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MODELING COGENERATION SYSTEMS WITH DOE-2.1C

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ABSTRACT

The most recent version of DOE-2, the Department of Energy's major computer program for building energy analysis, includes three new capabilities that make the program a state-of-the-art tool for analyzing cogeneration systems in commercial and residential buildings. First, the internal representation of the electricity generators available for cogeneration has been modified to permit easier specification of full- and part-load performance. Second, the algorithms used to allocate loads to the prime movers have been modified to permit modeling of more sophisticated operating strategies, including thermal load following. Third, DOE-2 can now accurately evaluate the economics of cogeneration, because the program can now accommodate sophisticated electric utility tariffs, including time-of-use rates, demand charges with ratchets, and the sell-back of electricity mandated by the Public Utilities Regulatory Policies Act. Examples of these capabilities are presented with results from a study of the economics of cogeneration in a hypothetical hotel building, using current utility tariffs and weather data from Southern California.

INTRODUCTION

Owners of many commercial buildings can reduce their energy bills by investing in cogeneration equipment; nevertheless, determining the technical and economic characteristics of a successful cogeneration system for a specific building is complicated by a number of interdependent trade-offs. For example, the engineer must be able to compare the dollar savings from reduced electricity bills, which often contain substantial charges for on-peak energy use and demands, against the relatively longer amortization periods for cogeneration equipment, which, unlike the operation of similar equipment in an industrial application, may not operate continuously. Similarly, when sizing a cogeneration plant for a commercial building, the engineer must account for the fluctuating thermal and electrical loads in commercial buildings. One general statement of the problem is that, to understand the net impact of these trade-offs, we need an engineering/economic analysis, which has a time-step that captures the dynamic relationships between four things: thermal and electrical requirements of commercial buildings, the operation of the cogeneration equipment, the utility interface to this operation, and the cost of the equipment.

The economics of cogeneration in commercial buildings have not been studied as thoroughly as those in industrial situations. Many studies correctly recognize the problems of analyzing commercial cogeneration but do not address them directly [SRI 1980; Battelle 1983]. Attempts to analyze commercial building loads tend to rely on simplifying assumptions, particularly regarding utility rate structures [OTA 1983; Cummings et al. 1982]. Several studies have performed detailed hourly simulations of commercial building cogeneration in the New York City area but have used customized software [Bright et al. 1980; Entek 1983; Rodberg et al. 1984]. In other words, the problems of analyzing opportunities for cogeneration in commercial buildings have been addressed only unevenly and are not generally useful or accessible to engineers considering specific projects.

This paper describes recent improvements to the DOE-2 building energy simulation program; these changes significantly improve the program's abilities to analyze the thermodynamic and economic properties of cogeneration systems in commercial buildings. We describe three specific changes:

- Modification of the internal representation of the electricity generators or prime movers available for cogeneration for easier specification of full- and part-load performance;

- Revisions to the algorithms used to allocate loads to the prime movers, which permits modeling of sophisticated operating strategies, including thermal load following;
- Accommodation of complex electric utility rate structures, including time-of-use rates, demand charges with ratchets, and the options for sell-back of electricity mandated by the Public Utilities Regulatory Policies Act (PURPA) [U.S. Congress 1978].

The use of the program with these modifications is illustrated in a simple case study of cogeneration economics for a hypothetical hotel located in Southern California.

MODIFICATIONS TO DOE-2

The DOE-2 program is a large, well-documented, public-domain computer program developed for the Department of Energy [Curtis et al. 1984]. It is a state-of-the-art tool that architects and engineers use to estimate building energy performance. The DOE-2 simulation's time-step is hourly. The structure and operation of a building can be entirely specified by user-inputs. In addition, an extensive library of dynamic default values is available. For central plant equipment (including cogeneration prime movers), the default performance specifications were taken from the technology evaluations performed for the Integrated Community Energy Systems project. The DOE-2 program has been validated extensively [Diamond et al. 1981].

The program estimates the annual energy use and energy operating costs of buildings in four sequential steps (see Figure 1).

- First, the heat losses and gains to building spaces, as well as process heating (e.g., domestic hot water) and electrical loads (e.g., lighting) are calculated in the LOADS subprogram.
- Second, the heating and cooling energy supplied to the air-side HVAC system(s) is calculated in the SYSTEMS subprogram.
- Third, the utilities (e.g., electricity and natural gas) required by a central plant to supply the heating, cooling, and electrical demands of the building are calculated in the PLANT subprogram.
- Fourth, the cost of these utilities is calculated in the ECONOMICS subprogram.

Modifications to the PLANT Subprogram

Since its inception, the DOE-2 PLANT program has allowed one to study the performance of on-site electrical generation and cogeneration as part of a building's central plant. Recent changes in federal and state laws, notably the Public Utilities Regulatory Policies Act (PURPA), have granted small power producers and cogenerators additional flexibility in the operation of non-utility-owned electricity generation facilities. These changes give cogenerators easier access to electric utility grids for purchase of additional electricity, as well as a regulated market for the sale of excess electricity. No longer must installations be sized to meet electrical peak demands, including redundant capacity, as in the days of total energy systems. Electricity may be freely sold to and bought from the local utility.

The DOE-2.1C version of PLANT acknowledges these regulatory changes with an entirely reworked concept of electricity generators, as well as heat- and electricity-driven chillers, when they are operated in a cogeneration mode. The new concept explicitly recognizes the energy value of both outputs of the cogeneration process -- heat and electricity. Previously, the user could only schedule operation based on the electrical output of the prime movers, and the associated heat recovered could only be used to the extent that a demand existed for thermal energy; any excess would be wasted. Now that the cogenerators can freely buy from and sell to the utility grid, operation no longer needs to be based solely on on-site electrical demands; for example, operation can be scheduled to eliminate wasted recoverable thermal energy.

The user can now specify a cogeneration mode of operation that is based on meeting either electrical or thermal loads. These features have been integrated with the existing command structure of PLANT so operation can be scheduled in either mode, during the course of a given day or on the basis of the magnitude of the load to be served. For example, the user can specify a cogeneration system that will track the thermal loads of a building where these loads may consist of heating or cooling loads (if a heat-driven, absorption chiller is available to accept recovered heat from the prime movers). In such a thermal tracking mode with interconnection to a utility, both outputs of the prime movers will be fully used, because the prime movers will be run so that all recoverable heat is used in the building and any excess electricity is sold to the utility. Such operation will result in the most efficient use of energy from the electricity conversion process. At another time of year, when utility rates are high for the facility (for example, the summer on-peak period of a time-of-use rate), operation can be scheduled to follow electrical loads to minimize purchases from the utility. In this operating mode, excess thermal energy will be wasted. In addition, the user can also specify operating strategies that run the plant to meet either the greater or lesser of the thermal or electrical loads, based on the relative prices of fuel and electricity In a final situation, where the utility rates for buy-back from the cogenerator are high (possibly due to capacity shortages by the utility) the generators can be run at maximum output in order to maximize sales to the utility.

To accommodate these new cogeneration capabilities, two aspects of the PLANT program were modeled: (a) equipment simulations and (b) load allocations.

The equipment simulations for prime movers (reciprocating internal combustion engine and gas turbine) and chillers (absorption, centrifugal, reciprocating, and double-bundle) have been rewritten. Formerly, the inputs and outputs for each type of equipment were related through a series of intermediate equations. Now they are related to one another directly with quadratic transfer functions. The coefficients to these equations remain user-definable or can be based on default values. The reformulation has two advantages: first, it is now easier for the user to specify the full- and part-load performance of equipment; second, the use of quadratic equations permits rapid determination of input values from output values, and vice versa, by solution of the quadratic equation, which is the basis for the revised load allocation algorithms.

The load allocation routines required several modifications. First, the original specification of prime mover equipment capacities now had to include a rating for thermal, as well as electrical, output. Next, the user-input load allocation instructions for prime mover operation were modified to permit load allocation on the basis of either thermal *or* electric loads. The allocation logic remains unchanged, only the nature of the loads being allocated have changed. The major modification to the load allocation routines took place in the default allocation algorithms, which are used in conjunction with or in place of user-specified operation. The PLANT program allows for varying levels of user-specified and default- optimized operation. For example, prime mover operation may be user specified on a daily/hourly basis, while chiller operation is determined by the program. At an even higher level of generality, only a cogeneration mode need be specified by the user (e.g., track thermal loads). The user-specified inputs for operation are boundaries or constraints for the program's internal logic, which attempts to optimize equipment operation. Generally, linear approximations are used for the equipment I/O relations, and no iteration is required. For one situation, however -- the determination of prime mover output when both heat- and electricity- driven chillers are present and a cooling load exists -- an iterative solution was necessary.

Modifications to the ECONOMICS Subprogram

Determining the economic value of cogeneration is complicated by the increasingly detailed structure of electricity rates. In the past decade, new approaches for electricity billing have gained wide acceptance. Time-of-day prices, demand ratchets, and lifeline blocks are now familiar features of rate structures for energy. For cogenerators of electricity, federal law permits several valuation options for the sale of electricity to the electric grid. These developments have all been recognized and incorporated into the ECONOMICS subprogram, which now performs all the economic calculations (formerly energy costs were calculated in PLANT and life cycle costs in ECONOMICS).

In order to represent the new features in current electricity rates, tariffs from a number of utilities were analyzed. We were able to represent these features by identifying four components and incorporating them into DOE-2:

- First, the DOE-2 user identifies the type of energy being valued and describes the components of a monthly bill (billing units, minimum charges, fixed charges, and rate limiters).
- Second, the user describes how energy used in the hours of a billing period is allocated into different billing categories over time. This component is used to specify time-of-day rate structures (e.g., on-, off-, and shoulder-peak periods) and rates that vary by season (e.g., winter versus summer).
- Third the user describes how charges for energy in a given billing category are determined. This component is used to describe block rate structures in which successive amounts of consumption have different rates (dollars per unit of consumption). The program can also accept rates that define tier boundaries endogenously based on demand (e.g., kWh/kW).
- Fourth, the user describes a handful of features that are unique to electricity tariffs. These features include demand ratchets and the PURPA-mandated options for the sale of electricity to utilities. The PURPA-mandated options permit cogenerators of electricity to choose one of two accounting conventions for valuing electricity sales. The first, called "net sale", first uses cogenerated power to offset purchases of electricity onsite and sells the excess at the utility's avoided cost rates. The second, called "simultaneous buy/sell" values all electricity generation at avoided cost but bills total on-site consumption at standard utility rates.

To summarize, the modifications to ECONOMICS allow users to calculate the energy costs of proposed building designs using actual utility rate schedules.

COMMERCIAL BUILDING COGENERATION CASE STUDY

This section demonstrates the capabilities of these modifications to version 2.1C of the DOE-2 program with a case study of cogeneration alternatives for a hypothetical hotel building located in Southern California. The evaluation consists of parametric DOE-2 simulations that estimate changes in annual operating costs of various cogeneration plant sizes and operating strategies relative to that of a conventional plant.

The hypothetical hotel building is based on an actual hotel built in 1981 and located in Bellevue, WA. The specifications of the building envelope and systems were modified to ensure compliance with ASHRAE Standard 90-1975 for the climate of Southern California [ASHRAE 1975]. The building contains over 300 guest rooms and many convention meeting rooms. It has 315,000 ft^2 (29,264 m^2) of floor area. The building features an atrium lobby, which is predominantly glazed. The building is served by a total of five HVAC systems. The operating temperatures and schedules of operation were taken from a standardized set operating profile developed especially for building simulation analyses of hotels [DOE 1979]. Table 1 summarizes major features of the building.

The simulations were performed using a data tape of weather information for Los Angeles that was developed specifically for building energy analyses [Crow 1981].

Figures 2 and 3 illustrate the time-varying hot water, heating, cooling, and electrical loads on the central plant for a typical winter and summer day, respectively. These are the loads that must be met by the central plant.

The conventional or base case central plant for the hotel meets these loads with a single domestic hot water heater for the hot water demands (efficiency = 0.75), two identically sized (621,000 Btu/h or 182 kW each) hot water boilers for the heating demands (efficiency = 0.75), two identically sized (200 tons or 705 kW each) hermetic centrifugal chillers (COP = 3.8) and a cooling tower for the cooling demands, and the local utilities for electricity and natural gas.

For this building prototype, the energy operating costs of three sizes of cogeneration plant were examined under three different operational strategies for a total of nine possible combinations. The cogeneration alternatives are specified as additions to the existing conventional plant so that, in case of failure, the energy demands of the building can be met by the conventional plant. In order to provide an additional summer heating load, one of the electricity-driven, centrifugal chillers was replaced with a heat-driven, absorption chiller of equal size. The COP of the absorption chiller is 0.6.

The first cogeneration sizing alternative consists of two 100 kW natural gas-fired engine generators equipped with heat recovery. The second sizing alternative consists of two 200 kW engine generators, and the third sizing alternative consists of two 300 kW engine generators. The full-load, electrical conversion efficiency of the engines is fixed for each engine size at 26.8%, and the maximum heat recoverable is also fixed at 49.4% of the fuel input.

The first operating strategy follows traditional cogeneration plant operating principles by running the engines to follow the building's electrical demands (Track Electric). As discussed previously, this was the only strategy specifiable in earlier versions of DOE-2. In this strategy, heat produced in excess of building demands will be wasted. The second strategy eliminates wasted heat by running the engines according to the demands for heat that is recoverable from the engines (Track Thermal). In this strategy, electricity produced in excess of building demands is sold to the utility. The third strategy simply runs the engines full out (Max Output). Excess heat is wasted, but excess electricity is sold to the utility.

Figure 4 illustrates how the different operating strategies affect the output of the engine generator for the 600 kW cogeneration plant on a typical summer day. The maximum output strategy is easily identified as a straight line set at the maximum rating of the plant. The lowest line, for the strategy that tracks electricity, indicates that the 600 kW plant exceeds the electrical demands of the building. Recall that, for cogeneration plants, electrical loads consist mainly of lighting, equipment, fans, and pumps, since much of the cooling load is being satisfied by heat-driven absorption chillers. When generation from the other strategies exceeds this level, electricity is being sold to the utility. The middle line, for the strategy that tracks thermal loads, indicates that by mid-day the heating demands exceed the thermal energy recoverable from the engine generators. At this point, the operation of the engines is at maximum capacity.

A recent (January 1987) time-of-use electricity rate schedule and set of prices for electricity sales and recent (January 1987) natural gas rate schedules were used to compare the operating costs of these alternative plant sizes and operating strategies relative to those for the conventional plant. The electricity tariff features three time-of-use periods (on-, mid-, and off-peak), each with a separate energy and demand charge that varies between winter and summer. The natural gas tariff requires that one account for natural gas used to cogenerate electricity at a lower rate than natural gas used by the boilers for heating and hot water generation. Since retail rates for the purchase of electricity from the utility exceed the rate the utility will pay for electricity, the Net-Sale option was specified for the contract to sell excess electricity to the utility.

The additional operating and maintenance costs of the cogeneration plant are the final cost ingredient necessary to compare the operating economics of a conventional plant to the cogeneration alternatives. A value of $0.015/kWh was used based on a recent survey of operating costs for cogeneration plants [Wasserman and McCold 1985].

The first figure of merit is simple payback. Although a thorough evaluation would consider other important factors, such as taxes, debt service requirements, and the time value of money, simple payback is a convenient method for ranking projects against one another. An assumed fixed cost of $100,000 plus an additional $1000/kW, depending on engine size, was used for the evaluation. The fixed-cost term is intended to represent the costs that do not vary with the size of the cogeneration plant; these costs include the incremental costs of the absorption chiller and the equipment required for interconnection to the utility. The variable-cost term is intended to represent the costs of the engine-generators and associated heat-recovery equipment. Table 2 summarizes the results of the payback calculations.

The results in Table 2 indicate that the most cost-effective (lowest payback) plant size is the 400 kW cogeneration plant. The smaller plant (200 kW) appears to suffer from some diseconomies of scale. That is, the savings are approximately half that of the 400 kW plant, but higher first costs (on a per unit of installed capacity basis) result in a longer payback. The larger plant, which does benefit from these economies of scale, does not provide correspondingly larger percentage savings, the net result being a longer payback period. This plant is, consequently, oversized relative to the hotel's average thermal and electrical demands, so that much of the capacity of the plant is unused.

Holding the plant sizes fixed, the best operating strategy is one that follows the electrical loads of the building. This outcome results exclusively from the high price of electricity relative to that of natural gas. This price is also high relative to the value of sales of electricity to the utility, and so these sales are less valuable than simply off-setting purchases from the utility. Consequently, the strategy that runs the engines at maximum output is less cost-effective than tracking the electrical loads of the building.

The second important figure of merit is the PURPA efficiency criterion, which requires that "the useful power output plus one half the useful thermal energy output of the facility must be.....no less than 42.5 percent of the energy input of the natural gas or oil to the facility" [FERC 1981]. Table 3 summarizes the results of the PURPA efficiency analysis.

The PURPA efficiencies in Table 3 indicate the degree to which the relative prices for electricity and natural gas skew the investment decision from one that is based on energy efficiency alone. The most cost-effective plant and operating strategy has one of the lower PURPA efficiencies. This result is simply a restatement of the extremely high cost of electricity that the cogeneration plant offsets. The value of electricity is so high that it is economical to recover less heat, i.e., throw away recoverable heat for the sake of increased production of electricity. For example, the operating strategy with the highest PURPA efficiencies is, not surprisingly, the one that operates the engines to track thermal loads. This strategy also has the longest payback period for any of the alternative sizes of plants considered. On the other hand, significant sales of electricity from the 600 kW plant run at maximum output reduce the PURPA efficiency below the minimum threshold.

This case study was intended to illustrate the general capabilities of DOE-2, version 2.1C, for simulating the thermodynamic and economic properties of a hypothetical cogeneration system. The results presented are, of course, unique to the assumptions made about the simulated building and systems and the economics used to evaluate them. The power of the program lies in its ability to provide a consistent and sound basis for evaluating a large range of such possibilities, both thermodynamic and economic. Specifically, the new capabilities significantly improve the ability of engineers to evaluate the economics of innovative cogeneration operating strategies using actual utility rates.

SUMMARY

Recent modifications to a large, well-documented, public domain computer program for building energy analysis have been described. These modifications substantially improve the program's ability to model the thermodynamic and economic properties of cogeneration systems in commercial buildings. The thermodynamic modifications include revised specifications of relationships between the thermal and electrical outputs of a cogeneration plant relative to its fuel inputs. These modifications facilitated the implementation of new operating strategies in DOE-2 that permitted operation based on thermal loads as well as operation independent of either thermal or electrical load. The ability of the program to calculate the energy costs of cogeneration plants were also modified. The user can now evaluate the energy cost of alternatives using actual rate schedules, including those with demand ratchets, time-of-use rates, and sales of electricity to the utility.

The capabilities of the modified program were demonstrated with results from a hypothetical case study of the economics of various sizes and operating strategies for a cogeneration plant in a large hotel located in Southern California. Using actual and current electricity and natural gas tariffs, the cost-effectiveness of each combination of size and operating strategies were evaluated. For this case study, it was noted that the high cost of electricity, in contrast to the lower cost of natural gas and the lower value of electricity sales to the utility, influenced the economics of the different combinations.

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TABLE 1
Summary of Hotel Building

Size	315,000 ft^2 (29,264 m^2); public areas - 30%, guest rooms - 65%, service areas - 5%.
Shape	10 floors; long north/south axis; atrium on west.
Construction	Reinforced concrete frame; 9 ft (2.7 m) floor-to-floor.
Glazing	70% on west; 54% on east; 10% on south; 4% on north.
Operation/Occupancy	24 hour operation; 2900 persons maximum. Rooms high at night; meeting rooms high during day; service areas round-the-clock (reduced at night).
Thermostat Settings	78 F (25.5 ^oC) cooling; 72 F (22.2 ^oC) heating with night setback to 68 F (20.0 ^oC);
Internal Loads	Lighting, equipment, elevators; 1.0 W/ft^2 annual average over all hours
HVAC	Guest rooms - four-pipe fan coil units; corridors, lobby-atrium, banquet rooms - separate variable-temperature constant-volume units; all public areas - variable air volume units
Economizer	62 F (16.7 ^oC), dry-bulb.
Heating Plant	2 621,000 Btu/h (182 kW) gas-fired hot-water generators; 1 655,000 Btu/h (192 kW) gas-fired domestic hot water heater Efficiency is 75%.
Cooling Plant	2 200 ton (705 kW) hermetic centrifugal chillers and cooling tower. Chiller COP is 3.8

TABLE 2
Payback Analysis for Cogeneration Plant Alternatives

Operating Strategy	A Electricity (k$)	B Natural Gas (k$)	C Standby (k$)	D O & M (k$)	E Sales (k$)	A+B+C+D-E Total (k$)	Savings (k$) (%)	Payback* (years)
Conventional	401.2	50.7	0.0	0.0	0.0	451.9		
2 - 100 kW								
Track Electric	204.3	166.7	1.9	27.6	0.0	400.5	51.4 (11.4)	5.8
Track Thermal	210.3	163.6	1.9	26.1	0.0	401.9	50.0 (11.1)	6.0
Max Output	204.3	166.7	1.9	27.6	0.0	400.5	51.4 (11.4)	5.8
2 - 200 kW								
Track Electric	65.8	158.8	3.8	52.0	0.0	280.5	171.5 (37.9)	2.9
Track Thermal	116.7	135.7	3.8	41.3	0.0	297.6	154.3 (34.1)	3.2
Max Output	65.8	165.4	3.8	55.2	5.7	284.5	167.4 (37.0)	3.0
2 - 300 kW								
Track Electric	6.7	166.0	5.8	62.4	0.0	240.9	211.1 (46.7)	3.3
Track Thermal	88.1	123.7	5.8	48.3	12.1	253.6	198.3 (43.9)	3.5
Max Output	6.7	198.5	5.8	82.8	48.7	245.0	206.9 (45.8)	3.4

* calculated using an installed cost of $100,000 plus $1,000/kW.

TABLE 3
Analysis of PURPA Efficiencies

	A Fuel (GBTU)	B Useful Electricity (GBTU)	C Recovered Heat (GBTU)	(0.5*B+C)/A PURPA Efficiency (%)
2 - 100 kW				
Track Electric	23.3	6.3	11.0	50.5
Track Thermal	22.2	5.9	11.0	51.5
Max Output	23.3	6.3	11.0	50.5
2 - 200 kW				
Track Electric	44.2	11.8	17.4	46.5
Track Thermal	35.6	9.4	17.4	50.9
Max Output	46.6	12.6	17.4	45.6
2 - 300 kW				
Track Electric	54.1	14.2	19.4	44.2
Track Thermal	42.2	11.0	20.4	50.2
Max Output	69.9	18.8	20.4	41.5

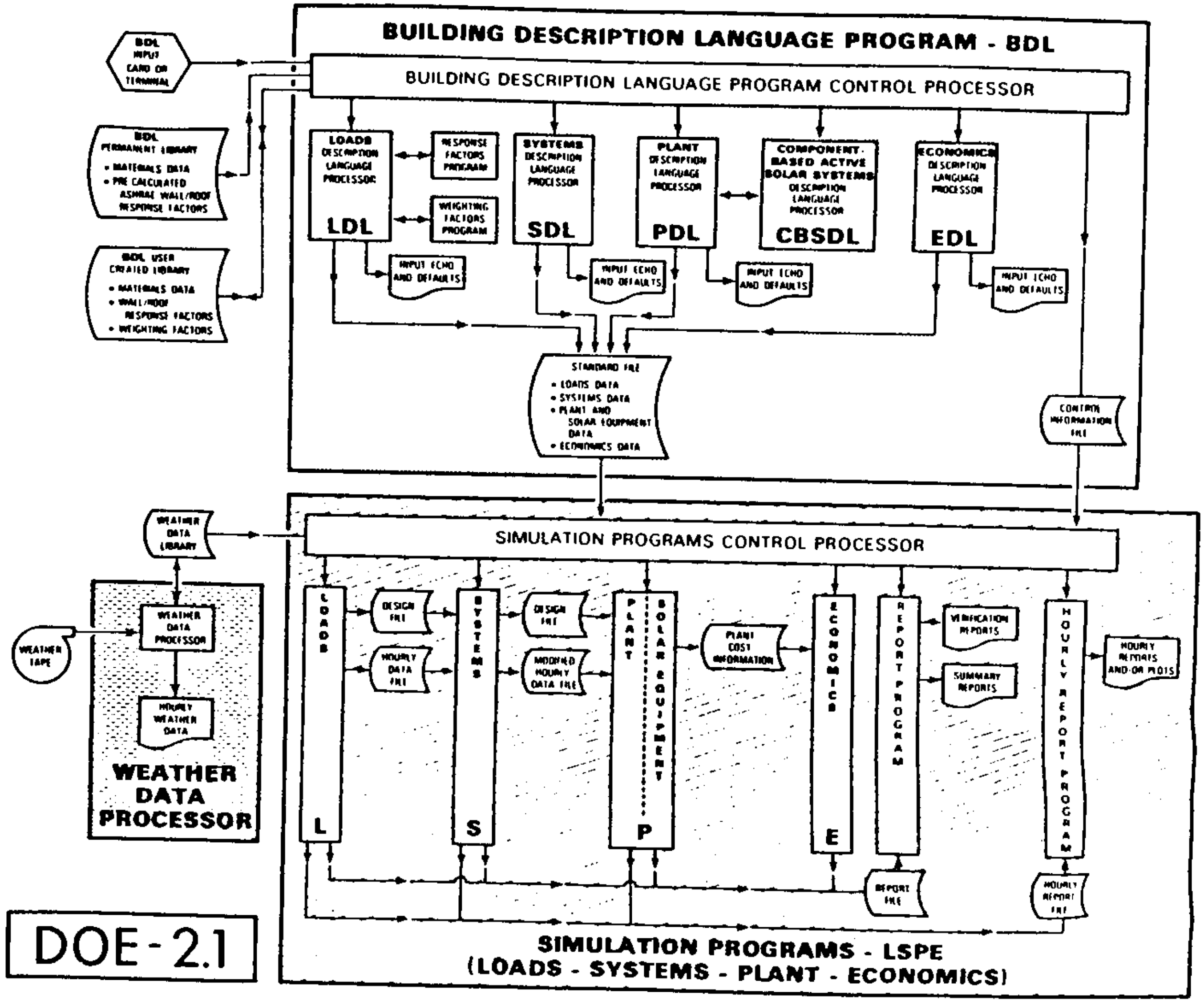

Figure 1 Schematic representation of the DOE-2.1 building energy analysis program.

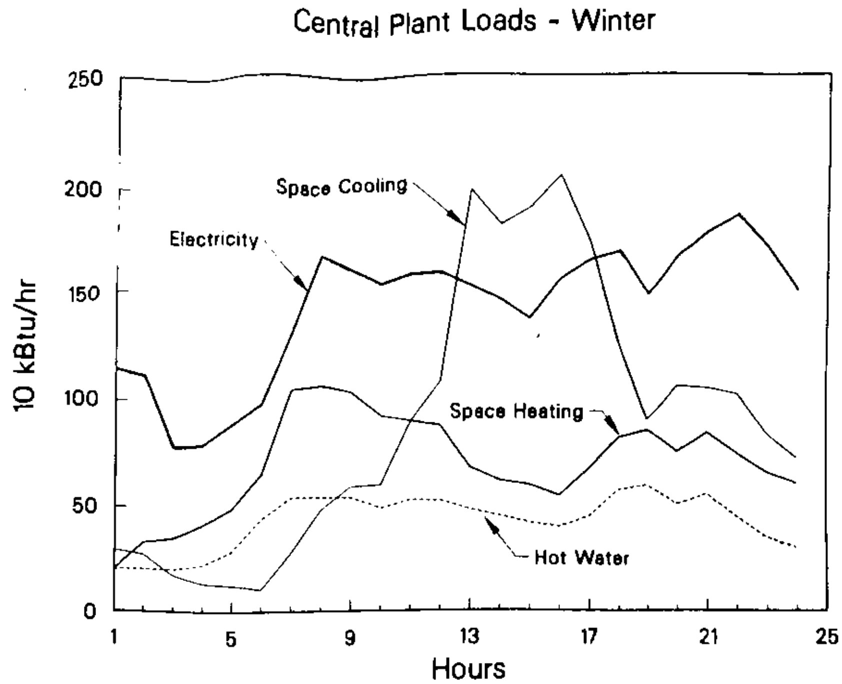

Figure 2 A typical winter day hourly load profile for the four primary end uses of the hypothetical hotel. These end-use demands constitute the loads that must be satisfied by the various conventional and cogeneration plant configurations. The space heating load has been stacked on top of the water heating loads, since the aggregate of these two end uses constitutes the primary heating load. Also note the electricity demand profile includes only electricity use for lighting, vertical transportation, and miscellaneous equipment loads (not, for example, electricity used to run chillers since the cooling demand may be satisfied by a combination of heat-and electricity-driven chillers).

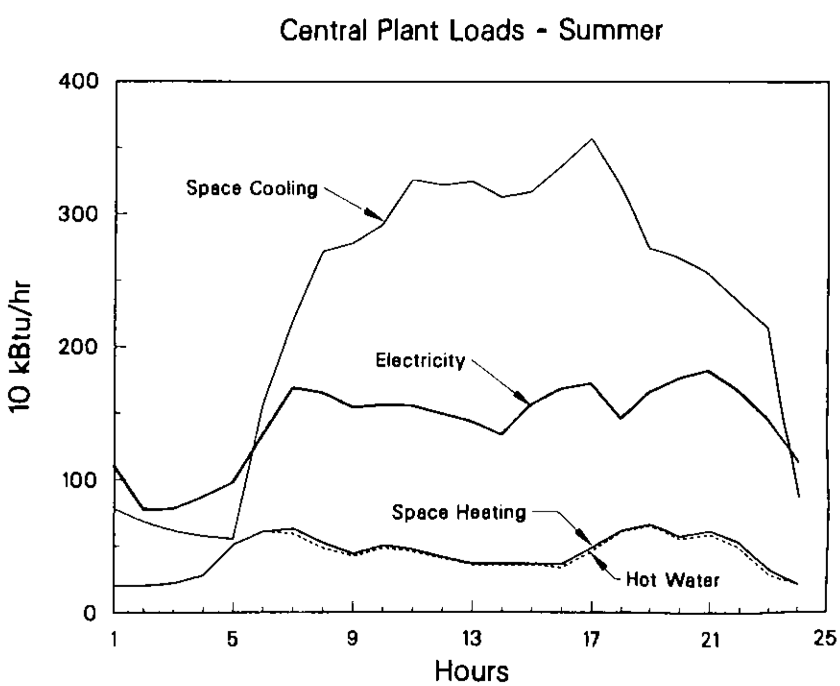

Figure 3 A typical summer day hourly load profile for the four primary end uses of the hypothetical hotel. These end-use demands constitute the loads that must be satisfied by the various conventional and cogeneration plant configurations. See comment on Figure 4 regarding interpretation of electricity load.

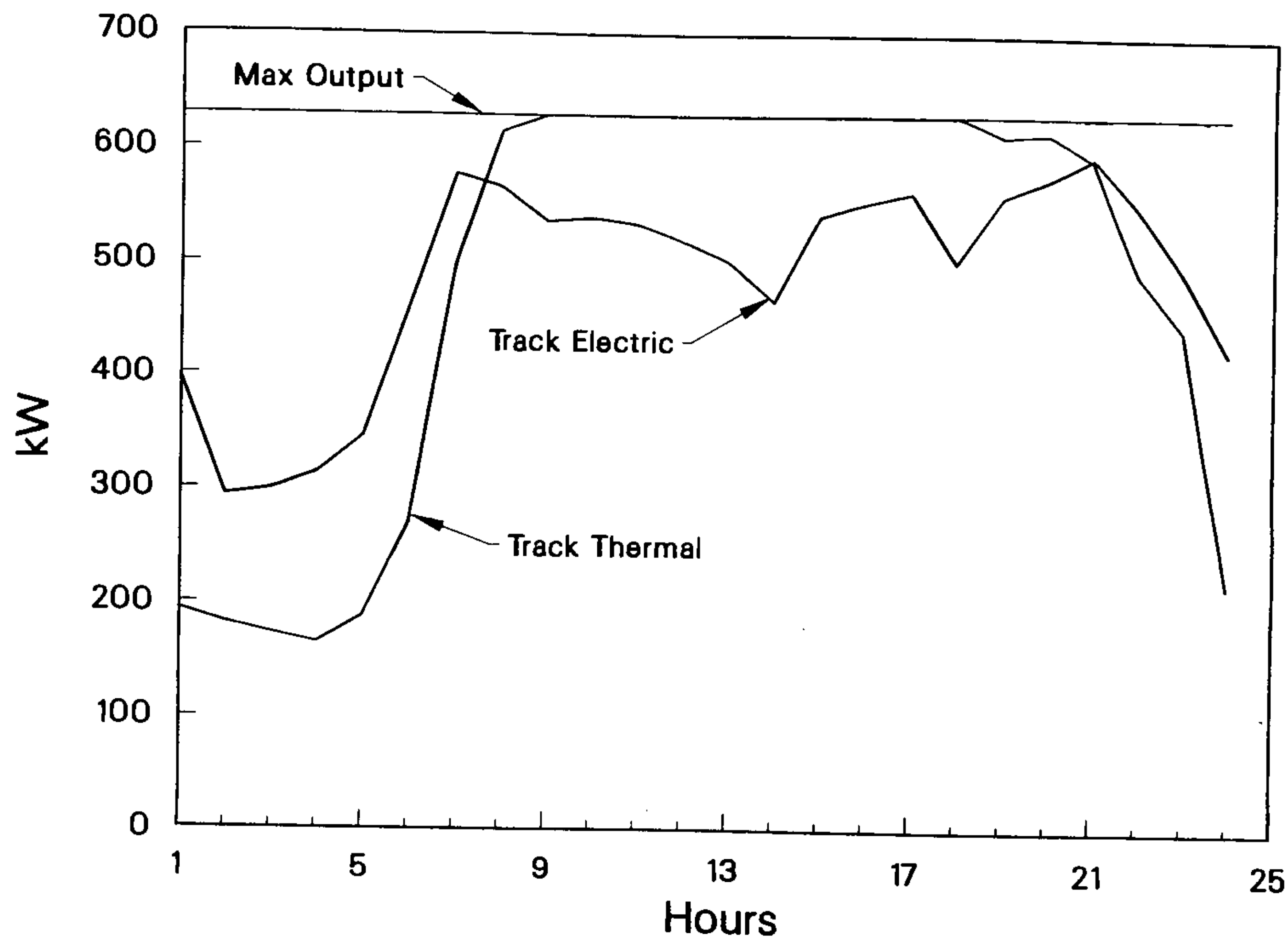

Figure 4 Comparison of hourly electrical loads on the 600 kW cogeneration plant resulting form different operating strategies. The loads being satisfied are those for the typical summer day depicted in Figure 3. In the early morning, electrical output from the thermal tracking mode of operation is less than the building electrical demands and so electricity must be purchased from the utility. Later in the day the electrical output from this mode exceeds the building's electrical demands and the excess is sold to the utility.

Discussion

J. KUTYLOWSKI, Moylan Engineering Associates, Dearborn, MI: Have you used the Cheng cycle for any building simulation? What are your feelings about using this cycle for cogeneration systems?

J.H. ETO: The Cheng cycle is a unique and very interesting variation of a combined-cycle prime mover. To date, I have not had the opportunity to study such systems with the DOE-2 program. Given the program's capability to accept performance specification exogenously from the user, the program should be able to model the performance of cogeneration systems employing the Cheng cycle.

S. BALAKRISHNAN, Synergic Resources Corporation, Bala Cynwyd, PA: Does the installed cost of the system change for the different operating modes? (The cost of controls for an electric tracking system could be greater than that for constant operation.) Is this difference significant?

ETO: The cost of controls for the hypothetical cogeneration systems examined in the paper are included in the fixed-cost component of the systems, but they are not identified explicitly. These costs would no doubt vary, depending on the type of control strategy employed. The principal value of a simulation-based study using DOE-2 is to assess the cost-effectiveness of these and other control strategies through a rigorous evaluation of their expected thermodynamic performance and a consistent treatment of the resulting utility cost changes. The capital cost assumptions must be developed independently.

D. PEDREYRA, Energy Systems Engineers, Aurora, CO: Did you use the mainframe or PC version of DOE 2.1C?

ETO: The mainframe version of DOE-2.1C was used in this study. It is my understanding that a PC implementation of version 2.1C is commercially available.

J. PHILLIPS, Lone Star Gas Co., Dallas, TX: When tracking electrically, was thermal storage considered?

ETO: Integrating cogeneration with thermal storage may prove to be a most attractive and certainly complementary application of these two technologies. Although DOE-2 can model both these systems and their interactions, the goal of the current study was to highlight DOE-2's cogeneration modeling capabilities in isolation. Accordingly, thermal storage was not considered.

K.V. VARTEVAN, Palmer Mechanical, Tulsa, OK: What was the percent kW allowance by the utility company in order to qualify for lower fuel rate?

ETO: The only prerequisite for obtaining the lower natural gas rate for cogeneration is certification from the Federal Energy Regulatory Commission (FERC) as a "Qualifying Facility." According to the FERC rules, there is no size limit for cogeneration facilities.