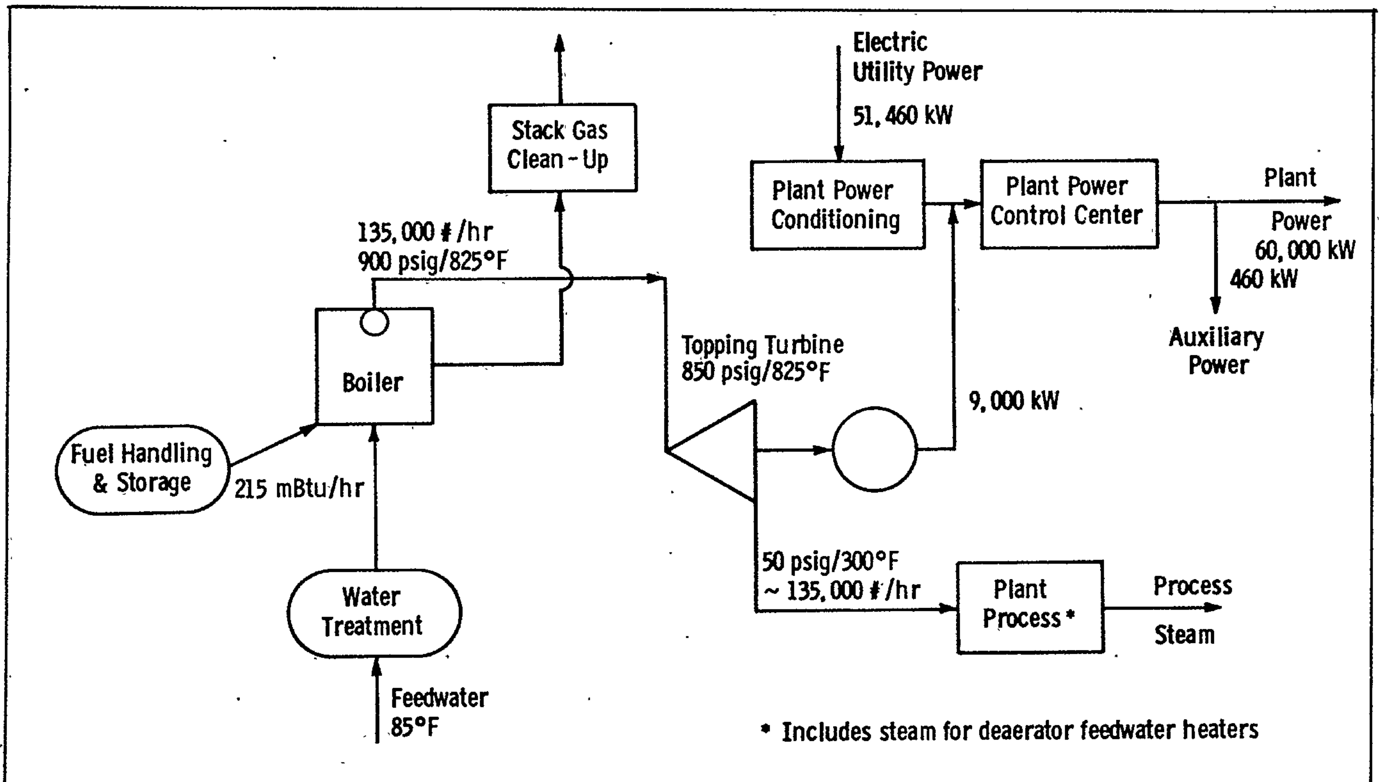

Fig. 9 — Schematic diagram for case 2 steam topping turbine

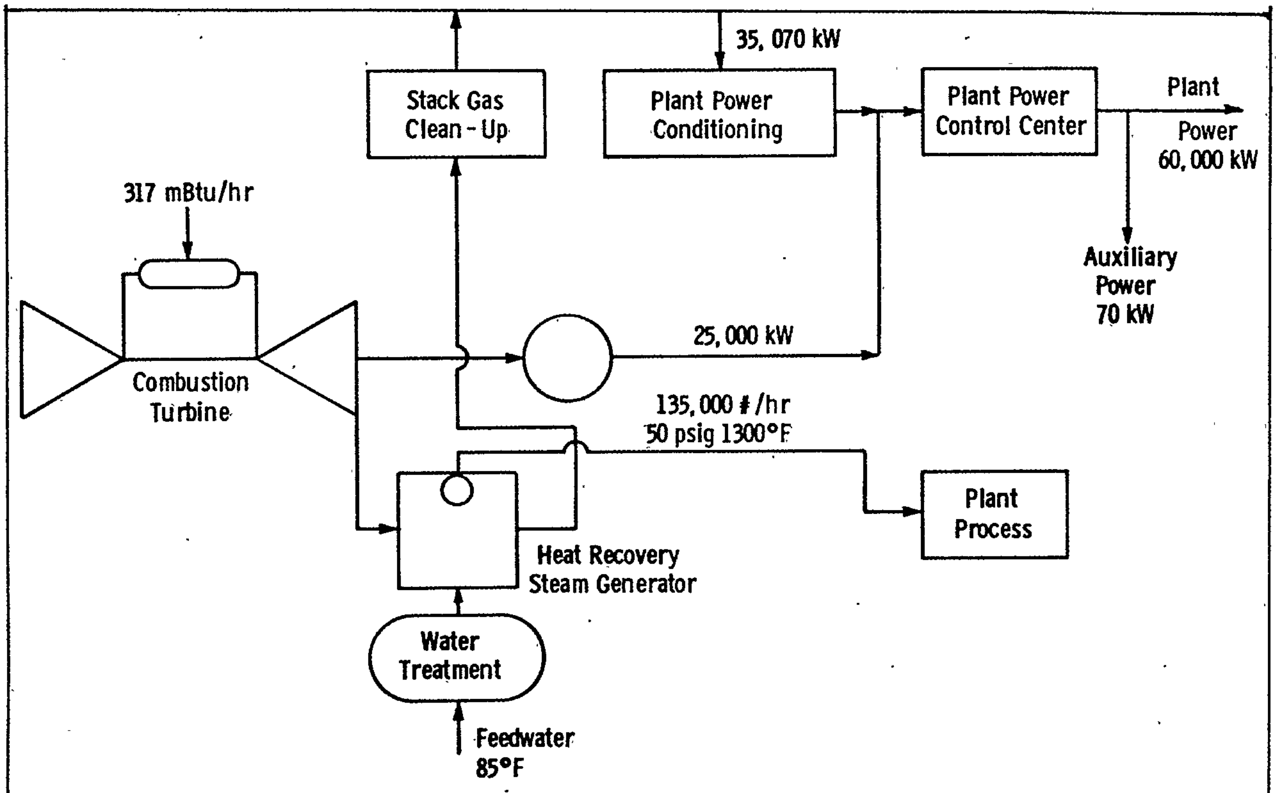

Fig. 10 — Schematic diagram for case 3 ; combustion turbine with waste heat boiler