A Software Tool for Modeling Combined Heat and Power Systems

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ABSTRACT

A properly designed software tool can provide a comprehensive simulation of proposed and existing combined heat and power (CHP) plant and system applications under varying rate structures and alternative environmental and other input scenarios.

The software model that we developed provides a fully integrated analysis of central power production plants that are linked to district energy applications using hot water or steam for heating and/or chilled water-cooling and/or refrigeration connected to a network of buildings or other residential, commercial, institutional, or industrial facilities. The program will provide designers, planners, engineers, investors, utilities, and operators with extensive technical, economical, and air emission information about a specific CHP application. The software can also be a valuable tool for community, military, regional, or national planners in defining all aspects of developing, evaluating, and justifying a new CHP project or upgrading an existing thermal system for CHP. Program output may be used to evaluate existing system performance or model the effects of various potential alternative system strategies including upgrades, expansions or conversion of thermal fluids (e.g., steam to hot water).

A major unique feature of the program is its capability to comprehensively analyze a central CHP plant interface application involving electrical power production and associated alternative options, such as thermal storage, for both heating and cooling systems in conjunction with various technical distribution parameters covering *both* the supply and return elements of an extensive piping distribution system. Important features of the software include: the capability to utilize a myriad of fuel and equipment options; determination of air emission impacts that can result from CHP or central energy plant implementation; and the evaluation of extensive economic scenarios including the influence of environmental taxes on a variety of fuel alternatives.

INTRODUCTION

Since the early 1980's the Washington State University Energy Program (formerly Washington State Energy Office) recognized that global well-being is intrinsically linked to energy policy decisions, as determined by health and quality of the environment and economic performance. As a result, it was decided that energy, environmental, and economic measures needed to be integrated into a quantitative model for predicting the impacts of alternative energy decision strategies. To fulfill this objective, a software modeling methodology was developed. During the past ten years, this software has gone through several evolutionary stages. The initial program was designed for DOS-based district energy system analysis applications. The current version of the software is a WINDOWS-based integrated combined heat and power

(CHP), thermal storage, and district energy production and distribution system modeling tool. The development and evolution of the software occurred as the result of extensive support from several sponsors including the New York State Energy Research and Development Authority, Swedish Council for Building Research, Swedish Trade Office, U.S. Air Force, U.S. Army Corps of Engineers, Department of Defense, U.S. Department of Energy, U.S. Navy, Public Works and Government Services Canada (Science Directorate), and Washington State University (developer and coordinator).

The software is a WINDOWS operating system (95/98/NT/2000) computer program that provides a fast and reliable method of modeling combined heat and power plants systems used in conjunction with district heating and cooling (DHC) and thermal storage. The program can effectively model both *proposed* CHP projects (e.g., to assist in assessing the technical and economic feasibility) and *existing* systems (e.g., to evaluate system performance and determine the effect of various alternatives for improving operating performance, system expansion or system modification upgrades).

CHP software allows master planners, utility planners, and engineering and operations personnel to evaluate existing system economic factors, performance, robustness, operation, and emergency response techniques; or to model the effects of various potential alternative strategies, including incorporation of CHP system repairs, system upgrades, system expansions, and operating strategies. The software can also be used to economically plan new system developments and related construction projects. The database is linked to a project map that is developed by using computer aided design (CAD) software. Location of each system user and operational CHP plant and/or associated thermal storage facility in the database is identified on the map. The map also contains a three-dimensional representation of the distribution network. Each node and distribution element depicted on the map is linked to a corresponding record in the project database. The program displays output and produces reports in both text and graphical formats.

The ***program*** provides ease of data manipulation, simplified procedures for performing comparative analyses of multiple scenario alternatives, and the acceptance of simulated hourly consumer plant and load data. Maximum coincident loading on the CHP plant and thermal storage interface, any pipe described in the heating or cooling distribution model, and connected thermal consumers can be determined by a specified scenario analyses for any hourly interval of a model year. Three-dimensional graphical input of physical system components (i.e., plant, piping, and consumers) is provided through AutoCAD. The program utilizes both metric (SI) or inch-pound-second (IPS) units, international currency units, and ASHRAE-compatible temperature bin data. Other features include use of the DOE-2 CHP energy plant simulation engine, ability to insert specific pump and valve curve operating data, graphical diagnostics of plant and system elements, and generation of extensive reports and plots of technical system and economic results of system performance.

CHP MODEL CONCEPT THEORY

The basic concept of a CHP model is to provide a hierarchy to the decision making process. Ideally, a CHP system model should be capable of a range of functions from preliminary technical and economic feasibility through system design, operational planning, and system expansion or renovation. The model should be able to handle multiple design or operational scenarios with a minimum amount of user input (manipulation); and provide quantitative analysis of environmental consequences resulting from burning specific fuels, using various equipment types, and displacing distributive power/heat applications with central district facilities. Finally, the model should be able to be effortlessly adapted to various ownership structures and financing options while maintaining extensive amounts of capital and variable cost data in a library system that is easily user-defined for each scenario alternative.

Because CHP systems are by nature geographical dependent, the model should provide or be easily interfaced with a CAD or GIS program that allows for precise location of all consumer loads, production equipment, and distribution systems components, including, for example, pipes, valves, and pumps.

DISTRICT ENERGY (HEATING & COOLING) and ELECTRICAL POWER PRODUCTION MODULE STRUCTURE

The district energy **and** electrical power production modules are organized to correspond to the general categories of information and function that are required to complete a CHP project analysis: General project description; Consumer heating and cooling loads; Production plants including storage units; Distribution system; Economics; and Library (support data that is used for program computations).

The software is designed for the integration of independently functioning modules, which are associated with common geographical and individual equipment databases for a specific application.

One of the main goals in the software development effort was to create a well-organized, modular structure that facilitates adding features and links to other programs. The modular structure provides a capability for performing a complete analysis of a single application (e.g., heating or cooling) or most common configurations of power, electrical and thermal alternatives. The modular program design structure format functions through the integration of six software programs. These programs communicate with each other by means of specially formatted data files and command line arguments. The programs are as follows:

- AutoCAD--computer aided design program (user furnished)
- HM-CHP--central controlling program
- HEATCALC--distribution network analysis program
- RELCOST—economic analysis program
- DOE-2 Plant Module—central plant, thermal storage and energy cost simulation program

MODEL ORGANIZATIONAL STRUCTURE

To be most effective, the software tool was developed by using a central control program that integrates proven existing independent sub-models or routines (Fig. 1), each having the capability of carrying out a specific task.

Figure 1 - Model and Sub-models Structure

The lowest level in the hierarchical system focuses upon a determination of consumer loads and central plant load profiles. Load information can be either gathered from historical data, e.g., utility bills or metered data if such information is available, or calculated on the basis of local weather data, topography, population, and specific system requirements, such as, building characteristics and use categories, e.g., residential, commercial, industrial, etc. In addition, it is important to simultaneously compile data relative to market analysis, including existing or proposed in-building equipment (type, condition, and age), and the internal distribution system based upon individual consumer load profiles and assumptions of market penetration. It is then possible for the model to simulate a system-wide load profile and calculate hourly system load density (the key to both technical and economic viability for new and expanded applications).

The second sub-model focuses on the design and optimization of the thermal and electrical supply facilities, including heat recovery, chilled water or ice thermal storage, etc. Based upon the calculation of consumer loads, electrical demand, and thermal and electrical load profiles of the area to be served, one or multiple CHP supply facilities must be designated so as to provide the most economical, energy-efficient, and environmentally acceptable option. The CHP plant(s) operate in accordance with a simulated 8760-hour input mode. The CHP plant can be configured with various types of production equipment -- boilers, chillers, cogeneration (engine- and turbine-driven generators), heat recovery equipment, thermal energy storage, and cooling towers. Equipment is specified by type (e.g., gas, oil, biomass, or coal-fired boiler; geothermal; open or hermetic-drive centrifugal chiller; single or multiple-effect or direct-fired absorber; reciprocating or rotary screw compressor; fixed or variable speed pump), and associated operating characteristics. The sub-model is structured in such a way that the user may easily simulate alternative supply equipment and operational strategies, including mixing and matching components and both base load and peaking unit alternatives. In addition, the program utilizes a storage wizard for optimal sizing of chiller equipment. Model operation is based upon standard weather tapes, and fully integrates the use of thermal energy storage (hot water, chilled water, and ice) source(s) with other equipment alternatives. The module also contains the ability to analyze complex energy cost structures such as seasonal, The third sub-model is used to model the thermal distribution network. This sub-model is tied directly to a graphical interface (CAD or GIS system) and has the capability of: generating distribution element lengths; defining location and specification of system pumps and valves; determining all relevant network parameters, e.g., distribution voltage(s), flows, temperatures, and pressures; utilizing flow or pressure gradient to dimension the thermal distribution network based on consumer loads and system losses. By means of the graphical interface, the user can lay out proposed system routes directly on the map and connect consumer loads and CHP facilities at chosen nodes or system regions. Once the system is geographically established, the user may easily make changes in the layout or run various scenarios based upon changes in the number of consumers or location and number of central energy production facilities to find the optimal network structure. This sub-model has two primary functions. The first is detailed planning of the distribution network. The second and more important function is determining the total cost of various support options and the relative impact of electrical and consumer loads and production strategies on the sizing of equipment and the distribution system, and ultimately, the economics of the system.

Both the plant and distribution models are interfaced with libraries of catalogued information regarding equipment options, electrical and fuel rate (including season and time of day) structures, and associated prices.

The final sub-model focuses upon financing and economic analysis. It is necessary in any economic analysis to include all capital investment cost associated with the energy production supply and the distribution system, as well as operation (including equipment performance factors) and maintenance cost. All cost categories provide for escalation over time. The economic sub-model also allows the user to consider the impacts of tax incentives as well as energy and environmental taxes imposed. Also, the model is capable of evaluating various economic parameters, such as cash flow, internal rate of return, and life cycle cost analysis.

Finally, financing the project is considered. Because certain financing options are available dependent upon ownership structure, the model treats financing by public and private entities differently. Public financing will almost always be done through the sale of some form of government-backed bond that usually carries a more attractive interest rate than would be available to the private sector. On the other hand, public entities normally do not pay taxes except for energy and environmental taxes, and rarely can take advantage of any tax incentives. Private entities, on the other hand, can raise capital through stock sales or private placement (equity). Also, private entities may borrow from a commercial bank or they may have the ability to sell bonds. Rates of interest can vary considerably as does expectations for rate of return on equity. Private entities do, however, have the ability to take advantage of tax incentives but must also pay local and federal taxes on income earned. Various depreciation alternatives can be evaluated for both public and private projects. Once again, the ability of the model to allow for iterative runs based on various inflation rates, interest rates, rates of return, depreciation schedules, and taxes and tax benefits that may apply to various equipment and fuel types, allows the user to determine the optional system both technically and economically.

Program output includes graphical analysis of the distribution system and text reports covering: economics; consumer information; aggregated consumer load; peak day profile by month and year; detailed production plant and distribution analysis for both supply and return systems; emissions; annual fuel and electrical use and cost; estimated annual and peak consumer thermal loads; capacity and cost of central energy plant; size and cost of distribution system;

distribution system flow; metered demand and use; system parameters of temperature, pressure, and heat transfer; reductions in air emissions; turn on and off reports for each type of equipment; and **cost per unit of thermal and electrical energy delivered.**

Special Program Features

Special features that are present in the software model include the ability to:

- Evaluate existing systems as to adequacy of capability (e.g., size and capacity) for meeting existing and future requirements.

- Determine system value and realistic operation and maintenance costs for use in negotiations with potential third party suppliers ***or*** to evaluate the performance of existing contractor operated systems.

- Estimate, for billing purposes, the cost of delivered service to each consumer where individual meters are not used.

- Determine if an existing system is capable of handling additional load or, if required, the least cost manner in which the system can be modified to satisfy new requirements; e.g., will the addition of thermal storage satisfy incremental load.

- Evaluate consequences of deregulation and alternative strategies including distributed generation, thermal storage to reduce peak costs, and the impact of various strategies affecting the operating costs to run the central plant.

- Evaluate strategies for cost effectiveness of repair, maintenance, or replacement of existing systems or system components.

- Determine the *optimal strategy* in which to comply with international or national air quality regulations.

- Accept existing maps/graphics from CAD systems.

- Utilize extensive e*ngineering* features that may resolve various problems, such as, expansion, contraction, capacity, flows, loads, rate and load profiles, etc.

- Determine all e*conomic* parameters, such as the ability for estimating the impact of repairs, addition of new segments or major system construction and/or alteration. The software will identify cash flow, rate of return, and life cycle costs for all alternatives.

- Provide for complete evaluation of assets for tax evaluation, or potential sale or privatization of systems.

- Be applicable in all countries in the *World.*

University of Washington Campus Expansion

The University of Washington (UW), located in Seattle, Washington, U.S.A., due to steady and unparalleled growth throughout the 1970s and 1980s, was facing a severe shortage of academic, research, and administrative facilities by the late 1980s. The University at that time occupied a 280-hectare site and served a student, faculty, and staff population of 55,000. The campus consists of 1,219,438 square meters of academic buildings, a research hospital, scientific research facilities, administration buildings, and student housing for approximately 4,000 students. In order to accommodate future growth in the student population, the UW developed a comprehensive plan for the Southwest Campus area, the only remaining undeveloped property available to the UW on its main Seattle campus. The plan was completed in 1990, and called for over 95,000 square meters of new construction to meet UW needs well into the 21st Century. In 1993, the UW entered into a contract with Sverdrup Corporation for the purpose of identifying the best means of supplying utility service to the Southwest Campus. The scope of work for the study included a life cycle cost comparison of three basic alternatives including computer modeling of the existing campus chilled water and steam distribution systems to ensure that any eventual interconnect of the Southwest Campus to the existing central distribution system would not negatively impact the system's integrity and reduce the overall reliability of the system to meet UW requirements. The district energy software package was selected, purchased, and used to model the system

In order to best meet the requirements of the anticipated development in the Southwest Campus, the UW commenced a study to look at three primary methods of supplying utility services. The alternatives included: 1) expansion of the central plant and construction of utility tunnels for service to the Southwest Campus; 2) the establishment of a peaking plant on the Southwest Campus, construction of utility tunnels to serve the area, and connection of the area to the central plant; and 3) the construction of block central plants each of which would serve a cluster of buildings in the Southwest Campus area adjacent to the plant with no connection to the central plant. Alternative 3 would provide for connecting to the central systems for natural gas, and primary and emergency power.

In order to determine which of the alternatives would have the lowest life cycle cost, the initial capital, operation and maintenance costs, replacement costs, total build-out capital costs, and associated (annual) costs over a 50-year economic life were analyzed.

Computer Modeling

Based on the projected loads, conceptual design of each alternative was developed. To develop the conceptual designs, it was necessary to analyze the existing distribution systems to determine what upgrades (if any) would be necessary to handle the increased loads. This analysis was performed using the district energy module in order to provide a fast and reliable means of modeling multiple district heating and cooling systems alternative scenarios. One of the main advantages of the use of the computer simulation software chosen was the ability to interface directly with CAD drawing files. This enables the distribution system to be analyzed without manually inputting the network lengths for each scenario and to easily determine both technical and economic consequences of various design alternatives.

Alternative A follows the UW's traditional practice of serving all campus utilities from a single central plant and utility tunnel distribution network. The design then extends the existing utility tunnel network into the Southwest Campus and interconnects it to the existing utilities. Alternative A also increases the capacity of the main campus distribution system in order to carry the increased flow going to the new Southwest Campus loads.

Alternative B involved the construction of a remote "peaking plant" on the Southwest Campus. Under this approach, the remote plant would supply the seasonal demands of the Southwest Campus that exceed the capacity of the existing power plant and/or capacity of the distribution system. The existing central system would supply normal (off-peak) demands of the new development. Alternative B extends the existing utility tunnel network into the Southwest Campus and interconnects to existing utilities, but it does not add capacity to the existing power plant and does not increase the capacity of existing distribution lines.

Under Alternative C, all necessary power plant equipment for the Southwest Campus development would be located in one of three block central plants, each of which would serve the cluster of buildings adjacent to the plant. Since the Southwest Campus would stand alone, independent from the main campus systems, no existing utility tunnel extensions would be constructed under this approach. The only interconnections would be electrical and communications, which would be accommodated through duct banks, and natural gas, which would be accommodated through direct burial piping.

Results

After approval of the conceptual designs, the study analyzed initial capital cost, operation and maintenance (O&M) costs, replacement costs, total build-out capital cost, and associated (annual) costs over a 50-year economic life for all utility systems. (This includes steam distribution, condensate return, and chilled water supply and return.)

Initial Capital Costs

The remote peaking plant (Alternative B) requires the minimum capital investment of the three alternatives. Its initial capital savings of $2.2 million (in 1993 dollars) when compared to expansion of the existing power plant (Alternative A) result from less demolition, lower distribution piping costs, and the deferral of boiler and chiller capacity. However, future boiler/chiller additions and ongoing operating and maintenance costs overcome any initial savings on a life cycle basis.

The block central plant approach (Alternative C) requires $0.3 million more in initial capital cost (1993 dollars) than expanding the existing power plant (Alternative A). Its additional mechanical/electrical equipment, and the building modifications necessary to accommodate this equipment, offset any potential savings in utilities distribution costs.

Life Cycle Costs

Alternative A achieves the lowest life cycle cost of the alternatives, saving $1.5 million over Alternative B and $5.7 million over Alternative C, during the 50-year economic life of the project, without considering displacement of other program uses by power plant equipment. Life cycle savings result principally from the economies in operation and maintenance personnel. Not only was Alternative C's labor cost found to be higher than the other alternatives, but it was also found to be the least energy efficient of the three alternatives and required a much higher ongoing replacement cost as well.

Economic Conclusions

The results indicate that it is more economical to take advantage of the standby capacity and the operating efficiencies of the centralized systems, rather than to duplicate this capacity and these operations at a number of remote sites. Under the decentralized alternatives, the loss of the diversity available from the central system results in a requirement for greater total equipment capacity than the centralized alternative. Similarly, the inability to provide standby capacity from the existing central utilities plant under the decentralized alternatives results in a duplication of standby capacity at each of the remote plants. In this and future campus development, it was concluded that the UW should fully utilize its past investment in utilities infrastructure in order to optimize life cycle costs and provide maximum system reliability and operational flexibility.

University of Colorado Study

In recent years, a consulting engineering firm entered into a contract with the University of Colorado's Department of Facilities Management for the preparation of a CHP and Chilled Water Distribution Master Plan. The objective of the study was to analyze and evaluate the existing CHP impacts associated with the constant volume chilled water production and distribution system at the University of Colorado's Boulder Campus and recommend system modification(s) necessary to create a primary/secondary pumping scheme incorporating variable volume flow that would meet the University's projection of expansion over a 15-year period as contained in an existing Land and Facilities Master Plan.

Background

The University of Colorado at Boulder has a central CHP with heating and cooling district energy that provides chilled water, steam, and electricity to buildings on campus. The chilled water system is based on three single stage absorption chillers having a combined capacity of 11.5 MW_t. All of the chillers use steam, a majority of which is generated from the waste heat of two 16 MW_e gas turbine generators.

The chilled water distribution system has been expanded through the years as new building construction required chilled water service. At a point in time, the distribution system configuration became unable to distribute chilled water to all of the buildings. In 1988, an engineering study was prepared for the chilled water system to determine why the central plant and distribution system was unable to meet campus requirements.

Present Study

The consulting engineering firm's analysis of the chilled water distribution network built upon the previous work and incorporated the use of the software package, developed by the Washington State University. The software was purchased by the University of Colorado explicitly for this study, and was retained by the University for future manipulation by the University staff and/or consultants.

The hydraulic analysis augmented by the flow analysis and economic modeling capabilities of the program defined the limitations of the existing system and allowed for expedient analysis of future flow scenarios to meet present cooling loads as well as planned campus expansion as defined by the master plan.

The evaluation of these scenarios, which considered maximum installed plant capacity for future chilled water loads, culminated in recommendations for phased modifications of the chilled water system, and identified future candidate facilities for addition to the system. The study also defined the campus loads that are incompatible with the chilled water system because of distribution system capacity shortfalls, and/or load locations.

The economic analysis performed concluded that additional chilled water capacity should not be supplied through the addition of steam absorption chillers due to the considerable higher value of the steam for electrical production. Future capacity requirements should instead be met through a combination of electrical-driven centrifugal chillers and thermal storage.

The consulting engineering firm, in evaluating the modeling capability of the software program used, concluded that in addition to flow analysis, the model allowed for complex thermal analysis of the piping system, calculation of the central energy plant capacity, emissions, and ever simulating the value of differing alternatives relative to cogeneration sales. These additional analysis capabilities have since been proven to be useful to the University during further analysis of other operational scenarios by both University personnel and a number of consulting firms that have been able to expand upon the original work. The University has concluded that the major advantage of adopting a comprehensive model is that it provides rapid generation of alternative design and operational strategies with minimal additional data input. It can also be used to test the security of the cooling system to withstand loading beyond design specifications.

Conclusions

The developments of such CHP models has given the planner and engineer a powerful tool by which to test various alternatives for system development, expansion, or revitalization by simulating various production facility configurations and distribution network lay outs based on calculated consumer loads. Although such models are becoming increasingly popular because of the tremendous amounts of data that can be handled in a rapid and cost-effective manner, it is well to remind the potential user that the accuracy of the calculations are totally dependent upon the validity and accuracy of the input data. No matter how careful and experienced the user, there will always be uncertainties in future fuel prices, labor costs, interest rates, load forecasts, and market penetration. However, by effectively using models, it is possible to determine the sensitivity of the economics to the most volatile parameters. In many cases, the optimum solution may also be the one that carries with it the most risk. The final decision will always have to be made by the person or persons in charge, and not by the model.