THE VALUE OF METERED DATA IN CHP DESIGN

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ABSTRACT

The key to a successful combined heat and power (CHP) system is proper sizing through identification of serviceable thermal loads. While countless stories of CHP failures point to improper initial design as the root cause, simple and effective methods to avoid this trap are too often ignored. The authors will review a case study that illustrates the value of metered data in CHP design. The authors have collected flow and temperature data at a large hospital in order to evaluate the potential heating demand that could be offset by a reciprocating CHP system with hot water heat recovery. The example shows that some CHP design approaches can lead to recommendation of a CHP system that is not economically advantageous for participants or efficiency programs. Targeted data collection can provide invaluable insight into actual thermal demands that can be offset, which in turn can guide proper sizing of systems for maximum annual operating efficiency and cost savings through full utilization of thermal waste heat.

The authors will present the case study, based on metered temperature and flow data collected with an ultrasonic flow meter from multiple locations within the facility. Details of the data collection approach and execution will be covered. The authors will also present common mistakes made in CHP analysis, and how those common errors can impact the end result if they are not found. In addition to information from numerous commissioning exercises conducted by the authors, it is expected that the hospital project that is the subject of the metering exercise will be nearing completion at the time of the conference, and the authors will present the results of the final installation.

INTRODUCTION

Distributed CHP systems installed by commercial and industrial end users have received increasing support from state and federal policies due to the potential for net efficiency improvements and energy cost reductions. A 2012 White House executive order specifically promotes CHP and energy efficiency in industrial facilities with the goal of installing 40 gigawatts of new, cost-effective CHP by the end of 2020 (1). In support of this goal, the executive order specifically directs government agencies such as the Department of Energy, Agriculture, and the Environmental Protection Agency to coordinate policies that encourage investment in support of industrial energy efficiency and CHP. By reducing energy costs through the use of efficiency and CHP, there is potential to reduce operating costs for commercial and industrial customers, thereby increasing national competitiveness and increasing grid resiliency.

The Department of Energy maintains a CHP project database that tracks CHP systems installed at industrial and commercial locations (2). Data from this source, shown in Figure 1, illustrates that the average capacity of CHP systems installed has been dramatically reduced since 2005.

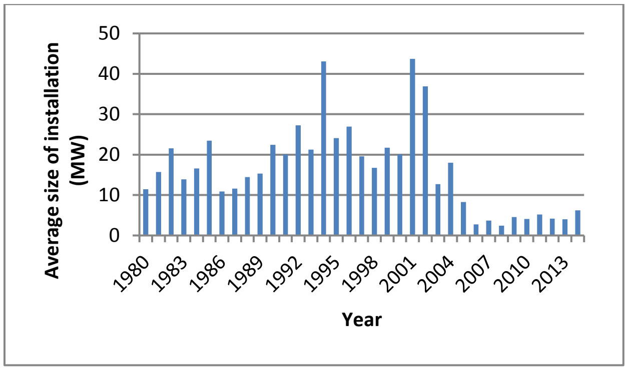

Figure 1. Average capacity of installed units, 1980–2015

The 2005 break toward smaller-scale CHP systems is believed to be attributed to a number of factors including revisions to the Public Utility Regulatory Policies Act (PURPA) of 1978, which created favorable regulations and economic conditions for CHP installations; the continued deregulation of utilities; and the high and volatile gas prices due to natural disasters and economic uncertainty (3). Distributed generation resources are also increasing in popularity with facility owners for many reasons, including energy cost savings, resiliency, greenhouse gas emissions reductions, and state support of growth for behind-the-meter installations (4).

Additionally, CHP technology has become widely supported with incentives through energy efficiency programs. The Department of Energy's (DOE's) CHP Policies and incentives database (dCHPP) currently lists 167 state and federal rebate, incentive, grant, loan, and tax benefit programs (5).

Nearly all efficiency incentive programs require that projects pass a cost-effectiveness or total resource cost test. These tests are intended to ensure that incentive funds are utilized on projects that result in positive returns for the ratepayers that fund the programs. Maximizing system operating efficiencies by sizing CHP systems for serviceable facility thermal loads also maximizes cost-effectiveness and coincides with efficiency program goals.

THERMAL LOAD FOLLOWING MAXIMIZES OPERATING EFFICIENCY AND COST-EFFECTIVENESS

Designing CHP systems to match facility thermal loads maximizes the operating efficiency, and cost-effectiveness, of those systems. Matching the CHP system's thermal output to the targeted serviceable facility thermal demands maximizes the size of the system while limiting thermal dumping or efficiency losses. Larger systems are desirable because they have the potential to generate more energy and offset more fuel for larger cost savings. However, when thermal dumping is required, energy and cost savings are diminished and overall system efficiency reduced, offsetting the benefits of oversized systems. While some building owners may see economic advantages to maximizing power generation on-site due to exceptionally high electric rates, in the long term, thermally base loaded systems will present the most cost-effective, efficient, and least-risk options for owners and incentive program rate payers.

In many cases, thermal loads can be harder to quantitatively measure than electrical loads. Equipment for measuring electrical loads is easily available and often included in building control system design, allowing for easy trending. Thermal loads, on the other hand, most often relate to the flow and temperature of hot water. While temperatures are easily metered and sometimes tracked by building energy management systems (EMSs), direct flow measurement is less common and is usually tracked through a proxy variable such as the system pump operating speed. This introduces uncertainty into the measurement because the flow through a pump cannot be exactly determined but only estimated based on pump design. Actual flows tend to vary due to specific system operating pressures and head.

CASE STUDY: 500,000 FT^2 HOSPITAL

The case study project was reviewed as part of a contract with a local energy efficiency program. Initially, a program-funded scoping audit conducted by the authors recommended that the facility investigate CHP systems as an opportunity for cost savings, resiliency, and efficiency. The applicant then applied for financial support to evaluate the CHP opportunity and received funding to hire a local engineering firm to conduct a study. The resulting study demonstrated some common errors in the approach to CHP design. The following discusses the case study of the facility and summarizes lessons learned in the review.

Facility Description

The facility in question is located in northern New England and was constructed in sections over many years. This resulted in a building with many different zones of air conditioning and water heating. The central boiler plant is composed of three medium-pressure steam boilers operating at 105 psi. Steam is distributed throughout the facility to produce hot water through heat exchangers, which is used for both domestic and heating end uses. Space heating is provided by heating coils in the air handling units served by a combination of steam and hot water along with perimeter hot water baseboard. The facility also has sanitation and laundry equipment.

The facility has significant summer reheat loads for dehumidification, as demonstrated by a significant summer fuel consumption. The facility fuel consumption is shown in Figure 2.

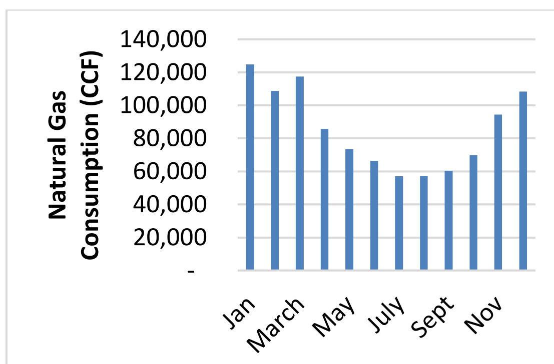

Figure 2. Facility Monthly Fuel Consumption

All of these factors combine to produce a facility with thermal loads that are difficult to quantify and serve with a CHP system.

The Technical Study Results

Initially, the engineering firm recommended a modular micro-turbine solution with a heat recovery steam generator utilizing an after burner. The system was specified at 1,200 kW and was sized to provide all facility steam requirements. The existing boiler plant would then remain as a backup. A review of this proposed system revealed that the annual thermal efficiency did not meet the program's requirement of 60%. Additionally, the proposed system was predicted to result in a large increase in natural gas consumption, which neither met program requirements or the participant return on investment (ROI) requirements. A large part of this was due to inherent inefficiencies of microturbines making medium-pressure steam. Some microturbines utilize heat recovery that reduces exhaust temperatures, reducing their ability to make steam under any pressure. This was further compounded in the initial submission by an error in the fuel consumption algorithm.

The initial submission for the modular microturbine solution utilized electric load data that was estimated using a Trane TRACE model and calibrated to monthly consumption. While this is not an entirely wrong approach, a much better approach is to request utility-recorded interval data, which is commonly available in 15 minute or hourly form. This allows the accurate determination of electric loading on the system and electric cost benefits. Figure 3 shows a sample of the modeled electric loading versus the actual utility interval data acquired by the reviewer.

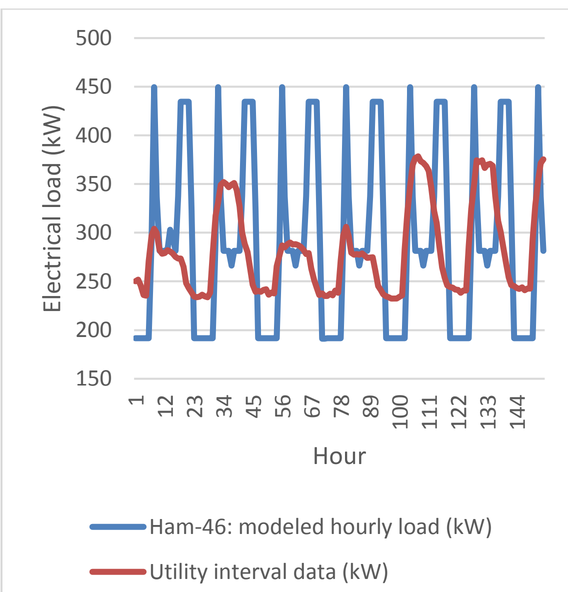

Figure 3. Sample of Modeled vs. Actual Electric Consumption

Note that while the modeled data averages on an annual basis the same as the actual interval data, the actual profile varies quite substantially.

The original analysis submitted also utilized LHV system specifications, which underestimates the fuel consumption of the proposed system. HHV specifications need to be used to accurately reflect fuel consumption and the ROI for the proposed system. CHP manufacturers generally express system performance and rated fuel consumption in terms of LHV. When not specified, the reviewer should always inquire with the manufacturer to understand whether the rated specifications are in terms of LHV or HHV. A common rule of thumb for converting LHV fuel input to HHV fuel input is to multiply by 1.1 (6).

The submitted analysis utilized a blended electric rate to calculate the annual electric generation cost benefits. This overestimates the electric cost benefits for several reasons; for example, total bills include service charges that are not reduced by CHP energy generation, and required system maintenance will reduce the actual demand benefits achieved in most cases. Figure 4 shows the generated electric cost benefits calculated using a blended electric rate compared against the electric cost benefits that were calculated by assuming maintenance will be performed every 1,500 hours or every other month, preventing demand charge offset for that month.

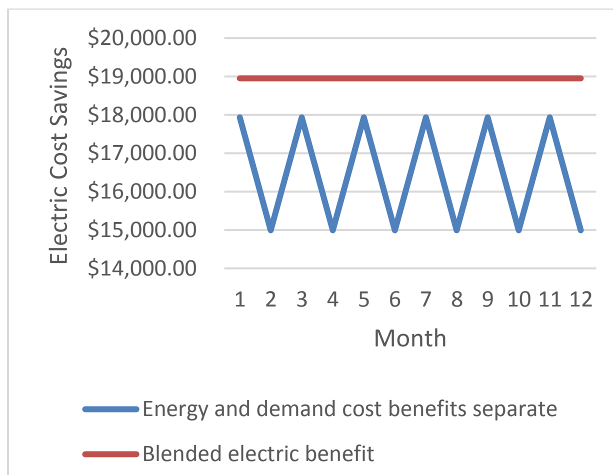

Figure 4. Blended vs. Individually Calculated Electric Benefits for Energy and Demand

Case Study Resolution

The customer, engineering firm, and reviewer conducted a meeting and agreed to investigate a hot water heat recovery solution. To this end, the reviewer volunteered to collect some data on thermal loading at a specific steam to hot water heat exchanger located in a mechanical room deemed most suitable for CHP in terms of proximity to electric interconnection and natural gas lines. A domestic hot water (DHW) heat exchanger close to the boiler was also metered. This was done by collecting a sample of flow data with an ultrasonic flow meter, and metering the heat exchanger supply and return temperatures and the amperage of the variable speed hot water pump serving the heat exchangers. Pump amperage was then correlated with metered flow data for analysis. Ultimately, the reviewer decided to deploy the ultrasonic flow meter for a full week on the smaller DHW heat exchanger because this system did not have a dedicated pump that could be metered. In addition, supply and return temperature data was also collected on the DHW heat exchanger. The metered results showed that the DHW heat exchanger had very little loading with an average of 0.8 therms per hour of load and was likely not a good candidate to connect to the CHP system. Fortunately, the loading on the larger hot water heat exchanger serving heating, and reheat loads was shown to average 13.7 therms per hour. This is significant enough to support a 250 kW system recovering 12.6 therms/hr in hot water with a thermal utilization of 98%.

As result of this analysis, the customer solicited a proposal from a vendor of a micro-turbine system and a reciprocating generator system of comparable sizes. The results for both systems showed high cost-effectiveness and very competitive simple paybacks. The customer has decided to pursue a reciprocating 250 kW CHP system and is currently in the process of implementation.

SUMMARY OF COMMON ERRORS MADE IN THE ANALYSIS OF CHP SYSTEMS

The following subsections introduce each of the common errors identified during the authors' review of the documented case study along with other CHP analyses and proposals by both engineering firms and CHP vendors.

Common Error #1: Sizing System Based on Monthly Utility Bills

Not all thermal loads can be served by a CHP system, so facility managers, owners, and engineers should use care to determine what loads can practically be served by the thermal output from a CHP system in project siting. Whenever possible, metered data should be collected to verify actual thermal loading through the use of direct measurement tools such as an ultrasonic flow meter. Facility managers and owners should carefully consider thermal end uses and possible CHP siting locations before investing in an analysis of a proposed system. There is motivation for CHP vendors to specify larger systems because they can make greater profit. They may try to sell this based on greater reductions in utility costs, but net increases in fuel consumption is a critical component of any CHP project's estimated return on investment. Customers should base decisions on overall system performance and project economics.

Common Error #2: Using Modeled Electric Data to Estimate Facility Electric Loads

There is no substitute for utility-collected hourly interval data, which should always be used to determine the electric loading at the facility and accurately quantify the magnitude of the "behind the meter" electric load that can be served by the CHP unit. In cases where CHP installations are intended to export energy back to the grid, caution should be exercised to ensure that "net metering" rules are clearly understood and correctly applied when predicting the economic impact of the installation. These rules vary between jurisdictions but typically only apply to the energy component of the electric costs. The importance of separately accounting for the energy and capacity components of the electric bill are discussed under Common Error #4.

Also, incentive programs usually have a goal to reduce loading on the electric distribution grid and typically do not recognize any benefit resulting from net metering in their determination of project cost effectiveness, which is typically a key metric used to judge eligibility.

Common Error #3: Using Lower Heating Value CHP System Performance Specifications

Another common mistake is the use of lower heating value (LHV) for the CHP input fuel to predict overall fuel consumption and calculate system efficiencies. LHV excludes the energy that is required to vaporize moisture that is produced as a reaction product from combustion. The higher heating value (HHV) includes this latent heat of vaporization, and fuels are usually sold in terms of HHV. For natural gas, the HHV is typically about 10% more than LHV. CHP manufacturers often provide equipment specifications based on LHV, resulting in approximately 10% higher operating efficiencies than if HHV was used. Many vendors will then apply the reported fuel consumption expressed in terms of LHV to directly predict fuel consumption. This practice understates the required fuel consumption and leads to predicted system performance and efficiencies that are better than will actually be achieved.

Equipment performance standards including fuel consumption rates should always be converted to the HHV basis in order to accurately predict the CHP system fuel consumption, overall efficiency, and economic returns.

Common Error #4: Calculating Electric Cost Benefits Using a “Blended” Electric Rate

Another very common mistake when determining the electric cost benefits of CHP systems is the use of “blended” or overall average $/kWh cost for electricity. While this simplifies the analysis greatly, it does not account for the fact that electric bills at sites where CHP units are installed almost always are comprised of separate and distinct components representing consumption and peak capacity requirements. The consumption component is based on the total energy consumed during the billing period and is expressed in kWh. The capacity component is based on the highest rate of consumption that occurs during defined segments of the billing period and is expressed as a peak kW value. These capacity or “demand charges” are most often based on the highest 15-minute average consumption occurring during peak demand periods defined by the utility rate tariff. If a CHP system is down for either scheduled or unanticipated maintenance during the peak demand time periods defined by the tariff, most of the benefits attributed to a reduction in the capacity component of the bill (e.g., peak demand charge) that month will not be attained.

In order to accurately predict the benefits associated with electric output from CHP installations, the reviewer must fully understand the rate structures for the distribution utility and the electric energy supplier and appropriately apply these rates to both the reduced consumption and the anticipated impact on the monthly peak demand for the facility. An accurate prediction of the monthly peak demand impact can be difficult. The derivation of this impact should be based on a model that reflects the anticipated grid-supplied energy purchases with and without the CHP system in place, and accounts for both scheduled and unscheduled downtime for the system. Any steps taken to mitigate the impact of a CHP system downtime on the monthly peak demand should be documented. These might include scheduling of all routine maintenance during off-peak periods, shedding of some facility loads when the CHP system is offline, or the operation of stand-by generation during these events.

Common Error #5: Neglecting Parasitic Loads

Often, CHP vendors neglect to include parasitic loads in their calculations of electric benefits, characterizing these loads as insignificant. In the authors’ review of small CHP incentive applications, parasitic loads vary with the size of the system and are approximately 2 kW for 85 kW systems, and 7 kW for 250 kW systems.

Parasitic loads are typically comprised of a pump to circulate a glycol-water mixture through the heat recovery jacket of the CHP system, and a thermal dump radiator fan. While the heat recovery pump usually operates continuously with the operation of the engine generator, the dump radiator fan will usually only operate during periods that the thermal output of the CHP system is greater than the thermal demands of the facility.

The common errors made in analyzing CHP opportunities discussed above are summarized in Table 1.

Table 1. Common CHP Analysis Errors and Lessons Learned

	Error	Lessons
#1	Oversizing system due to lack of analyzing servable CHP thermal loads	Investigate thermal loading through trending and metering in combination with facility utility bills and knowledge of hot water and heating end uses.
#2	Using modeling or other proxy of facility electric loads	Request utility interval data for analysis of demand and energy benefits.
#3	Use of LHV in determining CHP system fuel consumption	Natural gas is sold in terms of HHV, and CHP system performance should always be expressed in HHV to determine the economic benefits to customers.
#4	Using blended electric rates to calculate economic benefits	Cost benefits of CHP electricity generation should be analyzed in terms of demand and energy separately in order to accurately reflect the true impact on electric bills.
#5	Parasitic pump and fan loads	Parasitic electric loads should be reflected in the overall analysis.

CONCLUSION

In recent years, several evaluations of distributed generation CHP incentive programs have found that a large percentage of the systems were not in operation in as little as six to nine years (4) (7). Both studies found that rigorous up front investigation of system performance and overall utilization is critical for systems to achieve expected lifetimes. One reason for this could be that if thermal energy is not well utilized, the system is entirely dependent on high energy and demand costs to justify the operation of the system. Even under the best conditions, CHP systems typically lead to increased fuel usage for the facility, which results in sensitivity to fuel costs, which can be volatile.

In conclusion, the authors find that the most cost-effective CHP proposals are based on designing the system to serviceable facility thermal demands. This maximizes project cost-effectiveness for incentive applications and in most cases provides the best economic returns for the host sites.

A key benefit of small-scale on-site CHP installations is the opportunity they provide to utilize the thermal energy that is a by-product of electric generation and is generally not utilized at large scale merchant power plants.

Rigorous evaluation of the serviceable thermal loads at the host site, leading to appropriate sizing for the installation, is a key element in the development of cost-effective and environmentally beneficial CHP installations. Designing CHP systems to match facility thermal loads provides the highest annual operating efficiencies and utilization of the system. This reduces risk for system owner operators, and is more likely to lead to a system that achieves its expected useful life.

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