USE OF TIME-AGGREGATED DATA IN ECONOMIC SCREENING ANALYSES OF COMBINED HEAT AND POWER SYSTEMS

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ABSTRACT

Combined heat and power (CHP) projects (also known as cogeneration projects) usually undergo a series of assessments and viability checks before any commitment is made. A screening analysis, with electrical and thermal loads characterized on an annual basis, may be performed initially to quickly determine the economic viability of the proposed project. Screening analyses using time-aggregated data do not reflect several critical cost influences, however. Seasonal and diurnal variations in electrical and thermal loads, as well as time-of-use utility pricing structures, can have a dramatic impact on the economics. A more accurate economic assessment requires additional detailed data on electrical and thermal demand (e.g., hourly load data), which may not be readily available for the specific facility under study. Recent developments in CHP evaluation tools, however, can generate the needed hourly data through the use of historical data libraries and building simulation.

This article utilizes model-generated hourly load data for four potential CHP applications and compares the calculated cost savings of a

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CHP system when evaluated on a time-aggregated (i.e., annual) basis to the savings when evaluated on an hour-by-hour basis. It is observed that the simple, aggregated analysis forecasts much greater savings (i.e., greater economic viability) than the more detailed hourly analysis. The findings confirm that the simpler tool produces results with a much more optimistic outlook, which, if taken by itself, might lead to erroneous project decisions. The more rigorous approach, being more reflective of actual requirements and conditions, presents a more accurate economic comparison of the alternatives, which, in turn, leads to better decision risk management.

INTRODUCTION

Combined heat and power (CHP) projects (also known as cogeneration projects) usually undergo a series of assessments and viability checks before any commitment is made. A screening analysis may be performed initially to quickly determine the economic viability of the proposed project. If promising results are obtained from the initial screening, the project is subjected to evaluations of greater rigor and detail. The economic evaluation seeks to determine the degree of cost savings, if any, from using a CHP system to provide electricity and thermal resources (e.g., heating and cooling) when compared to a default or baseline condition (e.g., grid electricity and on-site boiler heat).

A simple economic screening may characterize the electrical and thermal loads on an annual (or other time-aggregated) basis. In this situation, the assumed available thermal energy of the CHP system is based on the annual average electrical power demand and the average power/heat ratio for the CHP system being evaluated. Similarly, the baseline annual electricity cost is determined as the product of the average cost per kilowatt-hour and the annual electrical demand. Simple screening analyses do not reflect several critical cost influences, however. Seasonal and diurnal variations in electrical and thermal loads can present load situations that cannot be reasonably met by a given CHP system. In addition, utility pricing structures may be based on seasonal and time-of-use tariffs, which will impact costs based on when the energy is used. A more accurate economic assessment requires an evaluation of the specific load patterns for electrical and thermal energy consumption. Unfortunately, this requires additional detailed data on electrical and thermal demand (e.g., hourly load data), which, although preferable, may not be readily available for the specific facility under study. Recent developments in CHP evaluation tools, however, can generate the needed hourly data through the use of historical data libraries and building simulation. Such simulation output can be used in place of actual hourly data, if it is not available, and can be further calibrated by scaling the simulation output to reproduce the actual facility's typical annual energy usage levels.

A recently released CHP simulation tool [1] can simulate the operation of 15 different building types in 233 distinct locations. The software package uses the DOE-2 building simulation engine [2] coupled with typical meteorological year (TMY) weather data files [3] to produce a custom simulation of a particular structure in a specific location. The software can also produce a data file containing the hourly load data for electrical, heating, and cooling demands for the building for an entire year. For this study, the software was used to generate hourly loads for four candidate applications for CHP in the Chicago area. The applications and relevant parameters are provided in Figure 1.

This article will focus on the operations-related cost elements of supplying energy to highlight the potential pitfalls in using time-aggregated analyses. A complete economic assessment of alternatives (e.g., life-cycle cost or net present value) would include the up-front capital cost of CHP equipment and any other fixed cost, in addition to the elements addressed here.

THE ANNUAL MODEL

Time-aggregated models simplify the data collection and computation process and are commonly found in initial screening tools [4] and analytic modeling [5]. For this study, data will be aggregated to an annual basis, such that electrical and thermal loads will be the total cumulative load over an entire year.

For the baseline (non-CHP) case, it is assumed that cooling requirements are met by electrically driven chillers. Electrical cooling loads were determined by dividing the cooling load expressed on a thermal, end-use basis by the average system coefficient of performance (COP). The total annual electricity consumption is determined

Figure 1. CHP Application Details

Office – High-rise; 9-story (plus basement) window-wall construction with 75 % wall glazing. 269,361 square foot floor area. Building construction materials are: walls – 1-inch stone + 3-inch R-10 insulation; windows - double-pane tinted; roof – 4-inch concrete + 5.5-inch R-17 insulation, dark roof color; general occupancy – 5 days per week.

Retail Store – 1-story slab on grade construction typical of a larger department store with 10% wall glazing. 60,030 square foot floor area. Building construction materials are: walls – 4-inch brick + 2.5-inch R-7.5 insulation; windows - double-pane tinted; roof - plywood + 6-inch R-19 insulation, dark roof color; general occupancy – 7 days per week.

Hospital – 5-story building with three independently controlled zone types (surgical suites, patient rooms, administration and services). Building wall glazing is 15 %. 500,400 square feet floor area. Building construction materials are: walls – 4-inch brick + 4-inch concrete + 3 inch R-10 insulation; windows - Double-pane tinted; roof – 2-inch concrete + 5-inch R-15 insulation, dark roof color; general occupancy – 7 days per week.

Hotel – 6-story building with 40 % wall glazing. Lobby and meeting rooms on first floor. Guest rooms on upper floors. 210,012 square feet of guest rooms. Building construction materials are: walls – 10-inch concrete + 3-inch R-10 insulation; windows - double-pane tinted; roof – 6-inch concrete + 5.5-inch R-17 insulation, dark roof color; general occupancy – 7 days per week.

as the sum of the hourly non-cooling loads plus the hourly cooling loads (expressed on an electrical basis). The annual cost for electricity is the product of the total electrical consumption times the average unit cost of electricity, expressed on a per unit energy basis (e.g., $/kWh). For the annual model, we use a single energy-related cost parameter for the unit cost of electricity, even though actual utility tariffs generally have both capacity demand (i.e., kW) and energy demand (i.e., kWh) components. Because the capacity demand component is typically determined on a "maximum use within the period" basis (where the period may be as small as an hour), demand charges may not be amenable for explicit inclusion when evaluating costs on a time-aggregated basis. However, to prevent the biasing of this study on the basis of the treatment of the benchmark utility costs, the average unit energy cost for electricity (i.e., \$/kWh) was determined from the annual electricity cost under the full hourly tariff model (including both capacity and energy costs) divided by the total annual electrical energy demand. This is similar in approach to the method used by the U.S. DOE Energy Information Administration to consistently report the cost of electricity across the 50 states and a multitude of tariff structures [6].

Heating requirements in the benchmark case are provided by natural-gas-fired boilers with an assumed fuel efficiency of 80 percent. The annual cost of heating is the product of the total fuel energy demand times the unit cost of natural gas, assumed in this study to be \$5/MMBtu.

For the CHP case, it is assumed that cooling will be provided by thermally-driven absorption chillers. Relative to the benchmark case, this will reduce electrical demand and increase thermal demand (i.e., now heating plus cooling demand). In a CHP system, there is a relationship between the amount of electricity produced and the available thermal energy, which can be characterized by the power to heat (p/h) ratio. Although the p/h ratio will vary somewhat with output levels of the prime mover, for this study, it is assumed to be a constant ratio of 0.7. Thus, for every kilowatt of electricity produced, there are 1.43 kilowatts of useful thermal energy assumed to be available. In the annual model, the total thermal energy available is based on the assumption that all the non-cooling electrical demand is met by the CHP system.

On an annual basis, if the ratio of total electrical demand to total thermal demand (including thermally-driven cooling) is greater than or equal to the system p/h ratio, then theoretically, a CHP system, sized for electrical demand, will be able to provide the needed thermal demand as well. If the ratio of total electrical demand to total thermal demand (including thermally-driven cooling) is less than the system p/h ratio, then the CHP system will not generate sufficient thermal output to satisfy all the thermal demand. In this situation, additional thermal energy must be provided by a supplemental heat source, such as a gas-fired boiler.

The demands and power to heat ratios for the four applications in this study are given in Table 1. As shown, the demand p/h ratio in all but the office application is less than 0.7, which therefore requires some supplemental thermal energy. It should be noted that the thermal demands in the first two columns of Table 1 are end-use requirements. The total thermal required in Table 1 is with respect to the CHP system and differs from the sum of the end-use requirements by the additional thermal energy needed for operation of the absorption chiller system (at an efficiency of 0.7).

The resulting costs for the benchmark and CHP systems under the annual model are given in Table 2. The electrical efficiency of the CHP system is assumed to be 30 percent, on a higher heating value (HHV) basis*. The CHP system cost includes a non-fuel operating and maintenance (O&M) cost of $0.01/kWh. As will be explained in the next section, the CHP cost in Table 2 also includes a utility standby charge for having the utility system available to provide energy in case the CHP is unavailable.

THE HOURLY MODEL

To assess the potential savings for a CHP system on an hourly basis, a spreadsheet model was developed that used as input the 8,760 hourly thermal and electrical demand requirements for the particular application obtained from the building simulation model [1]. As described in the previous section, the cost of utility-supplied electricity in the annual model is based on a time-aggregated average per unit energy value. In this model, however, we reflect the pricing structure of an electric utility tariff, in this case from the Commonwealth Edison Company in Chicago. The tariff structure is provided in Figure 2. As shown, prices for electricity vary on both a seasonal and diurnal basis. In addition, there is an additional standby charge if the customer has a CHP system. Heating cost is based, as in the annual model, on heating demand, a boiler efficiency of 0.8, and a unit gas cost of $5/MMBtu. The CHP system electrical efficiency (HHV) and non-fuel O&M cost are 0.3 and $0.01/kWh, respectively.

The operation of the CHP system is the most interesting and challenging part of the hourly model. In this study, the CHP system is assumed to be thermal following. That is, the hourly operating level of the CHP prime mover is determined by the thermal demand of the application – with one restriction: the system can not sell electricity back to the grid (i.e., reverse flow across the utility meter is either not permitted or is assumed to be of little monetary value). Thus, the system is thermal

*System efficiencies may be affected by ambient temperature, particularly for turbine systems. This effect is not included in this study.

Table 1. Electrical and Thermal Demands

Application	*Heating demand (GWh)*	*Cooling demand (GWh)*	*Non-cool electrical demand (GWh)*	*Total thermal required (GWh)*	*Demand power/heat ratio*	*Supplemental thermal required (GWh)*
Office	1.040	2.612	3.537	4.772	0.74	0.0
Retail store	0.903	0.648	1.075	1.828	0.59	0.293
Hospital	10.945	6.364	10.819	20.036	0.54	4.580
Hotel	4.927	3.362	4.049	9.730	0.42	3.946

Table 2. Annual Model Cost Results

Application	*Benchmark (non-CHP system)*				*CHP system*		
	Unit electricity price ($/kWh)	*Electric cost*	*Gas cost*	*Total cost*	*CHP cost*	*Supple-mental gas cost*	*Total cost*
Office	$0.101	$418,512	$22,185	$440,697	$251,021	$0	$251,021
Retail store	$0.075	$95,057	$19,263	$114,321	$76,274	$6,250	$82,523
Hospital	$0.063	$785,847	$233,459	$1,019,305	$767,909	$97,687	$865,596
Hotel	$0.070	$338,764	$105,091	$443,854	$287,364	$84,176	$371,540

Figure 2. Electric Utility Tariff

Non-CHP System
Demand (capacity) charge*—$16.41/kW/mo (June–Sept) $12.85/kW/mo (Oct – May)
Energy charge—$0.05022/kWh (9 a.m. – 10 p.m. M-F) $0.02123/kWh (all other times)

CHP System
Demand (capacity) charge—$15.16/kW/mo (June–Sept) $13.41/kW/mo (Oct – May)
Energy charge—$0.05022/kWh (9 a.m.-10 p.m. M-F) $0.02123/kWh (all other times)
Standby charge—$2.99/kW/month charged at electrical capacity of CHP unit

* Charged at the highest hourly capacity occurring in each month.

following to the extent that the hourly electrical production will not exceed the hourly demand*. The resulting available thermal energy from the CHP prime mover is then applied to the heating and cooling loads for that hour. Any shortfall of either heat or cooling is made up by supplemental boiler heat or electrically driven chillers.

With operation and cost of the CHP system now being determined on an hourly basis, two additional considerations that are not addressed in the annual model come into play. First, the cost of operating the CHP system in a given hour may be more expensive than the purchase of energy from the utility system. This is particularly likely during "off-peak" hours, when the energy charge for grid-based electricity is low. In such situations, it is more economic to not run the CHP system. In this study, we find that the CHP system typically does not run during the night hours when the "off-peak" tariff electric energy price is less than half the "on-peak" price.

A second important consideration is when the building demand is lower than the minimum desired operating level of the CHP system. As CHP prime mover efficiencies are degraded at low output levels, there is generally a minimum operating point at which the system is not oper-

*Electrical following was also evaluated with little difference in results.

ated. Energy is purchased from the grid when the demand goes below that level. In this study, it is assumed that the minimum operating point is 50% of rated capacity. Below that point, thermal and electrical energy is provided by the benchmark systems (i.e., boiler and grid). Thus, in the hourly model, the CHP system may not operate for a particular hour because of either low demand or relatively higher cost as compared with the benchmark case.

In addition, because thermal and electrical demands are not constant, there are many times when the CHP system can not supply the entire thermal and/or electrical demand for a given hour. As a result, supplemental energy is required. From the above limitations, it appears that there might be an optimum capacity level of the CHP system, which balances unserved demand resulting from insufficient capacity as well as minimal loads not served because of operating limitations. The existence of such an optimum point has been investigated in a previous study by Czackorski and Ryan [7].

In this study, the capacity of the CHP prime mover was evaluated between zero and the largest theoretical hourly load that could be supplied by the CHP system within the constraint of no electricity export. For each candidate prime mover size, the hourly operation of the system was calculated over the 8,760 hour period, and the resulting annual savings (if any) relative to the benchmark case was determined. To more quickly find the point of maximum savings (i.e., the optimum CHP system size), a generalized reduced gradient nonlinear optimization method was employed. The optimization approach used the GRG2 optimization code developed by Lasdon and Waren [8], as contained in Microsoft Excel. The resulting optimum capacity of the prime mover and the resulting electrical energy production is given in Table 3.

Table 3. Results of Capacity Optimization

Application	*Maximum annual non-cooling demand (kW)*	*Optimum CHP prime mover capacity (kW)*	*Annual CHP electrical generation (GWh)*
Office	1183	81	0.2
Retail store	178	7	0.02
Hospital	1588	396	1.40
Hotel	783	174	0.59

As shown in Table 3, the optimum capacity size of the CHP prime mover is considerably less than the maximum hour non-cooling demand for the year. Similarly, the amount of electrical energy provided at this optimum size, shown in Table 3, can be compared with the annual non-cooling electrical energy demand shown in Table 1 to observe that, at the economic optimum, the CHP system provides only a fraction of the non-cooling electrical energy demanded. This is a key difference between the annual and hourly models and is the result of the interplay between the magnitude and timing of the individual thermal and electrical hourly loads and the CHP system operational constraints.

The annual costs of the benchmark and CHP system under the hourly model are provided in Table 4.

COMPARISON OF THE MODEL RESULTS

We now examine the savings produced by CHP systems for the four applications developed in the two models. Table 5 presents the cost savings based upon the differences of benchmark and CHP system costs reported in Tables 2 and 4. The differences are more clearly seen in Figure 3.

As shown above, the annual model forecasts savings that are much greater than those determined in the hourly model. This is the result of the inherent assumption in the annual model that all the non-cooling electrical demand is satisfied by the CHP system. The annual model also assumes that all available thermal energy, as defined by the system power to heat ratio, is applied to satisfy the thermal demands of the application. We have shown in the previous section that not all electrical and thermal demands can always be met by a CHP system, owing to the variation in timing and magnitudes of these loads when considered on an hourly basis. Although finer levels of aggregation could be made (e.g., seasonal or monthly) in a time-aggregate approach, similar deficiencies will exist when conditions (e.g., tariff rates and/or loads) are changing at a faster rate than the aggregation level.

One should not conclude that time-aggregated models are strictly inappropriate, however. Such models have the benefit of requiring much less data and fewer computations. As mentioned earlier, potential projects are subjected to increasingly stringent evaluations. The time-aggregated model can serve as a quick screen to eliminate projects with clear economic disadvantage. Note from Figure 3 that the progression of

Table 4. Hourly Model Cost Results

	Benchmark (non-CHP system)			CHP system			
Application	*Electricity*	*Gas*	*Total*	*CHP operation*	*Grid electricity*	*Supple. gas*	*Total*
Office	$418,512	$22,185	$440,697	$12,059	$396,581	$18,286	$426,926
Retail store	$95,057	$19,263	$114,321	$1,201	$92,843	$18,887	$112,931
Hospital	$785,847	$233,459	$1,019,305	$93,541	$702,879	$192,731	$989,150
Hotel	$338,764	$105,091	$443,854	$39,561	$290,823	$91,206	$421,591

Table 5. Annual Cost Savings of CHP System

Application	*Annual Model*	*Hourly Model*
Office	$189,676	$13,771
Retail store	$31,797	$1,389
Hospital	$153,710	$30,155
Hotel	$72,314	$22,264

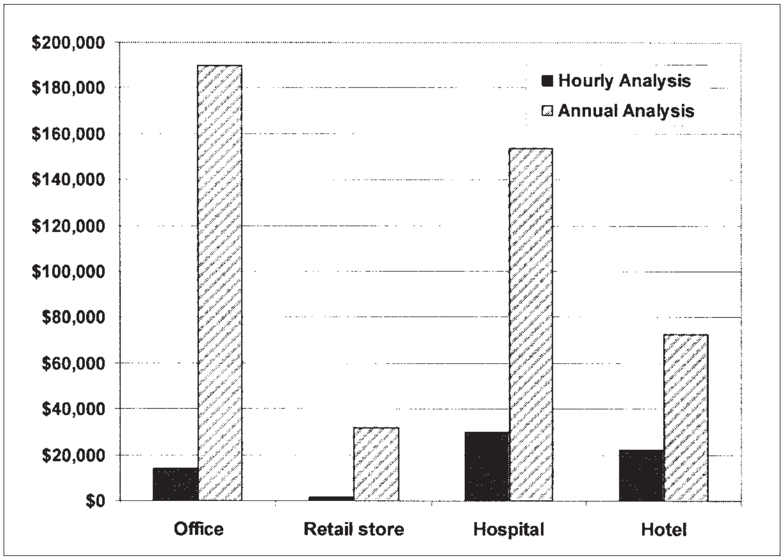

Figure 3. Annual CHP Savings

calculated savings from the annual to hourly model is increasingly conservative (i.e., savings projections become smaller for the more detailed model). Thus, if a potential project can pass the first (annual) screening, the additional efforts required for a more stringent model (hourly) may better define the likely economic viability and avoid erroneous decisions that could be made by relying on time-aggregated data alone.

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